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Presented by:
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Topic

Create an optimum hydraulic Fracturing Design of OMK-572 well using GOHFER 3D simulator

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DEDICATION

Almighty God, thank you for always being with me.

In the name of love and respect, I dedicate this work to my dear Mother and my dear father **Allah Yarahmo** for all their sacrifices, their love, their tenderness, their support, and their prayers throughout my educational journey.

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To all my friends with whom I spent my best moments.

To all my colleagues in the 2019-2024 Hydrocarbon class.

HAITHEM. B

DEDICATION

THANK YOU, ALLAH,

with my genuine gratitude and warm regard and in the name of love and respect, I dedicate this work with special feeling to my dear parent for their prayers, sacrifices, support and being patient with me during my education

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May ALLAH bless you and protect you.

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Almighty God, thank you for always being with me.

With sincere gratitude and heartfelt respect, in the name of love and respect, I dedicate this work with special affection to my dear parents for their prayers, sacrifices, support and patience during my training.

I want to say thank you:

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To all my friends with whom I had the best time.

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To all those who support me and support me

May Allah bless and protect you.

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API: American Petroleum Institute

BHLPP: Bottom Hole last pumping pressure

BHP: Bottom Hole pressure

BHST: Bottom Hole Static Temperature

CT: Coiled Tubing

D: Drain

FG: Factor gradient

FCD: Dimensionless fracture conductivity

FVF: Formation Volume Factor

GOR: Gas Oil ratio

GR: Gamma Ray

HF: Hydraulic Fracturing

S: Skin factor

Sp: Skin Perforations

HMD: Hassi Messaoud

HSP: High strength proppant

ID: Inside diameter

LPP: Last pumping pressure

MPLT: Memory production logging tool

NPT: No productive time

NPV: Net present value

OD: Outside diameter

ISIP: Instantaneous Shut in Pressure

Pc: Closure pressure

Pnet : Net pressure

PZS : Pressure Zone Stress **(Pnet)**

Ph: Hydrostatic pressure

PKN: Perkins- Kern- Nordgren model

KGD: Kristianovich- Geerstma Klerk model

PLT: Production logging tool

P-3D: Pseudo 3D

PPA: Proppant concentration, pounds of proppant added per gallon.

Cm: Compressibility of the matrix.

Cb: Compressibility of porous rock.

WOC: Water oil contact

GOC: Gas Oil contact

E: Young module

P: Layer pressure

Wf: The thickness of the fracture

Hf: The height of the fracture

Kf: Permeability of the fracture

Xf: Productive length of the fracture

Σi: Total principal stresses

Kh : the conductivité

Abstract:

The production of oil and gas from low-permeability reservoirs has been made possible by implementing hydraulic fracturing. Hydraulic fracturing improves the wells' productivity. An optimal fracture design can help understand the pressure distribution inside the fracture and the geometry of the fracture. To design an optimal hydraulic fracturing treatment, different digital simulators are used today to evaluate and predict the location, direction and extension of hydraulic fractures. So, we tried to create an optimum hydraulic Frac Design of well OMK 572 using GOHFER 3D. GOHFER is a 3D planar geometry fracture simulator with a fully coupled fluid/solid transport simulator. From the results we get it can be said that the GOHFER is a software with high accuracy and efficiency in designing fracturing operations.

Keywords: GOHFER, Hydraulic Fracking, Productivity index, Fracture Design, Proppant concentration, Matching, Stress, 3D Modeling.

Résumé :

La production de pétrole et de gaz à partir de réservoirs à faible perméabilité a été rendue possible grâce à la fracturation hydraulique. La fracturation hydraulique améliore la productivité des puits. Une conception de fracture optimale peut aider à comprendre la répartition de la pression à l'intérieur de la fracture et la géométrie de la fracture. Pour concevoir un traitement optimal de fracturation hydraulique, différents simulateurs numériques sont aujourd'hui utilisés pour évaluer et prédire l'emplacement, la direction et l'extension des fractures hydrauliques. Nous avons donc essayé de créer une conception de fracturation hydraulique optimale du puits OMK 572 en utilisant GOHFER 3D. GOHFER est un simulateur de fracture à géométrie planaire 3D avec un simulateur de transport fluide/solide entièrement couplé. D'après les résultats obtenus, nous pouvons dire que GOHFER est un logiciel d'une grande précision et efficacité dans la conception des opérations de fracturation.

Mots-clés : GOHFER, fracturation hydraulique, indice de productivité, conception de fracture, concentration de protège-de-manière, appariement, contrainte, modélisation 3D.

ملخص:

أصبح إنتاج النفط والغاز من الخزانات منخفضة النفاذية ممكنًا من خلال تنفيذ التكسير الهيدروليكي. يعمل التكسير الهيدروليكي على تحسين إنتاجية الآبار. يمكن أن يساعد التصميم الأمثل للكسر في فهم توزيع الضغط داخل الكسر وهندسة الكسر. لتصميم معالجة مثالية للتكسير الهيدروليكي، تُستخدم اليوم أجهزة محاكاة رقمية مختلفة لتقييم وتوقع موقع واتجاه وامتداد الكسور الهيدروليكية. لذلك، حاولنا إنشاء تصميم التكسير الهيدروليكي الأمثل للبئر OMK 572 باستخدام GOHFER 3D. جوفر (GOHFER) عبارة عن محاكي كسور هندسي مستو ثلاثي الأبعاد مزود بمحاكي نقل السوائل/ المواد الصلبة المقترنة بالكامل. ومن النتائج التي حصلنا عليها يمكن القول أن برنامج GOHFER هو برنامج ذو دقة وكفاءة عالية في تصميم عمليات التكسير.

الكلمات المفتاحية: جوفر، التكسير الهيدروليكي، مؤشر الإنتاجية، تصميم الكسر، تركيز المادة الداعمة، المطابقة، الإجهادات، النمذجة ثلاثية الأبعاد.

INTRODUCTION GENERAL:

Today, the largest oil fields in the world are experiencing a remarkable and gradual decrease in the rate of production, this observation being the result of an unsuitable exploitation policy on the one hand or a deterioration of the properties of the producing reservoirs on the other hand, proven by formation tests, sampling and analysis of surface production parameters, which thus gives damage to the formation.[1]

Among the treatment processes most used to overcome the problem of low productivity, there is hydraulic fracturing, this technique which continues to develop according to the evolution of technology and especially during the last decade, it is now put in place to "Bypass" the damaged areas. In addition to increasing production, it is important to be able to predict the expected results of a hydraulic fracturing operation. This knowledge is useful in planning economically reliable treatment and achieving desired production levels for the well.[1]

An effective hydraulic fracturing design is a key to achieving the expected results in terms of production, starting with a proper formation evaluation of underground formations containing hydrocarbons. The engineer in charge of the economic success of such a well must design the optimal fracture treatment and then assures that the optimal treatment is pumped successfully.

So, the frac-engineer should simulate the operation to obtain the more effective and optimal design that can help to understand the pressure distribution inside the formation and the geometry fracture...etc. We chose GOHFER 3D to do this, GOHFER 3D is a commercial fracture simulator owned by HALLIBURTON.

The aim of this study is to find out how GOHFER software can help us to create and improve hydraulic fracturing treatment.

So, in this study we try to create an optimum hydraulic Frac Design of well OMK 572 using GOHFER 3D. This thesis has been divided into three chapters:

Chapter I: Generalities On Hydraulic fracturing

the first one we aim to define the nature of the damage, its origin, its location and that the consequences of the damage on production also we carried out a geomechanically study corresponding to the properties of the rock and the constraints, then described the theory of hydraulic fracturing and its progress and there application, we also gave generalities on frac fluids, proppants, and fracturing equipment.

Chapter II: GOHFER Software

In this chapter we talked about hydraulic fracturing modeling and GOHFER 3D simulator and their applications and properties.

Chapter III: Case study and simulation results with GOHFER

In this chapter we used GOHFER to simulate and create a frac-design on the OMK572 well and compare the results obtained from GOHFER with the results that were recorded during the operation.

We evaluated the HF operation and their results thane we suggested some recommendations.

Chapter I:
Generalities on Hydraulic fracturing

Introduction

We call stimulation operation any treatment which makes it possible to considerably improve the productivity or injectivity of a well, by acting on the main factor, which is permeability, stimulation is any operation which aims to restore permeability around the well by eliminating the damage. Stimulation treatments fall into two main groups: matrix treatments and fracturing treatments.

Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a highly conductive flow path between the reservoir and the wellbore.

Matrix treatments are performed below the reservoir fracture pressure and generally are designed to restore the natural permeability of the reservoir following damage to the near-wellbore area.

Before taking a stimulation treatment, it is essential to clearly localize the nature of the problem to choose the appropriate treatment to remedy the situation.

The stimulation mainly aims to:

➢ Restore a formation damaged by drilling (cement, mud) or by damage suffered during completion, exploitation, matrix processing or during work-over and snubbing operations.

➢ Modify the petrophysical characteristics of the reservoir, by increasing permeability, either near the well or further in the formation. [2]

1. Formation damage

formation damage is defined as the impairment to the reservoir (reduced production) caused by wellbore fluids used during drilling/completion and workover operations. It is a zone of reduced permeability within the vicinity of the wellbore (skin) because of foreign-fluid invasion into the reservoir rock.

Typically, any unintended impedance to the flow of fluids into or out of a wellbore is referred to as formation damage. [3]

1.1. Location of the Damage

a. At the bottom of the well

Generally, we find deposits made up of sediments of various origins (particles from the formation, equipment corrosion products) or precipitates (salts, paraffins, asphaltenes).

b. Around the well

- **External cake:**

  The external cake is formed of solid mineral or organic particles deposited during drilling on the wall of the hole (to consolidate the walls of the well and reduce the infiltration of mud into the formation). Its elimination is done mechanically by scraping or chemically by washing with solvents or acids. [4]

- **The internal cake:**

  The internal cake is made up of fine solid particles coming from mud, cement, and completion fluids, is in a very thin ring near the well and blocks the pores, making the medium not very permeable. [4]

- **The invaded zone:**

  Beyond the internal cake is the zone invaded by the filtrates of mud and cement, which will modify the natural environment of the porous medium.[4]

1.2. The Skin factor:

The Skin is a factor expressing the reduction in the formation permeability compared to the original one, which causes an additional pressure to drop that decreases the production rate.

Moreover, the skin concept has always been used to measure flow anomalies near the wellbore. It characterizes any deviation from the ideal state of a vertical open hole well in a homogenous undamaged formation.[5]

$$S = \left(\frac{kh}{141.2q\mu B}\right) * \Delta pskin \text{ ....} \textbf{I.1}$$

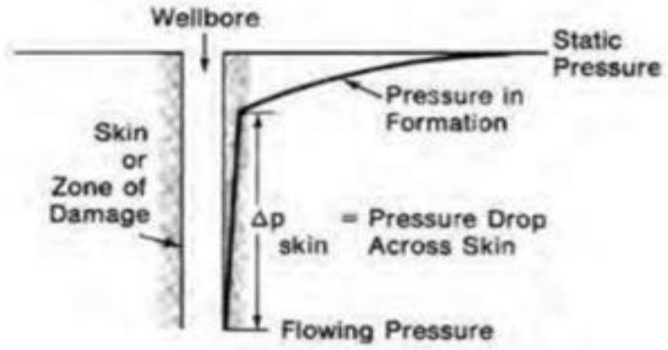


Figure I.1: Skin Representation.[4]

1.3.Skin origin:

The skin has several origins, the most important of which are:

- **The Perforations:**

  The ideal well model assumes that its contact with the formation extends over 360º, but with perforations it is easy to imagine that production is forced through them only.

  This results in a pressure loss which results in the skin Sp called wall effect coefficient and which is a function of the number of perforations, their distribution and their penetration powers. [6]

- **Partial penetration:**

  Partial penetration is characterized by the fact that a well produces on a formation thickness less than the total exploitable height. This will be the case when we want to protect ourselves against premature ingress of water or gas, or when we find ourselves in the presence of a clay barrier.

  It contributes to the existence of a positive skin (pseudo skin Sc) which varies depending on the thickness of the formation, the diameter of the well and the perforated height. [6]

- **Overall damage:**

  In all cases, additional pressure losses, located around the well (matrix), can be treated as skin. So, the skin that will be measured during a test is a result of all these skins. [5]

- **Skin due to inclination:**

  Considering an inclined well as a vertical well underestimates the real flow height, the inclination improves the flows around the well. [5]

- **Skin due to hydraulic fracturing:**

  Hydraulic fracturing creates a fracture of a certain geometry; this fracturing considerably improves the permeability around the well.[5]

2. Different types of stimulation

Stimulation can be subdivided into several types, including: [1]

- **Acidification:**

Acidizing is a treatment carried out at a pressure below the fracturing pressure during which acid is injected into the formation to improve the productivity and/or injectivity of the well. This process is mainly used to restore permeability around the well.

There are two types of acidifications:

simple matrix acidification which treats the entire matrix, and selective acidification which treats the matrix zone by zone.

- **Solvent washing:**

Injection of an organic solvent or surfactant can be used to remove damage caused by oil and water emulsions or paraffin deposits.

Each type of stimulation has its advantages and disadvantages, and the choice will depend on the nature of the problem.

- **Acid fracturing:**

Acid fracturing is accomplished by injecting acid at high pressure to dissolve rock and create a fracture. The acid dissolves non-uniformly, creating dissolution cavities, which increases porosity and permeability.

- **Hydraulic fracking:**

This operation consists of creating a fracture in the rock formation by applying pressure greater than the minimum stress.

This technique increases the permeability of the formation by creating a permeable drain which facilitates the flow of fluids towards the well. [2]

3. Hydraulic Fracturing:

3.1. Definition of hydraulic fracturing

Hydraulic fracturing is an oil and gas industry operation to extract hydrocarbon resources located in shale and other lithologies. It is a process whereby, after breaking the rock, a permeable drain is created to extend as deep into the formation as possible to allow for the efficient retrieval of hydrocarbons. This technique can be used when the well flow rate is insufficient, when the natural matrix permeability is very low, or in case of damage. [7]

3.2. Principle of hydraulic fracturing

The process of pumping into a closed wellbore with powerful hydraulic pumps creates enough downhole pressure to crack or fracture the formation. This allows the injection of proppant into the formation, thereby creating a plane of high-permeability sand through which fluids can flow. The proppant remains in place once the hydraulic pressure is removed and therefore props open the fracture and enhance flow into the wellbore. [7]

3.3. Purpose of Hydraulic Fracturing

Stimulation by hydraulic fracturing is an operation consisting of creating a permeable drain in the reservoir rock. The objective is to [7]:

- Modify certain petrophysical properties of the rock and increase Productivity or injectivity.
- Increase recovery speed by improving the Productivity index.
- Create by-passes between the reservoir and the bottom of the well therefore good conductivity in which the fluid flows towards the bottom of the well.

3.4. The constraints

The formations are subject to different stresses, which combine to maintain these rocks in a state of compression. The stress σ is defined as the force applied per unit area:

$$\sigma = \frac{\text{force}}{\text{surface}} \text{...........I.2}$$

Local state of constraints at depth:

There are two types of constraints:

- Total principal stresses(Ϭ).
- Effective principal stresses (σi).

These constraints are linked together by the following relationship:[8]

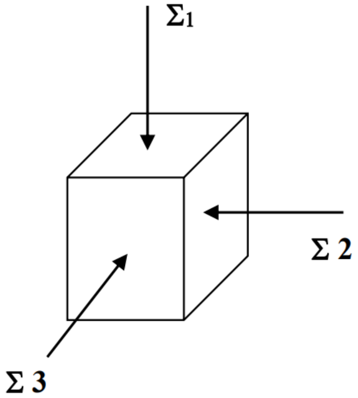


Figure I.2: Constraint Model. [8]

$$\sigma i = \sum i - \alpha P (i = 1,2,3) \text{......I.3}$$

$$\alpha = 1 - (cm/cb) \text{ .... I.4}$$

With:

PC: Layer pressure.

Cm: Compressibility of the matrix.

Cb: Compressibility of porous rock.

α: BIOT constant (0≤ α ≤1), α≈1

Mechanical properties of rocks

The rocks are characterized by:

Young E's modulus:

The rigidity of a material, called Young's modulus noted (E), is characterized by the slope of the curve: $\sigma = F(\varepsilon)$ … [9]

$$E = \frac{\sigma}{\varepsilon} \text{........... I.5}$$

When Young's modulus increases, the width of the fracture decreases, but the length increases.

Poisson coefficient

Dimensionless coefficient, defined as the ratio between the variation in lateral dimension (change in diameter) and the variation in axial or longitudinal dimension (change in length), when the sample is subjected to compression: [9]

$$\varepsilon z = \Delta L / L1$$

$$\varepsilon x = \Delta D / D1$$

$$v = -\varepsilon x / \varepsilon z$$

$$v = -\frac{\Delta D / D}{\Delta L / L} \text{........... I.6}$$

Where:

εz = Strain in z-direction (axial strain)

εx = Strain in x-direction (lateral strain)

ΔL= Change in length

L1 = Initial length

ΔD= Change in diameter

D1= Initial diameter

ν = Poisson's Ratio

Shear coefficient:

It is often practical in modeling to use the shear modulus noted **G**: [9]

$$G = \frac{E}{2(1+v)} \text{...........I.7}$$

General:

E: Young’s modulus.

v: Poisson's ratio.

3.5.Fracture geometry:

The performance of a fracturing operation depends on three following dimensions: [9]

Length Xf:

It is the distance between the well and the point located at the end of the fracture, so it can be the length or half-length of a fracture depending on whether the latter is one or two symmetrical wings.

Thickness Wf:

It is the spacing between the two vertical faces of the fracture.

Height Hf:

It is the distance along the vertical between the two points associated with zero thickness.

All this concerns the vertical fracture, as for the horizontal fracture we will have the height which replaces the thickness, and the opposite.

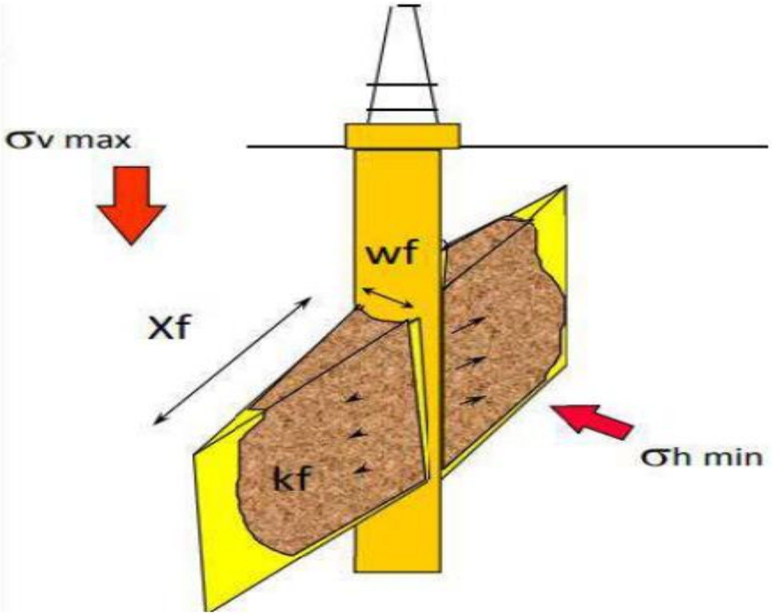


Figure I.3: the shape and orientation of the fracture. [9]

3.6.Fracturing Fluid

Fracturing fluids are different-based fluids with a small number of additives or chemicals (generally less than 1% of the volume of the fracturing fluid) that are used to treat the subsurface formation to stimulate the flow of oil or gas.

The fracturing fluid comprises 99.5% of water and sand, and the remaining 0.5% comprises additives. [10]

3.6.1. **The Objectives**

The functions of Fracturing fluid are:

- Initiate and propagate the fracture.
- Developpe fracture width
- Transport proppant throughout the length of the fracture.
- The fracturing fluid will be chosen according to several criteria such as: availability, security.

3.6.2. Properties of the fracturing fluids:

- Have proper viscosity to open the fracture and transport the propping agent.
- Be compatible with the formation of rock and fluid to avoid emulsion.
- Generate enough pressure to drop down the fracture to create a wide fracture.
- Be able to break and clean up quickly after the treatment.
- Be able to withstand high temperatures within the formation.
- Safety and environmental concerns.

3.6.3. Fracturing fluid types:

Industry has various hydraulic fracturing systems, and every formation requires a specific system.

a. Water-based fluids: Water-based fluids are the most widely used fracturing fluids because of their low cost, high performance, and ease of handling.

b. Oil-based fluids: These fluids are now only used in water-sensitive formations. It is less damaging to the formation than the previous type. However, it is expensive and operationally difficult to handle. [10]

c. Acid-Based fluids: The acid-based fluid is usually used to fracture carbonate formations in what is called the Acid fracturing technique. It presents a higher operational risk.

d. Multiphase Fluids:

- **Foams:** Foam is a stable mixture of liquid and gas. Foam fluids are most often used to fracture low reservoir pressures. Nitrogen and carbon dioxide are mostly used as energizing gases.
- **Emulsions:** Emulsion-based fracturing fluids are highly viscous solutions with good transport properties. The drawbacks of emulsions are the operational difficulties of mixing and higher friction pressure. [10]

3.6.4. Gelling Agent:

Gelling agents are added to the Fracturing fluid to increase viscosity; this increases the fracture width to improve proppant transport and reduce the friction pressure. In addition, the chemical structure of gelling agents allows for crosslinking. One of the first polymers used to vicosify water for fracturing applications was guar. It is a long chain, high molecular weight polymer composed of mannose and galactose sugars. When the guar is added to water, the polymer molecules become associated with many water molecules, unfold, and extend out into the solution as a result, the guar particle swell and hydrate. [10]

3.6.5. Additives

Various additives have been developed to enhance the performance of fracturing fluids: [11]

Table I.1: Types of additives used in fracturing fluids and their role. [11]

Additive Type	Description of Purpose
Cross-linker	**Crosslinking agents are used to increase the molecular weight of the polymer, therefore increasing the viscosity of the solution.**
Buffers	**Buffers are weak acids or bases added to the fracturing fluid to control and maintain the desired PH value.**
Clay stabilizer	**Clay stabilizers are chemicals used to stabilize clays and fines to prevent the clay from swelling and/or migrating through the matrix.**
Surfactant	**Used to prevent emulsions and promote cleanup of the fracturing fluid from the fracture. Moreover, it leaves the formation water-wet.**
Bactericide	**Enzymes from bacteria can feed on the polymers causing gel degradation. As a result, bactericides are added to the fracturing fluids to prevent the growth of it.**
Fluid-loss additives	**Fluid-loss agents are pumped during the pre-pad and pad stages of the fracturing treatment to reduce fluid loss into formation.**
Breaker	**A Gel breaker is introduced to reduce the fluid's viscosity intermingled with the proppant by cleaving the polymer into small-molecular-weight fragments.**
Temperature stabilizer	**Temperature stabilizers are used to prevent the degradation of gels at temperatures greater than 200 °F.**
Friction reducer	**Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.**

3.6.6. Fracturing fluid selection:

Selection of the fracturing fluid is based on the different properties of the fluid including viscosity, compatibility, resistance at high temperatures and the ability of degradation.

We consider the characteristics of the rock to fractured (temperature, Stress…).

Figure I.4: Fracturing fluid preparation in the LAB [12]

3.7.Proppant

Proppant is a solid material, typically Sand, Treated Sand or manufactured ceramic materials. It is used to keep fractures open after the fracturing job is completed. In other terms, it prevents the fracture from closing due to overburden stress. It provides a high-conductivity pathway for hydrocarbons to flow from the reservoir to the well. [13]

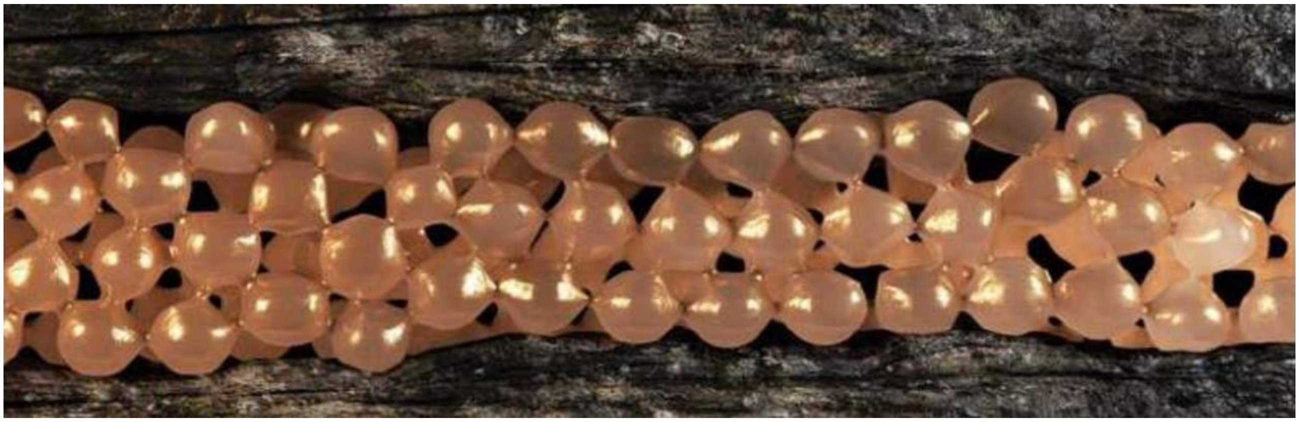


Figure I.5: An illustration of recently introduced coating [12]

3.7.1. **Types of Proppants**

- **Sand:** Due to its relatively low cost and availability, Sand is the most used proppant, especially in reservoirs with a low closure pressure of less than 6000 Psi.

Figure I.6: sand [12]

- **Resin-coated Sand:** Resin coatings may be applied to Sand to improve proppant strength or prevent proppant flow back. It is used in operations where the closure pressure is less than 8,000 Psi.

Figure I.7: Resin-coated sand [12]

- **Intermediate-strength proppant:** Because they are manufactured, they maintain better sphericity and particle size distribution. As a result, a greater fracture conductivity than the Sand. They are used in reservoirs where the closure pressures are up to 10,000 Psi.

Figure I.8: Intermediate strength Proppant [12]

- **High-strength Proppant:** Sintered bauxite and Zirconium oxide are high-strength propping agents. However, they are generally limited to use in wells with very high confining stresses (>10,000 psi) because of their greater cost.

Figure I.9: High-strength proppant [12]

3.7.2. **Proppant Properties**

The Proppant properties that affect fracture conductivity include: [10]

- **Grain size and Strength:**

  Large grains have more space between them, providing more permeability and allowing more hydrocarbons to flow when placed. Moreover, the grains of the proppant must be strong to withstand the closure stress.

- **Fines and Impurities:**

  A high percentage of fines or impurities present in the proppant can partially block the conductive path.

- **Roundness and Sphericity:**

  The rounder or spherical the proppant grain the better the proppant-pack porosity will be. This last can withstand higher closure stress while angular grains produce fines that reduce the proppant-pack conductivity.

- **Proppant density:**

  High-density proppants are more difficult to suspend in fracturing fluids and have a greater tendency to settle.

3.7.3. Proppant size:

Proppant particle (or grain) size is an important parameter for proppant evaluation and treatment designs, as it affects fracture conductivity and proppant transport. Grain size is measured in mesh size ranges.

The mesh size is defined by the number of openings across one linear inch of screen. [11]

Commonly used proppant sizes include:

- 12/20
- 16/30
- 20/40
- 30/50
- 40/70

Figure I.10: Different fracturing proppant size

3.7.4. Proppant Selection:

Proppant must be selected based on in situ stress conditions and other considerations, which include good physical properties (Strength, grain size and distribution, roundness and sphericity, proppant density), the permeability of the Proppant and the conductivity of the fracture. [14]

The major concerns of proppant selection are compressive strength and the effect of stress on proppant permeability. In general, bigger proppant yields better permeability. The figure shows permeabilities of various types of proppants under fracture closure stress.[15]

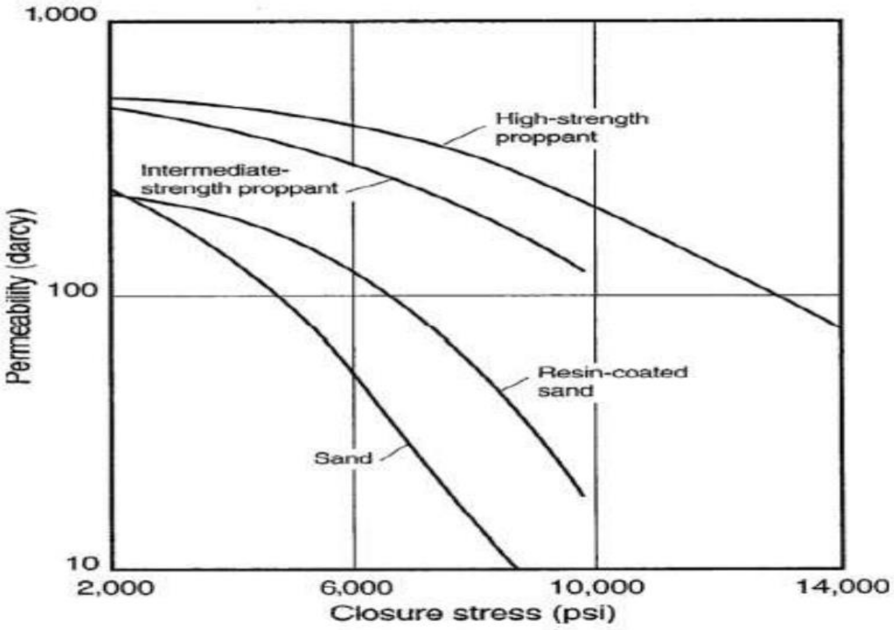


Figure I.11: Effect of fracture closure stress on Proppant pack permeability. [15]

3.8. Dimensionless fracture conductivity

The dimensionless conductivity of the fracture is represented by the ratio: [16]

$$FCD = \frac{kf*wf}{k*xf} \text{............I.8}$$

With:

- xf: Extension of the fracture (half length).
- wf: Fracture thickness.
- hf: Sustained height.
- K: The permeability of the formation.
- kf: The permeability of the fracture.

For fracturing to be optimal, it is enough that 2<FCD. [17]

3.9. The equipment of The Fracturation Operation

The implementation of a hydraulic fracturing treatment requires an array of specialized equipment, the necessary equipment to carry out typical hydraulic fracture operations are:

a. **Frac Tanks:** It is used to store water for the preparation of fracturing gel. The number of tanks depends on the volume of water required for the operation. [18]

Figure I.12: Frac Tanks.[19]

b. Hydration unit (PCM):

Precision continuous mixer is an equipment that continuously mixes dry polymer loadings with water that comes from tanks resulting in a linear gel. It is composed of centrifugal pumps, hydration tanks and mixers where water and polymer are mixed, a polymer storage bin and four liquid additives. This equipment is Built to reduce time and cost on location means no waiting time between mixing and pumping. [18]

Figure I.13: Hydration Unit (PCM).[19]

c. Blender (POD):

The blenders accurately mix Proppant, fracturing fluid and additives in the Vortex at a specified density in a preprogrammed, automatic mode. This density is measured by a radioactive densitometer that is based on the absorption of gamma rays by the measured fluid that will be captured by detectors that sense the gamma rays transmitted through the fluid and converts this signal into an electrical signal. The electronic panel processes the electrical signal into a density indication. Finally, the slurry is pumped in the low-pressure line of the manifold. [18]

Figure I.14: POD Blender.[19]

d. Sand Chief (Sand Feeder):

The sand chief is an equipment used to store Proppant on location and deliver it to the sand hopper of the blender. It is divided into four parts containing the different sizes of Proppant. The conveyor-equipped sand bin is the commonly used unit for delivering proppants to the blender. These units have several compartments for storing proppant. Each compartment has a set of hydraulically controlled gates at the bottom. When the gates are opened, proppant falls from the container onto a conveyor belt that leads to the blender. [18]

Figure I.15: Sand Chief. [19]

e. Missile (Frac Manifold):

It is an arrangement of piping or valves designed to control, distribute and typically monitor fluid flow; A frac manifold is used for directing treatment fluid and organize both low-pressure flow from the blender to the pumps and the high-pressure flow from the pumps down the well. It also provides an easy and efficient hook-up for up to 10 high-pressure pumps. [18]

Figure I.17: Missile.[19]

f. High-pressure pumps:

A Triplex pump sends the fracturing fluid at high pressure and rate to the well in the high-pressure line of the missile. High-pressure pumps should be installed close enough to the blender so that the discharge pumps on the blender can easily feed slurry to the intake manifolds on the pumps.

The number of pumps used is based on the horsepower of each pump (HHP). [18]

Figure I.18: High pressure pumps.[19]

g. Annulus pump:

It applies pressure inside the annulus to provide underbalanced pressure and prevents the collapse of tubing caused by the high pressures performed during hydraulic fracturing. [18]

h. Treating iron:

The size of the high-pressure pipe called treating iron used on a treatment between the high-pressure pumps and both the anticipated rates and pressures dictate the wellhead isolator.

Smaller lines have a higher maximum treating pressure limitation than the larger sizes. [18]

i. Wellhead isolation tool (Tree saver):

Treatments pressure can exceed the maximum working pressures of the wellhead equipment. Thus, the tree saver is used to protect the Christmas tree at the wellhead from damage and the possible failure that results from exposure to high pressure and abrasive fluids during fracturing jobs; it is Mounted on the Christmas tree. [18]

Figure I.19: Wellhead isolation tool.[19]

j. Treatment control vehicle (TCV):

It is a Data Monitoring Truck to control and operate equipment using data acquisition systems. It is a PC-based data acquisition and control system designed to monitor, and control pumping, mixing and blending equipment through sensors and cables related to equipment.

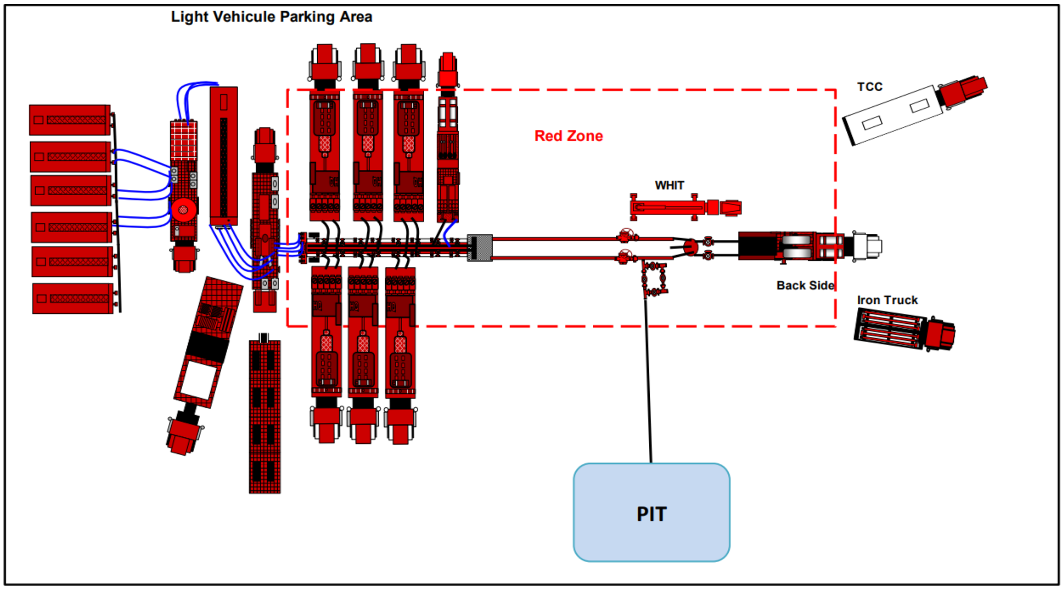


Figure I.20: Layout of equipment's.

4. Carrying Out Hydraulic Fracturing

4.1.candidate well selection

It is necessary to gather and classify the necessary information of the reservoir, well and the economic cost of the operation.

4.1.1. Geological Assessment:

Evaluate the geological characteristics of the potential well site, including the type of fluid in place, contact WOC and GOC, depth, porosity, and permeability. Fracturing is typically employed in formations such as shale, tight sandstone, or coalbed methane deposits.

4.1.2. Well information:

- **Well history:** Including drilling completion, tests and logs, previous interventions, nearby wells, fractured nearby wells.
- **Perforation condition**
- **Cementing condition**

4.1.3. Hydraulic Fracturing Simulation:

Conduct computer simulations or modeling to optimize the fracturing process. This involves determining the optimal injection rate, pressure, and proppant concentration to create fractures that maximize the flow of oil or gas from the formation.[20]

4.1.4. Environmental and Regulatory Considerations:

Evaluate potential environmental impacts and regulatory requirements associated with the fracturing operation. This may include obtaining permits, conducting environmental assessments, and implementing measures to mitigate risks such as groundwater contamination or surface water pollution.[17]

4.1.5. Economic Analysis:

Assess the economic feasibility of fracturing the well based on factors such as the cost of drilling and completion, estimated reserves, and current market conditions for oil and gas.[20]

4.2. Design Of Hydraulic Fracturing:

To execute a hydraulic fracturing task, engineers should be aware of the effect of the pumping rate and properties of the fluid on the geometry of the fracture and the propagation of the fracture within the in-situ stress, this will lead to a targeted length of propped fractures.

It entails the study of rock physics to consider the potential for a desired fracture configuration. Additionally, fluid mechanical considerations are employed to ensure that the necessary Proppant transport is possible, and rheology is employed to determine if the necessary fluid properties are possible. It additionally involves the selection of material and the operational considerations on site.

4.2.1. Injection Test (break down test):

Prior to the Calibration test a break down injection will be performed with Treated Water to identify the breakdown pressure which is considered as the upper bound of the closure. [21]

Moreover, it is used to:

- Verify if the formation absorbs the fluid.
- Determine fracture gradient and thus the treating pressure.
- Check the state of the downhole equipment and the quality of cement.

4.2.2. Thermometry (Temperature Log)

Before carrying out the fracturing operation, a so-called reference thermometry is recorded, to compare its profile to that which will be recorded after the break down test. Thermometry is therefore the tool that tells us about the height of the fracture if it occurs.

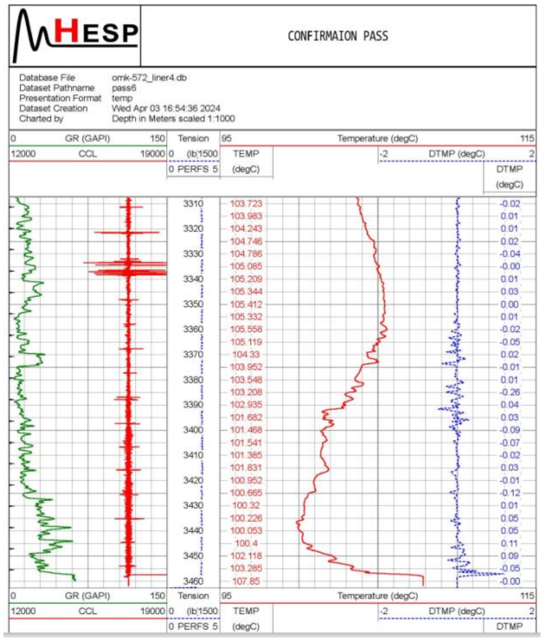


Figure I.21: Temperature Log

4.2.3. DataFRAC (calibration test):

A DataFRAC test is an injection-falloff diagnostic test performed without Proppant before a main fracture stimulation treatment. A total PAD volume will be injected into the formation then over flushed to the displacement volume with linear Gel to create a non-propped fracture in sufficient period.

The process is to break down the formation to create a short fracture during the injection period and observe closure of the fracture system during the ensuing falloff period.

The DataFRAC identifies values of parameters including that are critical to optimize fracture treatment design such as:

- Closure pressure (Pc).
- Instantaneous shut in pressure (ISIP).
- Fluid efficiency (η).
- Leak off coefficient.
- The frictions.
- Fracture gradient.
- Fracture geometry and the propagation model.

All these parameters allow us to establish the fracturing program that is to determine the flow rate, the volume of the injected fluid and the maximum concentrations of Proppants that must be injected during the Main Frac treatment.

The advantages of this test are:

- Minimizes the possibility of screen out resulting from inaccurate parameters.
- Optimizes treatment even when reservoir information is limited.
- Determines the essential parameters of the formation and the well.
- Reduces proppant-pack damage and treatment costs.[18]

4.2.4. Hydraulic Fracturing Parameters:

❖ Bottom-hole treating pressure (BHTP):

$$BHTP = Pw + Ph - P_{Pipe} - P_{Per} - P_{NWB} \qquad \text{I.9}$$

Where:

- Pw: Wellhead treating pressure

- Ph: Hydrostatic pressure
- P_{Pipe}: Pipe friction
- P_{Per}: Perforation friction
- P_{NWB}: Near wellbore friction.

❖ **Fracture Gradient (FG):** [22]

$$FG = \frac{\text{ISIP Bottom hole}}{\text{TVD Midperf}} \text{............I.10}$$

❖ **Fluid efficiency (η):** [22]

$$\eta = \frac{Vf}{Vt} \text{............ I.11}$$

Where:

- Vf: Volume within the fracture.
- Vt: total volume injected. [22]

❖ **Fluid loss coefficient:**

It is a major fracture design variable. It occurs after the filter cake is developed. Excessive fluid loss prevents fracture propagation because of insufficient fluid volume accumulation in the fracture. Therefore, a fracture fluid with the lowest possible value of fluid-loss (leak-off) coefficient should be selected.[18]

4.2.5. **Pressure matching & Redesign:**

Pressure matching with computer software is the first step to evaluate the fracturing job. This match is a part of the set of analysis performed on-site for the redesign of injection schedule to start the execution of the main frac.

4.2.6. Main frac & pump schedule:

- **Pre-Pad Stage:** In this initial stage, low viscosity fluid (linear gel) is injected into the well to initiate the fracture in the rock formation.
- **Pad Stage:** a higher-viscosity fluid is pumped down the borehole at high rate leads to Breaking down the formation and expands the fracture.
- **Slurry Stage:** Following the pad stage, the slurry stage involves the continued injection of fracturing fluid under high pressure to extend and propagate the fractures created in the rock formation. This stage aims to enhance the permeability of the reservoir and improve oil and gas flow.
- **Chasse du slurry:** In this step, the slurry is flushed out using a linear gel that is easy to evacuate during purging.

Conclusion

Hydraulic fracturing is a new oil recovery technique that is being introduced to improve well productivity and characteristics. The success of this operation depends enormously on the parameters chosen and the decisions taken to avoid any failure or any additional expense and to have a good return on the operation.

Chapter II:
GOHFER SOFTWARE

Introduction

A successfully working hydraulic fracture model must be able to assist in explaining the results acquired from a specific job that has been pumped or be able to predict the results of a specific job that is to be designed. For both cases of pre-treatment and post-treatment results, computer models need precise characterization of the studied reservoir, rock properties, and the stress state of the area, as well as detailed information on materials to be pumped.

There are a variety of fracture modeling software and simulation packages available to model fracture geometries during a hydraulic fracturing process. The three main classes of models that have been developed over time are the 2-dimensional (2-D), the pseudo-3-dimensional (P3D), and the well-developed 3-dimensional (3-D) models. [23]

- 2-Dimensional Models (2-D).
- Pseudo-3-dimensional (P3D).
- 3-dimensional models(3-D).

1. Selection of Fracture Model:

An appropriate fracture propagation model is selected for the formation characteristics and pressure behavior based on in situ stresses and laboratory tests. Clearly, a final schedule is generally developed using a fracture geometry model. However, the use of a properly calibrated fracture geometry model also enables the consideration of multiple scenarios for designing the optimum treatment for a specific application.

1.1.Dimensional Models (2-D):

The most common 2-D fracture models known in the industry are the Kristianovich, Geertsma, and De Klerk (KGD) model and the model created by Perkins and Kern which later was modified by Nordgren (PKN).

The application of these models in heterogenous reservoirs demands substantial manipulations to take place by making estimations of fracture heights. These estimations are usually field-measured values or based on previous experiences and results. Since this method requires user-input, inaccurate fracture height estimation will cause over- or under-prediction of height, ignoring the effects of leak-off. In this case, the fracture under investigation will result in out-of-zone growth, later causing completion and productivity issues. [23]

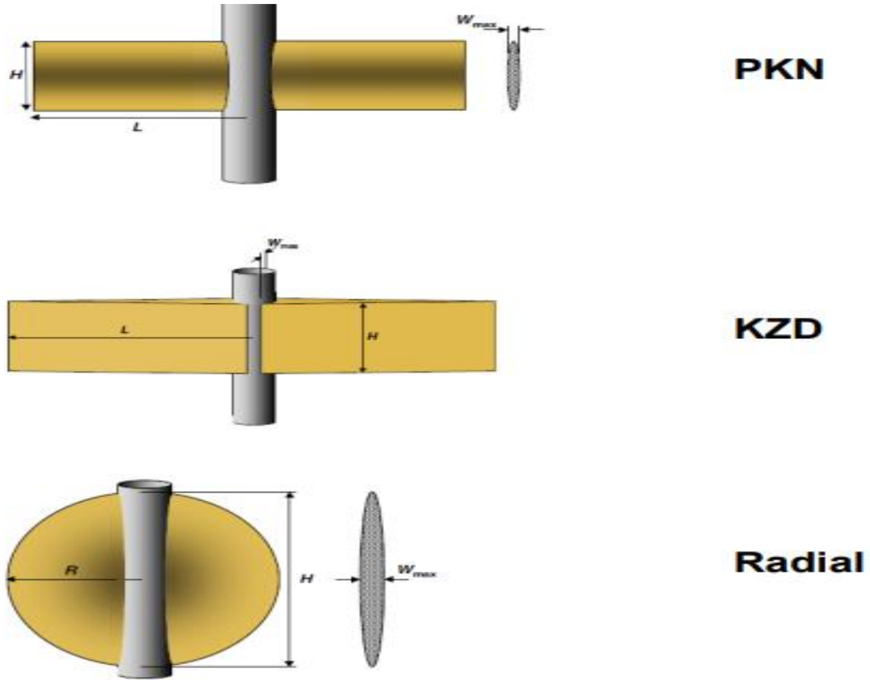


Figure II.1:2D fracture models (Wmax- maximum width; L-fracture half-length; H-fracture height, R fracture radius) [23]

Pseudo-3-dimensional (P3D):

Pseudo-3-dimensional (P3D) models differ from the 2-D models such that they do not require an estimate of fracture height but instead require “an input of the minimum horizontal stress in the proposed fracture zone and bounding layers” (Green, 2006). According to Green, a simplified depiction of fluid flow in the fracture is implemented in the P3D models to shorten the calculation time by estimating 2-D fluid flow and the pressure-width relation. As a result of innovative inventions and improvements in computer power, the P3D models are no longer preferred and are being substituted by the later fully 3-D models. [23]

Dimensional models(3-D):

The new and improved 3-D models produce relatively better results with the closest approximation to the actual hydraulic fracture growth. These models, however, require accurate stress contrast and other reservoir data. The positive side of the 3-D models is the calculation of fluid flow and pressure along the fracture uses a fully 2-D model of fluid flow to calculate the pressure. This type of calculation provides an accurate width at any point. However, these new models are lacking on “suitably detailed input data” to assist in precise evaluation and future development (Green, 2006). Such input data requires additional costs and time to the operating companies, which can be inconvenient to the process. [23]

Some of the more common 3-D models that are currently used in the industry are as follows:

- GOHFER – a fully 3-D simulator developed by Dr. Robert Barree as part of a PhD program at the Colorado School of Mines.
- MFRAC – a model developed by Bruce Meyer of Meyer & Associates, Natrona, Pennsylvania; and,
- FRACPRO – a model originally developed by Professor Mike Cleary at MIT and Resource Engineering Systems, Cambridge, Mass, sponsored by GRI.

From this net pressure response, the type of hydraulic fracture growth can be determined.

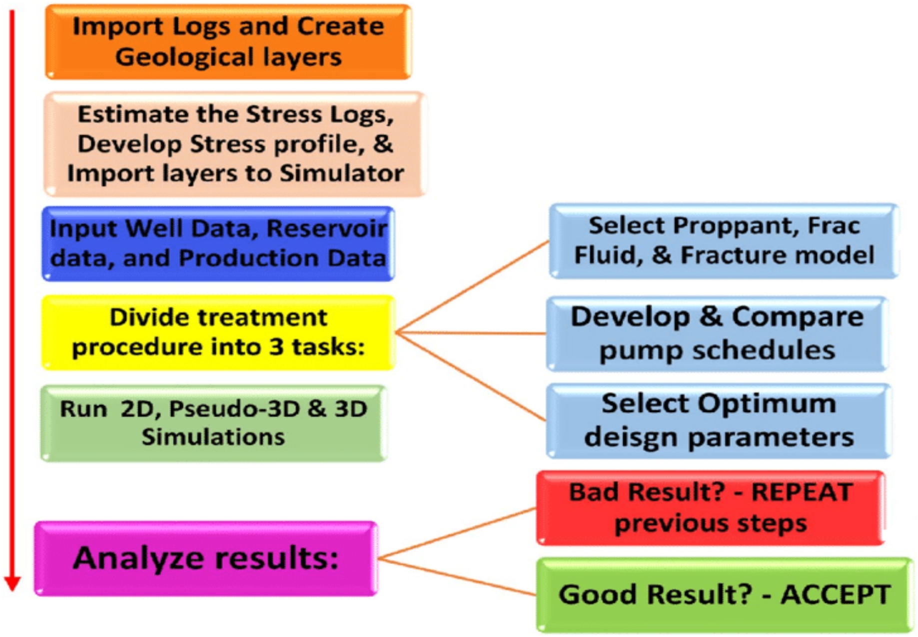


Figure II.2: Hydraulic fracturing design approach. [23]

2. GOHFER SOFTWARE:

2.1. Definition of GOHFER Software

GOHFER, which stands for Grid Oriented Hydraulic Fracture Extension Replicator, is a planar 3-D geometry fracture simulator with a fully coupled fluid/solid transport simulator that used in the petroleum sector. GOHFER was developed by Dr. Bob Barree of Barree & Associates in 1983 association with Stim-Lab, a division of Core Laboratories.

Geological, geo-mechanical, and three-dimensional hydraulic fracture models are all produced by GOHFER. The GOHFER software suite also includes the ability to do pressure diagnostics and production analysis.

Like a reservoir simulator, the application describes the entire reservoir using a grid layout. User-defined nodes that are entered with the necessary vertical and horizontal dimensions are used to make up the grid.[24]

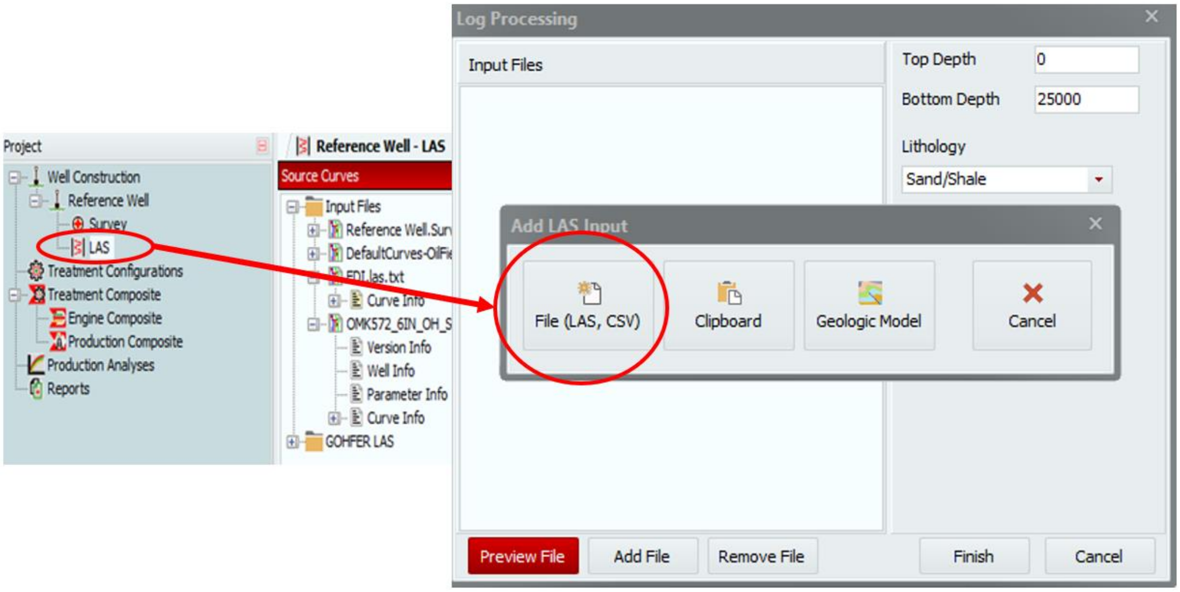
2.2. Modeling Process in GOHFER

To fully utilize GOHFER and create as accurate a model as possible as much input data as possible is required, and data should be available to verify the output model geometry, the process is normally refined by experience in certain areas and is often limited by the available computing time and the required outputs. Normally, the rock and reservoir data such as: identified pay, zone thickness, rock-mechanical properties, in-situ stresses etc., are derived from open hole logs, other wells in the area or are estimated based on experience in the region. The actual treatment and treatment data (fluid properties, pumping rates, proppant concentrations and quantity, etc.) are provided by the service company and are usually based on treatments that have been optimized practically in the area or found to work in geologically similar areas.[25]

GOHFER allows geologic structure to be included in the modeling to simulate fracture growth in complex folded and faulted regions. Fluid and proppant injection is automatically redistributed at each timestep to model simultaneous injection into multiple perforation sets or clusters in limited-entry or horizontal well treatments.[25]

2.3.INPUT’s Of GOHFER:

The grid-oriented feature of GOHFER™ is one of the important key factors that contributes to create Ideally model, The rectangular grid structure is used to describe the entire reservoir, serving the same function as a reservoir simulator, and it allows the assignment of complex and detailed descriptions of the fractured intervals. For each node (Gride), reservoir properties such as permeability, porosity, and pore pressure, and mechanical properties such as Young’s Modulus, Poisson’s Ratio, Biot’s constant, and tectonic stress are assigned. [26]



Top Depth 0

Bottom Depth 25000

Lithology Sand/Shale

Figure II.3: Add the Input Logs (LAS) to the GOHFER.

The list of important input required for a working model to be created using GOHFER are:

- Poisson’s Ratio
- Young’s Modulus
- Biot’s constant
- Resistivity log’s

- Permeability log
- Gamma-Ray log
- stresses (lateral and vertical variations)
- porosity log's

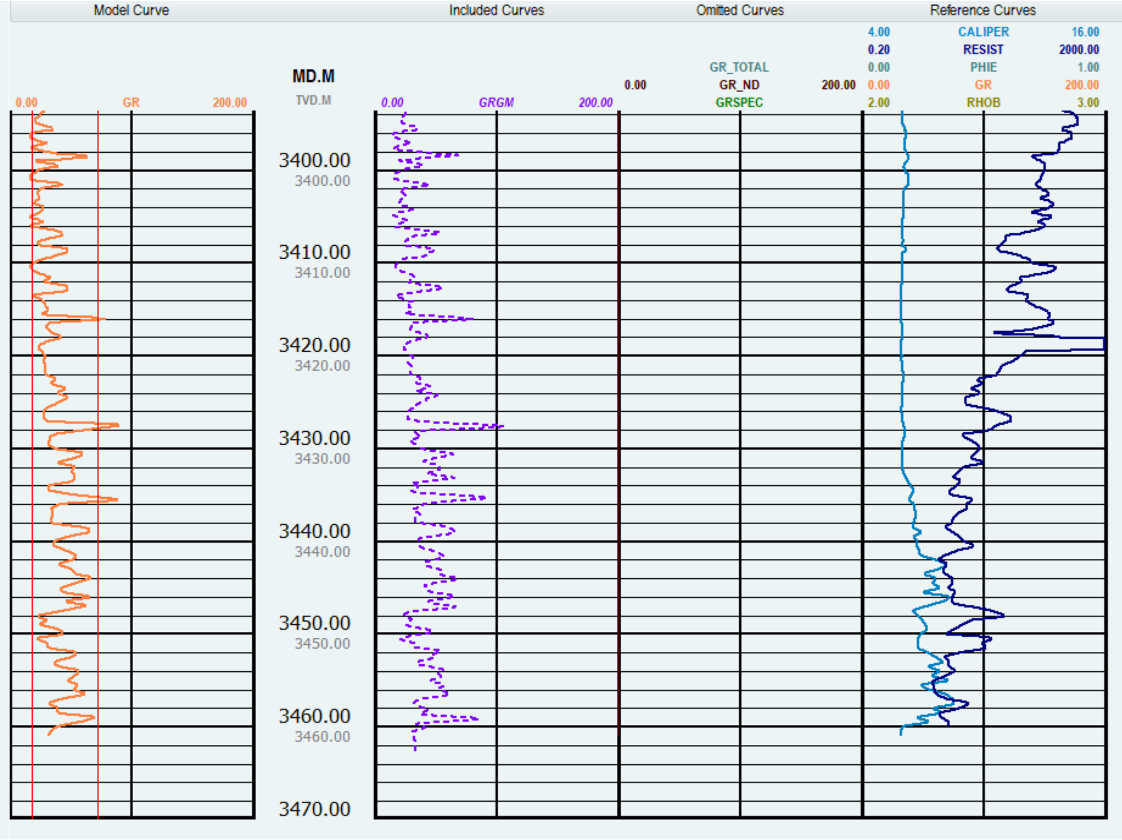


Figure II.4: The main screen layout displays the input curves and the generated output curves (Gamma-Ray Logs).

2.4.OUTPUT's:

The feature of GOHFER™ that serves the purpose of viewing output results from the fracture simulation is the HTGraph™.

The HTGraph™ is used to display the actual pressure, slurry rate, and proppant concentration curves acquired during a hydraulic fracturing job.

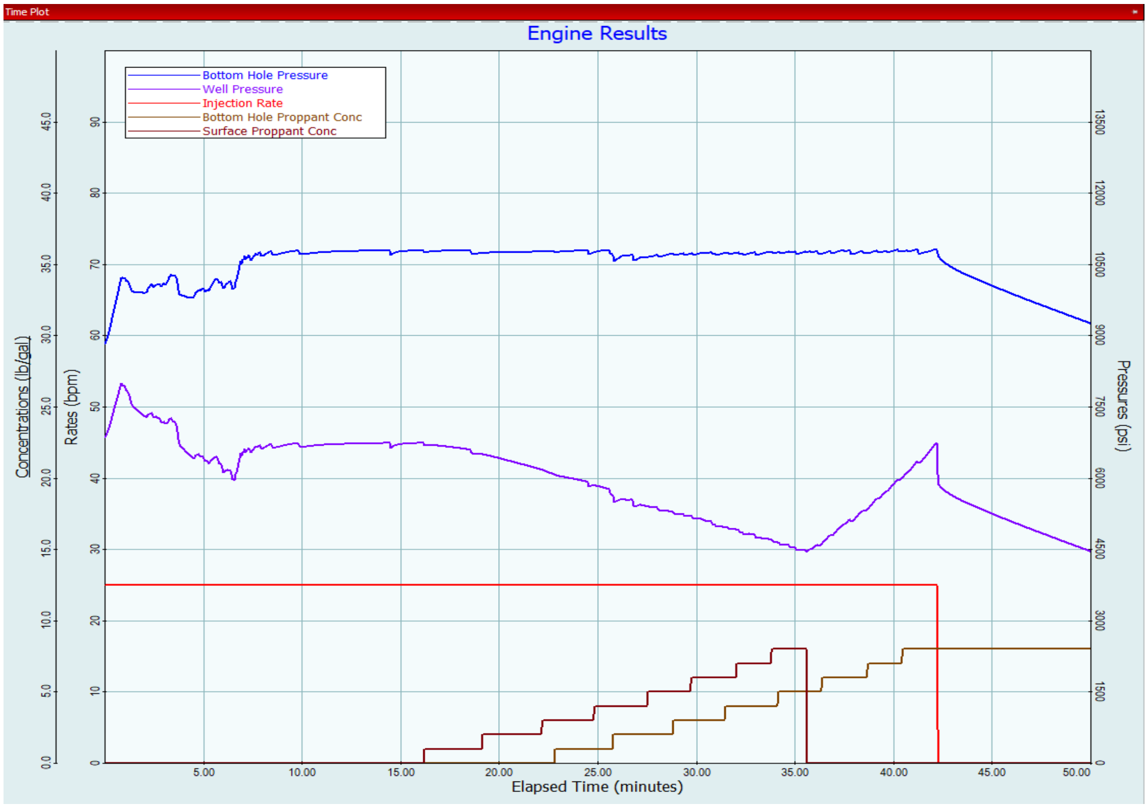


Figure II.5: The Design Curves Output in the GOHFER

- The Grid Step window that can give as a view about distribution of properties reservoir (stresses, porosity, Water Saturation, Permeability, Fracture pressure, Injection rate …)

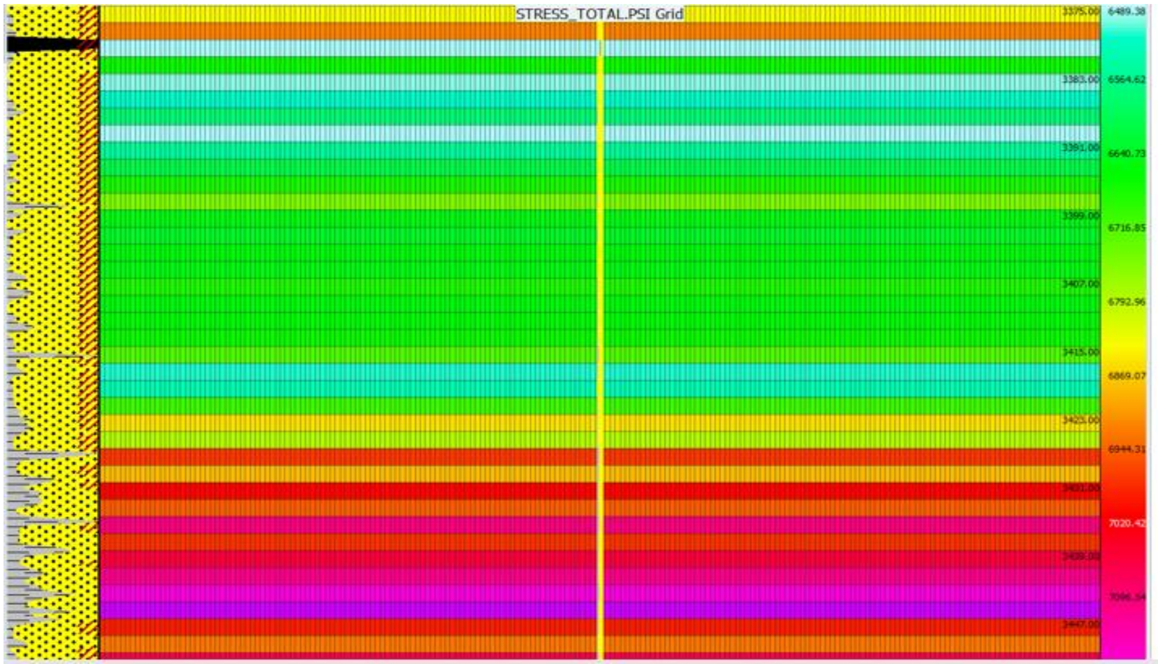


Figure II.6: A grid view that shows the distribution of stress of formation inside the reservoir.

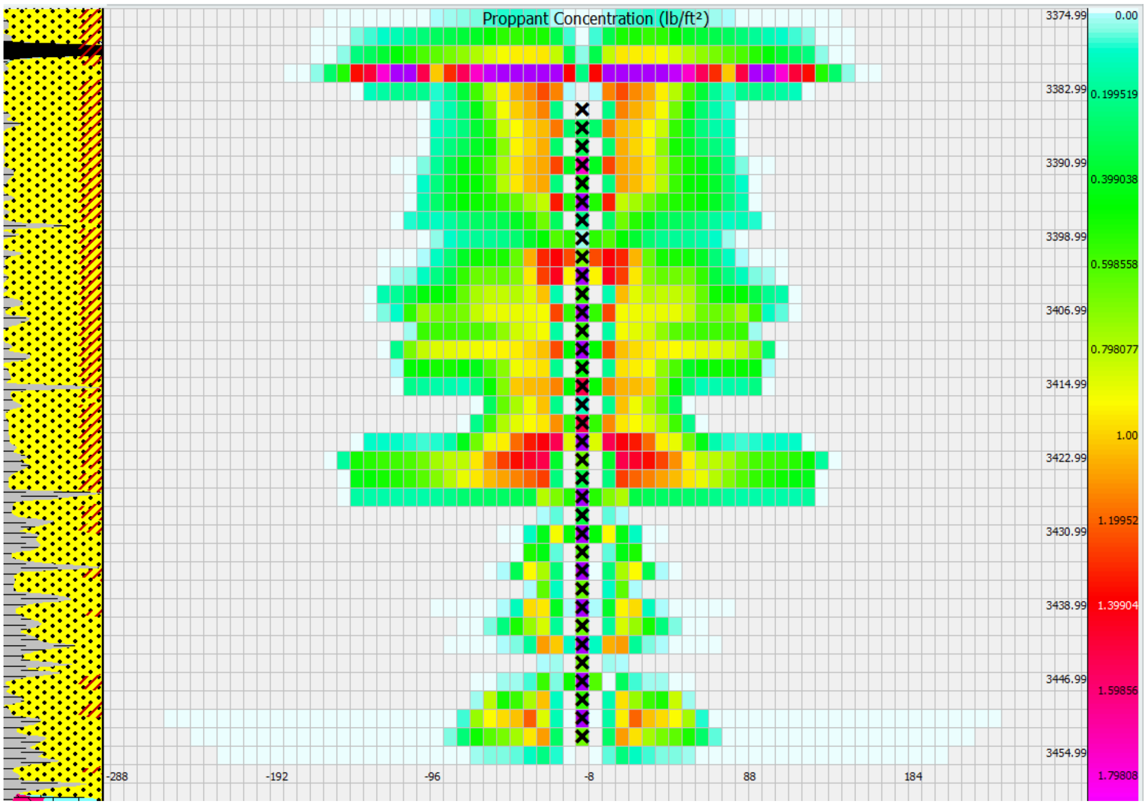


Figure II.7: A grid view that shows the Proppant Concertation inside fractur zones.

2.5. Workflow of GOHFER:

To perform a matching process in the GOHFER, we do the following steps:

1st step: Create a new GOHFER Project file.

1. import Log File to analyze LAS files and Complete Actual Simulation Input Process.
2. Define grids, formation zone, depth, formation rock type.

2nd step: create pre-design.

1. Perforation diameter, number of holes perforated.
2. Define wellbore, enter actual pumping schedule.
3. Save and run Design.

3rd step: Create mini-frac design and matching.

1. Define Pc, BHISIP, ISIP, Net pressure From Mini-frac Diagnostic.
2. View pressure plots, set stage locations, enter actual pumping schedule.
3. Adjust reservoir and grid properties to match pressures.
4. Run and view pressure match results.
5. View simulated fracture geometry.

4th step: Create the Main Frac Design.

1. Perforation diameter, number of holes perforated.
2. Define wellbore, enter actual pumping schedule.
3. Save and run Design.
4. view pressure results and view simulated proppant concentration.

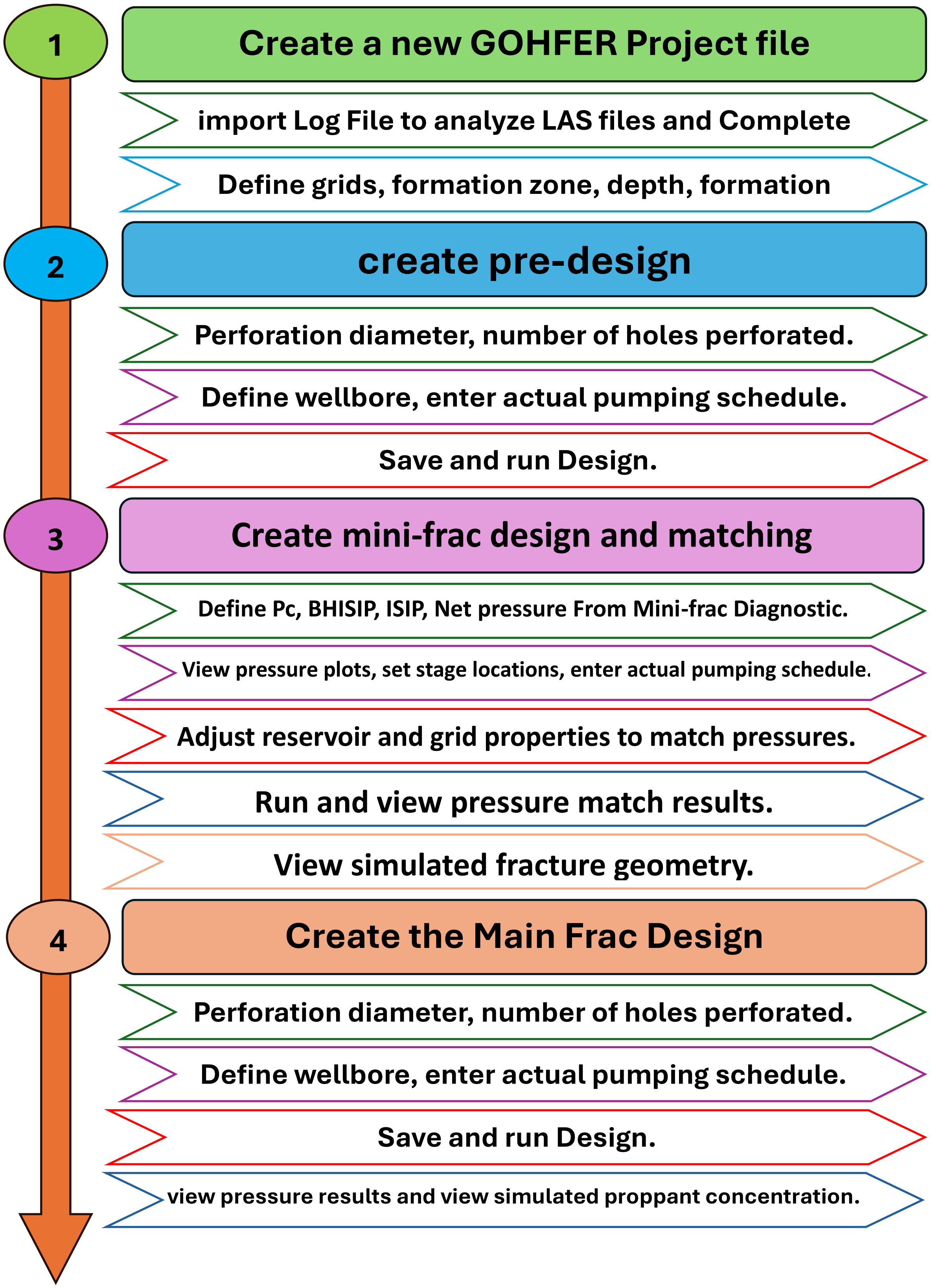


Figure II.8: The Workflow steps of GOHFER

2.6.Pressure Matching Process:

The ability to obtain as much input data as possible in building a hydraulic fracture model will reduce the needs for making assumptions and self-calculation. The problem in a hydraulic fracture simulation is attempting to match the simulator result to the actual field data. It is common to modify the input data to manipulate the model.

The pressure matching process refers to the task of matching the simulated GOHFER™ pressure curve with the actual pressure curve. The optimum simulation output is when both pressures and geometries are matched. [26]

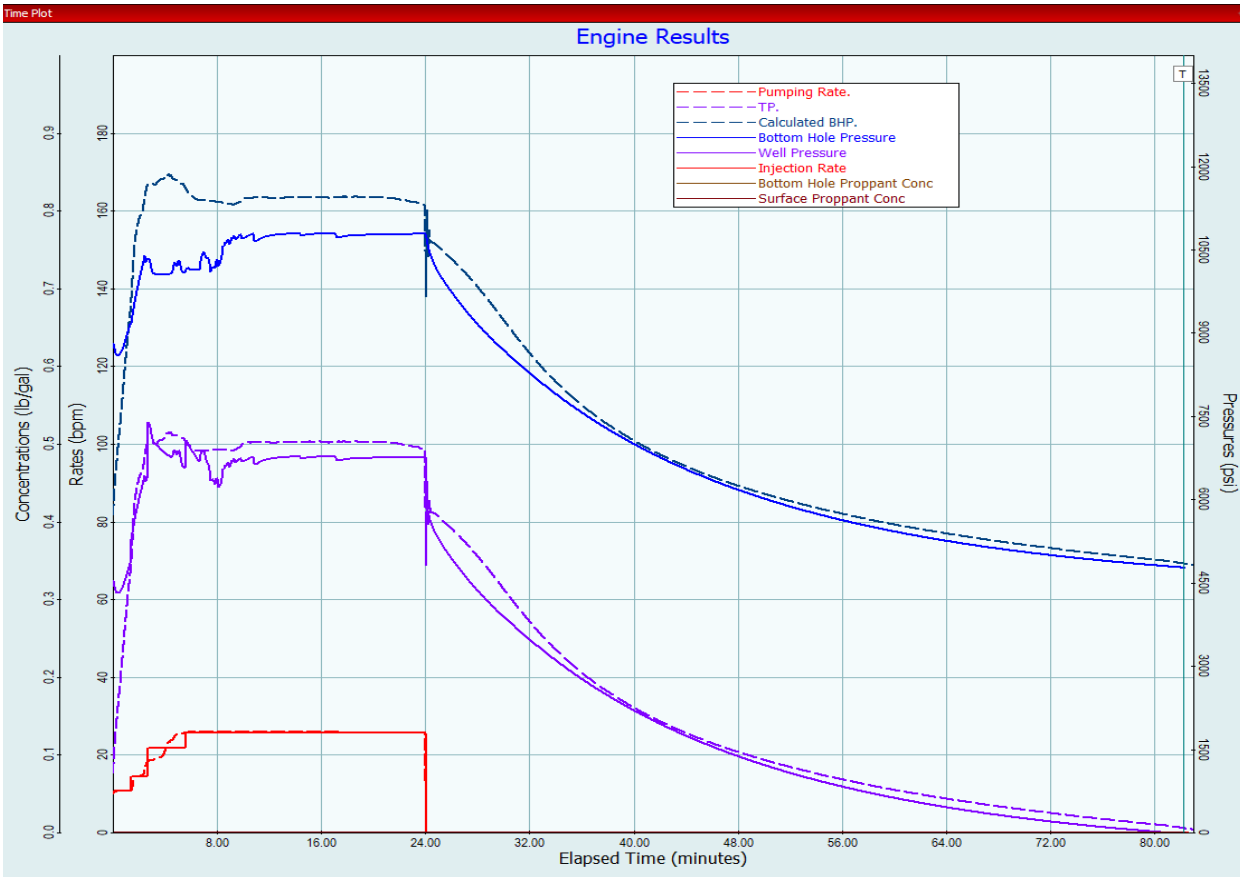


Figure II.9: the Matching of Minifrac Curves

2.7.Advantages Of GOHFER:

- The program uses a grid structure to describe the entire reservoir, like a reservoir simulator. [26]
- Is a 3D fracture geometry simulation Software.
- HF modeling software with a fully coupled fluid/solid transport simulator.
- Contains a big database of fluid rheology and proppant transport models, that have been extensively tested by laboratory research.
- It is considered one of the most reliable fracture simulators.
- It is very simple to give each element its own set of rock mechanical and reservoir properties, making the simulation of multiple formations very easy.
- Multiple perforated intervals can be designed (limited entry design, modeling of multiple fracture initiation sites simultaneously, modeling of perforation erosion). [26]
- The GOHFER Production Optimization feature provides a quick, convenient, and robust method to optimize completions based on spacing (well spacing or frac spacing) and by length (frac length or stage length). Using a consistent set of inputs for well, reservoir and economic properties. This can be used to determine an optimum economic completion to add value to your asset.
- Pressure diagnostics analysis based on the available data from step-rate, falloff and after closure analysis.

Conclusion

GOHFER is a planar 3-D Hydraulic fracturing modeling software with a fully coupled fluid/solid transport simulator. It is considered one of the most reliable fracture simulators.

To fully utilize GOHFER and create as accurate a model as possible as much input data as possible is required, and data should be available to verify the output model geometry.

The pressure matching process refers to the task of matching the simulated GOHFER™ pressure curve with the actual pressure curve, the optimum simulation output is when both pressures and geometries are matched.

Chapter III:

Study of hydraulic fracturing on the well OMK572 using GOHFER SOFTWAR

Introduction:

Hydraulic fracturing treatment in OMK572 was carried out to place a propped fracture in the ID & D1 units of the Cambrian reservoir based on its geo-mechanical and Petro-physical characteristics. The fracture will help increasing the production potential of the well and drain the hydrocarbons from the ID & D1 layers by connecting the wellbore to the clean zone in the reservoir and creates a conductive path to formation fluid, where our main objective is to create an optimum Final Main Frac Design using commercially fracture simulator GOHFER 3D.

1. Presentation of the Hassi Messaoud field:

The HMD field represents one of the most complex fields in the world. During its geological history, it underwent on the one hand an intense tectonic evolution characterized by compressive and distinctive phases and on the other hand, by the dia-genetic transformation in the reservoir during its burial over geological time, until the deposit took shape as represented by the current configuration.

This field extends over an area of approximately 2,500 km². Discovered in 1956 and put into widespread production in 1958.

The Hassi Messaoud field has more than 1,153 wells and is divided into 25 production zones. These zones are relatively independent and correspond to a set of wells communicating with each other and behaving in the same way from the point of view of reservoir pressure.

1.1. Geographical location:

The Hassi Messaoud field is located 650 km SE of ALGIER and 350 km from the Algerian-Tunisian border. It is bordered to the north by Touggourt, to the south by Gassi-Touil, to the west by Ouargla and to the east by El Bourma.

Its location in Lambert coordinates is as follows:

X= 790,000 - 840,000 Est.

Y= 110,000 - 150,000 North.

In geographic coordinates, it is limited:

- North by latitude 32°15.
- To the south by latitude 31°30.
- To the west by longitude 5°40.

- To the east by longitude 6°35.

1.2.Geological situation:

The Hassi Messaoud field occupies the central part of the north-eastern Triassic province. It is delimited by:

- To the West by the Wadi Mya depression.
- To the South by the Horst of Amguid.
- To the North by the Djamaa Touggourt structure
- To the east by the Ghadamès depression, Rhoude El Baguel and the Dahar shoals.

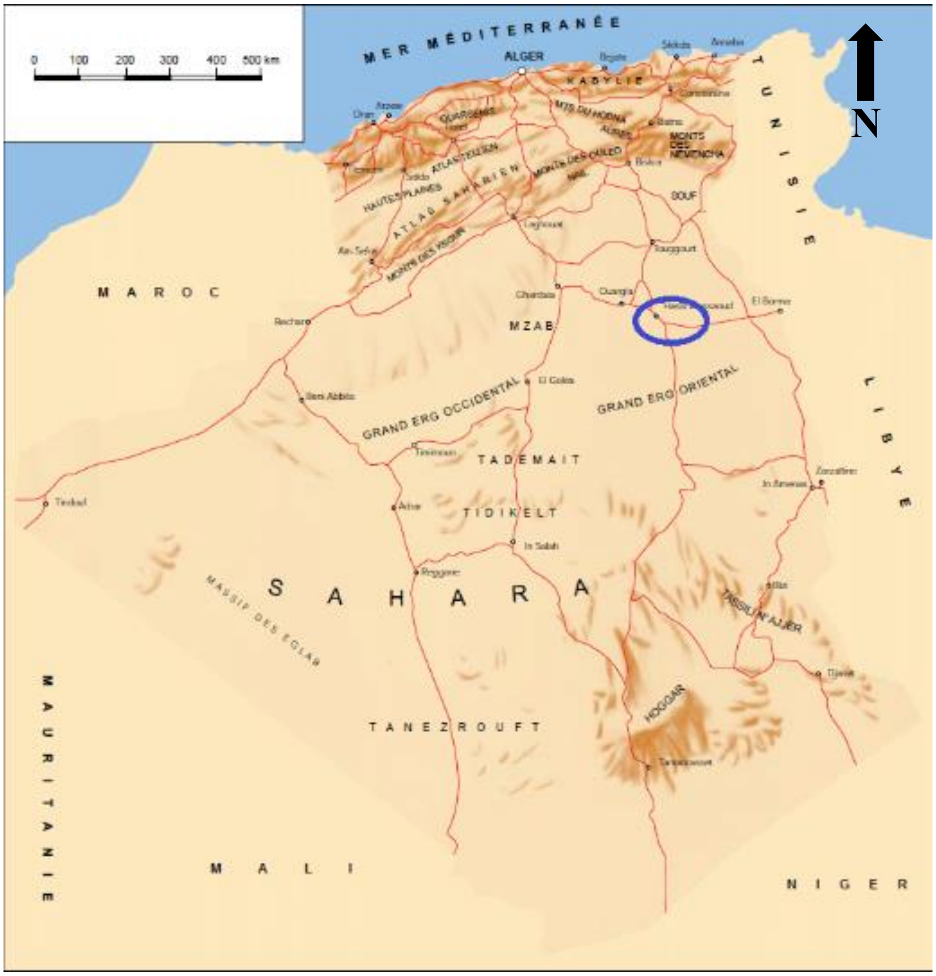


Figure III.1: Situation géographique du champ de Hassi-Messaoud [27]

2. Reservoir definition:

The HMD field represents one of the most complex fields in the world. During its geological history, it underwent on the one hand an intense tectonic evolution characterized by compressive and distinctive phases and on the other hand, by the dia-genetic transformation in the reservoir during its burial over geological time, until the deposit took shape as represented by the current configuration.

This field extends over an area of approximately 2,500 km². Discovered in 1956 and put into widespread production in 1958.

Hassi Messaoud reservoir is located under the Hercynian unconformity, it is protected by an important clay-salt cover from the Triassic. Hassi-Messaoud sandstones were subdivided at the start of the exploration of the deposit into four Zones: Ri, Ra, R2 and R3, where:

Ri Zone or isometric sandstones, usually very compact, subdivided into three sections D5 or (R70 – R 90).

Ra zone or anisometric sandstone, consisting of five drains (D1, ID, D2, D3 and D4).

Zone R2: Zone of quartzite sandstone, more clayey presenting and rarely reservoir qualities in its upper part (R200-R300), R2 ab (R200-R250).

Zone R3: Very coarse zone with very clayey micro-conglomerates, without any petroleum interest (R300-R400). (Figure)

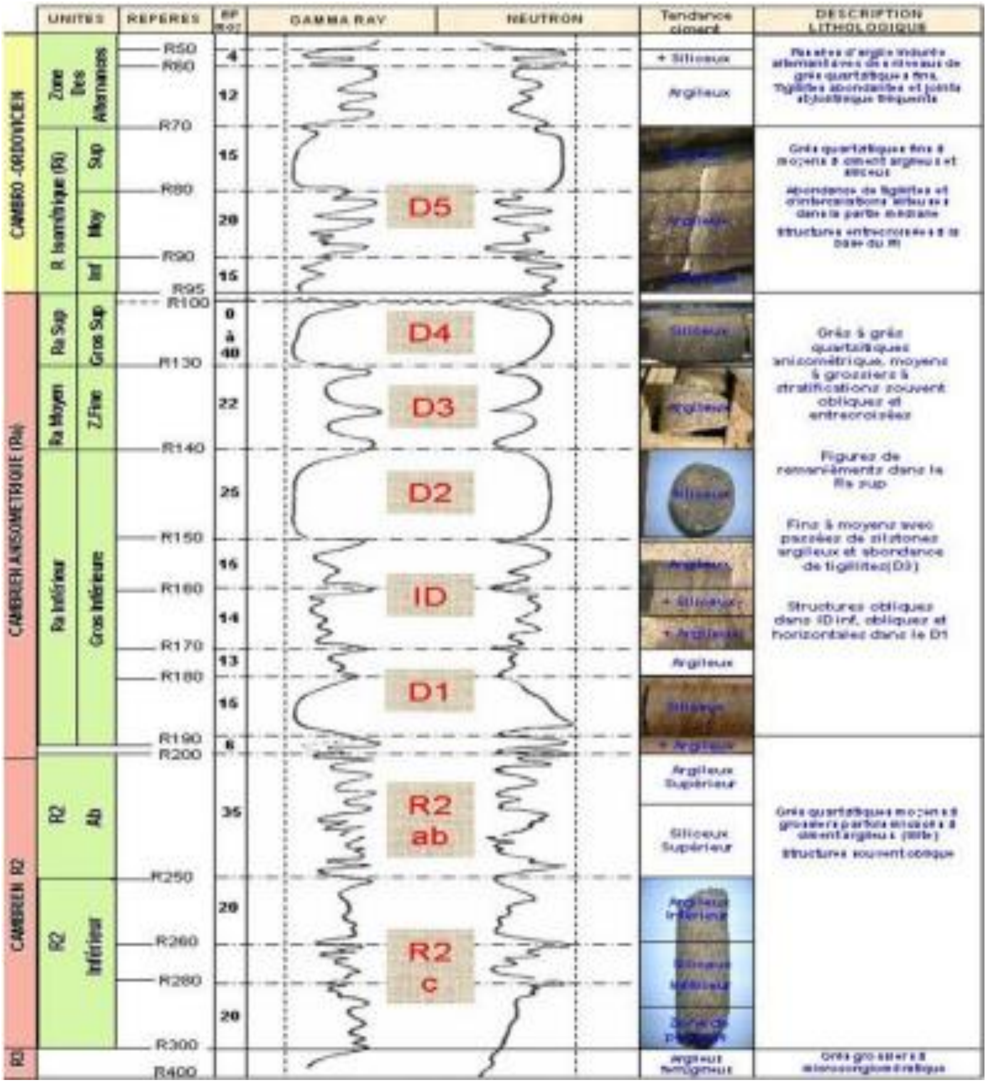


Figure III.2: Drains of the Cambrian of Hassi Messaoud.

3. History of the OMK-572 well

OMK-572 is an Oil producer Vertical well that was drilled on 25 Mars 2019, targeting the Cambrian reservoir ID & D1. The well is in HZN zone of Hassi Messaoud region.

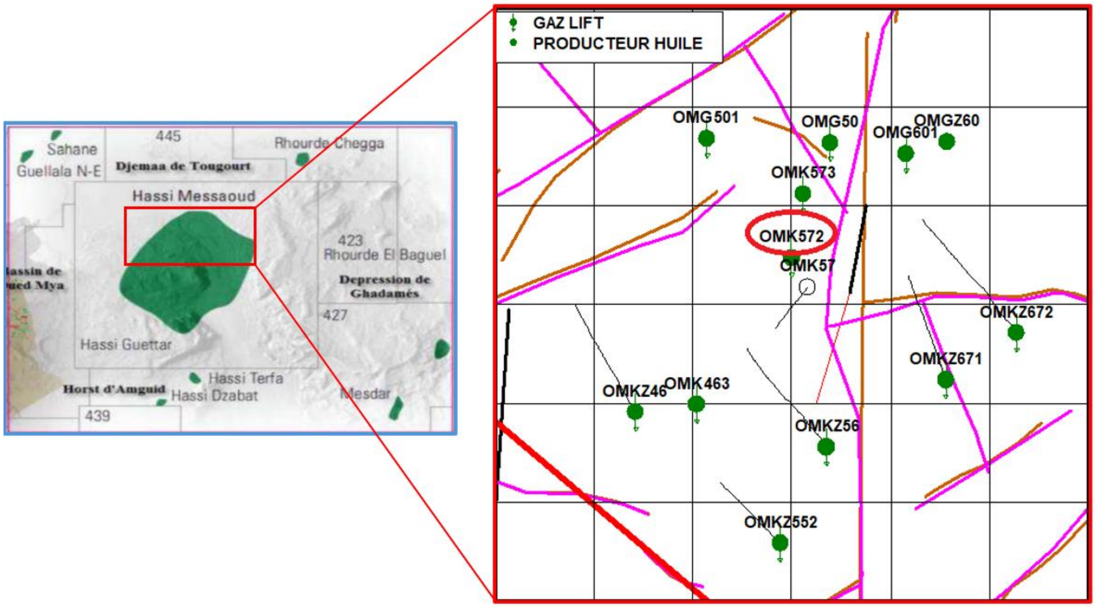


Figure III.3: Well Location Map

The well is completed with 4" ½ N.VAM 13.5# tubing at 3,330.35 mRT and 4 ½ Slotted liner completed form 3,332 m to 3,454 m.

Table III.1: Wellbore Parameters

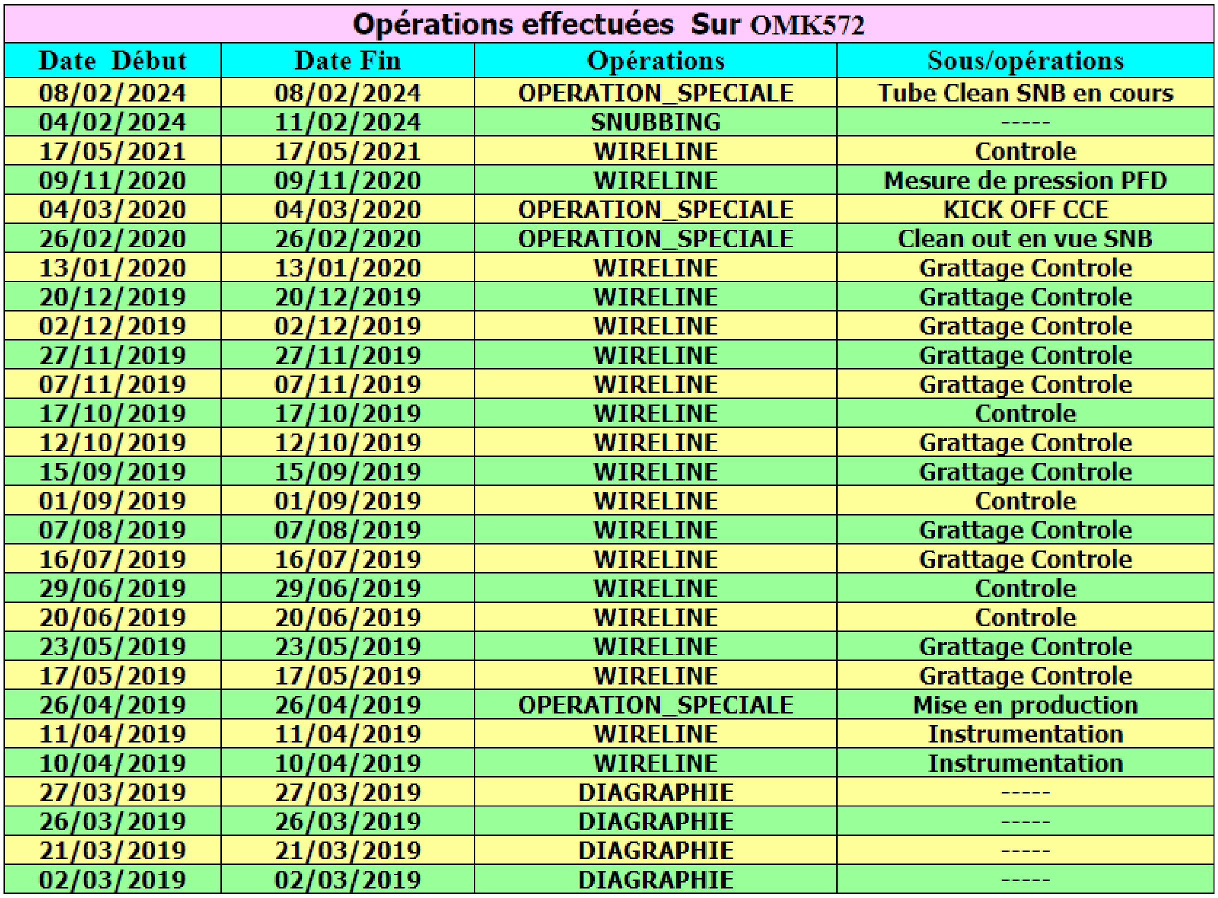
Name	Measured Depth (RT)	Outer Diameter in	Inner Diameter in	Linear Weight (lbm/ft)	Grade
Cemented casing	0-3,317	$9^{5/8}$"	8.681	47	P-110
Cemented Liner	2,596- 3,374	7"	6.184/6.094	29/32	P-110
Slotted Liner	3,332 - 3,454	$4^{1/2}$"	3.92	13.5	P-110
Tubing	0-3,330.35	$4^{1/2}$"	3.92	13.5	P-110 N.VAM
Packer Hydr WellCare	3,326.5	7"	-	32	-

Table III.2: Slotted Liner

Formation	Top MD (m)	Bot MD (m)	Bot MD (m)	Bot TVD (m)	Shot Density (spf)	Number of Perfs	Phase (DEG)	Hole Diameter (in)
Cambrian ID & D1	**3,374**	**3,454**	**3,374**	**3,454**	-	-	-	-

a. Well History:

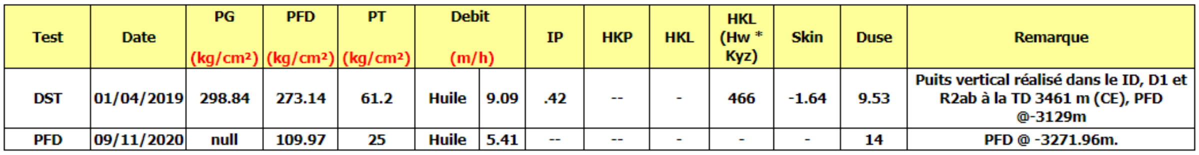
The table below summaries all the operations carried out in the well OMK572:



Opérations effectuées Sur OMK572			
Date Début	**Date Fin**	**Opérations**	**Sous/opérations**
08/02/2024	08/02/2024	OPERATION_SPECIALE	Tube Clean SNB en cours
04/02/2024	11/02/2024	SNUBBING	-----
17/05/2021	17/05/2021	WIRELINE	Controle
09/11/2020	09/11/2020	WIRELINE	Mesure de pression PFD
04/03/2020	04/03/2020	OPERATION_SPECIALE	KICK OFF CCE
26/02/2020	26/02/2020	OPERATION_SPECIALE	Clean out en vue SNB
13/01/2020	13/01/2020	WIRELINE	Grattage Controle
20/12/2019	20/12/2019	WIRELINE	Grattage Controle
02/12/2019	02/12/2019	WIRELINE	Grattage Controle
27/11/2019	27/11/2019	WIRELINE	Grattage Controle
07/11/2019	07/11/2019	WIRELINE	Grattage Controle
17/10/2019	17/10/2019	WIRELINE	Controle
12/10/2019	12/10/2019	WIRELINE	Grattage Controle
15/09/2019	15/09/2019	WIRELINE	Grattage Controle
01/09/2019	01/09/2019	WIRELINE	Controle
07/08/2019	07/08/2019	WIRELINE	Grattage Controle
16/07/2019	16/07/2019	WIRELINE	Grattage Controle
29/06/2019	29/06/2019	WIRELINE	Controle
20/06/2019	20/06/2019	WIRELINE	Controle
23/05/2019	23/05/2019	WIRELINE	Grattage Controle
17/05/2019	17/05/2019	WIRELINE	Grattage Controle
26/04/2019	26/04/2019	OPERATION_SPECIALE	Mise en production
11/04/2019	11/04/2019	WIRELINE	Instrumentation
10/04/2019	10/04/2019	WIRELINE	Instrumentation
27/03/2019	27/03/2019	DIAGRAPHIE	-----
26/03/2019	26/03/2019	DIAGRAPHIE	-----
21/03/2019	21/03/2019	DIAGRAPHIE	-----
02/03/2019	02/03/2019	DIAGRAPHIE	-----

Figure III.4: History of all operations

The table below shows the results of pressure test of OMK572:



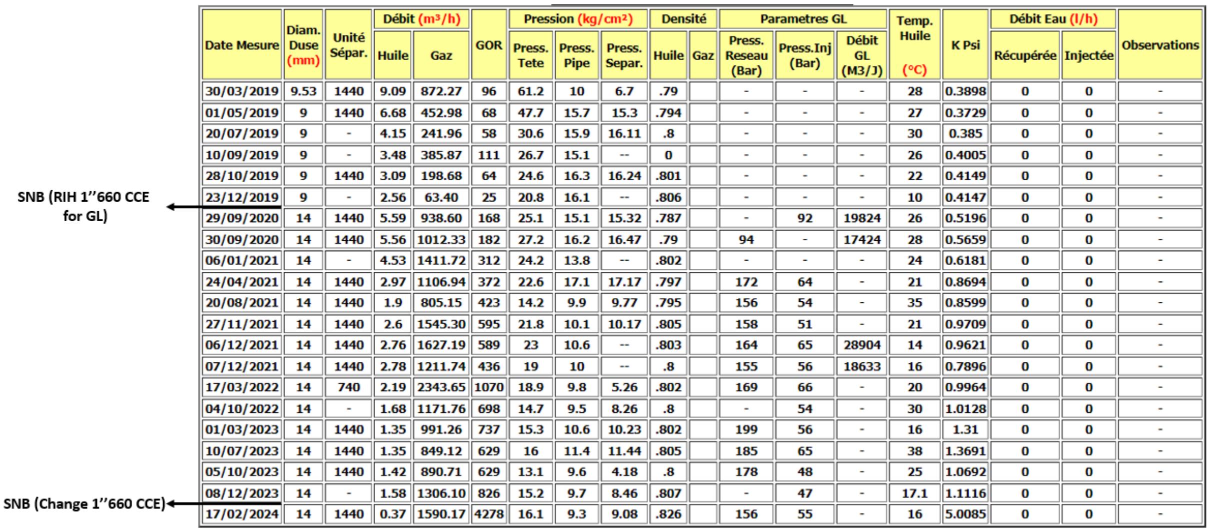
Test	Date	PG (kg/cm²)	PFD (kg/cm²)	PT (kg/cm²)	Debit (m/h)		IP	HKP	HKL	HKL (Hw * Kyz)	Skin	Duse	Remarque
DST	01/04/2019	298.84	273.14	61.2	Huile	9.09	.42	--	-	466	-1.64	9.53	Puits vertical réalisé dans le ID, D1 et R2ab à la TD 3461 m (CE), PFD @-3129m
PFD	09/11/2020	null	109.97	25	Huile	5.41	--	--	-	-	-	14	PFD @ -3271.96m.

Figure III.5: Pressure test

From DST:

- The well gives an Oil rate of 9.09 m3/h for drawdown of 26 kg/cm2 and Skin -1.64.
- Reservoir permeability = 466 md.
- The type of reservoir is homogeneous, with the presence of an intersection of two faults one at 21m and the other at 49m

The table below shows the results of production tests carried out in OMK572:



SNB (RIH 1''660 CCE for GL)

SNB (Change 1''660 CCE)

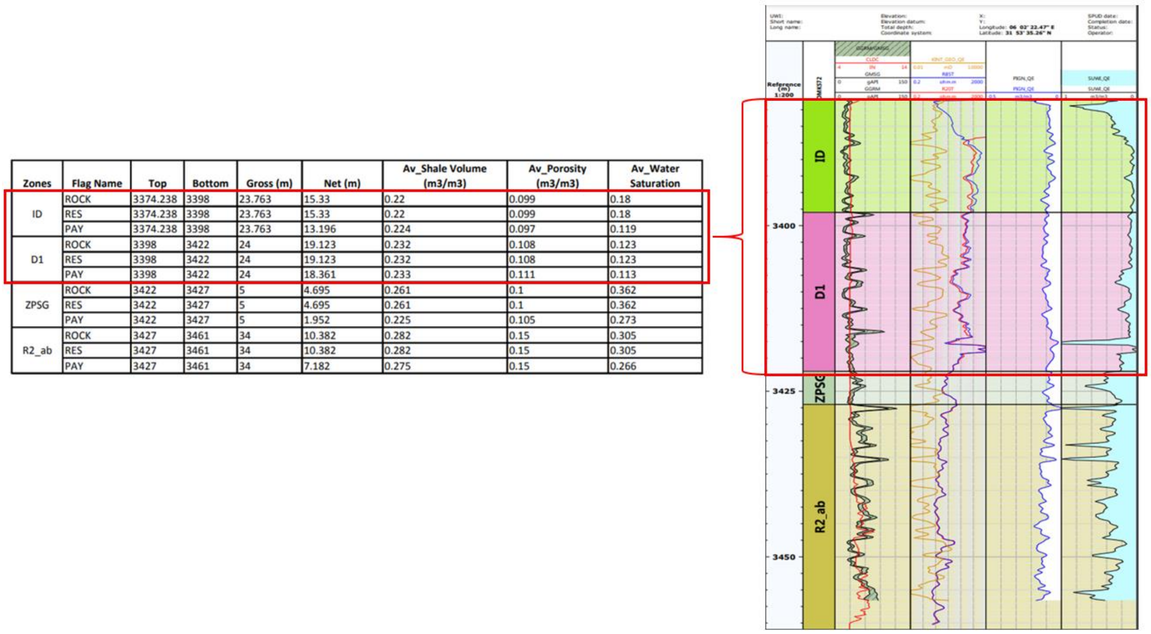
Date Mesure	Diam. Duse (mm)	Unité Sépar.	Débit (m³/h)		GOR	Pression (kg/cm²)			Densité		Parametres GL			Temp. Huile (°C)	K Psi	Débit Eau (l/h)		Observations
			Huile	Gaz		Press. Tete	Press. Pipe	Press. Separ.	Huile	Gaz	Press. Reseau (Bar)	Press.Inj (Bar)	Débit GL (M3/J)			Récupérée	Injectée	
30/03/2019	9.53	1440	9.09	872.27	96	61.2	10	6.7	.79		-	-	-	28	0.3898	0	0	-
01/05/2019	9	1440	6.68	452.98	68	47.7	15.7	15.3	.794		-	-	-	27	0.3729	0	0	-
20/07/2019	9	-	4.15	241.96	58	30.6	15.9	16.11	.8		-	-	-	30	0.385	0	0	-
10/09/2019	9	-	3.48	385.87	111	26.7	15.1	--	0		-	-	-	26	0.4005	0	0	-
28/10/2019	9	1440	3.09	198.68	64	24.6	16.3	16.24	.801		-	-	-	22	0.4149	0	0	-
23/12/2019	9	-	2.56	63.40	25	20.8	16.1	--	.806		-	-	-	10	0.4147	0	0	-
29/09/2020	14	1440	5.59	938.60	168	25.1	15.1	15.32	.787		-	92	19824	26	0.5196	0	0	-
30/09/2020	14	1440	5.56	1012.33	182	27.2	16.2	16.47	.79		94	-	17424	28	0.5659	0	0	-
06/01/2021	14	-	4.53	1411.72	312	24.2	13.8	--	.802		-	-	-	24	0.6181	0	0	-
24/04/2021	14	1440	2.97	1106.94	372	22.6	17.1	17.17	.797		172	64	-	21	0.8694	0	0	-
20/08/2021	14	1440	1.9	805.15	423	14.2	9.9	9.77	.795		156	54	-	35	0.8599	0	0	-
27/11/2021	14	1440	2.6	1545.30	595	21.8	10.1	10.17	.805		158	51	-	21	0.9709	0	0	-
06/12/2021	14	1440	2.76	1627.19	589	23	10.6	--	.803		164	65	28904	14	0.9621	0	0	-
07/12/2021	14	1440	2.78	1211.74	436	19	10	--	.8		155	56	18633	16	0.7896	0	0	-
17/03/2022	14	740	2.19	2343.65	1070	18.9	9.8	5.26	.802		169	66	-	20	0.9964	0	0	-
04/10/2022	14	-	1.68	1171.76	698	14.7	9.5	8.26	.8		-	54	-	30	1.0128	0	0	-
01/03/2023	14	1440	1.35	991.26	737	15.3	10.6	10.23	.802		199	56	-	16	1.31	0	0	-
10/07/2023	14	1440	1.35	849.12	629	16	11.4	11.44	.805		185	65	-	38	1.3691	0	0	-
05/10/2023	14	1440	1.42	890.71	629	13.1	9.6	4.18	.8		178	48	-	25	1.0692	0	0	-
08/12/2023	14	-	1.58	1306.10	826	15.2	9.7	8.46	.807		-	47	-	17.1	1.1116	0	0	-
17/02/2024	14	1440	0.37	1590.17	4278	16.1	9.3	9.08	.826		156	55	-	16	5.0085	0	0	-

Figure III.6: Gauging of OMK572

The results of the last Gauging show an oil rate of 0.37 m3/h.

From the first DST the well OMK572 gave Oil rate of 9.09 m^3/h but, during the time and from the last gauging the oil rate became 0.37 m^3/h so the well OMK572 did not gave the expected productivity and this due to the deposits and formation damage. So, The Company suggest a hydraulic fracturing to bypass the damaged zone and to increase the permeability of the reservoir.

The objective of Hydraulic Fracturing is to stimulate the ID & D1 units of the Cambrian reservoir. The Cambrian ID & D1 reservoir present an average of 10% porosity, and around 15% average of water saturation with a 22% shale volume.



Zones	Flag Name	Top	Bottom	Gross (m)	Net (m)	Av_Shale Volume (m3/m3)	Av_Porosity (m3/m3)	Av_Water Saturation
ID	ROCK	3374.238	3398	23.763	15.33	0.22	0.099	0.18
	RES	3374.238	3398	23.763	15.33	0.22	0.099	0.18
	PAY	3374.238	3398	23.763	13.196	0.224	0.097	0.119
D1	ROCK	3398	3422	24	19.123	0.232	0.108	0.123
	RES	3398	3422	24	19.123	0.232	0.108	0.123
	PAY	3398	3422	24	18.361	0.233	0.111	0.113
ZPSG	ROCK	3422	3427	5	4.695	0.261	0.1	0.362
	RES	3422	3427	5	4.695	0.261	0.1	0.362
	PAY	3422	3427	5	1.952	0.225	0.105	0.273
R2_ab	ROCK	3427	3461	34	10.382	0.282	0.15	0.305
	RES	3427	3461	34	10.382	0.282	0.15	0.305
	PAY	3427	3461	34	7.182	0.275	0.15	0.266

Figure III.7: Well Petrophysical Properties

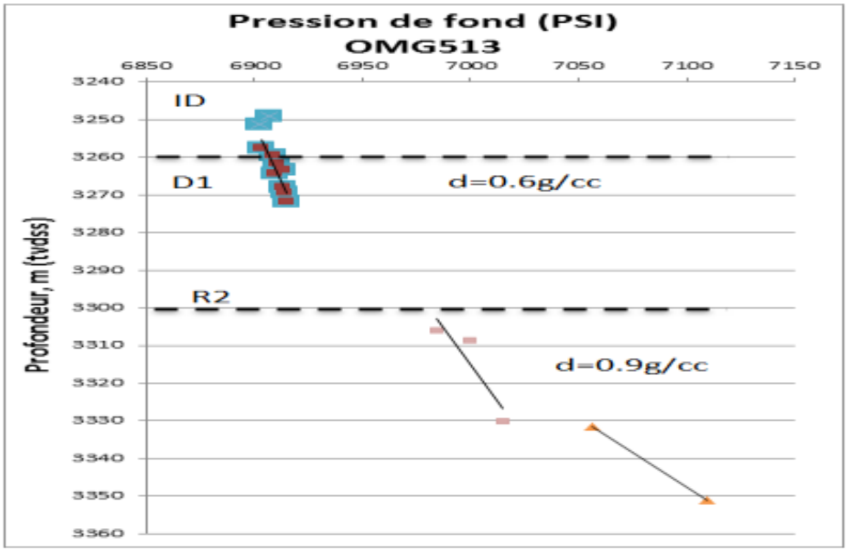


Figure III.8: WOC from neighboring well (OMG513)

- The theorical water contact is defined @ 3,502 mRT (-3,330m TVDSS).
- The ID & D1 present 3,555 psi (250 kg/cm^2) of reservoir pressure and temperature of 237˚F/114 ˚C.

b. Well Integrity:

Table III.3: Tubing burst/collapse Pressure

Production Tubing 4"1/2 P110 13.5#	Collapse (psi)	80% collapse (psi)	Internal Minimum Yield (psi)	80% Internal Minimum Yield (psi)
	10680	8544	12410	9928
Casing 7" NV P110 32#	Internal Minimum Yield @ 12460 psi (80% @ 9968 psi)			
Casing 9"5/8 P110 47#	Internal Minimum Yield @ 9440 psi (80% @ 7552 psi)			
Packer Differential Pressure	Wellcare Electrique P.Diff = 10000 psi			
Completion Fluid	Brine S.G = 1.26			

The pressure kickout for the treatment was calculated based on tubing burst/collapse with a packer maximum working pressure of 10,000 psi.

The final kickout pressure considered for the design program:

- Clean fluid (Injection test): 9,500 psi
- Clean fluid (Minifrac): 8,500 psi
- Clean fluid (Main Frac): 8,500 psi
- Slurry fluid at 1-4 ppg prop con: 8,000 psi.
- Slurry fluid at 1-4 ppg prop con: 8,000 psi
- Slurry fluid at 5-7 ppg prop con:7,500 psi
- Annulus A pressure: 3,000 psi

NOTE: 80% safety factor is applied and made in consideration.

c. Fluid & Proppant selection:

The recommended fracturing fluid system is 35 lbs Hybor G base fluid for Cambrian reservoir ID & D1 unit with 0.7gpt Cla-Web DRII, 1.0 gpt Losurf-300 and delayed cross-linked gel system containing 20/40 HSP & 16/30 High Strength proppant (HSP), based on reservoir temperature of 237 °F. (III.4, III.5, III.6)

The HSP proppant is considered for the Main treatment. Based on well geomechanics and field experience.

Table III.4: Treatment Fluid Compositions

Chemical Description	Concentration	Treated Water	Linear Base Gel 35#	Hybor G 35 #
WG-36	(lb/Mgal)		35	35
BE-3S	(lb/Mgal)		0.15	0.15
CL-28	(gal/Mgal)			1.2
CLAWEB DR-II	(gal/Mgal)	0.7	0.7	0.7
Fe-1A	(gal/Mgal)		0.1	0.1
Gel Sta L	(gal/Mgal)			3.0
K-38	(gal/Mgal)			2.4
Losurf-300	(gal/Mgal)	1.0	1.0	1.0
MO-67	(lb/Mgal)			2.2
SP BREAKER	(lb/Mgal)		1.0	
VICON NF	(gal/Mgal)		0.8	1.8

Table III.5: Linear Gel Additives

Description	Additive Name	Concentration
Gelling Agent	WG-36	35 lb/Mgal
Cross-linker	CL-28M	1.2 gal/Mgal
Cross-linker	K-38	2.4 gal/Mgal
Clay Control	CLAWEB DR-II	0.7 gal/Mgal
Surfactant	Losurf-300	1.0 gal/Mgal
Biocode	BE-3S	0.15 lb/Mgal
High pH Buffer	MO-67	2.2 gal/Mgal
Low pH Buffer	Fe-1A	0.1 gal/Mgal
Breaker	Optiflo-III	1.0 – 2.4 lb/Mgal
Breaker	Vicon-NF	1.5 – 2.4 gal/Mgal
Breaker	SP Breaker	1.0 gal/Mgal
Gel Stabilizer	Gel Sta L	3.0 gal/Mgak

Table III.6: Hybor-G 35# Cross-Linked Gel Additives

Description	Additive Name	Concentration
Gelling Agent	WG-36	35 lb/Mgal
Clay Control	CLAWEB DR-II	0.7 gal/Mgal
Low pH Buffer	FE-1A	0.2 / 0.1 gal/Mgal
Surfactant	Losurf-300	1.0 gal/Mgal
Breaker	SP Breaker	1.0 lb/Mgal
Breaker	Vicon-NF	0.8 gal/Mgal
Biocide	BE-3S	0.15 lb/Mgal

d. Chemical Description:

WG-36 : Gelling Agent (Guar).

CL-28M : Borate source delayed cross-linker.

K-38/Cl-31 : Instantaneous cross-linker.

Cla-Web DR-II : Clay control agent.

Losurf-300 : Non-Ionic Emulsion surfactant.

BE-3S : Biocide specifically tested for use in water-based.

MO-67 : High pH Buffer.

BA-20/FE-1A : Low pH Buffer.

OPTIFLO-III : Solid delayed-release breaker.

VICON NF : Liquid oxidizing breaker.

SP BREAKER : Solid oxidizing breaker for temperatures above 120°F.

Gel Sta L : Gel Stabilizer.

NOTE: the selection of proppant and fluid treatment is according to Service Company (HALLIBURTON in this case).

Figure III.9: MiniFrac broken Gel

Figure III.10: MiniFrac Cross-linked Gel

Figure III.11: Main Treatment Broken Gel

Figure III.12: Main Treatment Cross-linked Gel

4. Preliminary Main Treatment Design

The Preliminary Main Treatment Design contains a proposed Minifrac, and main treatment designs based on the reservoir and well data. This is only a guideline to the type of treatment that will be performed. Following the Minifrac analyses and temperature logs, the model parameters will be calibrated and the main treatments may be reviewed to reflect actual conditions.

Step 1: Generate Stress profile

The total Stress calculated by GOHFER is used to simulate the frac model. The model will be calibrated based on the Minifrac and temperature log results to reflect the actual conditions.

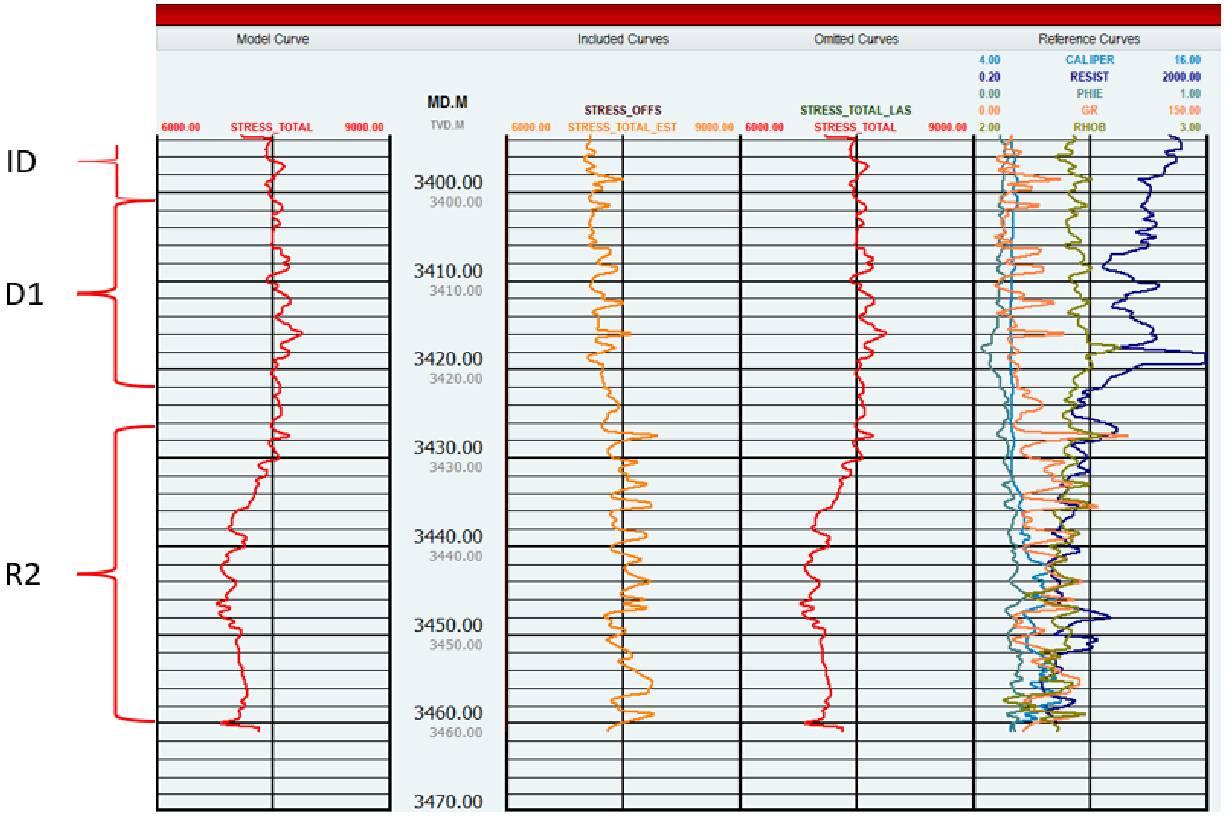
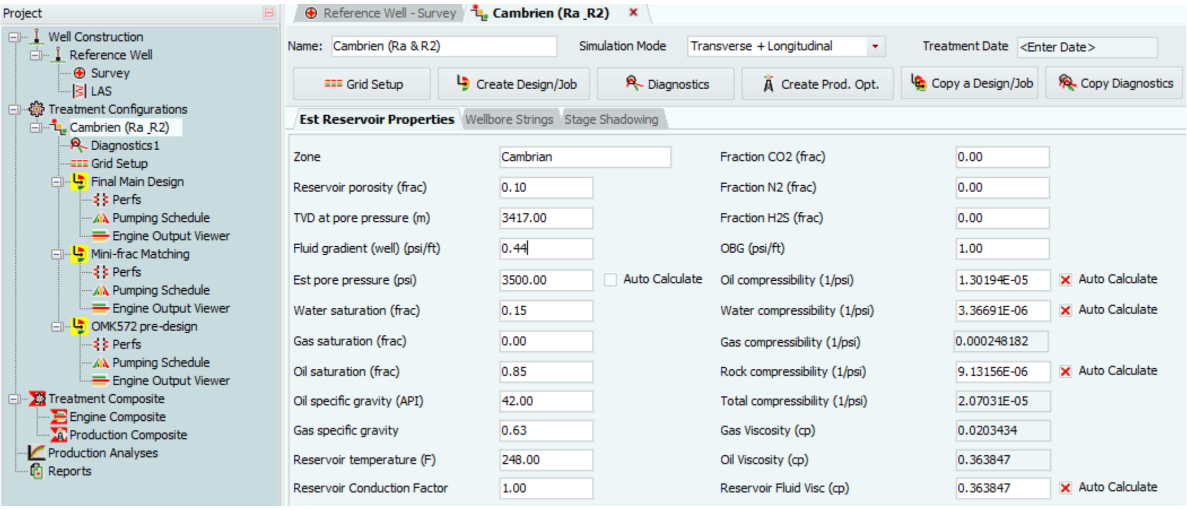


Figure III.13: Stress Profile

According to the stress profile (figure III.13), the stress in R2 is lower compared with the upper zones (ID & D1) with stress contrast of 800 psi.

According to that the fracture will propagate into the lower zone (R2).

Step 2: Create Geological Section & Define Reservoir Properties



Name: Cambrien (Ra & R2) Simulation Mode Transverse + Longitudinal Treatment Date <Enter Date>

Zone	Cambrian		Fraction CO2 (frac)	0.00	
Reservoir porosity (frac)	0.10		Fraction N2 (frac)	0.00	
TVD at pore pressure (m)	3417.00		Fraction H2S (frac)	0.00	
Fluid gradient (well) (psi/ft)	0.44		OBG (psi/ft)	1.00	
Est pore pressure (psi)	3500.00	☐ Auto Calculate	Oil compressibility (1/psi)	1.30194E-05	☒ Auto Calculate
Water saturation (frac)	0.15		Water compressibility (1/psi)	3.36691E-06	☒ Auto Calculate
Gas saturation (frac)	0.00		Gas compressibility (1/psi)	0.000248182	
Oil saturation (frac)	0.85		Rock compressibility (1/psi)	9.13156E-06	☒ Auto Calculate
Oil specific gravity (API)	42.00		Total compressibility (1/psi)	2.07031E-05	
Gas specific gravity	0.63		Gas Viscosity (cp)	0.0203434	
Reservoir temperature (F)	248.00		Oil Viscosity (cp)	0.363847	
Reservoir Conduction Factor	1.00		Reservoir Fluid Visc (cp)	0.363847	☒ Auto Calculate

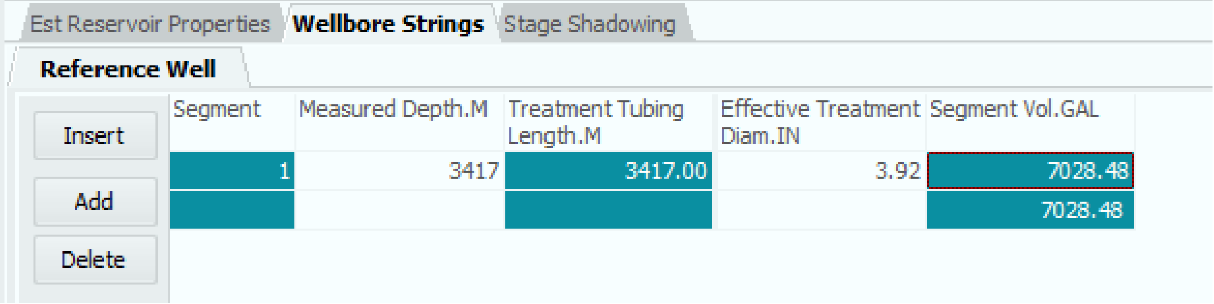
Figure III.14: Reservoir properties

In this step we entered the reservoir properties such as reservoir porosity, Sw, So…etc.

Step 3: Create Wellbore Strings

The frac fluid will be injected through 4”1/2 tubing with ID = 3.92”.

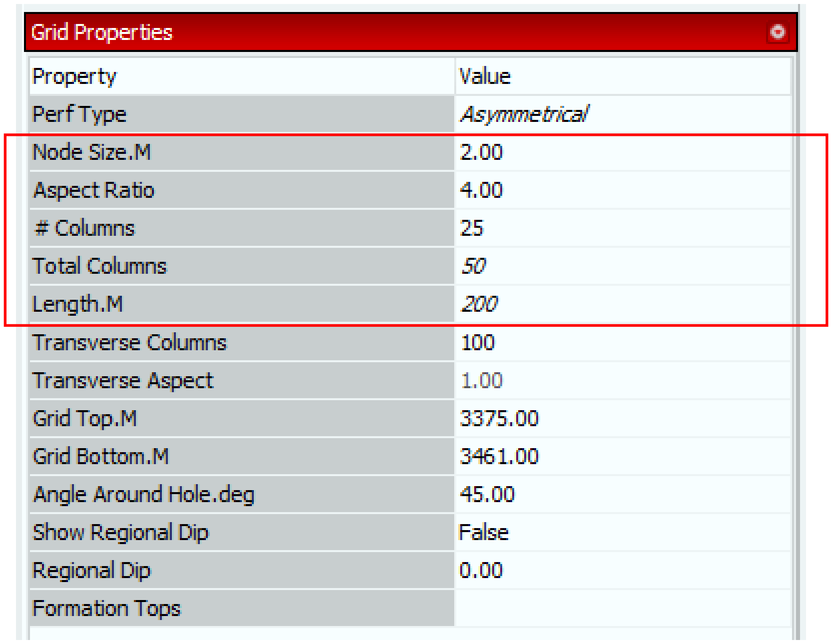
3417 m represents the middle of the reservoir.



Segment	Measured Depth.M	Treatment Tubing Length.M	Effective Treatment Diam.IN	Segment Vol.GAL
1	3417	3417.00	3.92	7028.48
				7028.48

Figure III.15: Wellbore Strings

Step 4: GOHFER Grid Setup



Grid Properties

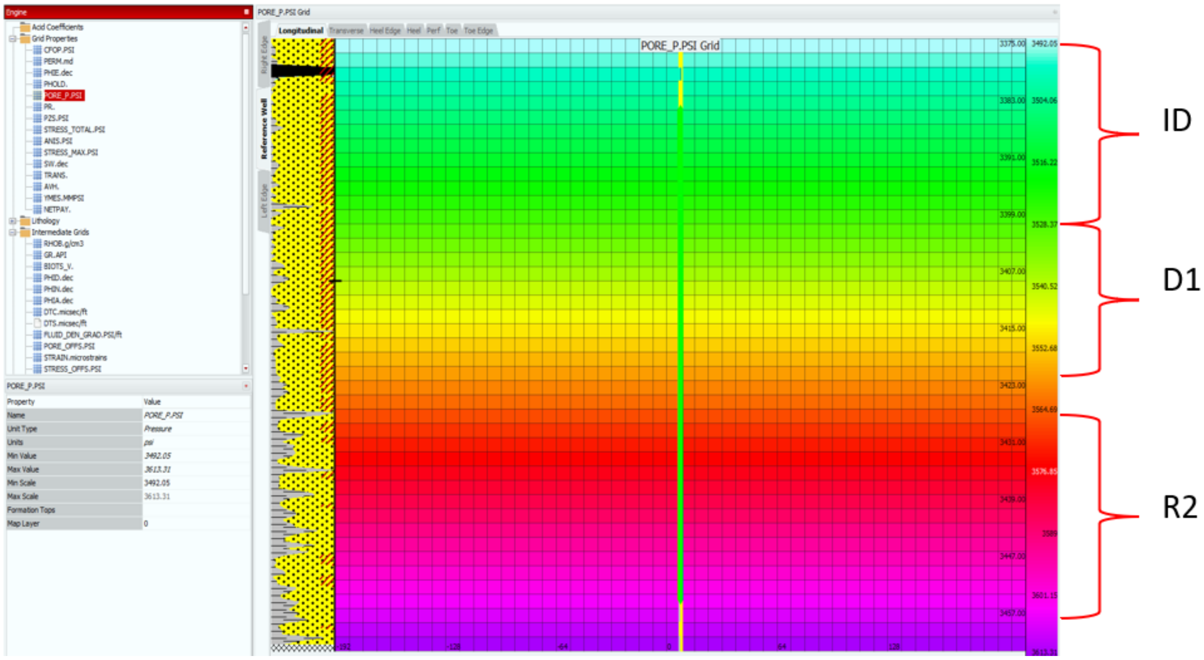
Property	Value
Perf Type	*Asymmetrical*
Node Size.M	2.00
Aspect Ratio	4.00
# Columns	25
Total Columns	*50*
Length.M	*200*
Transverse Columns	100
Transverse Aspect	1.00
Grid Top.M	3375.00
Grid Bottom.M	3461.00
Angle Around Hole.deg	45.00
Show Regional Dip	False
Regional Dip	0.00
Formation Tops	

Figure III.16: Grid Setup

- Node size represents the vertical height of each grid block (The default node height is 5 ft for oilfield units or 2 meters for metric units).
- Aspect Ratio determines the node length and describes the relationship of the node length to the node height (Aspect Ratio = Node Length / Node Height). A reasonable range for aspect ratio is 2 to 8.
- # Columns sets the number of columns in the grid for each side.

The following plots illustrates the distribution of pore pressure, total stress, permeability & PZS along the grids.

Plot 1: Pore Pressure



PORE_P.PSI

Property	Value
Name	*PORE_P.PSI*
Unit Type	*Pressure*
Units	*psi*
Min Value	*3492.05*
Max Value	*3613.31*
Min Scale	3492.05
Max Scale	3613.31
Formation Tops	
Map Layer	0

Figure III.17: Pore pressure grid output

The figure shows that the pore pressure is low in upper zones (D1&ID) comparing with lower zone (R2).

Plot 2: Total Stress.

As we have seen before, the stress in the lower formation (R2) is low compared to the upper ones (ID & D1).

Formation stresses will be calibrated after analyzing the Minifrac shut-in pressure decline.

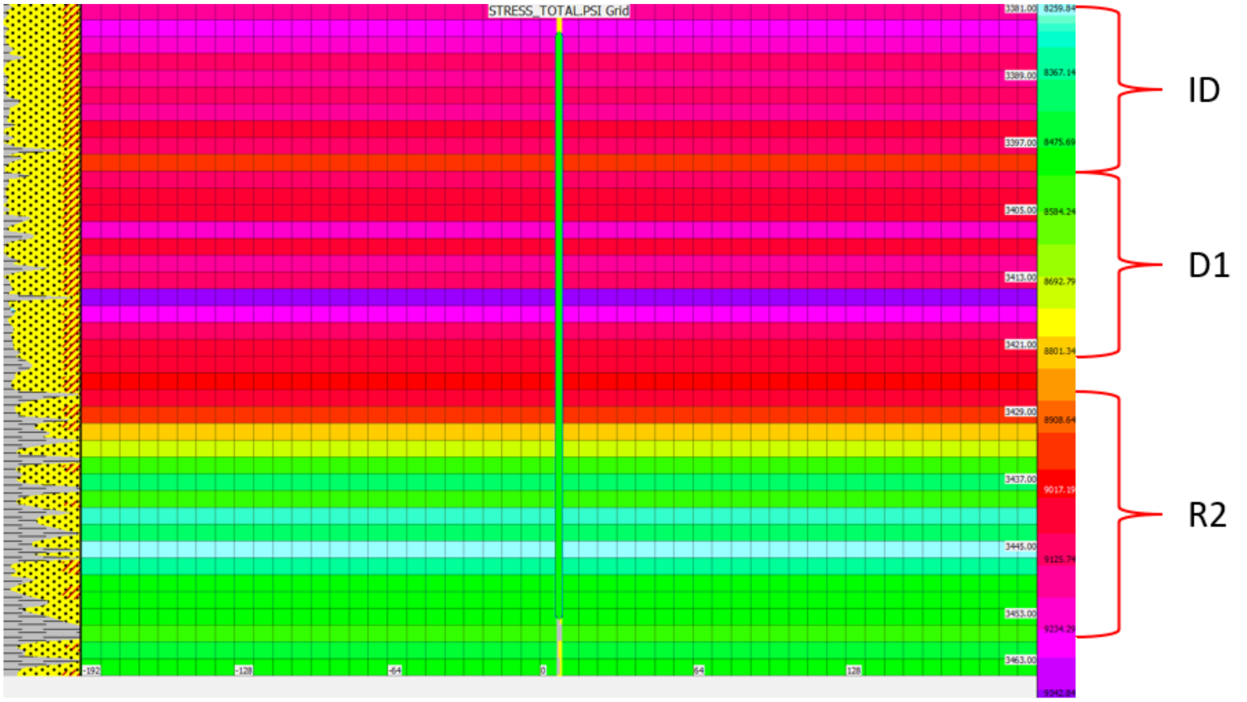


Figure III.18: Total stress Grid output

Plot 3: Permeability

R2 zone is a shaly zone that’s why the permeability of this zone is low compared to the upper zones (ID & D1).

Following the Minifrac injection test, it is necessary to adjust fluid Leak-off characteristics and the formation permeability to match the actual fluid efficiency obtained from the Minifrac pressure decline analysis.

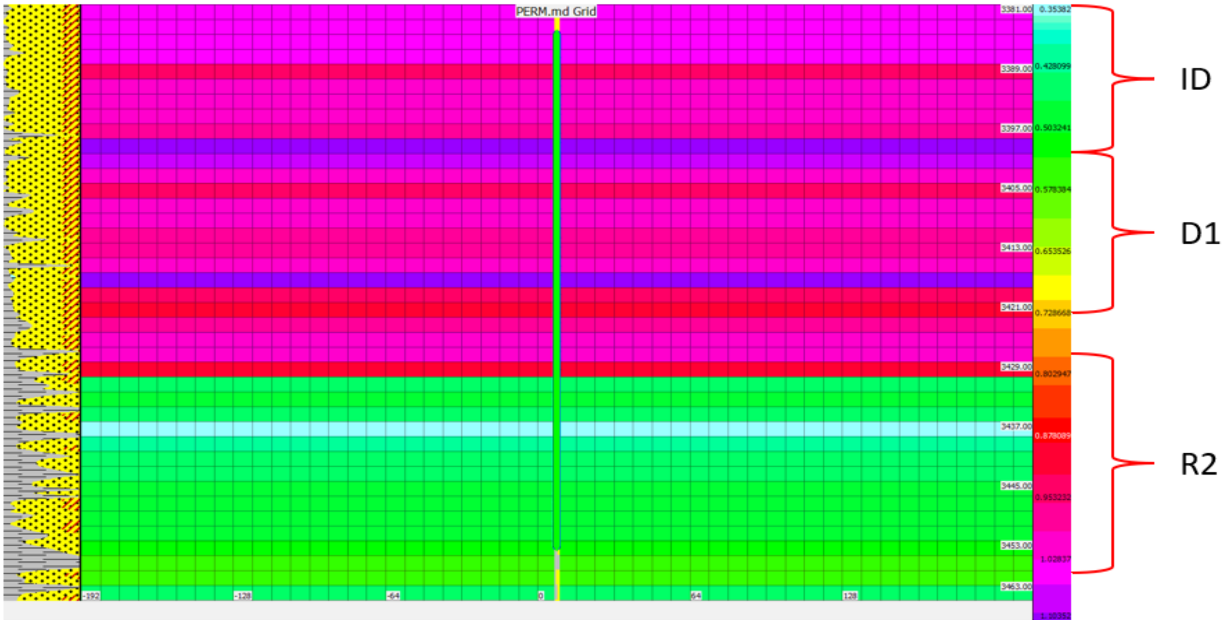


Figure III.19: Permeability Grid output

Plot 4: Pressure Zone Stress PZS (= Net Pressure)

PZS (net pressure) will be calibrated after analyzing the Minifrac shut-in pressure decline.

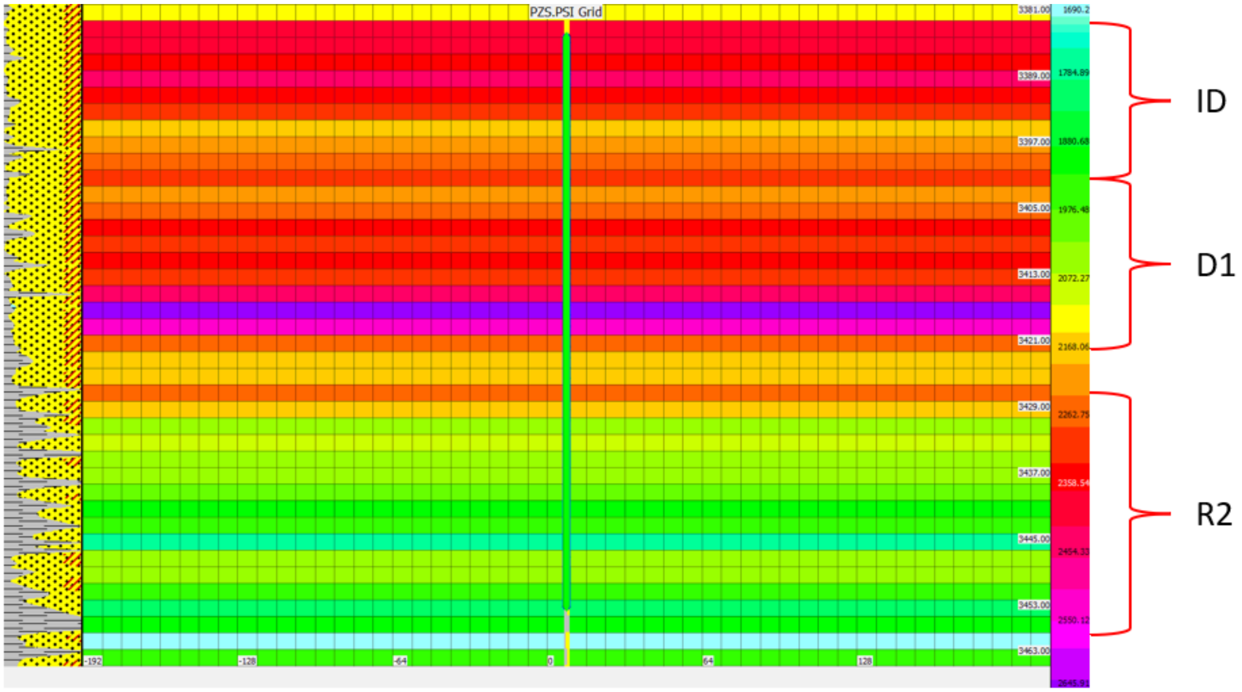
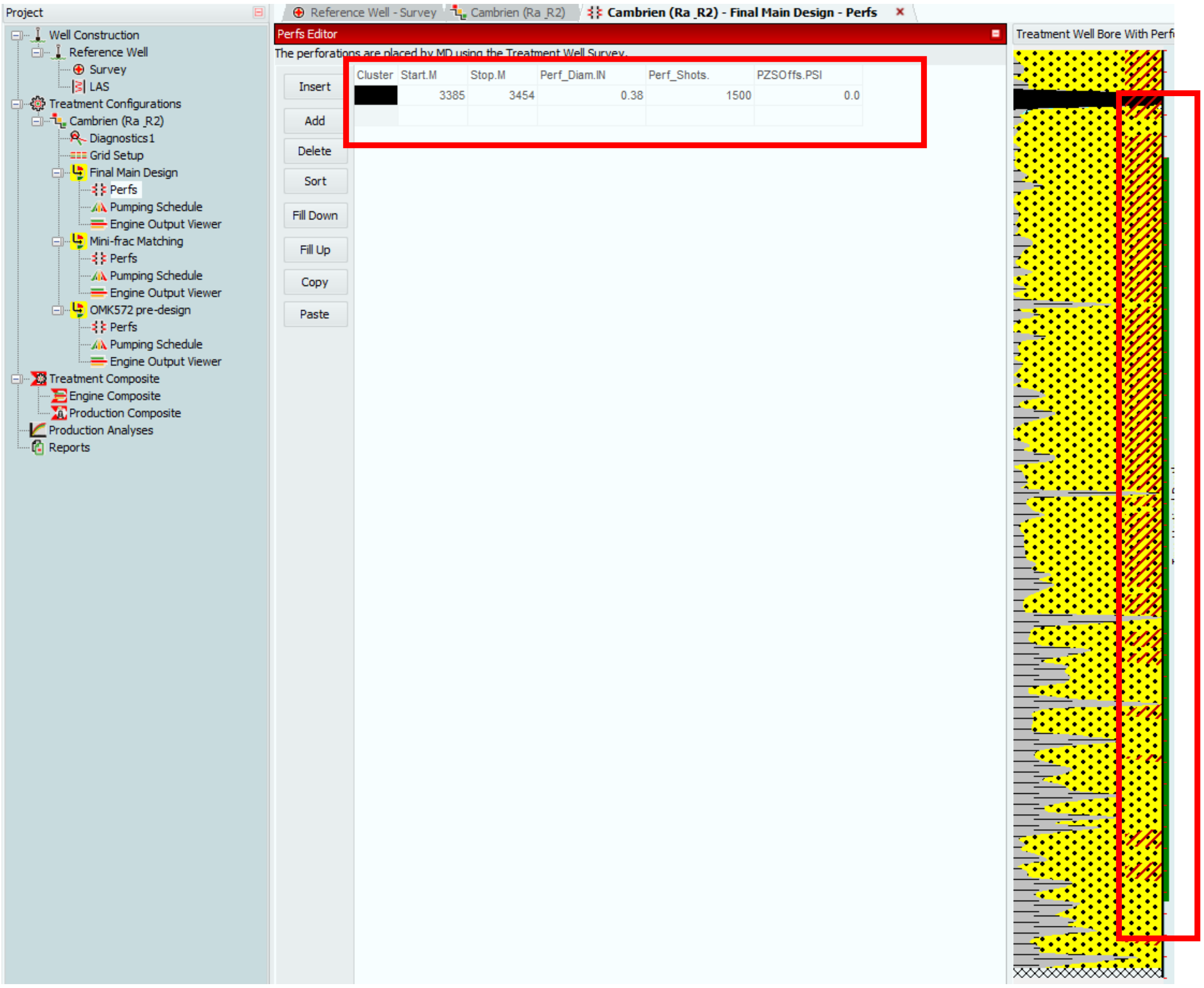


Figure III.20: Net Pressure Grid output

Step 5: Define Perforation Interval

- As the well is completed with slotted liner, we consider all the reservoir is perforated.
- Top perf = top reservoir
- Bottom perf = bottom reservoir
- Perf Shots = 6 shots/ft
- Perf inside diameter = 0.38 in.



The perforations are placed by MD using the Treatment Well Survey.

Cluster	Start.M	Stop.M	Perf_Diam.IN	Perf_Shots.	PZSOffs.PSI
■	3385	3454	0.38	1500	0.0

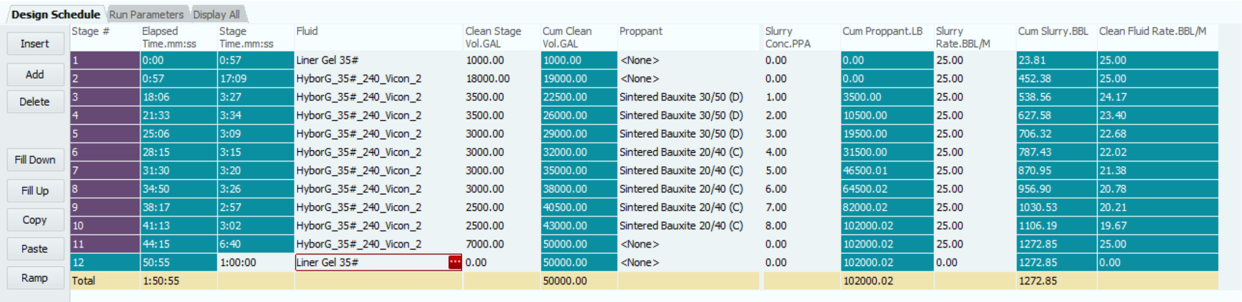
Figure III.21: Perforation Interval

Notes

The perforations will automatically be distributed among the associated nodes based on the start and stop depth(s) appropriately.

Step 6: Create Preliminary Main Design

- The recommended fracturing fluid system is 35 lbs Hybor G base fluid for Cambrian reservoir ID & D1 unit with delayed cross-linked gel system containing 20/40 HSP & 16/30 High Strength proppant (HSP).
- End of job Proppant concentration is 8ppg.
- The recommended job size is 100 klbs of Proppant.
- The recommended pumping rate is 25 bpm.



Stage #	Elapsed Time.mm:ss	Stage Time.mm:ss	Fluid	Clean Stage Vol.GAL	Cum Clean Vol.GAL	Proppant	Slurry Conc.PPA	Cum Proppant.LB	Slurry Rate.BBL/M	Cum Slurry.BBL	Clean Fluid Rate.BBL/M
1	0:00	0:57	Liner Gel 35#	1000.00	1000.00	<None>	0.00	0.00	25.00	23.81	25.00
2	0:57	17:09	HyborG_35#_240_Vicon_2	18000.00	19000.00	<None>	0.00	0.00	25.00	452.38	25.00
3	18:06	3:27	HyborG_35#_240_Vicon_2	3500.00	22500.00	Sintered Bauxite 30/50 (D)	1.00	3500.00	25.00	538.56	24.17
4	21:33	3:34	HyborG_35#_240_Vicon_2	3500.00	26000.00	Sintered Bauxite 30/50 (D)	2.00	10500.00	25.00	627.58	23.40
5	25:06	3:09	HyborG_35#_240_Vicon_2	3000.00	29000.00	Sintered Bauxite 30/50 (D)	3.00	19500.00	25.00	706.32	22.68
6	28:15	3:15	HyborG_35#_240_Vicon_2	3000.00	32000.00	Sintered Bauxite 20/40 (C)	4.00	31500.00	25.00	787.43	22.02
7	31:30	3:20	HyborG_35#_240_Vicon_2	3000.00	35000.00	Sintered Bauxite 20/40 (C)	5.00	46500.01	25.00	870.95	21.38
8	34:50	3:26	HyborG_35#_240_Vicon_2	3000.00	38000.00	Sintered Bauxite 20/40 (C)	6.00	64500.02	25.00	956.90	20.78
9	38:17	2:57	HyborG_35#_240_Vicon_2	2500.00	40500.00	Sintered Bauxite 20/40 (C)	7.00	82000.02	25.00	1030.53	20.21
10	41:13	3:02	HyborG_35#_240_Vicon_2	2500.00	43000.00	Sintered Bauxite 20/40 (C)	8.00	102000.02	25.00	1106.19	19.67
11	44:15	6:40	HyborG_35#_240_Vicon_2	7000.00	50000.00	<None>	0.00	102000.02	25.00	1272.85	25.00
12	50:55	1:00:00	Liner Gel 35#	0.00	50000.00	<None>	0.00	102000.02	0.00	1272.85	0.00
Total	1:50:55				50000.00			102000.02		1272.85	

Figure III.22: Preliminary Main Design Schedule

Step 7: Run Design

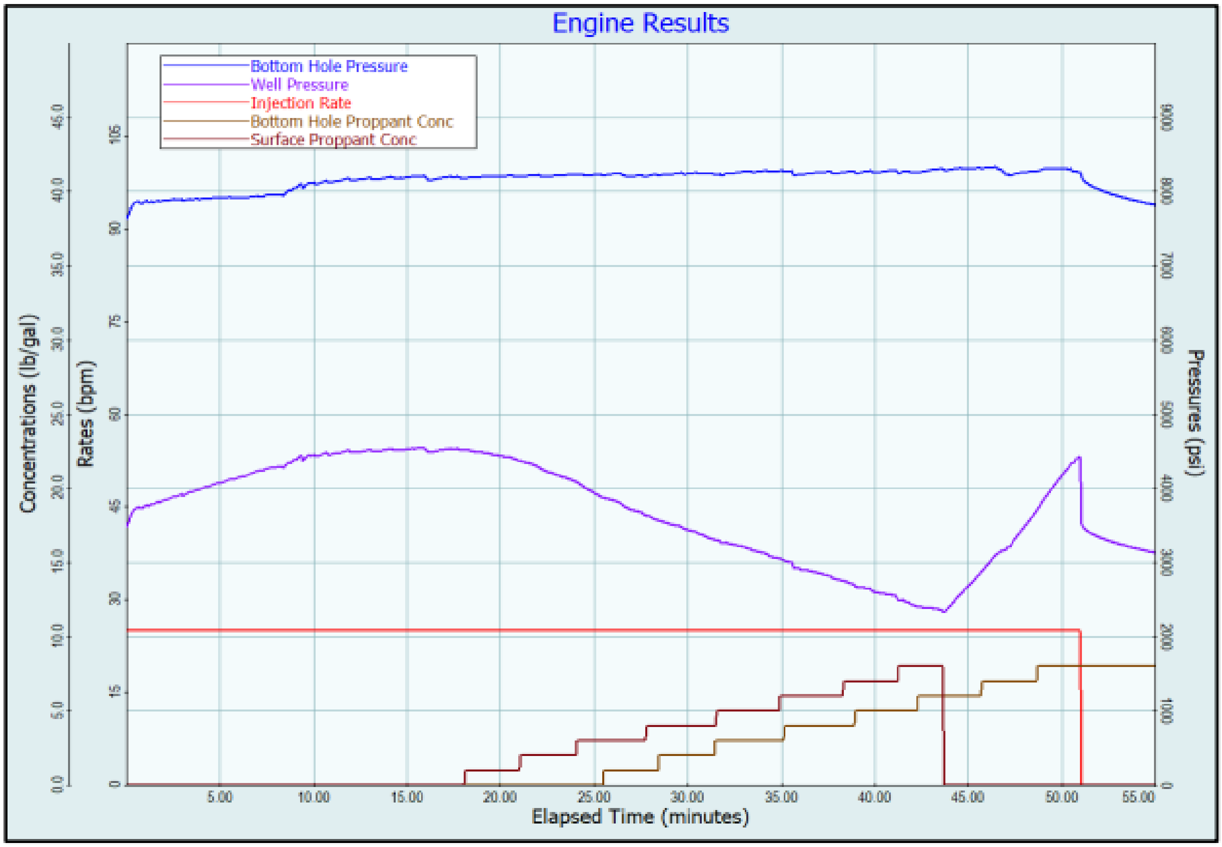


Figure III.23: Preliminary Main Treatment Plot

The figure (Figure III.24) above shows the expected BHP and Well Pressure curves during the main treatment

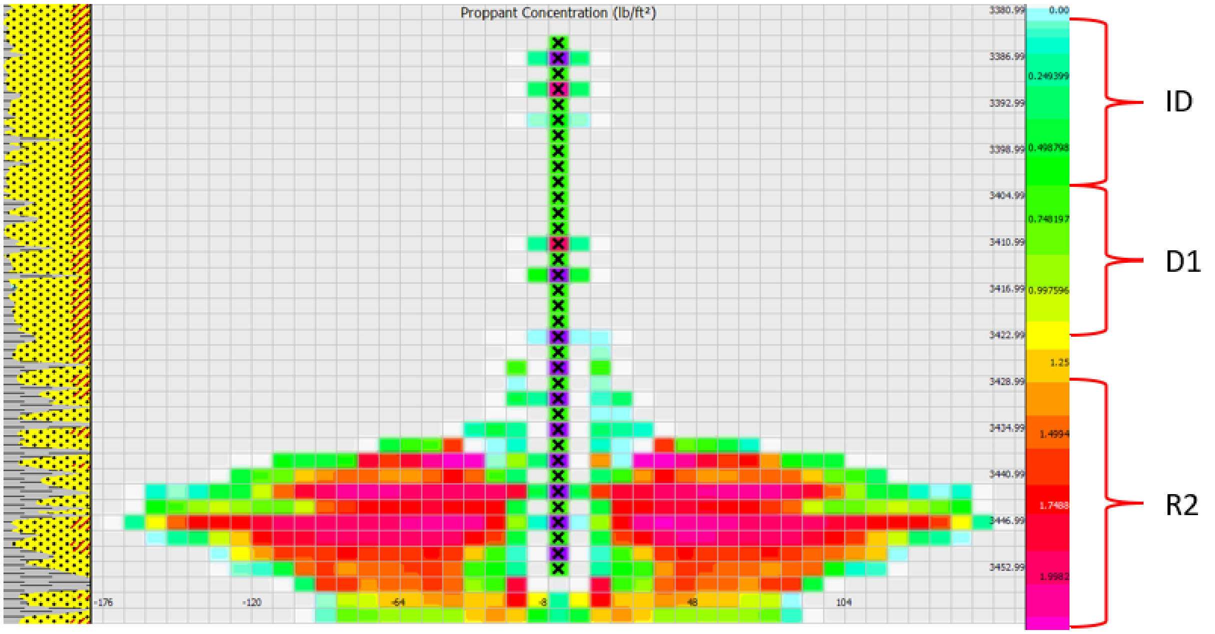


Figure III.24: Proppant Concentration in Fracture (lb/ft^2)

The simulation shows that the fracture is being created in the lower zone (R2) only.

- Top Fracture @ 3434 m
- Bottom Fracture @ 3460 m

Note: The main treatment design is only preliminary in nature and will be revised after the Minifrac & Temperature log.

5. INJECTION TEST:

On April 2nd, 2024, Injection test was conducted to grant that the reservoir is taking fluid and get an estimation of the in-situ stress status using the shut-in pressure decline analysis.

a. Injection test procedure:

1. Pressures test all treating lines and annulus.
2. Set all pumping units pressure kick-out and relief valves.
3. Increase annulus B and A to 500, 1800 respectively.
4. Begin the injection test by filling the hole with treated water at 2-5 bpm (Stage 1).
5. Continue pumping the Injection test with treated water until injection is verified then increase rate gradually to 15 bpm max (Stage 2)
6. Stop pumping and monitor pressure decline (stage 3)

b. Discussion of Injection Test

A summary of the Injection test, volumes, rates, and pressures are presented on the Table below.

Table III.7: Injection test summary

	Fluid Description	Planned Volume (gal)	Actual Volume (gal)	Slurry Rate Avg / Max (bbl/min)		Surface Press. Avg / Max (psi)	
Load Well / BD	**Treated Water**	**8,500**	**11,289**	**5.9**	**15.9**	**1,121**	**6,997**
Shut In	-	-	-	-	-	-	-

The Injection test shut-in pressure decline analysis is presented in Table below.

Table III.8: Injection test results

		Injection Test
Reservoir Injection Fluid		Treated Water
Volume Injected	(gal)	11,289
Avg. Injection Rate	(bbl/min)	15
Last Pumping Pressure	(psi)	11,031
ISIP	(psi)	10,443
Bottomhole Friction	(psi)	588
Fracture Gradient	(psi/ft)	0.93

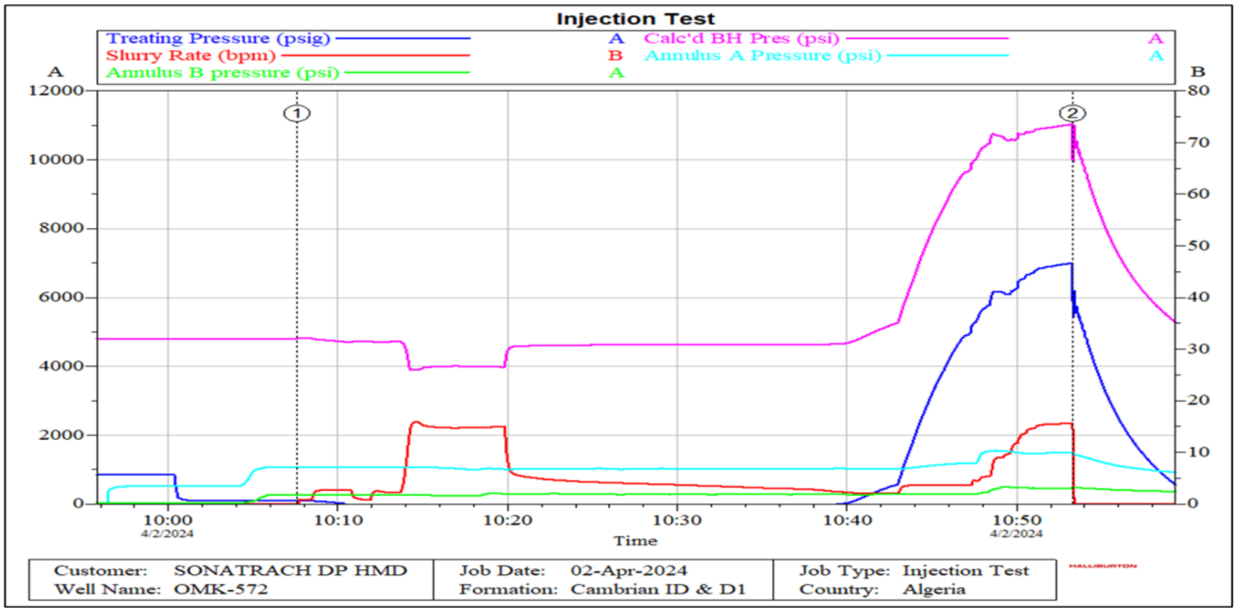


Figure III.25: Injection Test Plot

From the analysis of injection test plot and the table we obtain the following results:

- ISIP (Instantaneous Shut-In Pressure) = 10443 psi.
- LPP (Last Pumping Pressure) = 11031 psi.

c. Thermolog Analysis:

The temperature log was run immediately after the injection test in order to confirm the fracture propagation.

The log showed a cooling from 3360 mRT downwards to 3460 mRT which corresponds to the whole Cambrian reservoir, but the main cooling is in the R2 formation.

Our objective is to hydraulically fracture the upper zones (ID & D1), but according to thermolog, the fracture is propagated mainly in the lower zone (R2).

As the well is completed with slotted liner, we can’t isolate the lower zone (R2) with sand plug to force the fracture in the upper zone (ID & D1).

A decision was made to go for fracturing with the actual conditions (Appendix).

6. MINIFRAC:

The Minifrac was performed on March 3rd, 2024, to collect information to aid in the Main Fracturing treatment design and execution.

a. MiniFrac Procedure:

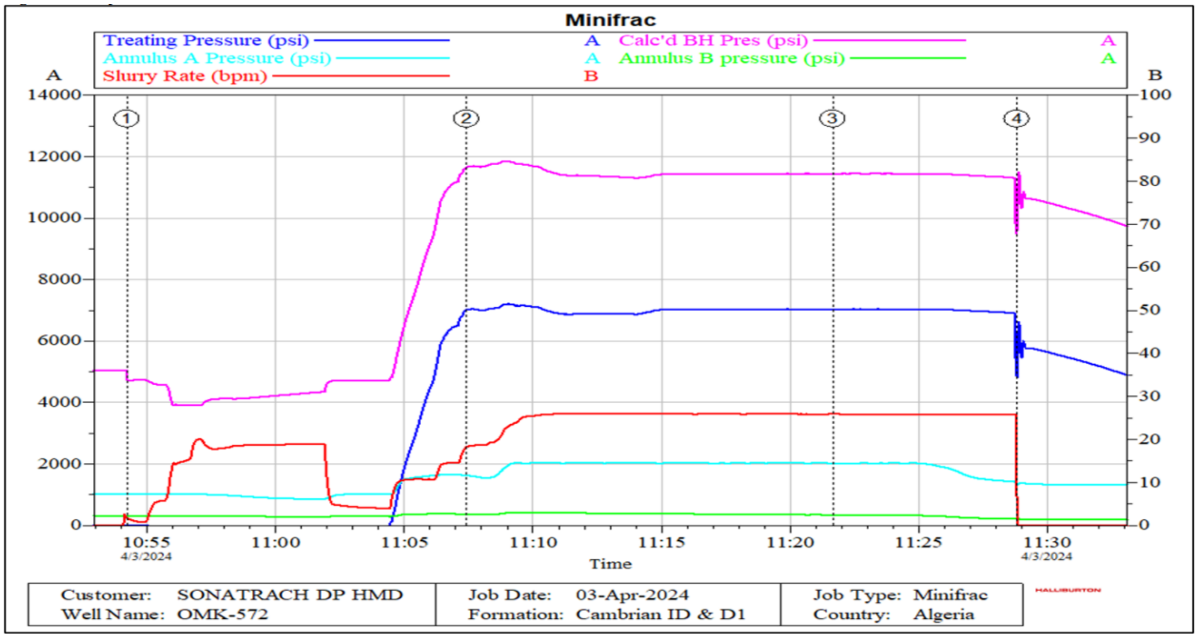
1. Pressures test all treating lines and annulus.
2. Set all pumping units pressure kick-out and relief valves.
3. Increase annulus B and A to 500, 1800 respectively.
4. Begin pumping a pre-pad of 1,000-gals linear gel and establish an injection rate of 25 bpm (stage 1).
5. Maintain rate at 25 bpm and pump a pad of Hybor G 35# of 15,000 gal (stage 2).
6. Displace the crosslinked gel with 7,700 gallons of linear gel 35# (stage 3).
7. Stop pumping and close ground valves, Monitor the pressure decline (Stage 4)

b. Discussion of MiniFrac

A summary of Minifrac, volumes, rates and pressures are presented in (Table III.9).

Table III.9: MiniFrac summary

	Fluid Description	Planned Volume (gal)	Actual Volume (gal)	Slurry Rate Avg / Max (bbl/min)		Surface Press. Avg / Max (psi)	
Pre-Pad	**Linrae Gel 35#**	**1,000**	**6,836**	**12.3**	**20.0**	**870**	**7,012**
Pad	**Hybor G 35#**	**15,000**	**15,016**	**25.1**	**26.0**	**7,007**	**7,210**
Flush	**Linrae Gel 35#**	**7,672**	**7,742**	**25.8**	**25.9**	**7,001**	**7,045**
Shut-In	**-**	**-**	**-**	**-**	**-**	**-**	**-**

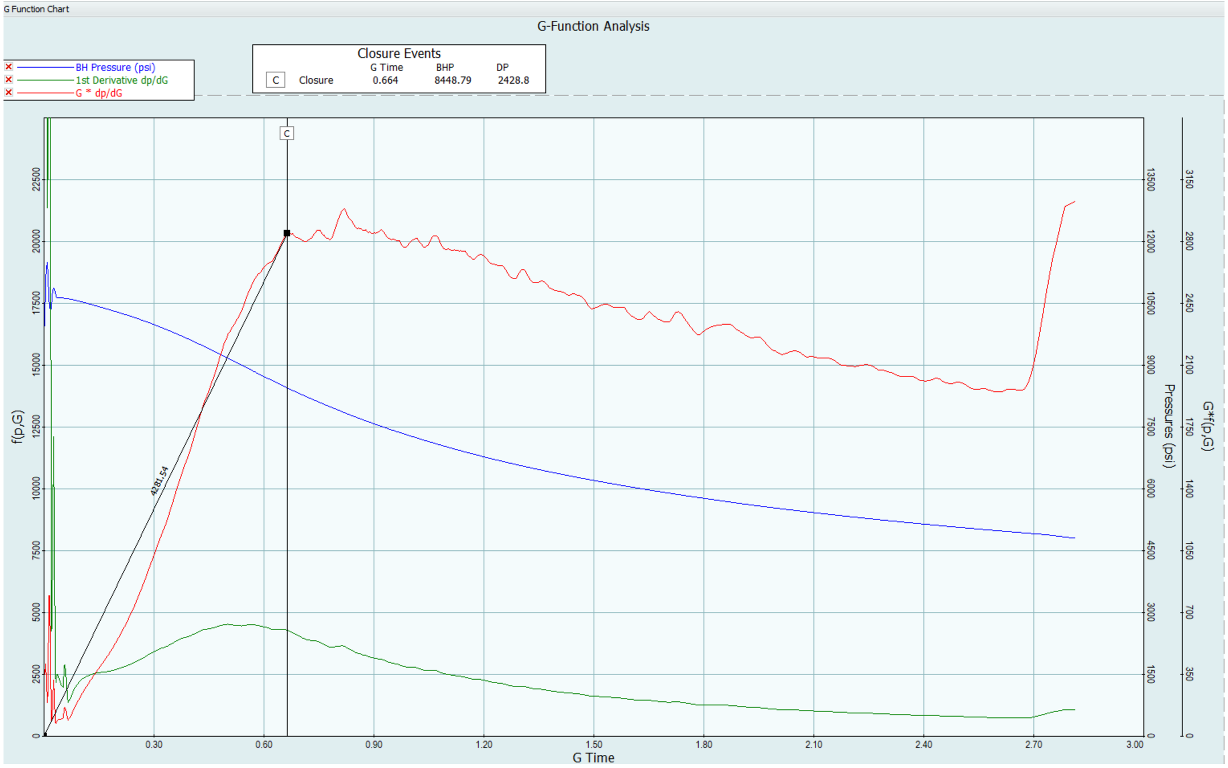


Customer: SONATRACH DP HMD
Well Name: OMK-572
Job Date: 03-Apr-2024
Formation: Cambrian ID & D1
Job Type: Minifrac
Country: Algeria

Figure III.26: Minifrac Plot

The Minifrac shut-in pressure decline was analyzed using the G-Function & Square Root methods (figures below).

The Minifrac registered a closure pressure of 8,505 psi with a corresponding fluid efficiency of 24.66%.



Closure Events

		G Time	BHP	DP
C	Closure	0.664	8448.79	2428.8

Figure III.27: G-Function Plots

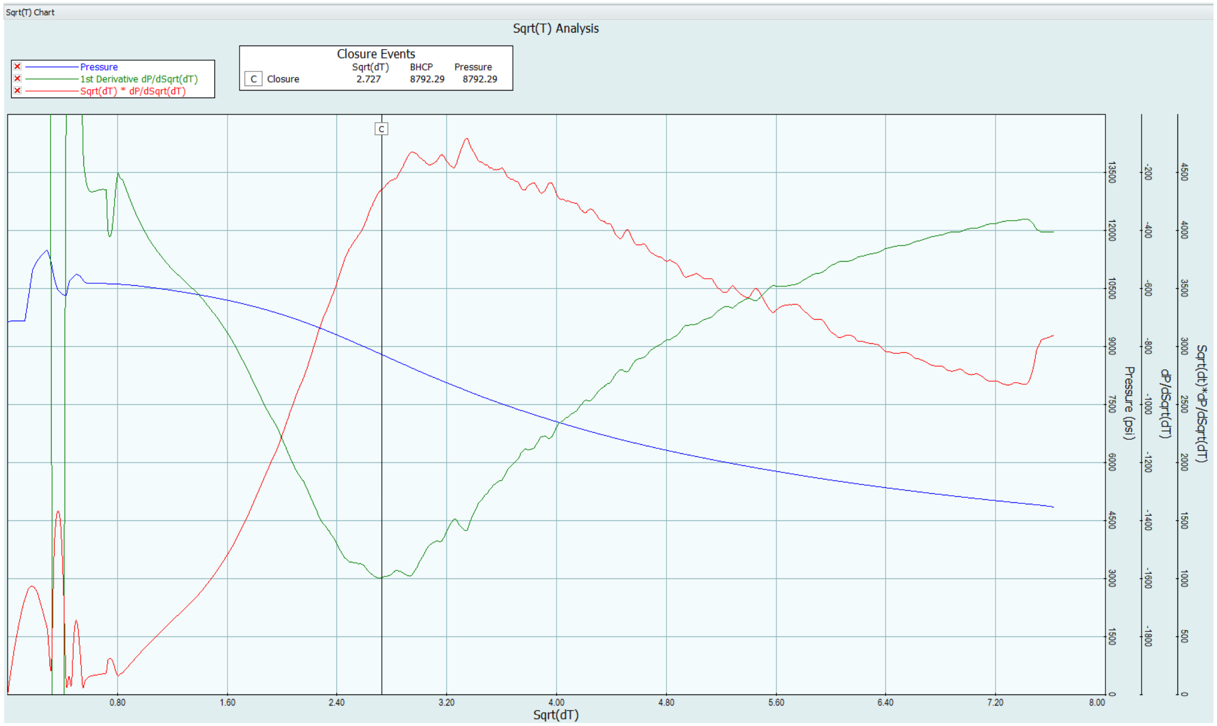
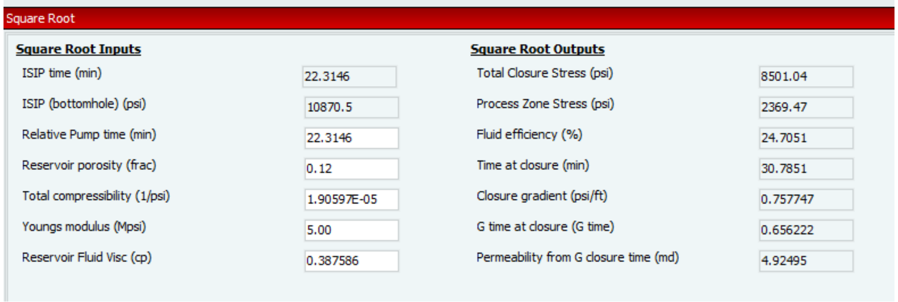


Figure III.28: Square Root Plots



Square Root

Square Root Inputs		Square Root Outputs	
ISIP time (min)	22.3146	Total Closure Stress (psi)	8501.04
ISIP (bottomhole) (psi)	10870.5	Process Zone Stress (psi)	2369.47
Relative Pump time (min)	22.3146	Fluid efficiency (%)	24.7051
Reservoir porosity (frac)	0.12	Time at closure (min)	30.7851
Total compressibility (1/psi)	1.90597E-05	Closure gradient (psi/ft)	0.757747
Youngs modulus (Mpsi)	5.00	G time at closure (G time)	0.656222
Reservoir Fluid Visc (cp)	0.387586	Permeability from G closure time (md)	4.92495

Figure III.29: Square Root outputs

The figures above (Figure III.29) represent the results of G-Function and Square Root plot where:

PZS (Net Pressure) = 2369.47 psi.

Pc (Closure Stress) = 8501.04 psi.

Fluid efficiency = 24.7 %.

Permeability = 4.92 md.

Note: Square Root Method Is used to minimize errors and correct the results of G-Function.

The Minifrac shut-in pressure decline analysis is presented in Table below.

Table III.10: MiniFrac shut-in pressure decline analysis

		Minifrac
Reservoir Injection Fluid		Hybor G35#
Volume Injected	(gal)	15,016
Avg. Injection Rate	(bbl/min)	25
Last Pumping Pressure	(psi)	11,295
ISIP	(psi)	10,748
Bottomhole Friction	(psi)	547
Fracture Gradient	(psi/ft)	0.96
Clouse Gradient	(psi/ft)	0.76
Clouse Pressure	(psi)	8,505
Fluid Efficiency	(%)	24.66
Net Pressure	(psi)	2,243

c. MiniFrac Matching

We need first to check the log temperature to determine the fracture top & bottom, then we adjust the minifrac parameters based on that interval.

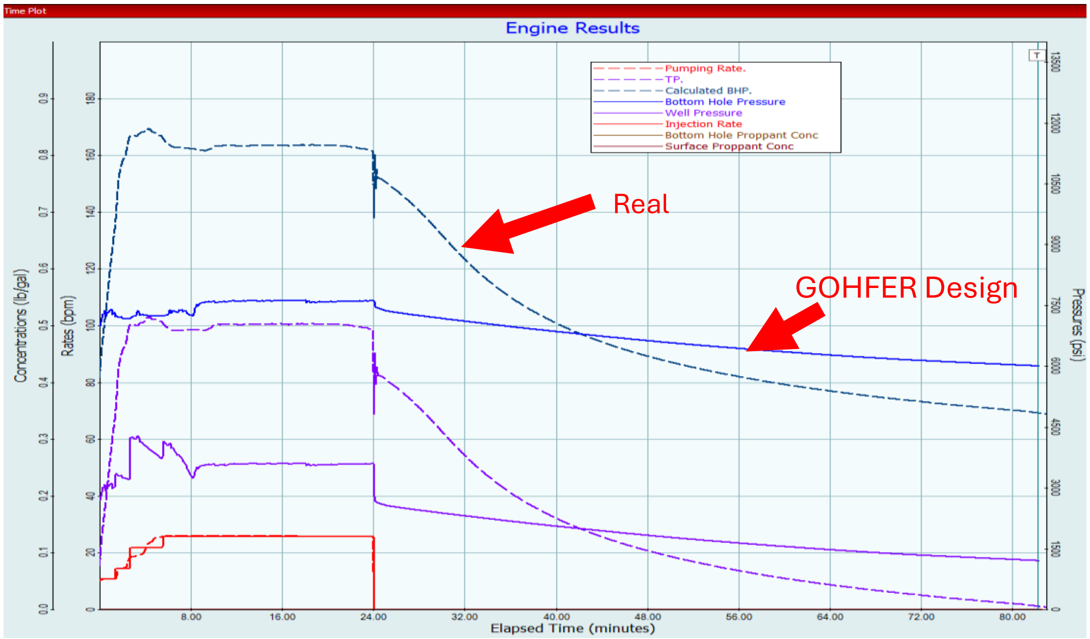


Figure III.30: GOHFER Minifrac before Matching

Matching parameters are in Grid Setup.

1)- Adjust the closure pressure to 8500 psi

- From GOHFER: Pc = 6800 psi.
- we need to add 1700 psi to match the measured closure pressure (8500 psi).

2)- Adjust the PZS to 2369.47 psi

- From GOHFER: PZS = 673 psi
- So we need to shift it to 2369.47 by adding 1696 psi.

3)- Adjust the permeability to match the pressure falloff

- From GOHFER: K = 0.109 md
- The matched k value is 0.4 md

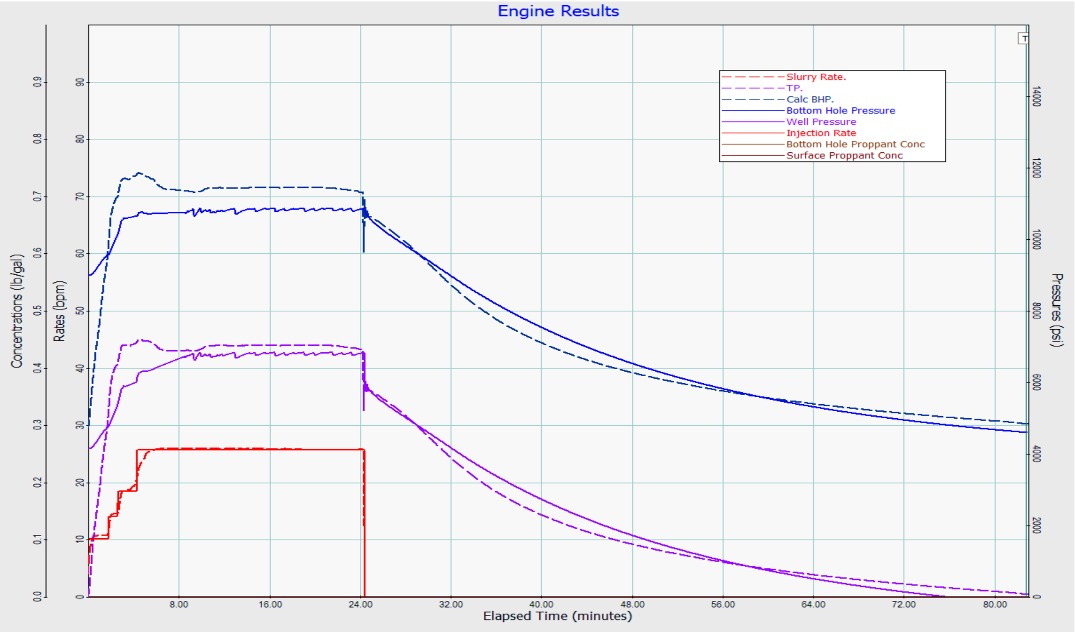


Figure III.31: GOHFER Minifrac After Matching

Matching considerations:

- Ensure that the stress profile is matched at the fracture initiation point.
- To match the falloff section, we focus on the permeability grid.
- We should take into consideration the frictions so they can affect the results of matching
- The better the matching, the more accurate and efficient the results are.

d. Final Main Frac Design

The main treatment design made for 71K lbs prop containing 8 stages 20/40 HSP.

For the near wellbore conductivity purposes, the final proppant concentration is 8 ppg if real time conditions permit.

The main treatment design simulation predicted that treatment would not be in the Screen out mode and the entire displacement could be pumped (Figure III.32). The average proppant concentration is displayed in (Figure III.33).

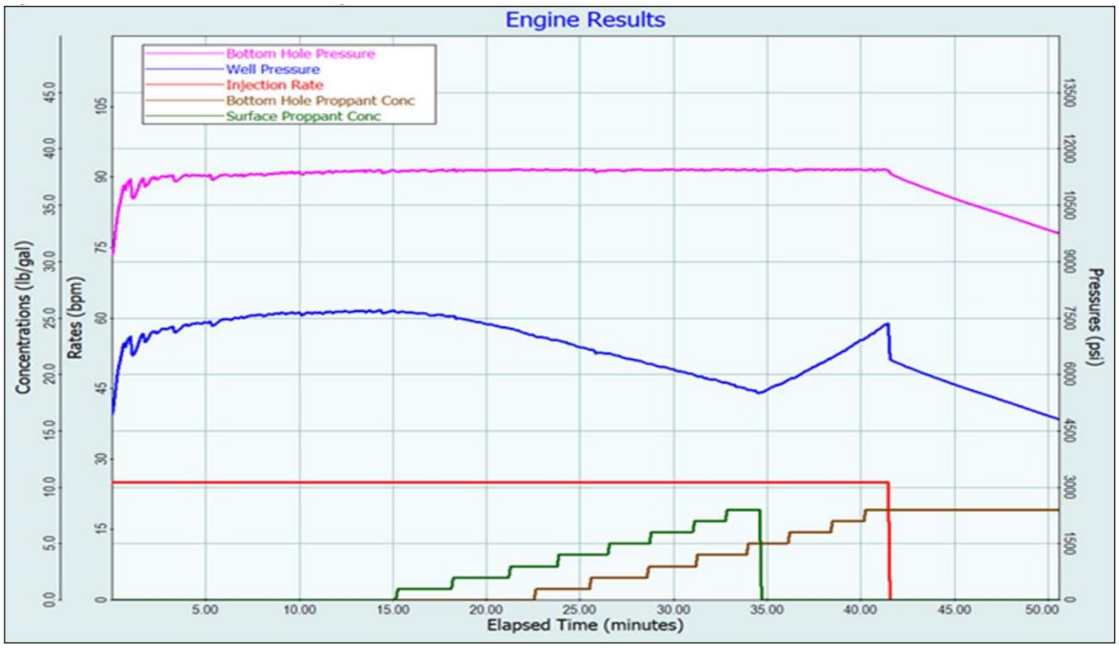


Figure III.32: GOHFER Main Treatment Design

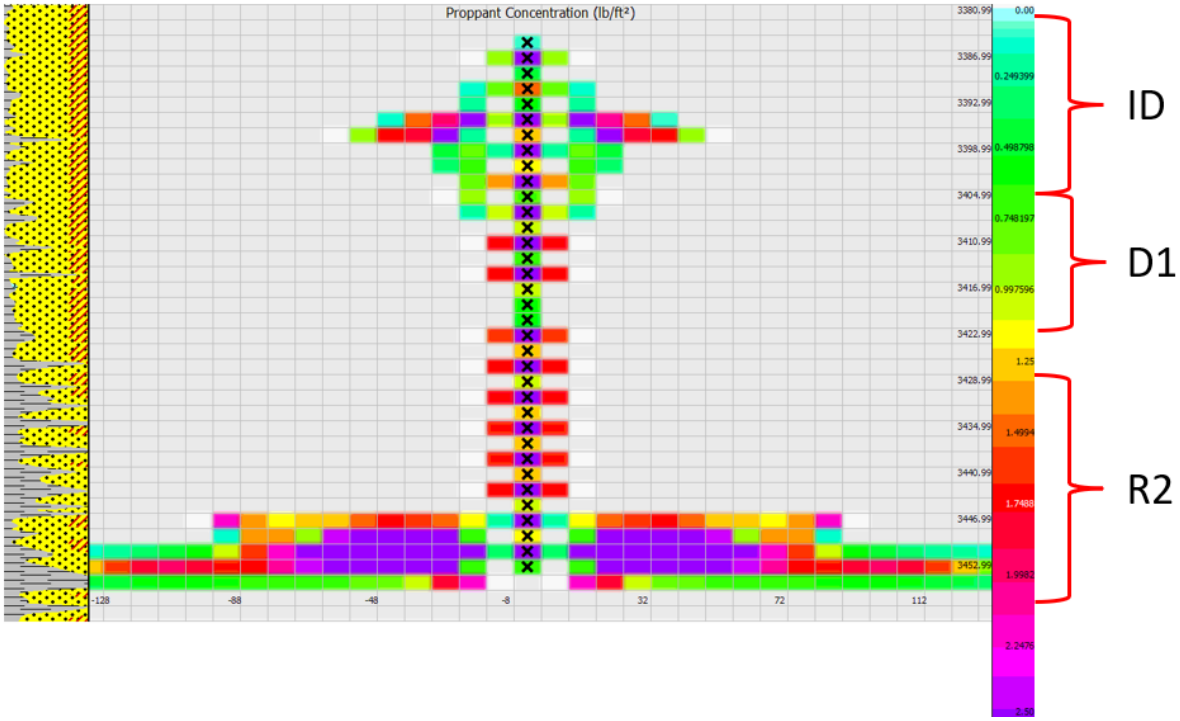


Figure III.33: GOHFER Main Treatment Design Proppant Concentration

7. MAIN FRAC:

a. Main Frac procedure:

1. Pressures test all treating lines and annulus.
2. Set all pumping units pressure kick-out and relief valves.
3. Increase annulus B and A to 500, 1800 respectively.
4. Begin pumping a pre-pad of 1,000 linear gal and establish an injection rate of 25 bpm (stage 1).
5. Maintain rate at 25 bpm and pump a pad of Hybor G 35# of 18,000 gal (stage 2).
6. Set the Pumps pressure kick-outs to 8,000 psi. (for 1-4 ppg SLF).
7. Continue injection of Hybor G 35# at 25 bpm and add 20/40 HSP in a proppant concentration of (from 1 to 4 lb/gal) of scheduled volume (from stage 3 to 6).
8. Set the Pumps pressure kick-outs to 7,500 psi. (for 5-7 ppg SLF).
9. Continue injection of Hybor G 35# at 25 bpm and add 20/40 HSP and 16/30 HSP (for proppant concentration of 7 and 8 lb/gal) in a proppant concentration of (from 5 to 8 lb/gal) of scheduled volume (from stage 7 to 10).
10. Displace the crosslinked gel with 7,300 gals of linear gel 35# (stage 11).
11. Stop pumping and close ground valves and monitor pressure decline (Stage 12)

b. Discussion of Main Frac Design

The Main Treatment was performed on April 4 th, 2024. Where we placed 69,398 lbs 20/40 HSP proppant into the formation at a max bottom-hole concentration of 8.22 ppg. Approximately 6,663 lbs was left inside the wellbore.

Summaries of the main treatment data are presented in **Tables III.11** and **III.12**. The main treatment plots are presented in **Figure III.34**.

Table III.11: Main Treatment Volume, Rate, and Pressure Summary

Stage Description	Planned Volume (gal)	Actual Volume (gal)	Slurry Rate Avg / Max (bbl/min)		Surface Press. Avg / Max (psi)		Calc'd BH Pressure Avg / Max (psi)	
Pre-Pad	1,003	2,740	11.6	19.0	1,701	6,904	11,487	11,576
Pad	16,147	15,998	25.8	26.3	7.168	7.731	11.446	11.641
1 ppg SLF	3,119	3,262	25.6	26.2	6,970	7,081	11,667	11,802
2 ppg SLF	3,220	3,199	25.2	28.3	6,781	6,897	11,898	12,024
3 ppg SLF	2.768	2.753	25.9	25.9	6.653	6,746	12,108	12,214
4 ppg SLF	2,852	2,825	25.9	25.9	6,516	6,573	12,336	12,473
5 ppg SLF	2,349	2,335	25.9	25.9	6.382	6,434	12,587	12,685
6 ppg SLF	2.416	2.390	25.9	25.9	6.267	6.326	12,652	12,748
7 ppg SLF	1,862	1,847	25.9	25.9	6,186	6,219	12,724	12,770
8 ppg SLF	1,913	2,553	25.9	25.9	6,139	6,168	12,482	12,628
Flush	7,051	6,989	25.9	25.9	6,808	7,580	-	-
Total	**44,700**	**46,890**						

Table III.12: Main Treatment Proppant Summary

Stage Description	Planned Proppant (lbs)	Proppant Pumped (lbs)	Prop. Conc. Avg / Max (lbs/gal)		BH Conc. Avg / Max (lbs/gal)	
Pre-Pad	-	-	-	-	-	-
Pad	-	-	-	-	-	-
Prop 1	3.000	2,987	2.64	5.57	2.65	5.57
Prop 2	6,000	5.317	1.77	2.06	1.77	2.07
Prop 3	7,500	7,273	2.91	3.20	2.92	3.22
Prop 4	10,000	9,750	3.91	4.40	3.94	4.43
Prop 5	10,000	9,991	5.00	5.35	5.05	5.40
Prop 6	12,000	12,035	6.07	6.45	6.12	6.48
Prop 7	10,500	10,526	7.06	7.46	7.13	7.49
Prop 8	12,000	15,823	7.83	8.40	7.87	8.22
Displacement	-	2,359	0.98	6.39	-	-
Total	**71,000**	**76,061**	**63,398 lbs 20/40 HSP**			

Proppant Loaded in Mountain Mover	**79,367**	**Lbs 20/40 HSP**

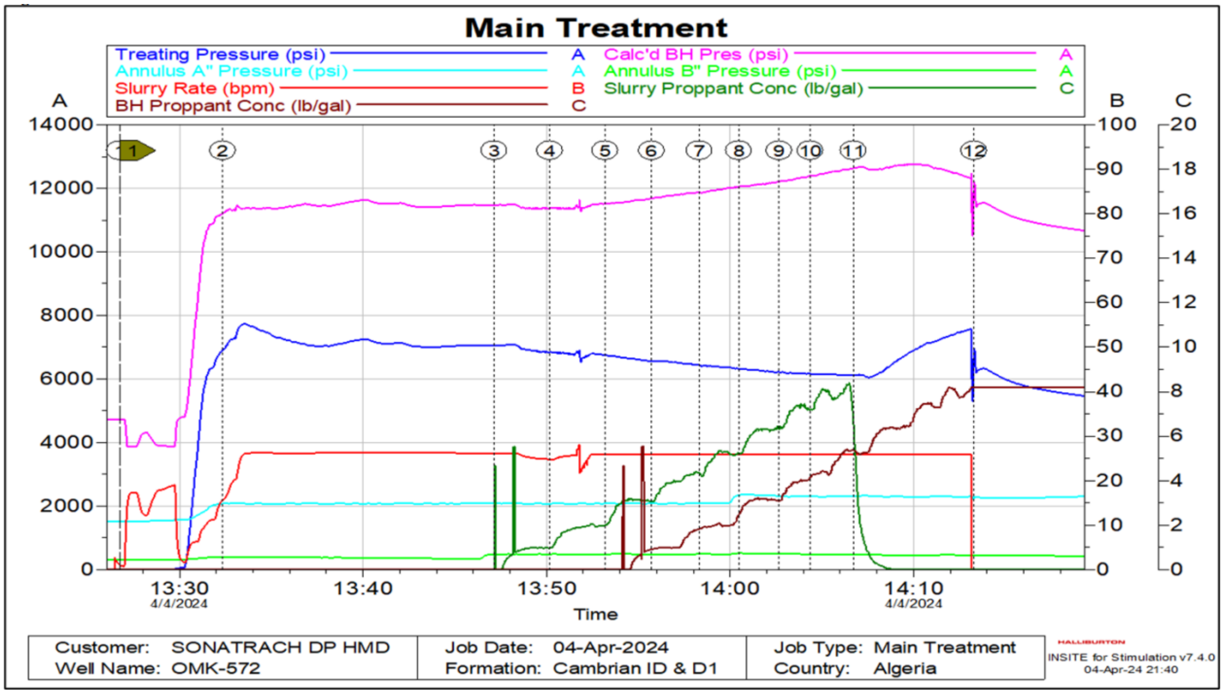


Figure III.34: Main Treatment

8. POST FRAC EVALUATION

Table III.13: Post Frac evaluation

	Before Frac	After Frac
Choke (mm)	Closed	14
Oil rate (m3/h)		0.8
Gas Rate (m3/h)		1538.75
GOR (Sm3/m3)		1925
Water Rate (l/h)		0
WHP		19.7
PP		10.4

The results of post frac shows that:

- New Oil rate = 0.8 m^3/h (increasing of 0.5 m^3/h) with zero water rate.
- The targeted zone was ID & D1 but due the frac propagated in the R2 zone due to the low stress of the lower zone (R2) comparing with the upper zones.

CONCLUSION:

The treatment was executed without any HSE incident. The primary objective of the hydraulic fracturing treatment was to place a propped fracture in the ID & D1, however the low stress in the lower zone (R2) leads to fracture propagation mainly across that zone, in addition, The job size was limited to prevent the fracture from propagating down towards the water zone.

The Post frac evaluation shows insignificant increase in well productivity (the new Oil rate is 0.8 m^3/h, with total proppant injected volume of 76061 lbs), due to not perfectly fracking the target interval (ID & D1).

GENERAL CONCLUTION:

To recover as many hydrocarbons as possible and eliminate damage in reservoirs, hydraulic fracturing is being developed around the world. It consists of injecting under pressure a fluid loaded with solid particles called proppant to fracture the reservoir rock to increase the productivity index. Some problems cause operations to fail such as tortuosity, screen out...etc.

So, software simulators are used to generate program designs for fracking jobs, to know the stages of this operation and to reduce problems that could happen during the process to ensure improved production.

We used the GOHFER 3D simulator to show how it could help us generate a frac design that would improve production, as we studied the OMK572 well fracturing job, which was done On April 4th, 2024, so we got the following results:

- The final main fracking treatment design is identical to the real design applied on the well, which indicates the quality and accuracy of the GOHFER 3D work in simulation.
- Through the results, we were able to determine that the fractures did not target the desired drains (D1, ID).
- From the resulting simulations, the proppant concentration was deficient in the reservoir layers (D1, ID), leading to insufficient conductivity (FCD).

From what we get and what we observe from the hydraulic fracturing results applied to OMK572 it can be said that the GOHFER 3D simulator is a software with high accuracy and efficiency in designing fracturing operations. Still, it needs the largest possible amount of data and logs of the wells to generate the most accurate results.

RECOMMENDATION

Based on the above facts, we recommend the following:

- Complete future hydraulic fracturing candidate wells with cemented liner and perforate only the ID & D1 to control the fracture propagation.
- preliminary design is recommended before starting the job to predict the propagation of the fracture into the formation and the probability of the job to succeed.
- Use new diverting techniques to control the placement of fluids and Proppant into the target formation (like Broadband Sequence (BBS) Technique by Schlumberger)

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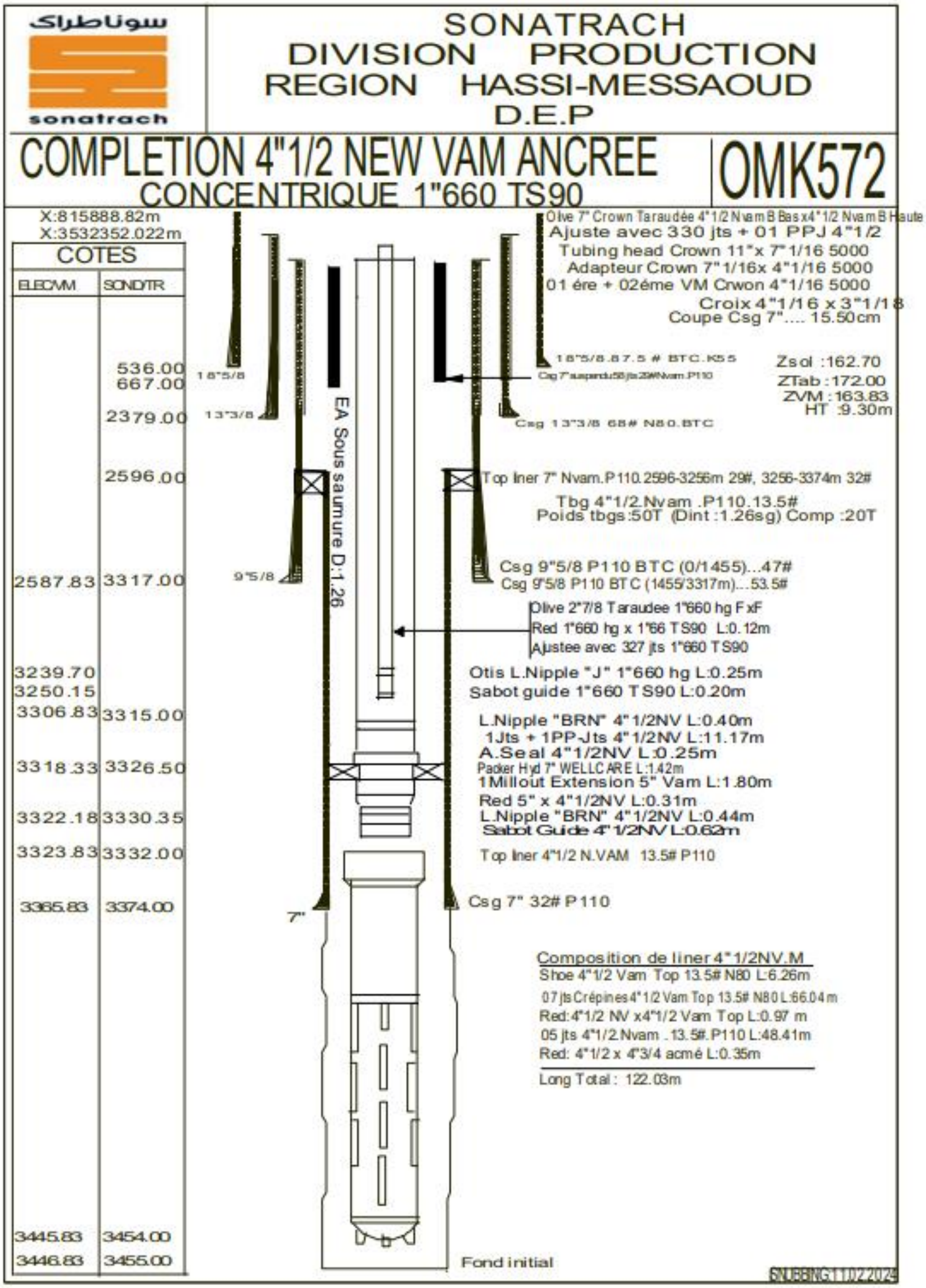
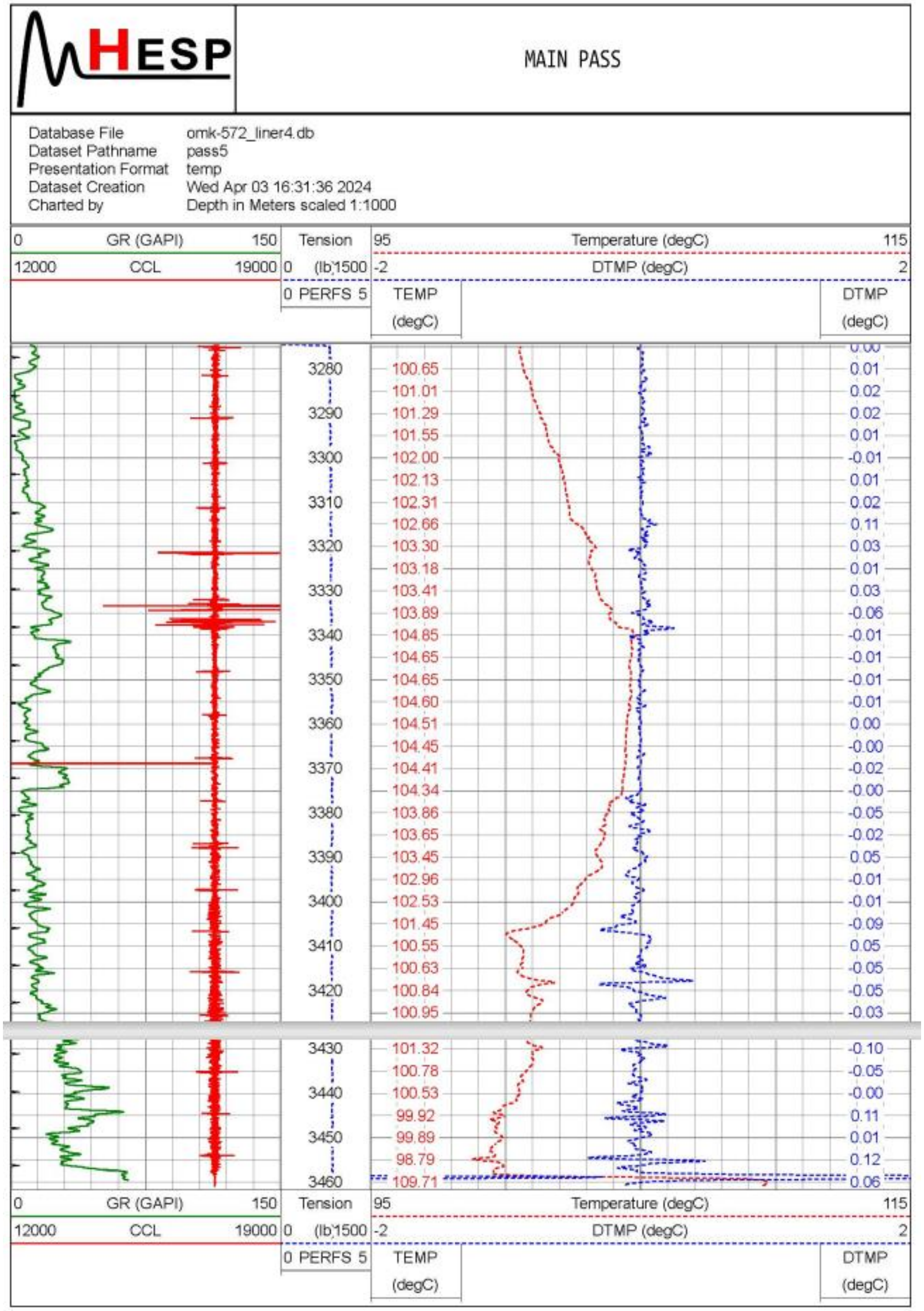
Appendix:

Appendix 1: Technical sheet of the OMK572 well



Appendix 2: Thermolog of OMK572



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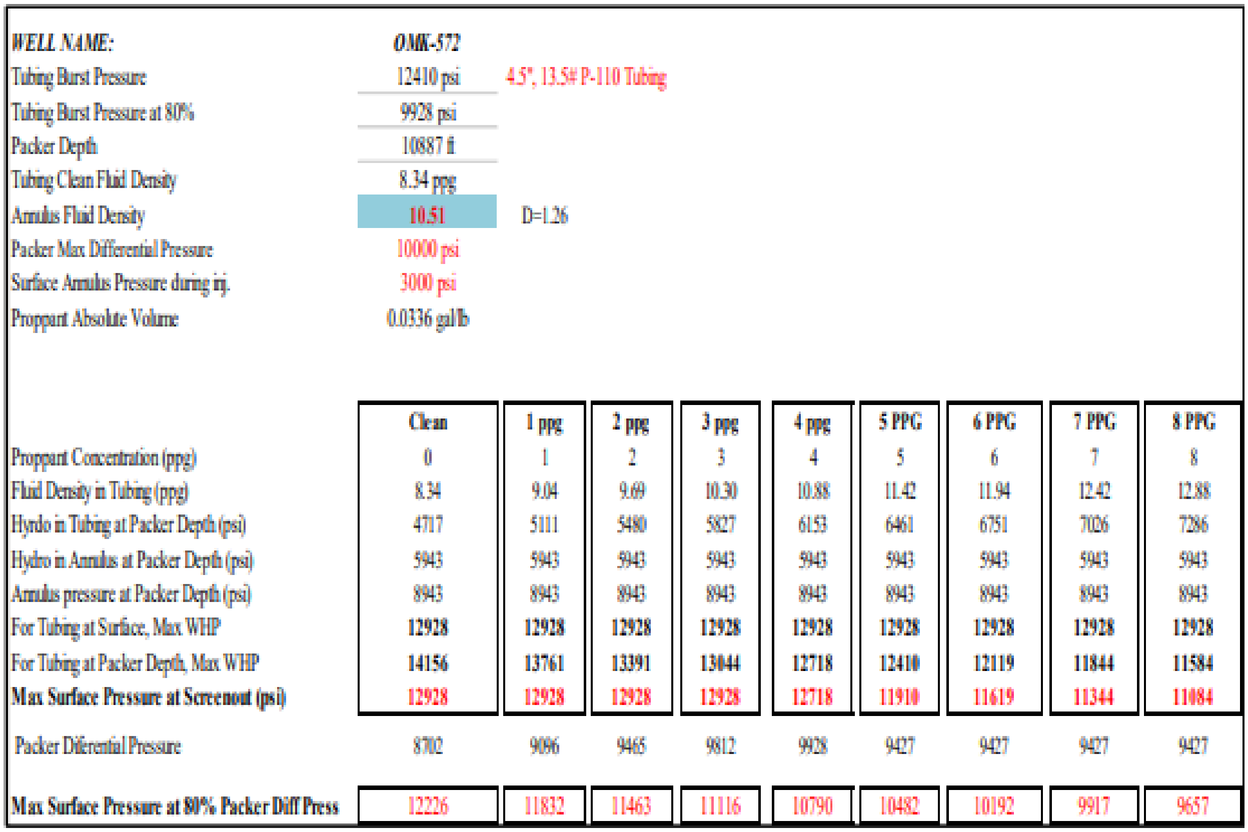
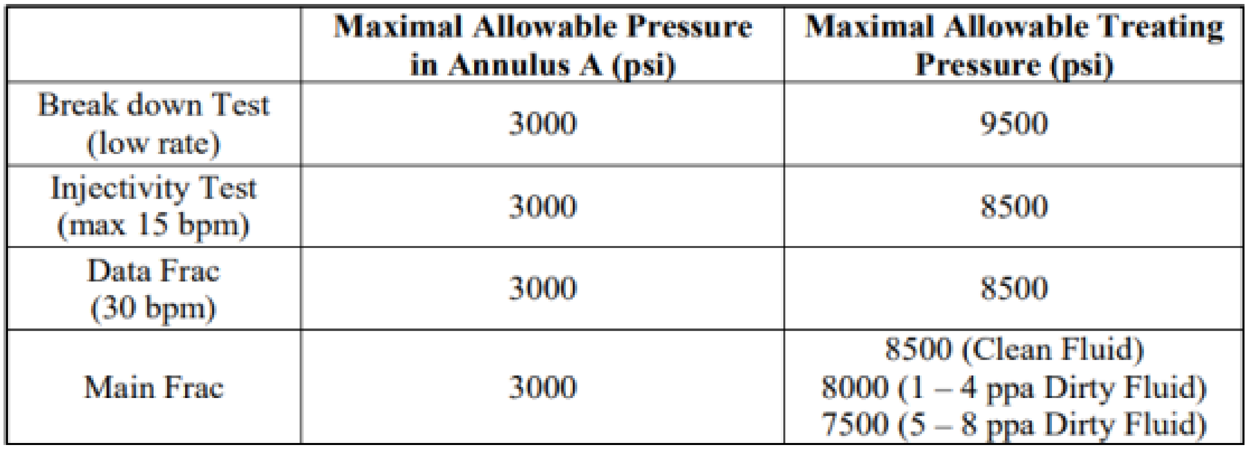
Dataset Pathname pass5
Presentation Format temp
Dataset Creation Wed Apr 03 16:31:36 2024
Charted by Depth in Meters scaled 1:1000

Appendix3: SURFACE PRESSURE LIMITATION



WELL NAME:	***OMK-572***	
Tubing Burst Pressure	12410 psi	4.5", 13.5# P-110 Tubing
Tubing Burst Pressure at 80%	9928 psi	
Packer Depth	10887 ft	
Tubing Clean Fluid Density	8.34 ppg	
Annulus Fluid Density	**10.51**	D=1.26
Packer Max Differential Pressure	10000 psi	
Surface Annulus Pressure during inj.	3000 psi	
Proppant Absolute Volume	0.0336 gal/lb	

	Clean	1 ppg	2 ppg	3 ppg	4 ppg	5 PPG	6 PPG	7 PPG	8 PPG
Proppant Concentration (ppg)	0	1	2	3	4	5	6	7	8
Fluid Density in Tubing (ppg)	8.34	9.04	9.69	10.30	10.88	11.42	11.94	12.42	12.88
Hyrdo in Tubing at Packer Depth (psi)	4717	5111	5480	5827	6153	6461	6751	7026	7286
Hydro in Annulus at Packer Depth (psi)	5943	5943	5943	5943	5943	5943	5943	5943	5943
Annulus pressure at Packer Depth (psi)	8943	8943	8943	8943	8943	8943	8943	8943	8943
For Tubing at Surface, Max WHP	**12928**	**12928**	**12928**	**12928**	**12928**	**12928**	**12928**	**12928**	**12928**
For Tubing at Packer Depth, Max WHP	**14156**	**13761**	**13391**	**13044**	**12718**	**12410**	**12119**	**11844**	**11584**
Max Surface Pressure at Screenout (psi)	**12928**	**12928**	**12928**	**12928**	**12718**	**11910**	**11619**	**11344**	**11084**
Packer Diferential Pressure	8702	9096	9465	9812	9928	9427	9427	9427	9427
Max Surface Pressure at 80% Packer Diff Press	12226	11832	11463	11116	10790	10482	10192	9917	9657



	Maximal Allowable Pressure in Annulus A (psi)	**Maximal Allowable Treating Pressure (psi)**
Break down Test (low rate)	3000	9500
Injectivity Test (max 15 bpm)	3000	8500
Data Frac (30 bpm)	3000	8500
Main Frac	3000	8500 (Clean Fluid) 8000 (1 – 4 ppa Dirty Fluid) 7500 (5 – 8 ppa Dirty Fluid)

Appendix

Appendix 4: Depot

	Date	Puits	Prise de	Résultats
1	2019-05-17	OMK572	3444m	Boue à base d'huile +12,5% Sels (NaCl)
2	2019-06-22	OMK572	3452m	Boue à base d'huile
3	2019-08-07	OMK572	3450m	Boue à base d'huile 7,83% Sels , 3,67% FeCO3 , 6% CaCO3 , 5,47% MgCO3 Reste: la baryte

Table: Analyse laboratoire (OMK572)

	Date	Puits	Prise de	Résultats
1	2018-10-04	OMK573		46 % Résidu insoluble (en cours)+ 11% Sels (NaCl) + 15% CaCO3 + 6,5% MgCO3 + 14% FeCO3
2	2018-10-22	OMK573		23 % sels (NaCl), 9 % CaCO3, 9 % FeCO3 boue à base de baryte
3	2018-11-26	OMK573	3457m	13,20% Sels (NaCl) ,8,49% CaCO3 , 6,31% FeCO3 , 5,45% MgCO3 Reste:
4	2018-12-14	OMK573	3457m	27,23% Sels (NaCl) + 9% Huile + 9% CaCO3 + 6% MgCO3 + 3,4% FeCO3 + 2% Oxyde de fer Reste grés fins de formation
5	2019-05-22	OMK573	3460m	100% Sels
6	2019-09-06	OMK463	3465m	09% Sels,26% CaCO3, 34,3% MgCO3 , 23% FeCO3 Reste:Grès fins de formation
7	2020-01-17	OMK463	3299m	95% Sels (NaCl) , Reste: trace d'huile
8	2020-01-22	OMK463	3294m	95% Sels , Reste Trace d huile
9	2020-03-30	OMK463	3024m	100% Sels(NaCl)
10	2020-06-01	OMK463	3174m	73% Sels (NaCl) , reste grès de formation
11	2020-07-12	OMK463	3263m	79% sels(Nacl),Reste argile
12	2020-09-18	OMK463	2525m	85% Sels Reste grés fins de formation
13	2020-09-27	OMK463	2734m	100% Sels
14	2021-09-07	OMK463	2664m	99 %sels(NaCl) ,Reste: Grès fins de formation + trace d'huile

Table : Analyse laboratoire (Puits Voisin)