PEOPLE'S DEMOCRATIC AND REPUBLIC OF ALGERIA

MINISTRY OF HIGH EDUCATION AND SCIENTIFIC RESEARCH

N° Series: ………./2021


KASDI MERBAH UNIVERSITY-OUARGLA

**Faculty of Hydrocarbons, Renewable Energy and Science of Earth and Universe**

**Department of production of hydrocarbons**


**DISSERTATION**

**To obtain the master's degree**

**Option: Production**

Presented by:


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-TITLE-

# Multistage Hydraulic Fracturing With Horizontal Wells In Unconventional Reservoirs (Study Case: Timimoun Field IRS-A Well)

Publically defended on:  06/20/2021

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# *Acknowledgements*

*Above all, our sincere praises go to ALLAH the Almighty for giving us strength and patience to carry on and reach this level to finish this dissertation.*

*There are a number of people without whom this thesis might not have been written, and to whom we are greatly indebted.*

*First, we would like to express our gratitude to our supervisor Professor* ***CHETTI DJAMEL EDDINE*** *who honored us with his acceptance to guide and supervise us researching this paper.*

*Second, we express our sincere thanks to the members of the jury:* ***Mr. LEBTAHI Hamid*** *and* ***Mr. DJEBBAS Fayçel****, for their valuable comments and insightful suggestions.*

*Foremost, we would like to thank* ***Mr RIGHI Youcef*** *for his guidance and patience all along the realization of this work.*

*Finally yet importantly, our sincere appreciation goes to* ***Mr Meriouma, Mr. Mehifer, Mr. Boufaghes Mohcene, Merabti Imene, Merabet Zineb, Sabri Amina*** *and everyone who helped us in the New Technics department at EP/SONATRACH, IRARA base.*

# Dedication

I dedicate this study wholeheartedly To my dear father M.lahcen who gave me everything, with nothing in return, for his fatherly love, his unconditional support throughout my studies, and for the trust he always showed me.

To my lovely mother DJAHNIN Hakima, for her sacrifice in order to make me one of the best.

To my two brothers ISLAM, and DHIAA and my sisters YOUSRA, TAKWA and FATIMA for thier encouragement.

To my dear MOHAMMED, CHAIMA and HADIL, who helped me to carry out this work.

And last but not least to all my classmates who made this journey more special and memorable.

Islah Kadri

This study is wholeheartedly dedicated to my beloved parents, ABDELKADER and BOURBIA AZIADI….my source of inspiration who continually provide their moral, spiritual, emotional, support..

To my brothers CHEMSEDDINE, CHARAFEDDINE and my sister CHAHRAZED, who shared their words of encouragement.

And last but not least, to my friends HADIL, RACHA, CHAIMA and my classmates who made this journey easier and more fun.

Safa Cherfaoui

This thesis is proudly dedicated to all my precious family and friends…

To my parents, ABDELKRIM and BELATTAR FATMA, the most helpful parents ever who gave me love, trust, patience, support, and encouragements.

To my caring brothers SALAH and MOHAMED and my sisters MERIEM, SARAH and ZOUINA who have been a great source of motivation.

To my dear friends HADIL, SHEIMA, RACHA and AYMEN and my colleagues who supported me and believed in me…

Sawsen Chebouki

## Abstract:

Multistage hydraulic fracturing using horizontal wells has been an integral part of unconventional reservoirs exploitation because of their specific characteristics. The process uses long horizontal wells divided into many stages; Fluids are pumped down into each stage to generate a fracture, which increases the permeability of the formation to allow economic resource extraction. Reaching these results requires an optimal designing of the hydraulic fracturing treatment where we obtain the optimal treatment parameters in order to maximize the production with some constraints such as the cost and treatment capability.

This thesis provides a guide for a better fracturing treatment design, with a study case where we reach the required design and improve the productivity in tight reservoirs.

**Keywords:** unconventional reservoirs, hydraulic fracturing, horizontal wells, multi-stage fracturing, treatment design.

## Résumé :

Multistage frac dans les puits horizontaux est une opération essentielle pour l'exploitation des réservoirs non conventionnels à cause de leurs caractéristiques spécifiques. Le processus utilise de longs puits horizontaux divisés en plusieurs étages, les fluides ensuite sont pompés dans chaque étage pour générer une fracture qui augmente la perméabilité de la formation et permettre l'extraction économique des ressources. Pour atteindre ces résultats, un design de traitement de fracturation est nécessaire pour obtenir les paramètres de traitement optimaux afin de maximiser la production avec certaines contraintes telles que le coût et la capacité de traitement.

ce travail fournit un guide pour réaliser un design de traitement de fracturation, avec un cas d'étude ou on atteint les résultats requis avec l'amélioration de la productivité dans les réservoirs tight.

**Mots Clés :** Fracturation hydraulique, Multistage frac, puits horizontaux, réservoirs non-conventionnels.

## ملخص:

التكسير الهيدروليكي متعدد المراحل في الآبار الأفقية تعتبر عملية مهمة في استغلال الخزانات غير التقليدية نظرًا لخصائصها المحددة. تستخدم العملية آبارًا أفقية طويلة مقسمة إلى عدة طوابق، حيث يتم ضخ السوائل في كل طابق لإِحداث كسر وزيادة نفاذية الخزان مما يسمح باِستخراج الموارد النفطية. يتطلب الوصول إلى هذه النتائج تصميمًا مثاليًا لمعالجة التكسير الهيدروليكي حيث نحصل على معايير المعالجة المُثلى من أجل زيادة الإنتاج رغم وجود بعض القيود مثل التكلفة والقدرة على المعالجة.

تقدم هذه المذكرة دليلاً أفضل لتصميم معالجة التكسير الهيدروليكي، مع حالة دراسية تتضمن دليل للوصول إلى التصميم المطلوب وتحسين الإنتاجية في الخزانات الضيقة.



**الكلمات المفتاحية:** التكسير الهيدروليكي، الأبار الافقية، التكسير الهيدروليكي متعدد المراحل، الخزانات غير التقليدية

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# Abbreviations

| | |
|---|---|
| **CT** | Coiled tubing**.** |
| **CBM** | Coalbed methane. |
| **CSM** | Coal seam methane. |
| **KCL** | Chlorure de potassium. |
| **PLT** | Production logging tools. |
| **PNP** | Plug-and-Perforate. |
| **BACS** | Ball-activated completion system. |
| **CTACS** | Coiled tubing-activated completions systems. |
| **MSHF** | Multi stage hydraulic freacturing. |
| **HHP** | Hydraulic horse power. |
| **KGD** | (Kritianovitch and Zheltov, Geertsma and DeKlerk, further refined by Daneshy) |
| **PKN** | (Perkins and Kern, Nordgren). |
| **NPT** | Non-productive time. |
| **SEM** | Scanning electron microscope. |
| **SEM** | Scanning electron microscope. |
| **ISP** | Intermediate Strength Proppant. |
| **TW** | Treated water. |
| **MBTU** | Million british thermal unit |

# Nomenclature

| | | |
|---|---|---|
| **FEP** | [Psi] | The fracture extension pressure. |
| **ISIP** | [Psi] | Instantaneous shut-in pressure. |
| **FCP** | [Psi] | Fracture closure pressure . |
| $\boldsymbol{\sigma}$ | [Psi] | Stress |
| $\boldsymbol{\sigma_v}$ | [Psi] | Vertical stress. |
| $\boldsymbol{\sigma_{h,min}}$ | [Psi] | Minimum horizontal stress |
| $\boldsymbol{\sigma_{h,max}}$ | [Psi] | Maximum horizontal stress |
| **F** | [Psi ] | Force |
| $\boldsymbol{\varepsilon}$ | - | Strain |
| $\boldsymbol{\varepsilon_y}$ | - | Radial strain |
| $\boldsymbol{\varepsilon_x}$ | - | Axial strain |
| $\boldsymbol{\delta_x}$ | | Change in direction |
| **E** | [Psi] | Young’s modulus |
| $\boldsymbol{\nu}$ | - | Poisson’s modulus |
| **G** | [Psi] | Shear modulus |
| **T** | [min] | Shut- in time |
| $\mathbf{t_p}$ | [min] | Total pumping time |
| $\mathbf{t_{inj}}$ | [min] | Injection time of calculating slurry concentration (); |
| $\mathbf{t_{pad}}$ | [min] | Time to pump the pad volume |
| **P** | [Psi] | Pressure |
| $\mathbf{P_1}$ | [Psi] | Inlet pressure. |

| | | |
|---|---|---|
| $\mathbf{P_2}$ | [Psi] | Outlet pressure. |
| $\mathbf{\Delta P_h}$ | [Psi] | Hydrostatic pressure drop. |
| $\mathbf{P_{si}}$ | [Psi] | Surface injection pressure. |
| $\mathbf{\Delta P_f}$ | [Psi] | Frictional pressure drop. |
| $\mathbf{P_{bd}}$ | [Psi] | Formation breakdown pressure. |
| **Gc** | - | The G-function time at fracture closure |
| $\mathbf{Gdp/dG}$ | - | G-function derivative |
| **w** | [ft] | Fracture width. |
| $\mathbf{x_f}$ | [ft] | Fracture half-length, ft. |
| $\mathbf{h_f}$ | [ft] | Fracture length |
| $\mathbf{r_f}$ | [ft] | The radius of the fracture |
| $\mathbf{A_f}$ | [$ft^2$] | Fracture area ; |
| $\mathbf{r_p}$ | [ft] | Payzone thickness/ fracture height; |
| $\boldsymbol{\alpha}$ | - | Leak of factore |
| $\boldsymbol{\eta}$ | - | Fluid efficiency |
| $\boldsymbol{\mu}$ | [cp] | Fluid viscosity |
| $\boldsymbol{\rho}$ | [g/cm3] | Density of fluid,; |
| $\boldsymbol{\gamma_0}$ | | Oil specific gravity |
| $\overline{\mathbf{W}}$ | [ft] | Average fracture width |
| $\mathbf{F_{CD}}$; | - | Dimensionless fracture conductivity |
| $\mathbf{k_f}$ | Md | Fracture permeability, |
| **k** | Md | Formation permeability |
| $\mathbf{K_L}$ | - | Fluid loss multiplier |
| $\mathbf{C_L}$; | [$ft/(min)^{1/2}$] | Fluid loss coefficient in |

| | | |
|---|---|---|
| $\mathbf{C_t}$ | [psi] | Pressure pumping |
| **CL** | - | Fluid filtration |
| $\mathbf{C_p}$ | [Ppg] | Proppant concentration in; |
| $\mathbf{M_p}$ | [Lbs] | Proppant weight |
| $\boldsymbol{\phi_p}$ | - | Proppant porosity |
| **d** | [In] | Pipe inner diameter |
| **D** | [In] | Tubing diameter. |
| **L** | [Ft] | Tubing length,. |
| **q** | [bbl/min] | Injection rate; |
| **Q** | [bbls/day] | Oil flow rate,; |
| $\mathbf{V_{inj}}$ | [bpm] | Injection fluid volume ; |

# Introduction

Unconventional gas resources have received a great attention in the past decade and become the focus of the petroleum industry for the development of energy resources worldwide. These reservoirs present specific characteristics with extreme low-permeability, a higher heterogeneity and a complex of fracture network. Because of their low-permeability, production from unconventional reservoirs requires multi-stage hydraulic fracturing using long horizontal wells divided into many stages to access large volumes of oil and gas bearing formations. Fluids are pumped down into each stage of the well to generate a fracture which increases the permeability of the formation to allow economic resource extraction.

An effective hydraulic fracturing design is a key to achieve the expected results in terms of production from unconventional reservoirs. There are many factors which must be considered while designing and executing hydraulic fracturing operation. These factors are not only limited to pump rate, size and concentration of propping agent, fracture spacing or number of fractures, fracture geometry and conductivity but there may be more parameters such as geological formation, reservoir and rock properties, type of reservoir fluids etc. These parameters can vary significantly at different locations around the globe. There is no universal method of hydraulic fracturing which can be applied anywhere in the world without proper formation evaluation of underground formations containing hydrocarbons.

The objective of this study is to analyze the fracturing treatment and the technical challenges of the IRS-A well represented as a connection with a productive fault by generating a long propped fracture length to increase the possibility of intersecting natural fractures.

This thesis has been divided into three chapters:

The first chapter includes an introduction about Timimoun filed and unconventional reservoirs, generalities about horizontal wells and hydraulic fracturing operation in unconventional reservoirs.

The second chapter present the pretreatment formation evaluation and focuses on HF treatment design from proppant, fluid and model selection to production forecast.

The third chapter is dedicated to IRS-A evolution and design, including its location and geophysical propreties and finally an economic evaluation of the operation.

# <u>CHAPTER 1:</u>

## Hydraulic Fracturing In Unconventional Reservoirs

# CHAPTER I: HYDRAULIC FRACTURING IN UNCONVENTIONAL RESERVOIRS

## Introduction:

Unconventional oil and gas reservoirs are being explored recently in Algeria and became the main source of cleaner energy around the world. Due to the low permeability in these formations, hydraulic fracturing is the best technology used to create highly conductive channels that provide fluid flow from rock matrix to production wells, and therefore, increase the productivity and production rate in horizontal wells adapting the Multistage fracturing technique which allows economic resource extraction.

## I.1 Unconventional resources:

There is no established formal definition of unconventional gas resources in the petroleum industry. The term ‘unconventional resource’ is used for oil and gas plays where the permeability, porosity, and fluid trapping mechanisms are different from those found in conventional carbonate and sandstone reservoirs. Unlike in a conventional play where the porosity and permeability are high enough to allow flow of the resource without aggressive well stimulation, within an unconventional reservoir the fluids are more tightly trapped within the smaller pore spaces within the formation and do not flow freely unless aggressive stimulation is implemented [1]. To this, production from these reservoirs requires stimulation and fracture treatment to be economically beneficial.

Three types of unconventional reservoirs exist [2]:

1. **Sandstone and carbonate oil and gas reservoirs**: The only main difference to conventional reservoirs is very low permeability (this category includes tight gas).
2. **Coalbed methane (CBM):** also referred to as coal seam methane or CSM. These reservoirs consist of gas released during the formation of coal that has not migrated into other formations.
3. **Shale oil and gas reservoirs**: These are reservoirs of almost no native permeability, which are generally the source rock for the oil and/or gas and from which the oil and/or gas has not significantly migrated.

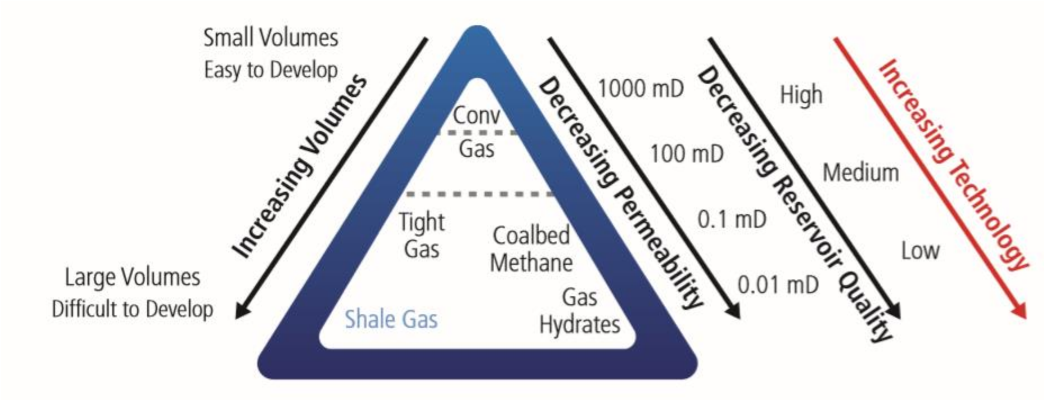


**Figure I.1:** The unconventional resource triangle. [2]

## I.2 Timimoun field [3] :

The Timimoun or Gourara basin, the subject of this study, belongs to the Western Saharan platform. It includes a Precambrian basement on which rests in unconformity a powerful sedimentary cover ranging from the Paleozoic to the Cenozoic. The Saharan platform, made up of several basins, is subdivided into three provinces: western, central (Triassic) and eastern.

### I.2.1 Geographic location:

The Timimoun basin is located in the central part of Western Sahara, it is bounded by longitude 1 ° West and 3 ° East and latitude 24 ° and 32 ° North. The basin covers an area of approximately 121,164 km².

### I.2.2 Geological situation:

The Timimoun 'Gourara' basin is located in the western part of the Saharan platform, it is located about 900 km south-southwest of Algiers, it is limited: To the east by the mole of Idjerane-M'zab and to the North-East the dome of Allal. To the north by the Meharez vault, the Oued Namous vault and the Djofra saddle. To the west by the saddle of Beni abbes, by the vault of Azzene which separates it from the basin of Sbaà and the Ugarta and further south by the mole of Azzel Matti. The southern limit corresponds to the outcrops of Hoggar.

### I.2.3 Geological Context and stratigraphy:

Timimoun field, where the existence of a gas petroleum system is largely proven. All petroleum objectives of the zone are of Palaeozoic ages (Ordovician to Late Devonian). The Timimoun field is located in a complex structural setting bordered to the North by the Namous Oued and to the South by the Ahnet Basin and Touareg Shield. The Idjerane M’Zab Mole constitutes its eastern edge. It is limited to the West by the “Voûte d’Azzène” and the NW-SE

Ougarta Montain separating the Timimoun basin in the North and the sub Sbaâ Basin in the South-West. The sedimentary accumulation reaches up to 4000 meters

The tectonic phases are numerous in this area of cratonics sutures. The Pan African orogenic phase begins in the Precambrian by a West compression responsible for the collision between the African Shield and the West African Craton. It is followed during the Cambrian/Ordovician by a distension and subsidence resulting in the formation of Arénigienne stage tilted blocks. The current stratigraphy resulted from a relatively complex geological history leading to the preservation of Palaeozoic deposits (Cambrian to Carboniferous) and Mesozoic (Cretaceous).

The Timimoun basin saw these global tectonics amplified by periodic reactivations of the Pan African Cambrian structure that separates the Algerian and the West African cratons. The fractures in the main N130° network direction resulting from the actual maximum stress are mainly open. The N50 fractures are mostly closed. However, they may also be sometimes open as found in HYR wells.

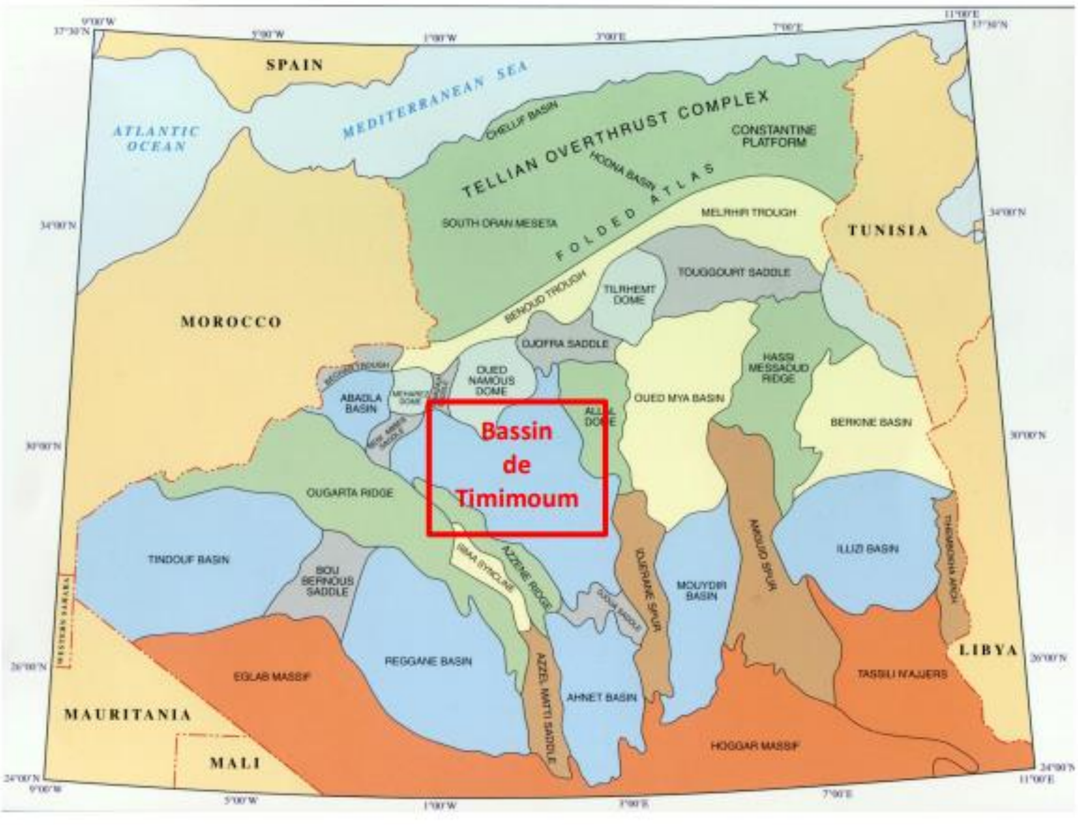


**Figure I.2:** Timoum field geological location. [3]

## I.3 Generalities about horizontal wells:

Horizontal wells are an alternative method of drilling when vertical wells do not yield enough fuel or are not possible. Drilling at some non-vertical angle can hit targets and stimulate reservoirs in ways that a vertical well cannot. Combined with hydraulic fracturing previously unproductive rocks can be used as sources for natural gas. Examples of these types of deposits include formations that contain shale gas or tight gas.

The advancement of horizontal drilling has been most important in developing the ability to obtain natural gas from Unconventional resources .

The advantages of horizontal wells can be considered as followings [4]:

- Larger flow area.
- Reduce possibility of water or gas cresting.
- Use in enhanced recovery applications.
- Created multiple small fractures.
- Cross several interested pay zones.

## I.4 Hydraulic Fracturing in unconventional reservoirs:

### I.4.1 Generalities about Hydraulic fracturing:

Hydraulic fracturing, informally referred to as “fracking”, is an oil and gas well development process that typically involves injecting water, sand, and chemicals under high pressure into a bedrock formation via the well. This process is intended to create new fractures in the rock as well as increase the size, extent, and connectivity of existing fractures. Hydraulic fracturing is a well-stimulation technique used commonly in low-permeability rocks like tight sandstone, shale, and some coal beds to increase oil and/or gas flow to a well from petroleum-bearing rock formations. A similar technique is used to create improved permeability in underground geothermal reservoirs. [5]

### I.4.2 Objective of hydraulic fracturing:

Fracturing consists of the injection of a treatment fluid at a pressure higher than the fracturing pressure of the formation, thus opening channels with very high permeability, in which the effluent can flow much more easily, which increases well throughput and productivity.

### I.4.3 Multistage Fracturing techniques:

Multistage fracturing is a commonly used stimulation operation usually performed on low permeability formations. The complex formations and extreme conditions require several individual zones to be completed and fractured to access the entire horizontal interval. Multistage fracturing has offered one of the best solutions to save money and time in such complex reservoirs, there are several ways to perform multistage fracturing, such as perf-and plug, coiled tubing, and sliding-sleeve, which is selected depending on the well and the completion design. It is also works in the opposite way, to best access the reservoir efficiently, companies are designing the well and selecting completion methods based on the multistage fracturing technique which fits the specific condition. [6]

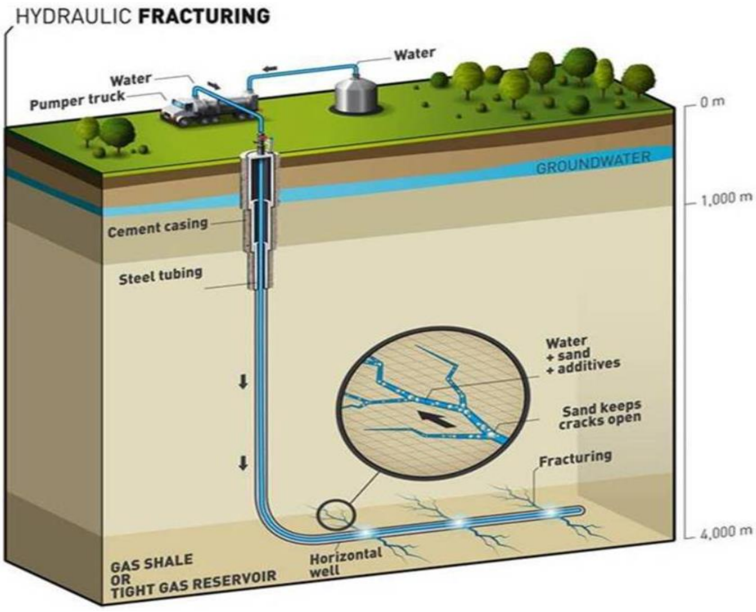


**Figure I.3:** Hydraulic fracturing operation. [7]

### I.4.4 The Basic Process:

Hydraulic fracturing is a technique utilized in unconventional resources to access previously inaccessible hydrocarbon reserves. It is usually integrated with horizontal drilling to enhance reserve recovery.

In tight gas development, fracture treatment is done in several isolated stages along the horizontal well because it is impossible to apply pressure along the entire length of the well bore due to distance constraints (1000 to 5000ft). Perforations are created in the wellbore within the interval bounded by packers, using a perforating tool.

Fracture treatments are carried out at the well site, using heavy equipment including pump trucks, blenders, proppant tanks, and fluid tanks. A fracture treatment can be divided into stages: the pad stage, the slurry stage, and the displacement or flush stage [8]. The fracturing fluid is pumped through the perforated intervals at high pressures in order to create fractures in the surrounding formation (pay zone). Hard particles commonly known as proppants, are added to the fracturing fluid and pumped into the formation after the fractures have been created. The propping agents hold open the newly created fractures, to facilitate hydrocarbon recovery.

The design of fracture treatment is a complex task, which involves analysis, planning, experience and rigorous observation of different stages in the entire process. [9]

## I.5 Surface equipment [10]:

- **Pumping units:** This pumping unit makes pumping the treatment fluid possible at very high pressures.
- **Blender:** The Blender allowed the proppants to be mixed with water and additives.
- **LFC Hydration Unit:** LFC is an oil-based polymer blend, we mix it with water using the hydration unit to better prepare our gel.
- **Cabinet for treatment monitoring**: Necessary for monitoring and recording data during processing.
- **Treesaver (well insulation tool):** It is equipment that allows the treatment fluid to be pumped at a surface treatment pressure higher than that of the well.
- **The Frac Tank**: The frac tank is a reservoir where water is stored, this water is necessary for gel preparation. The storage capacity per tank is 20,000 Gallons, the number of tanks that must be available depends on the volumes planned for the operation.
- **Proppant storage tank:** Proppant has to be stored on location, ready for use. It has to be kept clean and dry, and must be delivered to the blender smoothly and quickly.

In addition to all of the above equipment, there are also other equipment such as: Lab Van, flowmeters, pressure gauges and high pressure treatment lines.

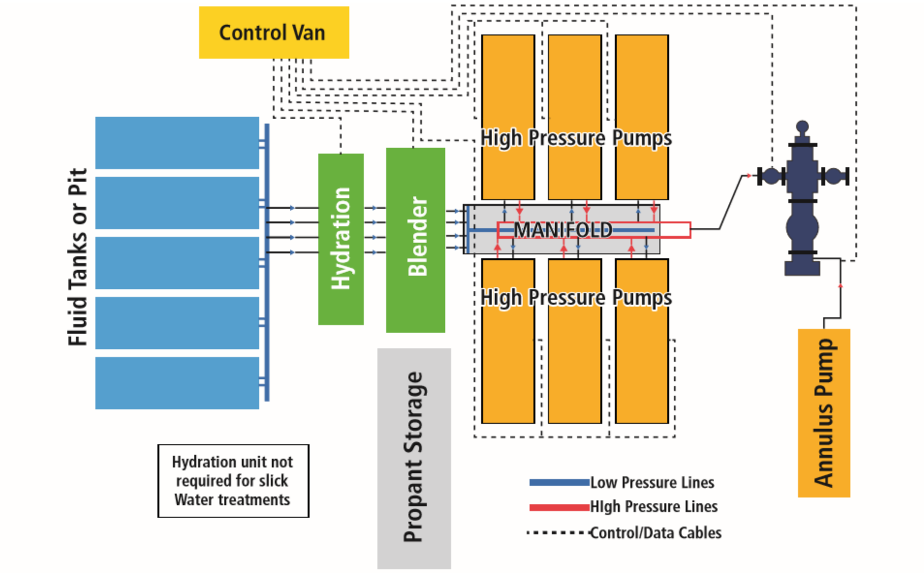


**Figure I.4:** Hydraulic fracturing surface equipment. [10]

## I.6 Multistage Completion Systems in horizontal wells [2]:

Wellbore completion tools are installed after a well is drilled and enable any completion techniques required to make the well product, such as acidizing or perforating. Wellbore completions in unconventional plays, isolate different sections in the well for hydraulic fracturing. There are a variety of different techniques used in these applications; each one enables multistage hydraulic fracturing.

### I.6.1 Plug-and-Perforate Completion Systems:

The plug-and-perforate completion system is the most common type of multistage completion system used today. This system uses cement to isolate the annulus, and perforations to breach the cemented liner to provide a fluid-flow path during fracturing and production. Fracturing plugs are used to isolate the previously fractured stages and divert the fluids out of the perforations. When the fracturing job is finished, the plugs are milled out to put the well on production.

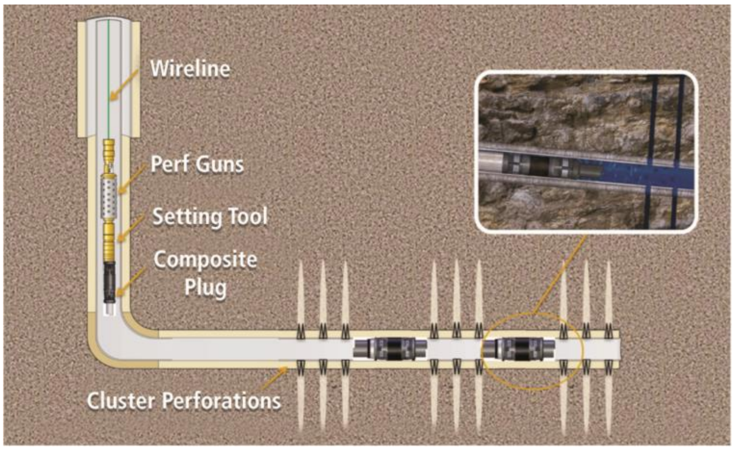


**Figure I.5:** Wellbore diagram of a plug-and-perforation job. [2]

### I.6.2 Frac point system Ball-Activated:

The ball-activated completion system (BACS) uses ball activated fracturing sleeves to perform multistage hydraulic fracturing. Balls and ball seats are used to open the sleeves and divert the fracturing fluid into the individual stages.

This operation Relies in four basic steps: the ball is dropped for the next stage into the clean fluid flush for the previous stage, then it lands on the seat isolating it from below. A pressure is applied against the ball to open the sleeve. The fracturing begins without ever shutting down the pressure pumping units.

This process is then repeated until all stages are fractured.

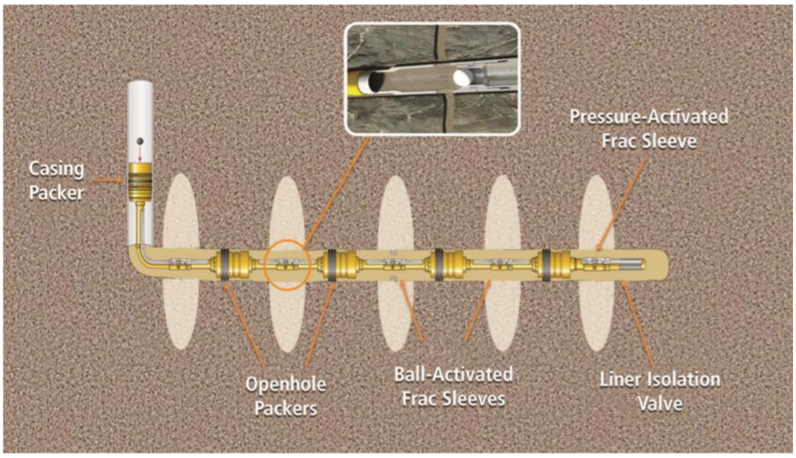


**Figure I.6:** Wellbore diagram of the bacs *[2]*

### I.6.3 Frac point system shifting tools Activated (coil tubing):

Coiled tubing-activated completions systems (CTACS) use coiled tubing (CT) to achieve multistage isolation. There are two primary methods with CT:

- **Coiled Tubing-Activated Fracturing Sleeves:**

The CT-activated fracturing sleeves provide the flow path for the fracturing fluids to enter each stage. There are two types: One type is the mechanically shifted sleeves that rely on mechanical force from the CT to shift the sleeve open. Another option is the pressure-balanced sleeves. These sleeves have internal pressure ports at the top and the bottom of the sleeve. These sleeves are opened by using a CT packer to create a pressure imbalance across these ports.

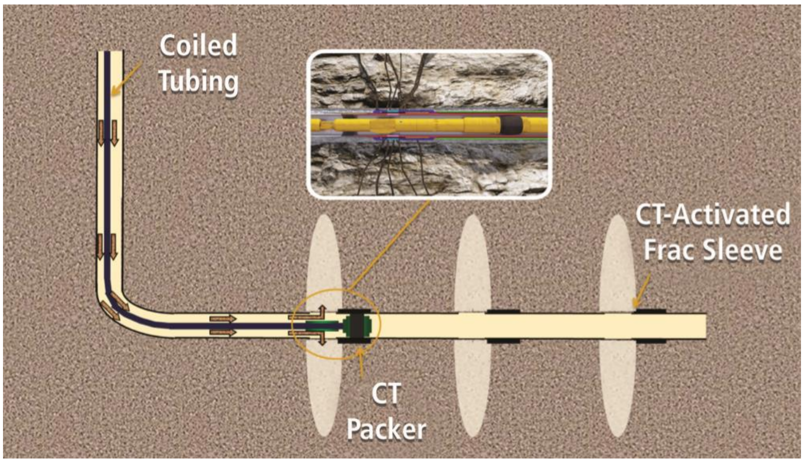


**Figure I.7:** Coiled tubing-activated fracturing sleeves completion [2]

- **Abrasive Perforator :**

An abrasive perforator is an alternative to conventional perforating guns. The abrasive perforator is a CT tool that creates holes in the casing by pumping fluid and sand through the CT and into the casing in an abrasive manner.

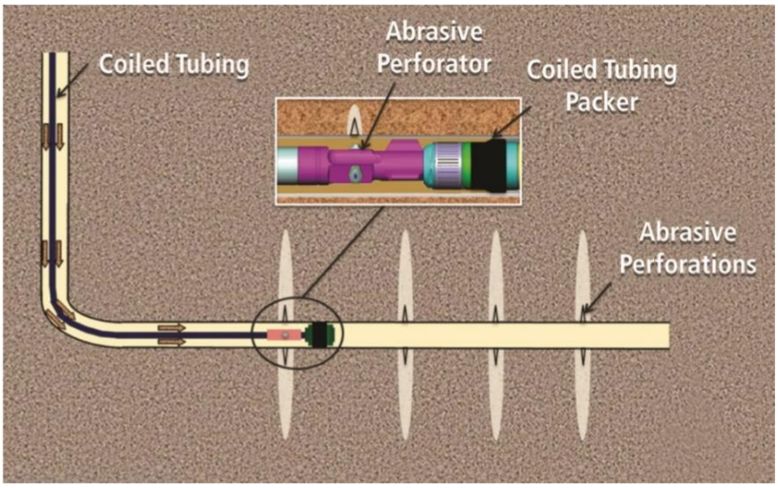


**Figure I.8:** Coiled Tubing-Abrasive Perforator *[2]*

**Table I-1 :** benefits and considerations compared for PNP, BACS, and CTACS [2]

| | PNP | BACS | CTACS |
|---|---|---|---|
| Number of stages | Virtually unlimited | Limited | Virtually unlimited |
| Stage Placement | Flexible | Fixed | flexible with abrasive perforator |
| Contingency Options | Full diameter | Diameter restrictions | Full diameter and CT in completion sting |
| Fracturing logistics | Pressure pumping, wireline, Ct | Pressure pumping | Pressure pumping, CT |
| Fracturing Operational Efficienty | Set up/down between stages | Nonstop | Brief fracturing job shut down between stages |
| Post Fracture | Mill out plugs | Restricted diameter | Full production diameter |

## I.7 Execution of multistage fracturing:

The course of a hydraulic fracturing treatment is as follows:

### I.7.1 Injection test [10]:

It consists of injecting a fluid such as; treated water, brine, or crude in a fracturing regime to:

- Check if the formation absorbs the fluid (hence, the name of the Injection test).
- Determine the fracturing gradient.

This test is performed in two steps:

- **Step test:** (evolution of the propagation pressure). It consists in injecting fluid into the well at increasing flow rates in stages of equal duration and this until the breaking of the rock, after fracturing, the flow rate is kept constant in order to determine the evolution of the propagation pressure as well as the profile injection
- **Constant flow test:** (determine areas of fluid absorption). The test consists of pumping fluid (water at 2% KCl) at a constant rate until the rupture; the rate is kept constant for a determined time, in order to allow the fracture to propagate. Pumping is stopped to record the pressure drop (Fall off). During pumping, PLT passes are made to determine the areas of fluid absorption, this test is repeated at different flow rates to ensure the assessment of the height of the fracture.

### I.7.2 Mini frac tests (Data Frac, Shadow Frac) [11]:

The minifrac is designed to be as close as possible to the actual treatment, without pumping any significant volumes of proppant. The minifrac should be pumped using the anticipated treatment fluid, at the anticipated rate. It should also be of sufficient volume to contact all the formations that the estimated main treatment design is anticipated to contact. A well planned and executed minifrac can provide data on:

- fracture geometry,
- rock mechanical properties, and fluid leakoff
- information that is vital to the success of the main traitement.

The minifrac includes two tests:

- **Step rate test:**

This test determines the Fracture Extension Pressure (FEP). It consists first of injecting the base fluid (treated water) at a low rate, then gradually increasing this rate in increments, and maintaining it for a sufficient time until the pressure stabilizes (5 to 10 min). All of this must be accompanied by a continuous recording of the pressure.

This makes it possible to draw two curves P as a function of Q and the intersection between them gives us the pressure of extension of the fracture after projection on the pressure scale.

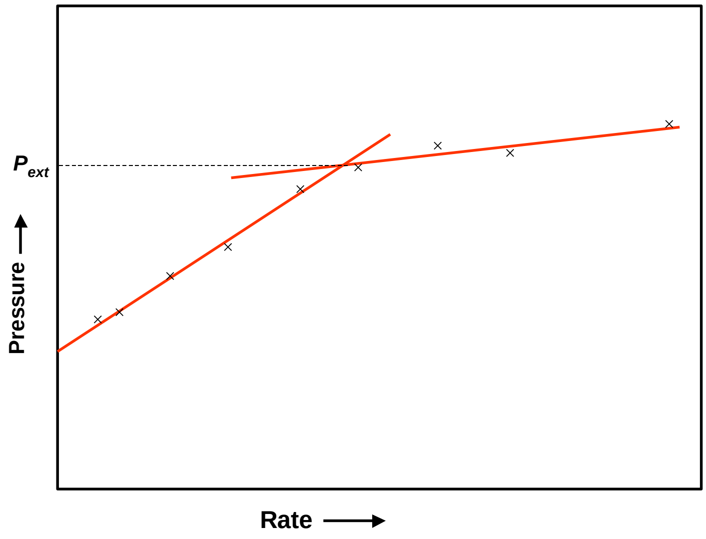


**Figure I.9:** Step rate test [11]

- **Pressure decline test:**

This test consists of creating a mini-fracture in the formation with the same fluid as that proposed for the main treatment. It is divided into two stages:

- Mini frac step, which makes it possible to determine the propagation model.
- Fall-off step or pressure drop after mini frac, which determines:
  - The efficiency of the treatment fluid (η).
  - Fluid filtration (CL).
  - The geometry of the fracture (width, length, and thickness).

This test consists first of injecting the fluid into the formation at the rate of the main treatment proposed, and maintaining it until 10 to 15% of the total volume proposed for the treatment is pumped. Then stop the injection and close the well to enter the second phase, which is the fall-off, allowing the pressure at the bottom to drop.

### I.7.3 The main treatment [10]:

It is divided into three stages:

- **Injecting a Pad**: The Pad is a fracturing fluid, generally a very viscous crosslinked gel not loaded with propping agent, injected at the head to initiate and develop a fracture by giving it a width such as to allow the passage of the balls.
- **Slurry injection:** Slurry is a mixture of cross-linked gel and proppant (proppant) with additives frac fluid, this mixture is used to maintain the fracture.
- **Flush displacement:** In this step, the slurry is driven out by a linear gel that is easy to remove during clean up.

### I.7.4 Clean-out of wells after treatment:

The moment of disgorging is determined by the change in the pressure at the wellhead after the treatment. The well is opened when the pressure is stable.

- This process is then repeated until all stages are fractured.

## I.8 Analysis of hydraulic fracturing:

After performing the treatment, the results should always be evaluated and analyzed to define the optimal design for performing the main treatment. The most applied methods are:

### I.8.1 Pressure decline analysis [12]:

After analyzing the curve recorded during the MiniFrac test data which consists of identifying closure and analyzing the early pressure falloff period while the induced fracture is closing, we can obtain the following parameters:

- **Break down Pressure:** this is the pressure required to initiate the fracture, so it must exceed the minimum stress of the hole.
- **Instantaneous shut-in pressure (ISIP):**

ISIP = Final injection pressure - Pressure drop due to friction …… (I.1)

- **Fracture gradient:**

$$\text{Fracture Gradient} = \frac{\boldsymbol{ISIP}}{\boldsymbol{Formation\ Depth\ (ft)}} \quad \ldots\ldots \text{(I.2)}$$

- **Net Fracture Pressure ($\Delta p_{net}$):** Net fracture pressure is the additional pressure within the frac above the pressure required to keep the fracture open. It is an indication of the energy available to propagate the fracture.

$$\Delta p_{net} = \text{ISIP - Closure Pressure} \ldots\ldots(I.3)$$

- **Fluid efficiency**: The fracture volume is divided by the total volume pumped. It can be determined by Nolte's Function G method.

$$\text{Fluid Efficiency } = \frac{G_C}{2 + G_c} \ldots\ldots(I.4)$$

Gc is the G-function time at fracture closure

- **Formation leakoff** characteristics and fluid loss coefficients or Filtration coefficient: we can calculate it by a simple relation:

Total pumped volume (%) = Filtration coefficient (%) + Fluid efficiency (%I)……(I.5)

- **Propagation pressure:** This is the pressure necessary for the fracture to propagate.

- **Fracture closure pressure (FCP)**: this is the pressure necessary to keep the fracture open. It is almost equal to the minimum horizontal stress

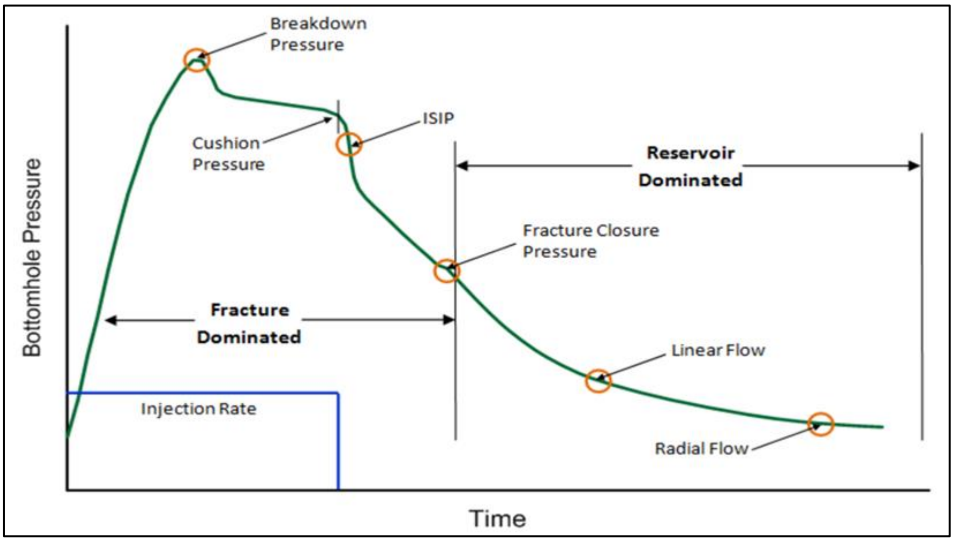


**Figure I.10:** Idealized pressure curve for a minifrac test. [12]

In order to determine the closing pressures on the pressure decline curve, various methods have been developed in this direction, the most used methods are:

#### I.8.1.1 G-Function method [12]:

Briefly, the G-function analysis draws a tangent line from the bottom of Gdp/dG until the deviation from a straight line, at this point a straight line is drawn where the intersection with the pressure curve is recorded as closure pressure.

The basic G-Function calculations are based on the following equations:

$$G(\Delta t_D) = \frac{\pi}{4}(g(\Delta t_D) - g_0) \text{ ...... (I.6)}$$

$$g(\Delta t_D) = \frac{4}{3}\left((1 + \Delta t_D)^{1.5} - \Delta t_D{}^{1.5}\right); \qquad for\ \alpha = 1 \text{ ...... (I.7)}$$

$$g(\Delta t_D) = (1 + \Delta t_D)sin^{-1}((1 + \Delta t_D)^{-0.5}) + \Delta t_D{}^{0.5}; \qquad for\ \alpha = 0.5 \text{ ...... (I.8)}$$

$$\Delta t_D = \frac{(t - t_p)}{t_p} \text{ ......(I.9)}$$

$*g_0 = \frac{1}{2}$ For $\alpha = 0.5$

$*\ g_0 = \frac{4}{3}$ For $\alpha = 1$

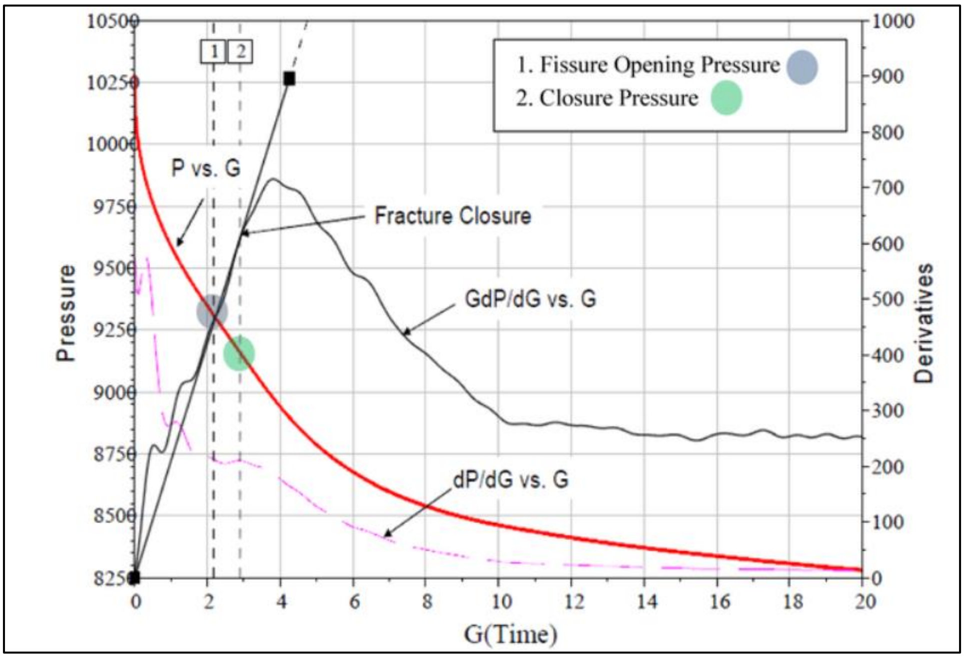


**Figure I.11:** Pressure evolution versus G-time [12]

### I.8.1.2 Square Root Time method [12]:

Fracture closure can be identified by the peak of the first derivative on the sqrt(t) plot, which corresponds to an inflection point on the pressure curve. The semi-log derivative behaves similar to the G-Function Analysis. A user-defined (Sqrt(t)) analysis line may be added to the sqrt(t) plot to help identify the point of inflection.

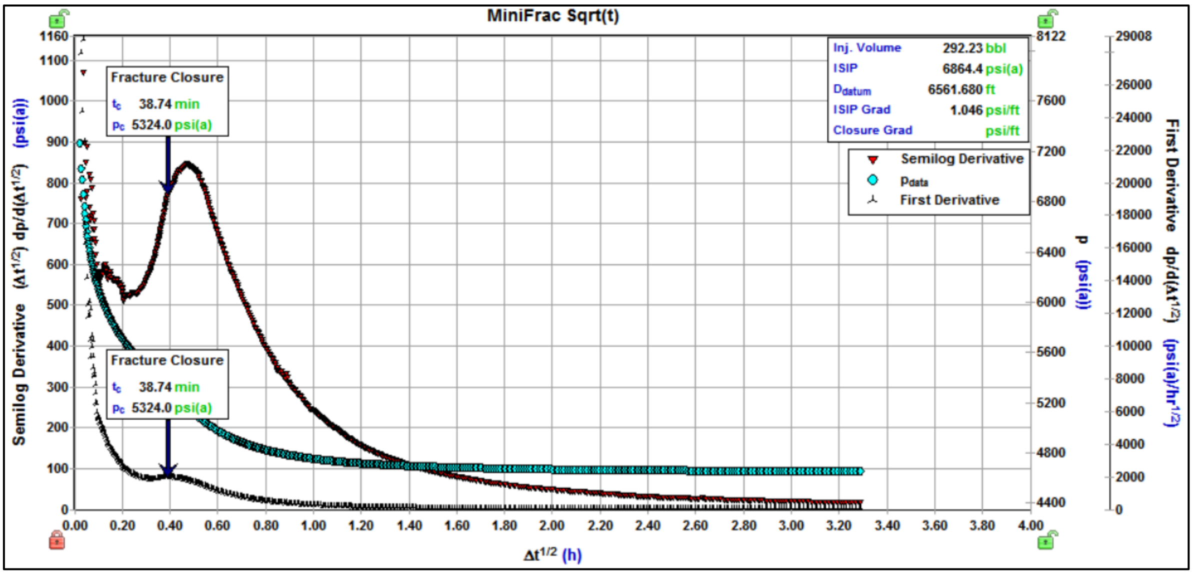


**Figure I.12:** Pressure evolution versus Squae Root Time [12]

## I.8.2 Nolte and Smith analysis [13]:

This method analyzes the expected response of pressure formation during fracture propagation. Nolte and Smith then established a curve of pressure versus time on a Log-Log graph, their analysis results are shown in the table associated with the following figure:

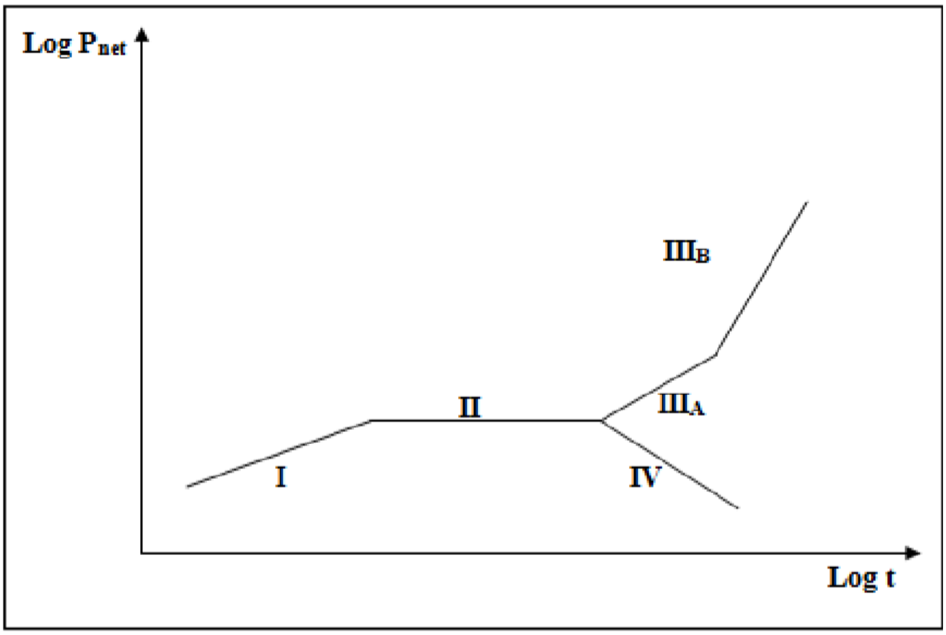


**Figure I.13:** Propagation pressure curve as a function of time**.** [13]

**Table I-2 :** curve analysis results.

| Row index | Approximate slope | Interpretation |
|---|---|---|
| I | 1/8 to ¼ | The fracture extends in length and slightly in height ,So it spreads according to the PKN model |
| II | 0 | The increase is regulated by an increase in height in barriers or by natural fissure openings, So the fracture spreads radially |
| $III_A$ | 1 | Extension restriction and width increase (W) |
| $III_B$ | 2 | Extension restriction (on only one active side) |
| IV | Negative | Height increase in another low stress area. (screenout) both models, KGD and Radial can be considered. |

# Chapter 2 :

## Hydraulic Fracturing Design

# CHAPTER II: HYDRALIC FRACTURING DESIGN

**Introduction:**

An effective hydraulic fracturing design is a key to achieve the expected results in terms of production from unconventional reservoirs; the treatments are designed based upon the knowledge obtained from pre-treatment formation. Specifications of fracturing fluid and proppant, fluid volume, proppant weight requirements, fluid injection schedule, proppant mixing schedule and predicted injection pressure profile should be planned properly before going to the field operation.

## II.1 Pre-fracture formation:

Testing the target formation to determine geological and mechanical properties is part of the design of a MSHF operation. Pre-fracture testing is usually done to determine important geomechanical aspects of the formation (in situ stress, Young's modulus, etc.) as well as a wide range of geologic properties which will affect production (porosity, permeability, etc.). A good estimation of the formation's properties is valuable when it comes to planning a MSHF operation, as well as to the post-fracturing analysis. [1]

### II.1.1 Geologic Considerations:

Understanding the geologic deposition pattern is important before designing a specific fracture treatment to get the probable size of the reservoir for design and stimulation treatment. There are many aspects which should be considered during geologic evaluation of the candidate formation/reservoir. These aspects / parameters are [14]:

**Drainage area:**

Represents the area from which hydrocarbons are recovered such the size and shape, which is a function of geology and the fracture dimensions. To optimize the hydraulic fracturing treatment, two important proprieties must be obtained: fracture length and drain radius. It is possible, then, to determine optimum fracture length and drainage radius by constructing a relationship between flow rate and time as function of fracture length and drainage radius.

**Lithology:**

The lithology of a reservoir is an important factor to know before designing a hydraulic fracturing treatment. Furthermore, lithology can be important depending upon certain geologic environment; it is a better way to determine fracturing fluid for each reservoir type. For a sandstone reservoir, a water or oil based fracturing fluid will probably be selected, while acid based fluid is applied sometimes in shallow carbonate reservoirs.

**Clay Content:**

Knowing the type and distribution of the materials that fills the pores is very important. Many low permeability reservoirs contain a large quantity of clay minerals in the rock fabric and pore space. The type of minerals and their location in the rock matrix can be of vital importance to interpret well logs and reservoir behavior.

**Fault patterns:**

Any geological study must consider the knowledge of regional and local stress pattern in the study area. In-situ stresses are very important in the design of a hydraulic fracture treatment. Localized and regional stress patterns in an area are controlling factors in determining the orientation of hydraulic fractures and that the state of stress underground is not hydrostatic but depends on tectonic conditions.

### II.1.2 Geomecanichal proprieties:

In general, rock mechanics is a branch of geomechanics where the focus is on rock deformation and possible failure of rock due to the applied manmade or natural forces. This requires advanced understanding of formation in situ stress conditions and stress behavior around the fracture as it generates and propagates to the formation. Stress, strain, and deformation are essential parameters required for characterization of mechanical properties of the rock. [2]

### II.1.2.1 In-situ stresses and Strain

**Stress:**

If a force, F is acting on a body with a cross-sectional area, A, perpendicular to the direction of action of the force, then the stress,$\sigma$ induced in this body is equal to the force divided by the area:

$$\sigma = \frac{F}{A} \dots \dots (II.1)$$

**Strain:**

Strain is a measure of how much the material has been deformed when a stress is applied to it. As the force, F is applied in the x-direction, the original height of the block of material, x, changes by $\delta_x$ (so that the new height is $x - \delta_x$). [15] The strain in the x-direction, ε is given by:

$$\varepsilon_x = \frac{\delta_x}{x} \dots \dots (II.2)$$

### II.1.3 Rock mechanics proprieties:

**Young modulus:**

Young's modulus is a measurement of stress over strain. Simply put, when hydraulic fracturing occurs, Young's modulus can be referred to as the amount of pressure needed to deform the rock. Young's modulus measures a rock's hardness, and the higher the Young's modulus, the stiffer the rock. A higher Young's modulus will help to keep the fractures open. [15]

$$E = Young's\ modulus = \frac{\sigma}{\varepsilon} \dots \dots (II.3)$$

σ =Stress, Psi

ε =Strain

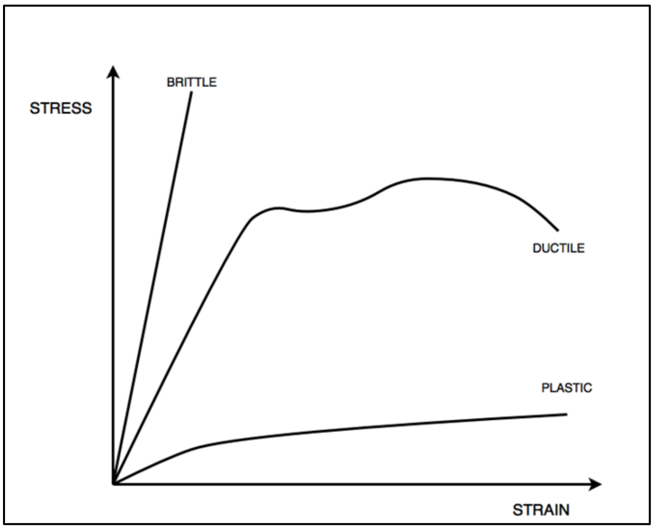


**Figure II.1:** Young's Modulus [15]

**Poisson's modulus:**

Poisson's ratio measures the deformation in material in a direction perpendicular to the direction of the applied force. Poisson's ratio changes from layer to layer, the best formations to hydraulically fracture have the lowest Poisson's ratios.

Poisson's ratio can be measured from a core sample in the lab and a compressive force is applied on it. Afterward, the height and diameter changes are measured (strain in x- and y-directions). [15]

$$\nu = Poisson's\ modulus = -\frac{\varepsilon_y}{\varepsilon_x} \ldots\ldots (II.4)$$

$\varepsilon_y$ =Radial strain $\varepsilon_x$= Axial strain

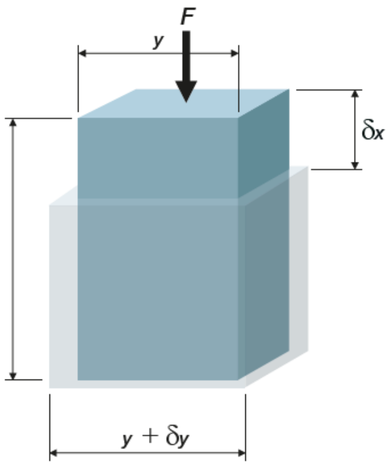


**Figure II.2:** Application of the force f in x-direction and production of deformation in y-direction. [16]

**Shear modulus:**

The shear modulus is similar to Young's modulus, except that it refers to the material being in shear rather than in compression or tension. It defines how much energy is required to elastically deform a material in shear. [15]

$$G = \frac{E}{2(1+\nu)} \ldots \ldots (II.5)$$

$\mathrm{E} = \mathrm{Young's\ modulus}$

$\nu = \mathrm{Poisson's\ modulus}$

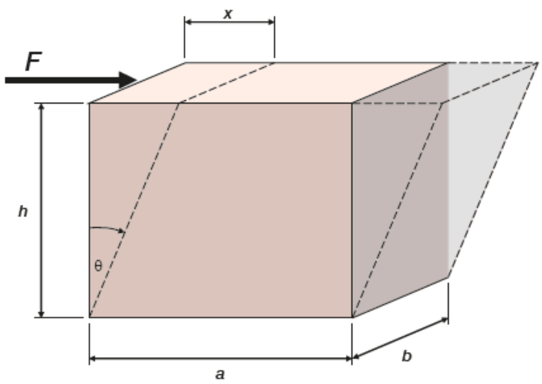


**Figure II.3:** Force f applied to produce shear modulus. [16]

### II.1.4 In-Situ Stress and Fracture geometry:

In-situ stresses are the stresses within the formation, which act as a loa d (usually compressive) on the formation. They come mainly from the overburden, and these stresses are relatively easy to predict. However, factors such as tectonics, volcanism and plastic flow in adjacent formations can significantly affect the in- situ stresses these factors are much harder to predict. [16]

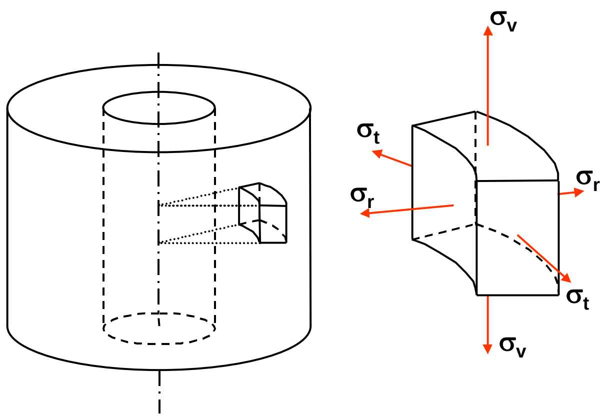


**Figure II.4:** in-situ stress distribution. [16]

**Vertical stress:**

Vertical stress, also referred to as overburden stress, is the sum of all the pressures applied by all of the different rock layers. Every formation contains fluid and rock and each one must be accounted for separately. [15]

$$\sigma_v = \rho . g . h \dots \dots (II.6)$$

**Minimum horizontal stress:**

Minimum horizontal stress is approximated as fracture closure pressure. It is a direct result of overburden stress; Poisson's ratio determines the amount of stress that can be transmitted horizontally [15]. Minimum horizontal stress or fracture closure pressure can be obtained from either a diagnostic fracture injection test (DFIT) or by using the following equation:

$$\sigma_{h,min} = \frac{\nu}{1-\nu} \times (\sigma_v - \alpha P_P) + \alpha P_P + P_{Tectonic} \dots \dots (II.7)$$

**Maximum horizontal stress**

Maximum horizontal stress is more challenging to calculate. The minimum horizontal stress is calibrated from fracture closure analysis either from surface low-rate injection tests (minifracture), downhole wireline straddle packer injection tests (microfracture). Then the magnitude of maximum horizontal stress can be estimated from the occurrence of borehole breakouts, induced fractures, or fracture initiation pressure (formation breakdown) recorded during openhole microfracturing tests.

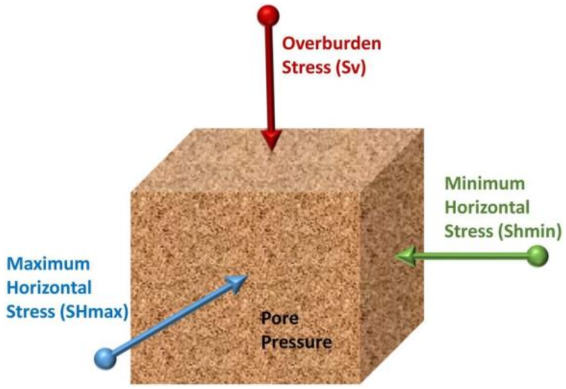


**Figure II.5:** Minimun, maximun and vertical stresses on a rock [2]

## II.1.5 Fracturing geometry:

### II.1.5.1 Fracturing orientation:

Fractures will always propagate along the line of least resistance. In a three dimensional stress regime, a fracture will propagate so as to avoid the greatest stress. This means that a fracture will propagate parallel to the greatest principal stress, and perpendicular to the plane of the greatest principle stress. This is a fundamental principle – therefore the key to understanding fracture orientation is to understand the stress regime itself. [16]

Fracture orientation is influenced by various factors such as overburden pressure, pore pressure, tectonic forces, Poisson’s ratio, Young’s modulus, fracture toughness, and rock compressibility.

**a. Transverse fractures:**

To create transverse fractures, the well needs to be drilled (placed) parallel to the minimum horizontal stress or perpendicular to the maximum horizontal stress.

### b. Longitudinal fractures:

To create a longitudinal fracture, the well needs to be drilled parallel to the maximum horizontal stress or perpendicular to the minimum horizontal stress.

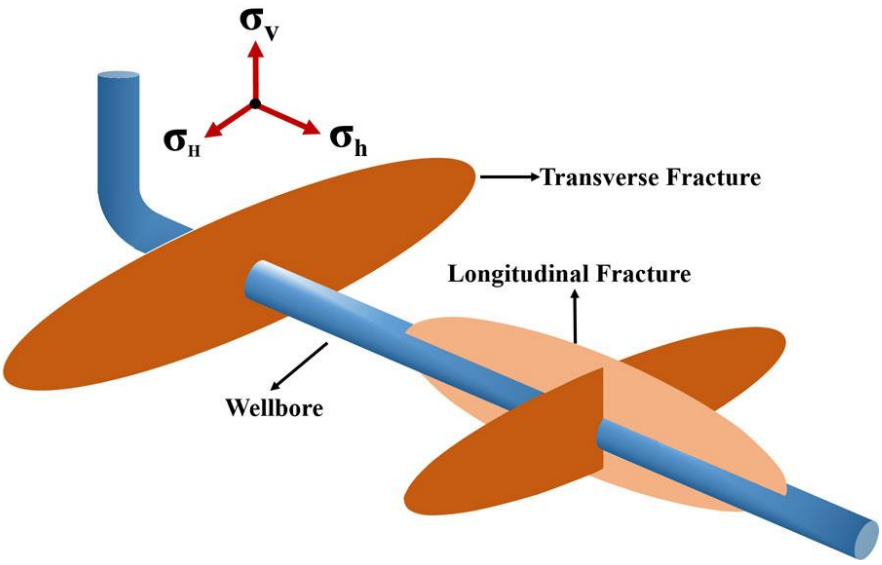


**Figure II.6:** transversal and longitudinal fractures [2]

### II.1.5.2 Fractures geometry:

Every fracture, regardless of how it was pumped or what it is designed to achieve, has certain basic characteristics. All fracture modelling is designed around determining these three characteristics, height H, half-length X and width W. Once these three characteristics have been determined, other quantities such as proppant volume, fracture conductivity and ultimately production increase can be determined.

### Two-Dimensional (2-D) Fracture Geometry:

Three main models existed; radial, KGD (Kritianovitch and Zheltov, Geertsma and DeKlerk, further refined by Daneshy) and PKN (Perkins and Kern, Nordgren). However, below is a brief, qualitative description of the models. [16]

- **KGD**

In this model, fracture height is fixed and width is proportional to fracture length. This model also assumes constant width against height and slippage at the formation boundaries.

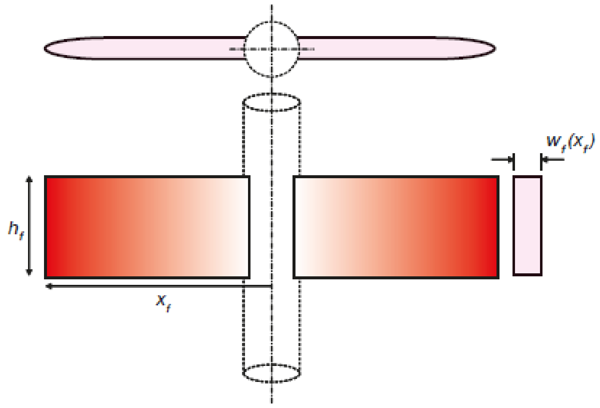


**Figure II.7:** KGD fracture model [16]

- **PKN**

In this model, the fracture height is again assumed to be constant. However, this time there is no slippage between the formation boundaries, and the width is proportional to fracture height.

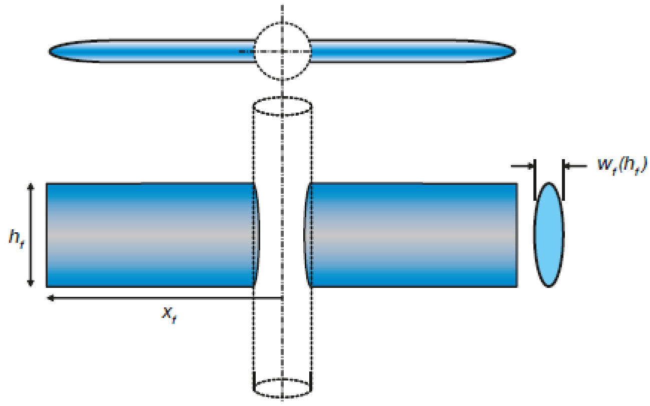


**Figure II.8:** PKN fracture model [16]

- **Radial**:

Various radial models have been developed, but in each one the height is assumed to be directly related to the fracture length, such that $h_f = 2r_f$ (the radius of the fracture). In this model, fracture width is proportional to fracture radius.

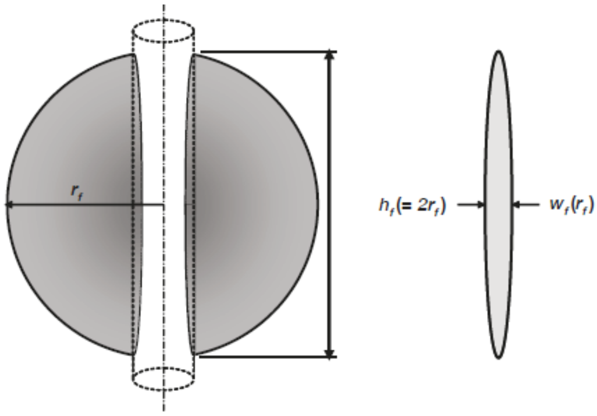


**Figure II.9:** Radial fracture model [16]

**Three dimensional (3-D) fracture geometry:**

Today, most fracture modeling is performed using lumped-parameter 3-D simulators. These models are considerably more sophisticated than the 2-D models but are not fully 3-D [14]. The main fracture simulation 3D models used in the industry today are FracPro, frac cade, Gopher and MFrac. They are used on well over 90% of all treatments currently performed.

- **FracPro simulator:** FracPro software can effectively model any type of pressure stimulation job, including horizontal well fracturing, multiple perforated intervals and limited entry wells. [17]
- **Meyers Frac simulator:** MFRAC- is a pseudo-3D hydraulic fracturing simulator that models penny, GDK and PNK geometries and accounts for the parameters affecting fracture propagation and proppant transport. [11]
- **Gopher simulator:** GOHFER™ software is one of the more commonly used software packages in the oil and gas industry to model complex hydraulic fractures in the subsurface, such as the subject tight gas sand reservoir in the Uinta basin. [17]
- **FracCADE simulator**: FracCADE" fracturing design and evaluation software incorporates a range of complexities, from 2D models to extensive laterally coupled three-dimensional simulators [18]

### II.1.5.3 Wellbore stability:

Orienting and drilling stable wellbores for efficient drilling can reduce non-productive time (NPT) and drilling costs in the build, hold, and lateral sections of the wellbore. This is key to successful unconventional play development. A stable wellbore is required for proper wellbore completion, stage isolation, and effective stimulation. Horizontal wells are drilled in the direction of minimum horizontal stress to propagate transverse vertical fractures oriented perpendicular to wellbore direction. Also the open-hole stability may require the analysis of horizontal weak planes (beddings), laminations, or natural fractures. Addressing shale anisotropy in wellbore stability studies and the analysis of in-situ stress directions and magnitudes are important geomechanic engineering contributions in drilling unconventional reservoirs. [2]

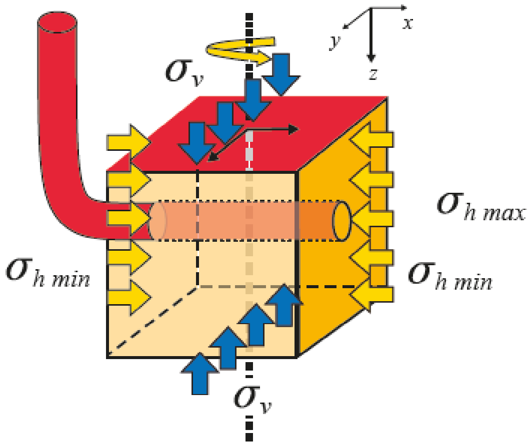


**Figure II.10 :** In-situ stresses in horizontal drilling. [2]

## II.1.6 Determination of Geological Formation Properties:

Porosity and permeability are important properties to determine before a well can be deemed economically viable; they are the primary governing parameters of gas flow to the hydraulic fracture and wellbore [1].

**Porosity:**

It is the ratio of the volume of the void space between the grains of the rock to the total volume of rock mass. It can be determined through core testing; though undamaged whole core is needed.

**Permeability:**

It is a measure of the ability of the rock to transmit fluids under a pressure gradient. It can be affected by many factors including testing scale, pore types and size, effective stresses, pore pressure, and grain shape.

**Mineralogy:**

It is generally established through thin section examination, X-ray diffraction, oxides analysis, and scanning electron microscope (SEM) analysis. The mineralogical composition of the rock affects the strength and mechanical behavior of the overall rock mass.

### II.1.7 Characterize Lateral for Fracture Placement [2]:

By understanding the distribution of critical properties along the lateral, the operator can target productive zones, determine optimal stage placement and design effective stimulation treatments that optimize reservoir contact, conductivity and productivity. There are three types of data required to characterize the horizontal lateral:

- Information about the Natural Fractures (location, prevalence, direction and conductive) determined from LWD High Definition (HD) Resistivity Image logs.
- Stress profile data (used in fracture design to initiate and propagate fractures) usually obtained from vertical pilot wells as the horizontal well will be landed in the pay zone only intersecting the non-prospective formation above the target with no possible characterization of the formation below the pay zone. Acoustic Logging tools can provide information on stresses along the lateral, but very few operators opt for this risky approach.
- Reservoir/Geological/Geochemical data (mineralogy, brittleness, TOC levels, porosity) and well site Cuttings Analysis system (XRD, XRF and Pyrolysis).

## II.2 Hydraulic fracturing treatment design:

A hydraulic fracturing design should follow the following procedure:

- Selection of a fracturing fluid,
- Selection of a proppant,
- Determination of the maximum allowable treatment pressure.
- Selection of a fracture propagation model,
- Determination of treatment size (fracture length and proppant concentration),

### II.2.1 Selection of Fracturing Fluid:

The selection of a proper fracturing fluid involves several considerations. It starts with choosing the pad volume where one must consider what and how much pad is required to create the desired fracture geometry and conductivity. This is followed by estimating the compatibility with the reservoir, mineralogy and reservoir fluids, stress regime, rock mechanical properties, reservoir pressure, and completion type. The major considerations for fluid selection are usually viscosity (for width, proppant transport or fluid loss control) and cleanliness (after flow back) to produce maximum post fracture conductivity. [14]

#### II.2.1.1 Fracturing fluid types:

Fracturing fluids must be stable at high temperatures, pumping rates, and shear rates. For fracturing treatments use several types of fracturing fluids and fluid additives. The types of fluids include:

- Water-based fluids
- Oil-based fluids
- Foam and emulsions
- Acid based

**Water-based fracturing fluids:**

Water-based fluids are used in the majority of hydraulic fracturing treatments nowadays. Water is relatively inexpensive and widely available in most areas of the world. Rheological properties (viscosity, for example) can be adjusted as desired very easily by adjusting polymer loading and additive loading even during the job if required either in stages or continuously. [19]

**Oil-based fracturing fluids:**

Oil-based fracturing systems were the first fracturing fluids to be used. Although they are compatible with most reservoirs, currently oil-based fluids are rarely used due to the higher cost compared to water-based fluids, as well as because of environmental restrictions.

Oil-base fluids are operationally difficult to handle and expensive, but these fluids are less damaging to a hydrocarbon-bearing formation than water-base fluids. Thus, oil-based fluids are used only in formations that are known to be extremely water-sensitive. [19]

**Foam and emulsions fracturing fluids:**

Foams are made by mixing a gas phase such as N2 or CO2 (internal phase) with a liquid phase such as water, CO2 (external phase), and a suitable foaming surfactant is used to maintain the stability of the foam produced, such as iodine or hydrogen peroxide. The quality of the form depends on its composition, and high-quality foams have higher percentages of gas. [19]

**Acid-based Fluids:**

Acid fluids are used for low-permeability and acid-soluble rocks. The application of acid fracturing is confined to carbonate reservoirs and is never used to stimulate sandstone, shale, or coal-seam reservoirs. The best choose for acid treatments is reservoirs with temperature less that 200°Fand the maximum effective stress on the fracture less than 5000 psi. [19]

**Table II-1:** Fluid caracteristics. [19]

| Base Fluid | Fluid Type | Composition | Used for |
|---|---|---|---|
| **Oil-Based fluid** | linear gel | oil, gelling agent | short fractures, water-sensitive formations |
| | crosslinked gel | oil, gelling agent, crosslinker | long fractures, water-sensitive formation |
| | Emulsion | water, oil, emulsifier | moderate length fractures, good fluid loss control |
| **Water-Based fluid** | linear gel | water, guar, HPG, HEC, CMHPG | short fractures, low temperature |
| | crosslinked gel | water, crosslinker, guar, HPG, CMHPG or CMHEC | long fractures, high temperature |
| | Slickwater | water, sand, additives | short and narrow fractures, low temperature |
| **Acid -Based fluid** | linear gel | acid, guar or HPG | short fractures, carbonate formations |
| | crosslinked gel | acid, crosslinker, guar or HPG | long and wide fractures, carbonate formations |
| | Emulsion | acid, oil, emulsifier | moderate length fractures, carbonate formations |
| **Foam-Based fluid** | water-based water | foamer, N2 or CO2 | low pressure formations |
| | CO2-based N2 | liquid CO2 +N2 | low pressure formations |

### II.2.1.2 Fracturing fluid additive [2]:

Fracturing fluid additives are used to perform some important functions in the hydraulic fracturing. They enhance fracture creation and help in increasing the proppant carrying capability. Various additives are used to break the fluid, control fluid loss and improve fluid efficiency, minimize formation damage, adjust PH, control bacteria or improve high-temperature stability.

The following provides descriptions of typical fracturing fluid additives:

- **Gelling Agents.** Used to viscosify the fluid.
- **Buffers.** Used to control the pH of the fracture fluid for polymer hydration as well as crosslinking and gel stability.
- **Crosslinkers.** Used to exponentially increase the fluid viscosity.
- **Biocides.** Used to kill bacteria in the mix water, biocides are designed to prevent a colony of bacteria from developing in the first place, rather than for killing an existing colony.
- **Surfactants.** Used to reduce the surface tension, interfacial tension between water and formation fluids, and also to change the contact angle of the leakoff fluid for easier recovery.
- **Friction Reducers.** Used to reduce the friction pressure and hence associated horsepower requirement for the pumping operation, friction reducers also protect equipment from wear and tear due to the high pumping rates of slickwater jobs.
- **Gel Stabilizers.** Used to increase the fluid stability of crosslinked gels at elevated temperatures.

### II.2.2 Selection of Proppant :

Proppant must be selected on the basis of in situ stress conditions. Major concerns are compressive strength and the effect of stress on proppant permeability. For a vertical fracture, the compressive strength of the proppant should be greater than the effective horizontal stress. In general, bigger proppant yields better permeability, but proppant size must be checked against proppant admittance criteria through the perforations and inside the fracture. The Figure bellow shows variation in proppant pack permeability under fracture closure stress. It can be observed that as the closure stress increases, the permeability decreases for different type of proppants. [14]

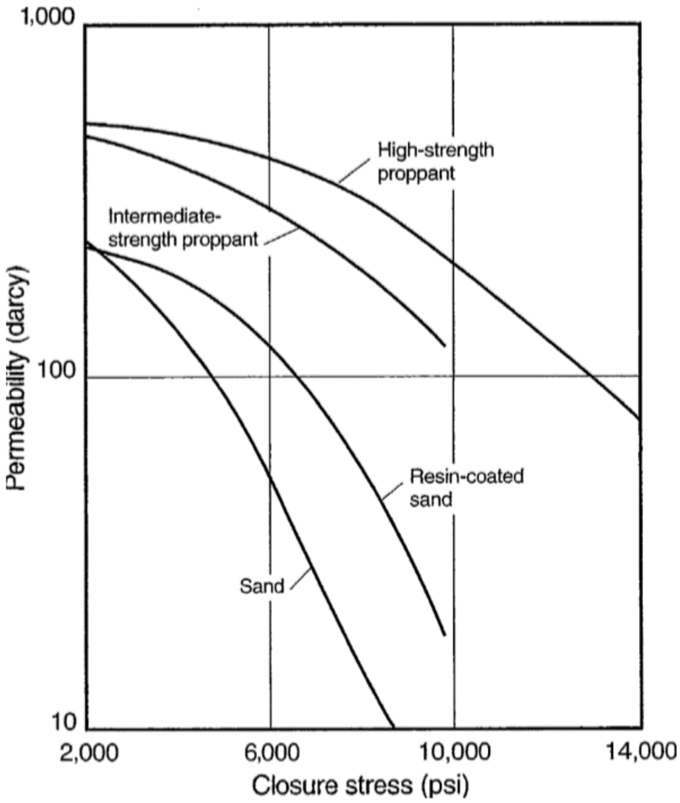


**Figure II.11**: effect of fracture closure stress on proppant pack permeability [14]

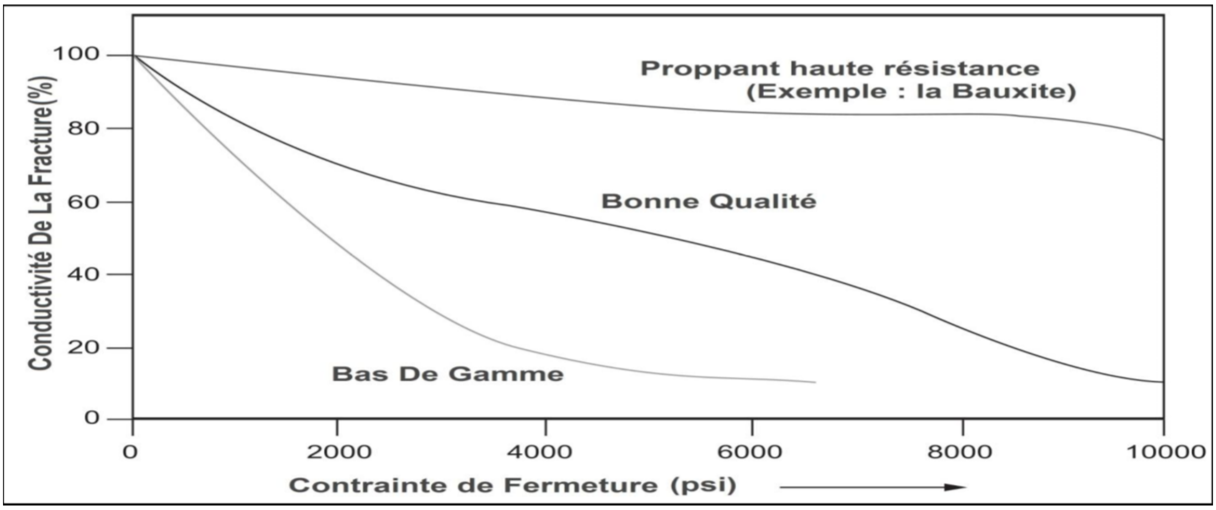


**Figure II.12:** Conductivity versus closure stress

### II.2.2.1 Propant types:

The 4 main proppant types that are used commercially in oil and gas industry are sand, resin-coated, sintered bauxite, and intermediate strength proppant [20].

**Sand:**

The two major types of send used in hydraulic fracturing are:

- Ottawa Sand: is a high-quality sand, white in color, pure quartz composition, high roundness and sphericity, it is recommended for formations with net closure stresses up to 6,000 psi.
- Brady Sand: is another high-quality sand used for fracturing, characterized by its slight angularity and presence of feldspars. A Brown Sand with closure stresses below 5,000 psi .

**Resin-Coated Sand:**

Resin-coated proppant are commonly used to improve well stimulation result in hydraulic fracturing to prevent proppant flow back, fracture evacuation; and increase fracture conductivity. The most commonly resin used to coat proppants are epoxy or phenolic resins. resin-coated sands can be used at closure stresses greater than 8,000 psi.

**Bauxite (High-strength and intermediate-strength):**

High-strength sintered bauxite and intermediate-strength sintered bauxite are usually made from bauxite and kaolin, they offer excellent roundness and sphericity. These proppants contain corundum, one of the hardest materials known, and offer the greatest strength for deep wells with high stress (greater than 12,000 psi), temperature environments, and providing high fracture conductivity. Sintered bauxite proppants are available in sizes ranging from 12- to 70-mesh with a specific gravity of 3.4 and greater.

**Intermediate Strength Proppant (ISP) – Ceramics:**

Generally, a ceramic is any nonorganic, non-metallic solid formed by high temperature processing (above 875°F). These ceramic proppants have less strength than the intermediate- and high strength sintered bauxite proppants but greater strength than sand.it provide excellent resistance to high closure pressures up to 14,000 psi.

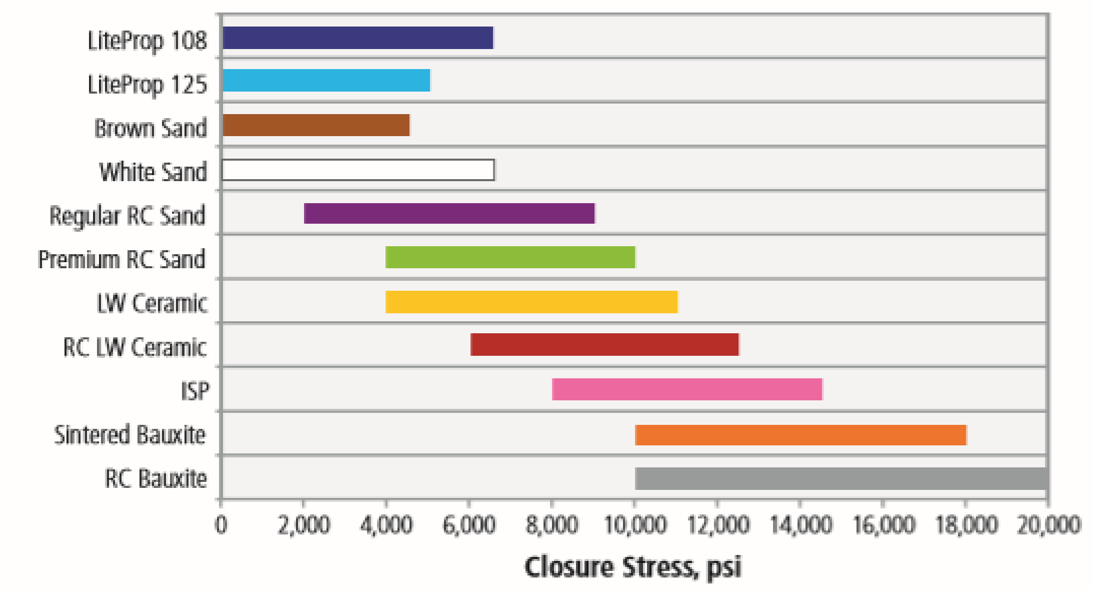


**Figure II.13:** recommended closure stress ranges for various types of proppants [2]

### II.2.3 Calculation of Maximum Treatment Pressure [14]:

The maximum treatment pressure is expected to occur when the formation is broken down. The bottom-hole pressure is equal to the formation breakdown pressure and the expected surface pressure can be calculated by :

$$P_{si} = P_{bd} - \Delta P_h + \Delta P_f \ldots\ldots (II.8)$$

Where :

$P_{si}$= surface injection pressure, psia; $P_{bd}$= formation breakdown pressure, psia

$\Delta P_h$= hydrostatic pressure drop, psia; $\Delta P_f$ = frictional pressure drop, psia

frictional pressure drop $\Delta P_f$ can be estimated with the following formula :

$$\Delta P_f = \frac{518\rho^{0.73} q^{1.73} \mu^{0.207}}{1000 D^{4.79}} L \ldots\ldots (II.9)$$

Where:

ρ = density of fluid, g/cm3; q = injection rate, bbl/min; μ = fluid viscosity, cp

D = tubing diameter, in.; L = tubing length, ft.

### II.2.4 Selection of Fracture Model:

Fracture Geometry The two basic types of geometries 2D (PKN, KGD, radial), 3D (planner 3D, lumped 3D, discrete P3D) are presented above.

### II.2.5 Selection of Treatment Size [14]:

The optimum design for a fracture treatment is one in which the pad volume has leaked off into the formation and the proppant has reached the tip at the end of pumping, leaving the fracture filled with the proppant-laden slurry to provide a fairly uniform propped width and sufficient conductivity to minimize the pressure drop during production.

The fracture length primarily defines treatment size. Fluid and proppant volumes are controlled by fracture length, injection rate, and leak-off properties. A general statement can be made that the greater the propped fracture length and greater the proppant volume, the greater the production rate of the fractured well. Limiting effects are imposed by technical and economic factors such as available pumping rate and costs of fluid and proppant.

This section demonstrates how to design treatment size using the PKN fracture model for simplicity. Calculation procedure is summarized as follows:

1. Assume a fracture half-length Xf and injection rate qi and calculate the average fracture width w using a selected fracture model.

Fracture area estimation :

$$A_f = \frac{(1-\eta)V_{inj}}{2g(\Delta t_D = 0)(C_L r_P \sqrt{t_{inj}})} \ldots\ldots (II.10)$$

$$A_f = A_{f1} \times 2 \ldots\ldots (II.11)$$

Length estimation :

$$X_f = \frac{A_{fra1}}{2h_f} \ldots\ldots (\mathrm{II.12})$$

width estimation :

$$\overline{W_f} = \frac{2g(\Delta t_D = 0)(C_L r_p \sqrt{t_{inj}})\eta}{(1-\eta)} \ldots\ldots (II.13)$$

2. Based on material balance, solve injection fluid volume $V_{inj}$ from the following equation:

$$V_{inj} = V_{frac} + V_{leakoff} \ldots\ldots (II.14) \ , \qquad V_{inj} = q_i t_i \ldots\ldots (II.15)$$

$$V_{frac} = A_f \overline{W} \ldots\ldots (II.16)$$

$$V_{leakoff} = 2K_L C_L A_f r_p \sqrt{t_i} \ldots\ldots (II.17)$$

$$K_L = \frac{1}{2}\left[\left[\frac{8}{3}\eta + \pi(1-\eta)\right]\right] \ldots\ldots (II.18)$$

$$r_p = \frac{h}{h_f} \ldots\ldots (II.19)$$

$$A_f = 2x_f h_f \ldots\ldots (II.20)$$

$$\eta = \frac{V_{frac}}{V_{inj}} \ldots\ldots (II.21)$$

$$V_{pad} = V_{inj}\frac{1-\eta}{1+\eta} \ldots\ldots (II.22)$$

Since:

$K_L$ depends upon fluid efficiency $\eta$ which is not known in the beginning, so, numerical iteration procedure is required. This procedure is explained below.

$$q_i t_i = A_f \overline{W} + 2K_L C_L A_t r_p \sqrt{t_i}$$

$t_i$ $\qquad\qquad$ $K_L = \frac{1}{2}\left[\frac{8}{3}\eta + \pi(1+\eta)\right]$

$\downarrow$

$V_{inj} = q_i t_i$

$V_{frac} = A_f \overline{W}$ $\qquad \eta = \frac{V_{frac}}{V_{inj}}$

$V_{pad} = V_{inj}\left(\frac{1-\eta}{1+\eta}\right)$

Where:

$V_{inj}$ = injection fluid volume; η = fluid efficiency; $\overline{W}$ = average fracture width;

$A_f$ = fracture area; $r_p = \frac{h}{h_f}$ = payzone thickness/ fracture height;

$C_L$ = fluid loss coefficient in ft/ $(min)^{1/2}$ ; $K_L$ = fluid loss multiplier

1. Generate proppant concentration schedule using:

$$C_p(t) = C_f\left(\frac{t - t_{pad}}{t_{inj} + t_{pad}}\right)^{\varepsilon} \ldots\ldots (II.23)$$

Where $C_f$ is the final proppant concentration in ppg. The proppant concentration in pounds per gallon of added fluid is expressed as;

$$\acute{C_p} = \frac{C_p}{1 - {C_p}/{\rho_p}} \ldots\ldots (II.24)$$

And

$$\varepsilon = \frac{1 - \eta}{1 + \eta} \ldots\ldots (II.25)$$

2. Predict propped fracture width using :

$$W = \frac{C_p}{\left(1 - \phi_p\right)\rho_p} \ldots\ldots (II.26)$$

Where:

$C_p$ = proppant concentration in ppg; $M_p$= proppant weight in lbs.; $\phi_p$= proppant porosity

$t_{inj}$= injection time of calculating slurry concentration (min); $t_{pad}$= time to pump the pad volume

$$C_p = \frac{M_p}{2x_f h_f} \ldots\ldots (II.27)$$

$$M_p = \overline{C_p}\left(V_{inj} - V_{pad}\right) \ldots\ldots (II.28)$$

$$\overline{c_p} = \frac{C_f}{1 + \eta} \ldots\ldots (II.29)$$

## II.3 Productivity of Fractured Wells [14]:

Hydraulically created fractures gather fluids from reservoir matrix and provide channels for the fluid to flow into wellbores. Apparently, the productivity of fractured wells depends on two steps: receiving fluids from formation and transporting the received fluid to the wellbore. Usually one of the steps is a limiting step that controls the well-production rate. The efficiency of the first step depends on fracture dimension (length and height), and the efficiency of the second step depends on fracture permeability. The relative importance of each of the steps can be analyzed using the concept of fracture conductivity defined as.

$$F_{CD} = \frac{k_f w}{k x_f} \dots\dots (II.30)$$

Where:

$F_{CD}$= dimensionless fracture conductivity; $k_f$ = fracture permeability, md

w = fracture width, ft; $x_f$ = fracture half-length, ft. k = formation permeability

The effect of stimulation on production rate is illustrated in the following figure

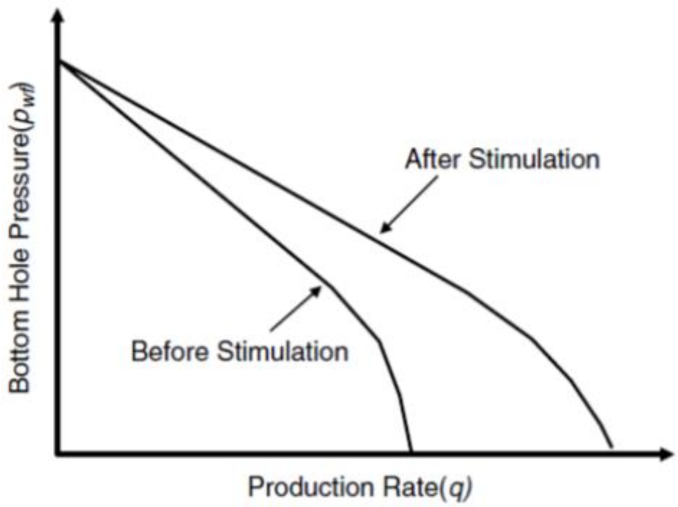


**Figure II.14 :** Production rate versus Bottom hole pressure. [14]

# <u>Chapter 3 :</u>

## IRS-A Well Hydraulic Fracturing Study And Evolution

# Chapter III: IRS-A WELL HYDRAULIC FRACTURING STUDY AND EVOLUTION

## Introduction:

The objective of this study is to analyze the fracturing treatment and the technical challenges of the IRS-A well represented as a connection with a productive fault. Therefore, for this study, field data from horizontal offset wells with multistage fracturing were used. Tracer studies were conducted and the results were also used as input information. This study concerns the following steps:

- Stage fracturing treatment design
- Stage fracturing Completion design
- Progress of the Stage-Frac operation
- Performance evaluation by simulation

The objective for this fracture stimulation treatment is to generate a long propped fracture length due to the relatively low permeability and to increase the possibility of intersecting natural fractures.

## III.1 Reservoir information [21]:

The main productive reservoirs of the Timimoun Basin are the Lower Devonian sandstones (for essential to dry gas). They belong to the series including Emsien, Praguien and Lochkovien, series is mainly clay-sandstone. These series have been deposited on Silurian clay levels.

Emsien reservoirs are in a porosity range of up to 15% (Barouda) with a mean around 10%. The permeability's, generally> 0.1 mD.

A correlation system has been established on existing wells, based on a stratigraphic interpretation, sequential: correlation of "MFS" (maximum flood surface area)

The average thickness of the Emsien Reservoir on the structure of Irharen South is between 3 and 6m the deposit model shows continuous reservoirs that are gradually thinning from East to West at the perimeter scale of Timimoun. The well concerned with our study are situated in the southern Irharen area, the Emsien reservoir.

## III.2 IRS-A Well Evaluation:

### III.2.1 Well Location:

The Irharen Sud (IRS-A) well is a development well in the southern area of the Timimoun field. It is a horizontal well that was drilled to assess the Lower Devonian reservoirs, most specifically the Pragian and the Emsian, multistages fractured with frac point system.

The forecast trajectory is designed so as to land subhorizontally in the Emsian Reservoir at 1974m north-west of the existing penetration on IRS-C, which is thus used as a pilot well for IRS-A. A drain of 600m minimum will be drilled in the upper part of the massive sandstones in an azimuth N 282°. IRS-A is located approximately 2000 m northeast of the IRS-B and IRS-C wells.

The Emsien reservoir is the sole objective of IRS-A, solid sandstone recognized by dry gas from the IRS-B well. the Emsien reservoir has already been penetrated by IRS-B and IRS-C (medium quality) and IRS-D (poor quality).

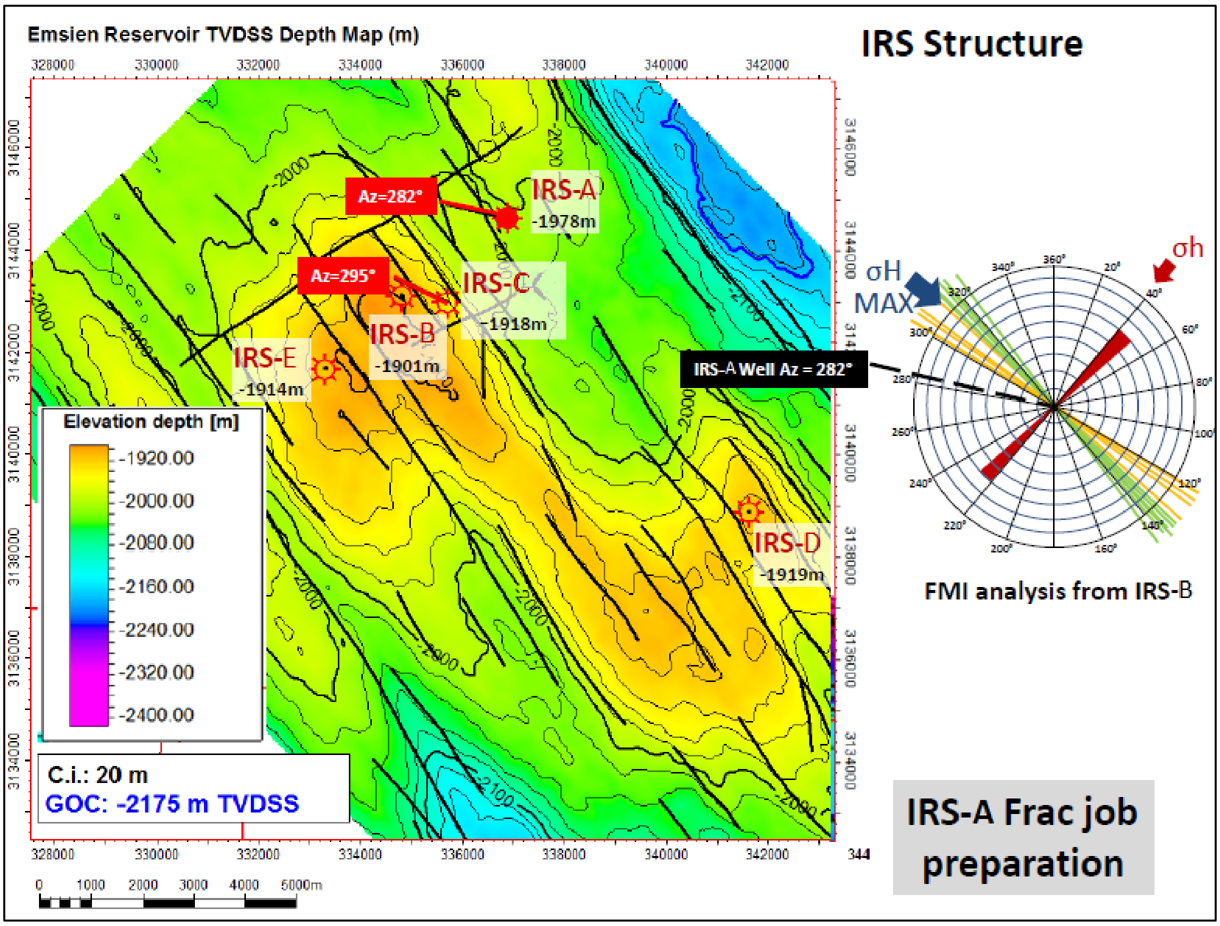


**Figure III.1:** IRS-A Location [21]

### III.1.1 Offset Information:

Three wells have been fractured (or attempted) during the exploration phase. Of these three wells, two treatments were performed in the Emsian formation in IR-E and IRS-B.

**Table III-1:** Offset wells fracture information**.** [21]

| **Well** | **Interval** | **Depth** | **Frac Gradient** | **Pump Rate** | **BH Pressure** | **Max BH Pressure** | **Proppant Placed** | **Max BH Conc** |
|---|---|---|---|---|---|---|---|---|
| | | m | psi/ft | bpm | Psi | Psi | lbs. | lbsm/gal |
| IR-D | Lochkovien | 2439 | 1.21 | 17 | 10,900 | 11220 | 15600 | 0.8 |
| IR-D | Pragian | 2237 | 0.93 | 34 | 10000 | 11615 | 16500 | 3.2 |
| IR-E | Lochkovien | 1949 | 1.11 | 31 | 7600 | 10277 | 26400 | 3.2 |
| IR-E | Emsien | 1624 | 1.04 | 31 | 6400 | 6600 | 67400 | 5.1 |
| IRS-B | Lochkovien | 2506 | 1.15 | 25 | 9850 | 10300 | 111600 | 6.7 |
| IRS-B | Emsien | 2309 | 1.06 | 25 | 9400 | 10050 | 213600 | 8.0 |
| IRS-D | Emsien | 2370 | 1.04 | 20 | 9300 | 8890 | 22000 | 9.5 |

#### III.1.1.1 Stages position:

Generally, the fracturing stages are chosen according to defined selection criteria, taking on consideration the reservoir properties interpretation (GammaRey, Resistivity, gravity and porosity) and the stress profile calculated from these logs. (Annex 8)

#### III.1.1.2 Estimated Reservoir Properties:

The main reservoir properties were estimated from the IRS-D well logs. (Annex 3)

**Table III-2:** Estimated reservoir properties.

| Well | Top bottom | Gross | Net | Av-shale | Av-porosity | Zones volume | Av-water | Satur-ation |
|---|---|---|---|---|---|---|---|---|
| **IRS-D** | Emsien-res. | 2334.29 | 2351.03 | 16.740 | 4.420 | 0.048 | 0.069 | 0.242 |

### III.1.1.3 Stress calculations :

The IRS-A stress is calculated from the stress of IRS-D estimated from sonic, which is the lowest in the perforation interval of 2390 meters. It shows that a large stress contrast between the upper and lower bounding shale sections will cause a contained fracture over the Emsien productive sands.

A plot of the results of IRS-A stress is shown below; where we can see that the average **minimum horizontal stress** is estimated to be **1.0 psi/ft** in the perforated interval.

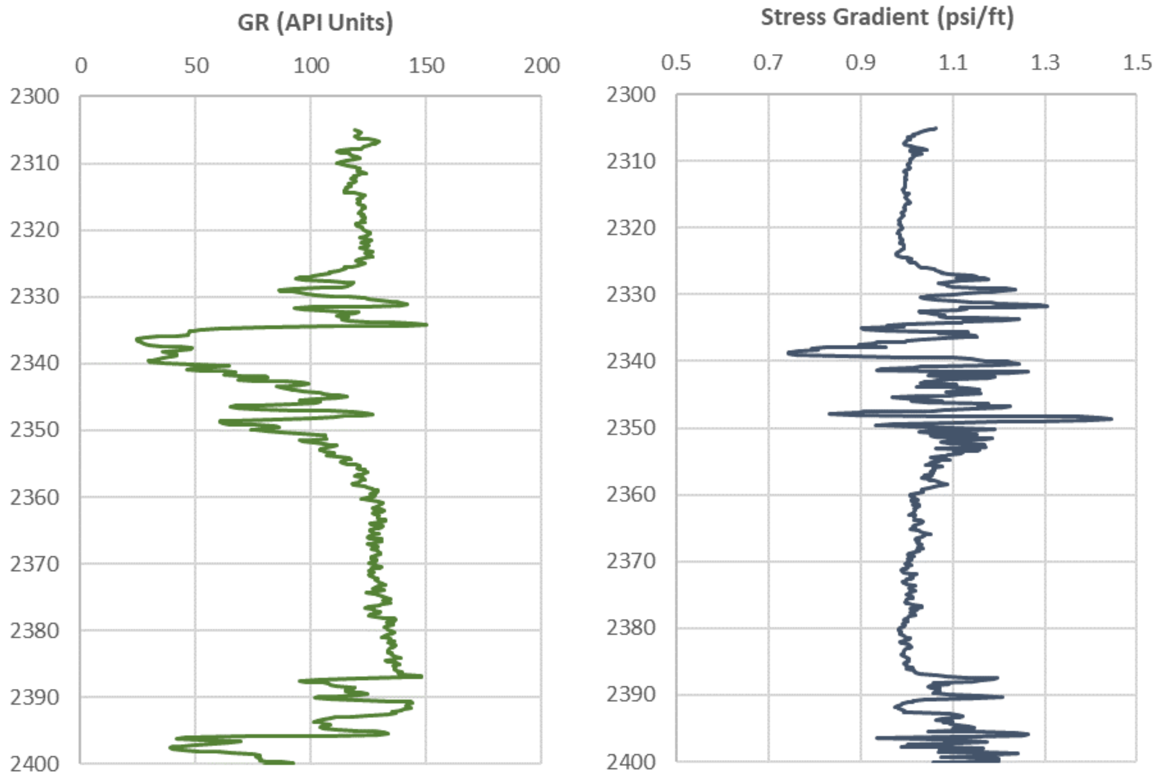


**Figure III.2:** IRS-D Stress profile [21]

### III.1.2 Completion placement and design:

The Frac sleeves position was based on analysis of the geomechanical properties and the petro-physical interpretation. The perforation interval was selected based on the highest area of reservoir quality. (Annex 7)

The fracture intervals and sleeves and packer placement for IRS-A were chosen based on the available processed logs and the ID of hole configuration. 6 sleeves were chosen, four of which will be fracture stimulated.

**Table III-3:** IRS-A Frac Sleeve position depth.

| Frac sleeve | Depth (m) |
|---|---|
| CMB Frac Sleeve 1 frac stage 1 | 3268.244 |
| CMB Frac Sleeve 2 frac stage 2 | 3233.852 |
| CMB Frac Sleeve 3 frac stage 3 | 3160.241 |
| CMB Frac Sleeve 4 frac stage 4 | 3082.814 |
| CMB Frac Sleeve 5 frac stage 5 | 2975.776 |
| CMB Frac Sleeve 6 frac stage6 | 2913.539 |

The completion recommended for this treatment is the Baker Hughes FracPoint™ Completion System, specifically designed for multiple fracture treatments in open-hole horizontal wellbores.

The system features CMB frac sleeve open and closed by coiled tubing. (Annex 8)

## III.2 Injection and Minifrac tests:

### III.2.1 Stage number one (3268.244 m):

The injection test has been repeated for all stages to ensure the well-formation contact in every perforation. Due to the high value of bottom-hole frictions, acid injection was the solution to minimize the loss of pressure.

Datafrac is usually pumped in one stage to obtain information that are vital to the success of the main traitement, but in this case, it was better to ensure this information by pumping another datafrac in the second stage.

### III.2.1.1 Injection test:

Open ground valve, start pumping a volume of 16667 gal of treated water gradually to establish rate at 2 bpm, the breakdown at 9563 psi.

- Bottom-hole: Lpp = **8229** psi; ISIP = **8876** psi; ΔP = **647** psi.
- Surface : Lpp = **7157** psi; ISIP = **5180** psi ; ΔP = **1977** psi.

- Switch to acid:

Start pumping **15% Hcl** at **5** bpm, the pressures: Tp = **1212** psi BHP = **4644** psi, Volume of Acid (15% Hcl): **2004** gals.

- Bottom-hole: Lpp = **8228** psi; ISIP = **8676** psi; ΔP = **448** psi.
- Surface : Lpp = **7177** psi ; ISIP = **5209** psi ; ΔP = **1968** psi.

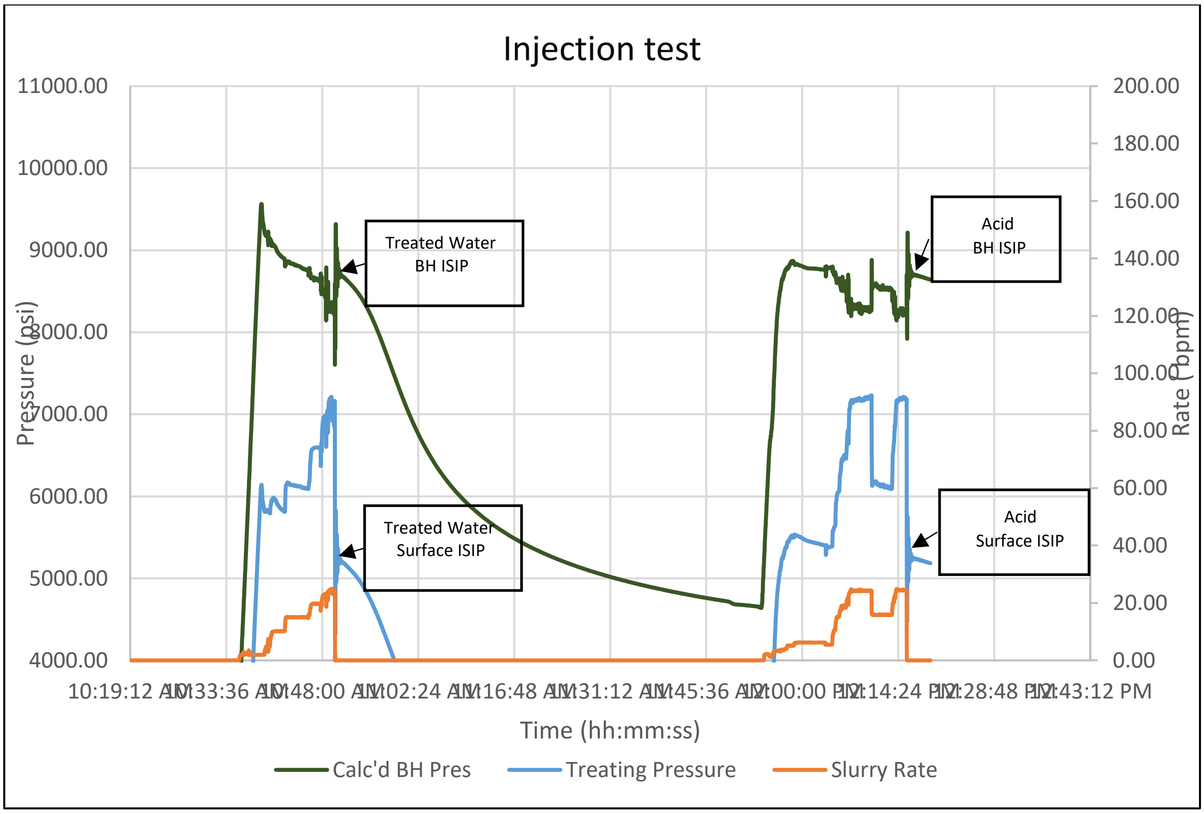


**Figure III.3:** Pressure versus rate plot for injection test

### III.2.1.2 Mini frac analysis:

A minifrac was pumped with **28046 gal** of Hybor H35 fluid and displaced with 35# gel. Open ground valve, start pumping a volume of **9843** gal of 35# linear gel and increase rate gradually to reach **25 bpm**.

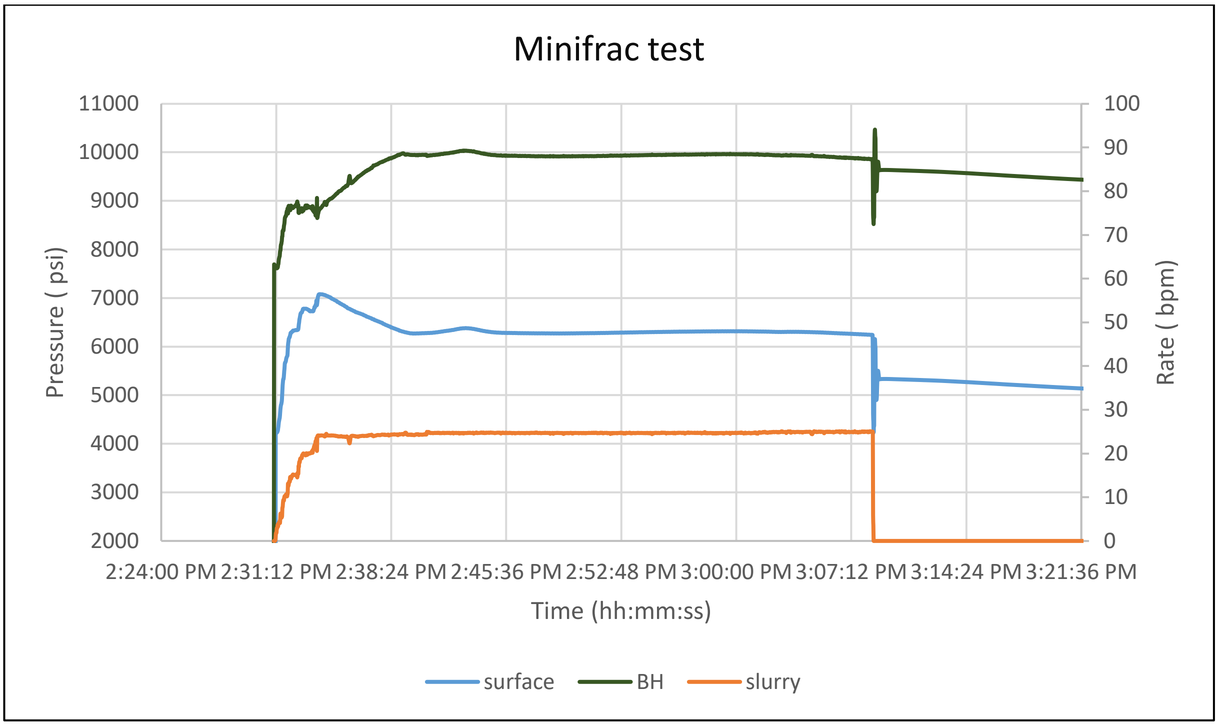


**Figure III.4:** Pressure versus rate plot for Minifrac test

### III.2.1.3 Pressure decline analysis:

The pressure decline information from the Mini-frac was analyzed to determine instantaneous Shut-in pressure, Closure Pressure, Net pressure, and fluid efficiency.

- **Determination of Instantaneous shut-in pressure (ISIP):**

Instaneous shut-in pressure ($ISIP_{BH}$) and last pumping pressure ($LPP_{BH}$) can be located easily from pressure evolution chart shown below.

We draw a vertical line from the point corresponding to the injection stopping time of the fluid. Then the stabilized pressure drop line is extrapolated; the point of intersection of the two lines corresponds to the ISIP.

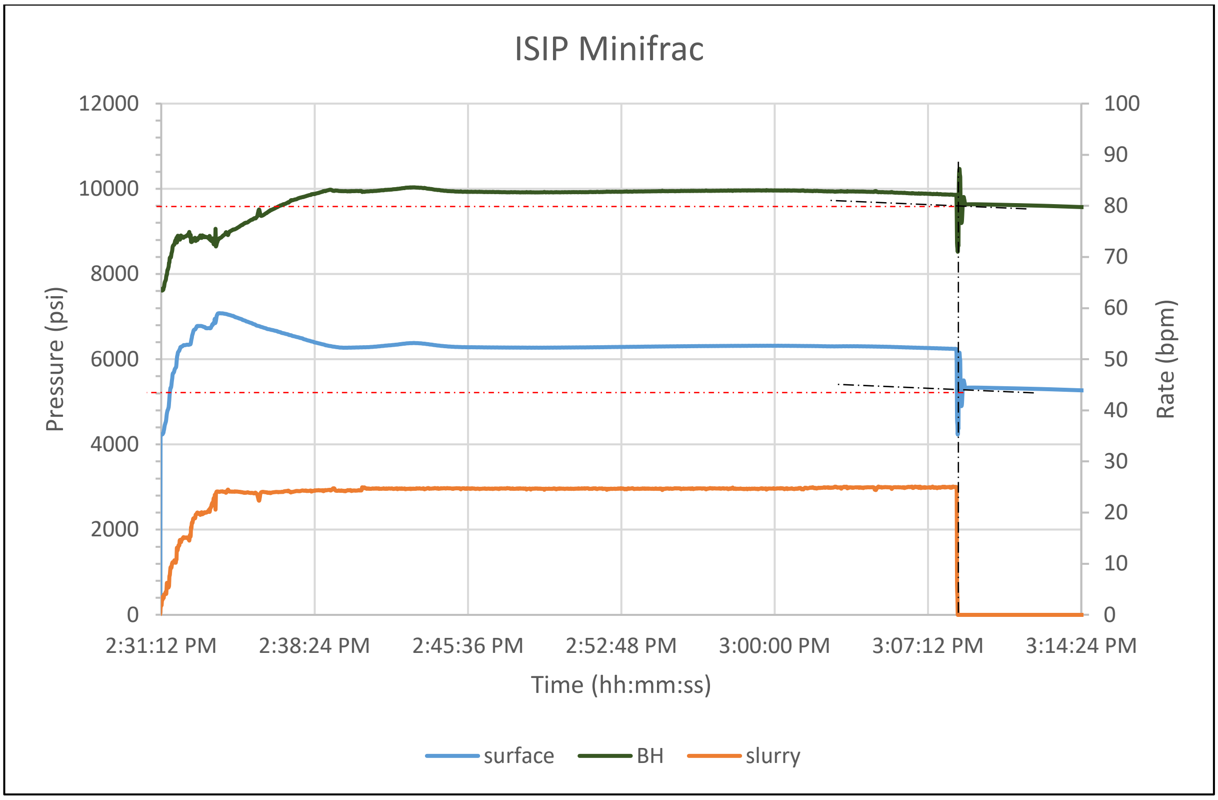


**Figure III.5:** ISIP Determination from Minifrac plot

- Bottom-hole : ISIP= **9600** psi; LPP=**9856,92** psi; ΔP = **256,92** psi
- Surface : ISIP= **5298** psi; LPP=**6240,42** psi; ΔP = **942.42** psi
- Fracture gradient =1.21 Psi/ft

- **Closure pressure determination by G-function and Square root of time methods:**

The calculation of the closure pressure (CP) is essential, in fact it corresponds to the minimum horizontal stress ($\sigma_h$). The value of ($\sigma_h$) is an essential data to determine the parameters of the fracture.

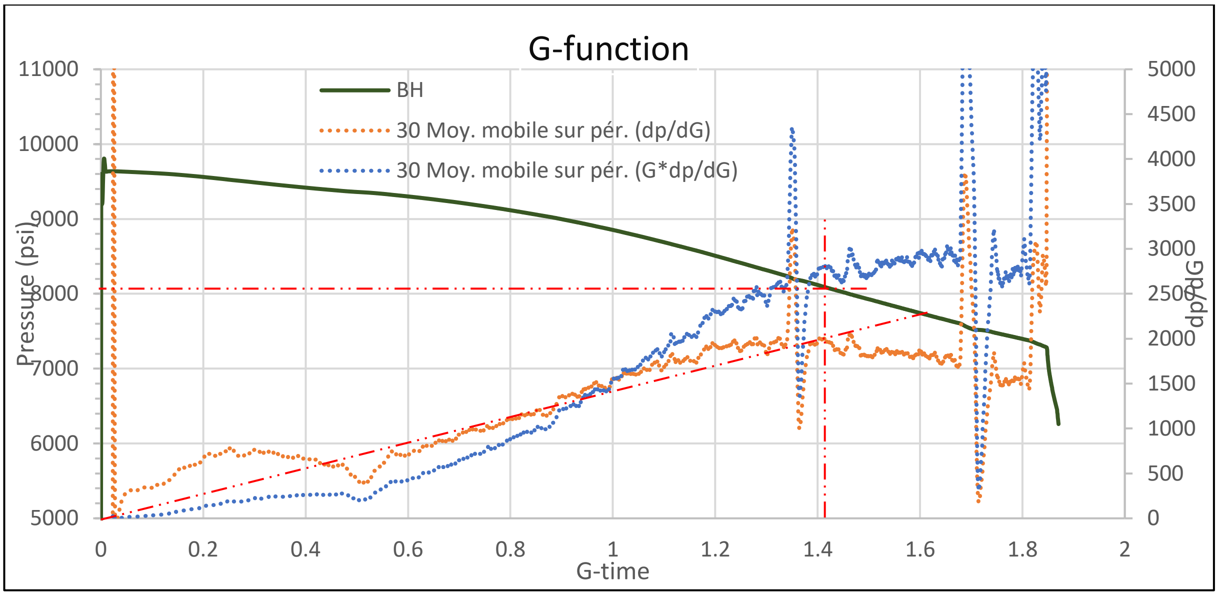


**Figure III.6:** Closure pressure determination from G-function plot

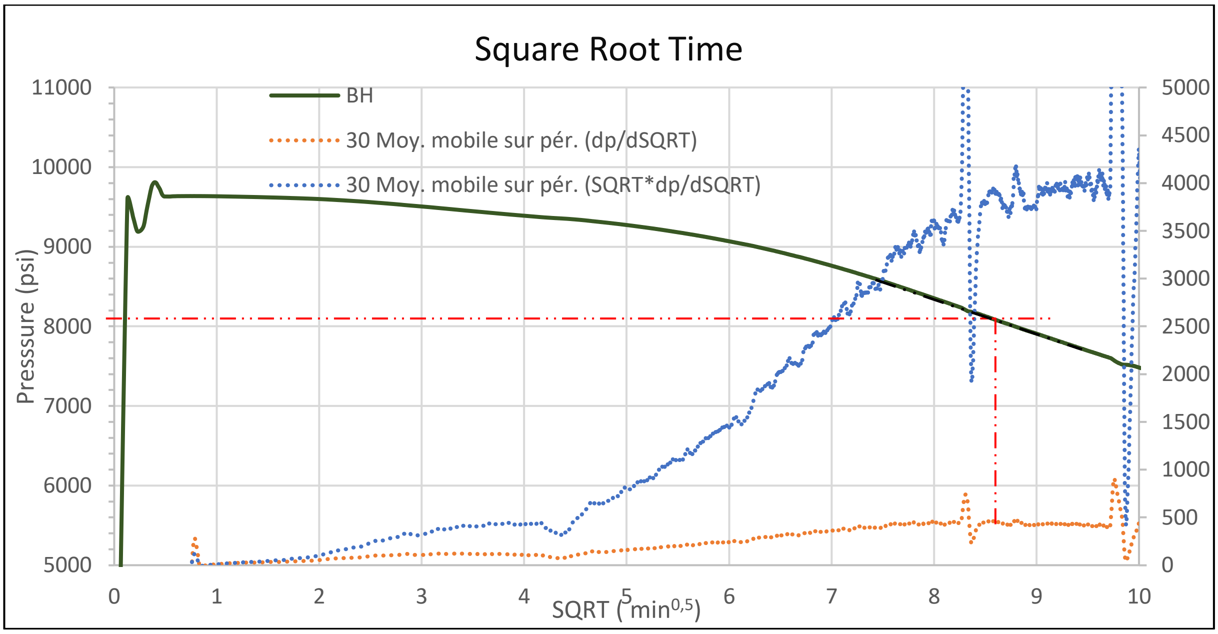


**Figure III.7:** Closure pressure determination from square root time plot

Nolte G-function plot and Square Root time plot methods gave the results below:

**Table III-4**: Square Root Time and G-function methods' results for stage 1.

| | Symbol | SQRT | G | Unit |
|---|---|---|---|---|
| Closure Pressure | CP | 8175 | 8150 | Psi |
| Closure gradient | $G_c$ | 1.03 | 1.03 | Psi/ft |
| Net pressure | $P_{NET}$ | 1600,4 | 1607 | Psi |
| Fluid efficiency | $T_c$ | 41.01 | 40.87 | % |
| Closure Time | η | 12 | 12 | Min |

### III.2.2 Stage number 2 (3233.833 m):

#### III.2.2.1 Injection test:

- Downhole: Lpp = **10350** psi; ISIP = **9450** psi; ΔP = **900** psi.
- Surface: Lpp = **7650** psi ; ISIP = **6000** psi ; ΔP= **1650** psi

#### III.2.2.2 Minifrac Pressure decline analyses results:

- Surface : ISIP = **5950** psi ; Lpp = **6950** psi; ΔP = **1000** psi,
- Bottom-hole: ISIP = **9300** psi; Lpp = **9900** psi; ΔP = **600** psi,
- Fracture gradient of **1.17** psi/ft.

The table below shows the final essential parameters esstimated from both method Nolte G function and Square Root Time:

**Table III-5**: Square Root Time and G-function methods' results for stage 2.

| | Symbol | Nolte G | SQRT | Unit |
|---|---|---|---|---|
| Closure Pressure | CP | 7,539 | 7,539 | Psi |
| Closure Gradient | $G_c$ | 0.95 | 0.95 | Psi/ft |
| Net Pressure | $P_{NET}$ | 1,711 | 1,711 | Psi |
| Time to Closure | $T_c$ | 12 | 13 | min |
| Fluid Efficiency | η | 51.03 | 51.03 | % |

- The results from the second minifrac test are similar to the first one, consequently, the information estimated from the first test are applicable.

### III.2.3 Fracture propagation model determination:

The Net Pressure plot is only obtained after the end of the MiniFrac. The fracture model could be estimated from the net pressure plot, although this process is very difficult, even having recourse to strong software, to find and trace the good slopes which characterize a given model.

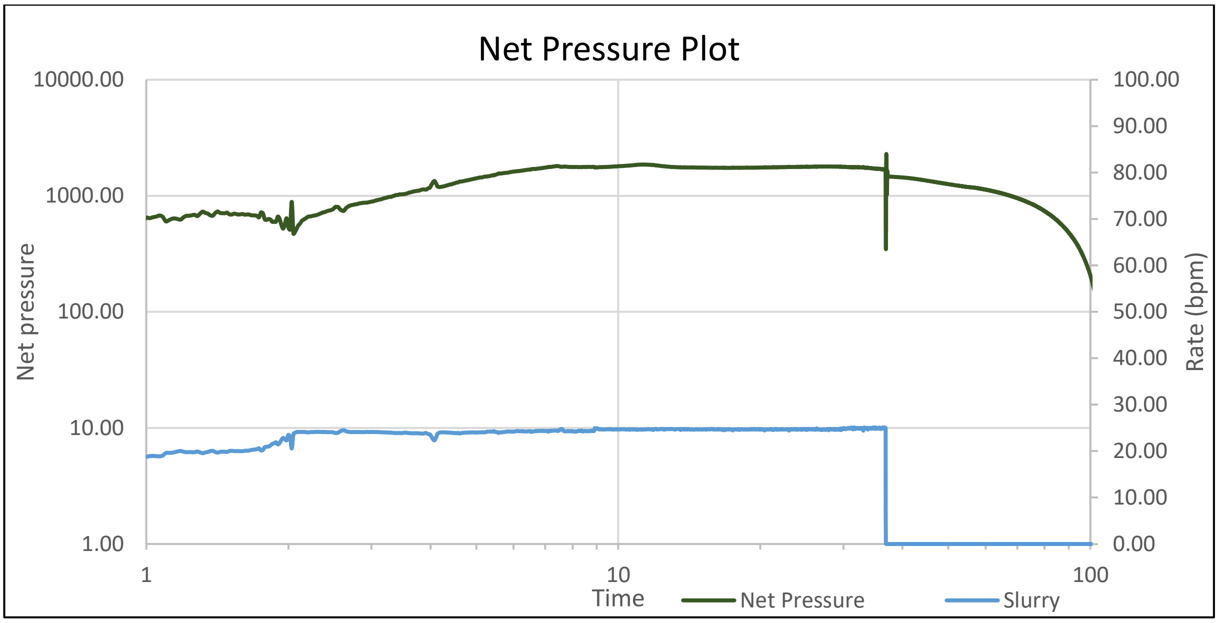


**Figure III.8:** Net pressure plot

According to Nolte analysis, it is limited to the algebraic sign of the slope (positive, negative or zero). We observe from the start that the slope is slightly positive ≈ PKN

Therefore, the model considered is therefore **PKN**

### III.2.4 Measured values and simulator's values comparaison:

**Table III-6:** Comparative table of calculated values and Software results.

| Parameters | Symbol | Meyer frac results | | Calculated values | | Unit |
|---|---|---|---|---|---|---|
| | | SQRT | Nolte-G | SQRT | Nolte-G | |
| **Closure Pressure** | **CP** | **8099** | **8099** | **8100** | **8110** | **Psi** |
| Closure gradient | $G_c$ | 1.02 | 1.02 | 1.03 | 1.03 | Psi/ft |
| Net pressure | $P_{NET}$ | 1618 | 1618 | 1600.4 | 1607 | Psi |
| Time to closure | $T_c$ | 13 | 12 | 12 | 12 | Min |
| Fluid efficienty | η | 55.28 | 55.28 | 41 | 41.23 | % |

By comparing the measured values and those obtained from MeyerFrac software, we note that:

- A small difference observed with the values of the closure pressures, which can be explained by the sensitivity of the choice of the corresponding characteristic point that becomes delicate especially with the dispersion of the points of the derivative curve of the pressure.
- Accuracy is required for all parameters obtained by interpreting pressure recordings during the Minifrac, in order to use its parameters as necessary data for the design of the main treatment.

## III.3 Main Treatment Design:

### III.3.1 Fracturing fluids and proppant selection:

Knowing that in our case, the reservoir temperature is equal to 125 ° C and stress of 9464.4 Psi, the selection of the fracturing fluid and proppant type is made according to the operating conditions (the temperature of the reservoir, the exposure time of the fluid, the filtration, the compatibility between the frac fluids and those of the formation, etc.).

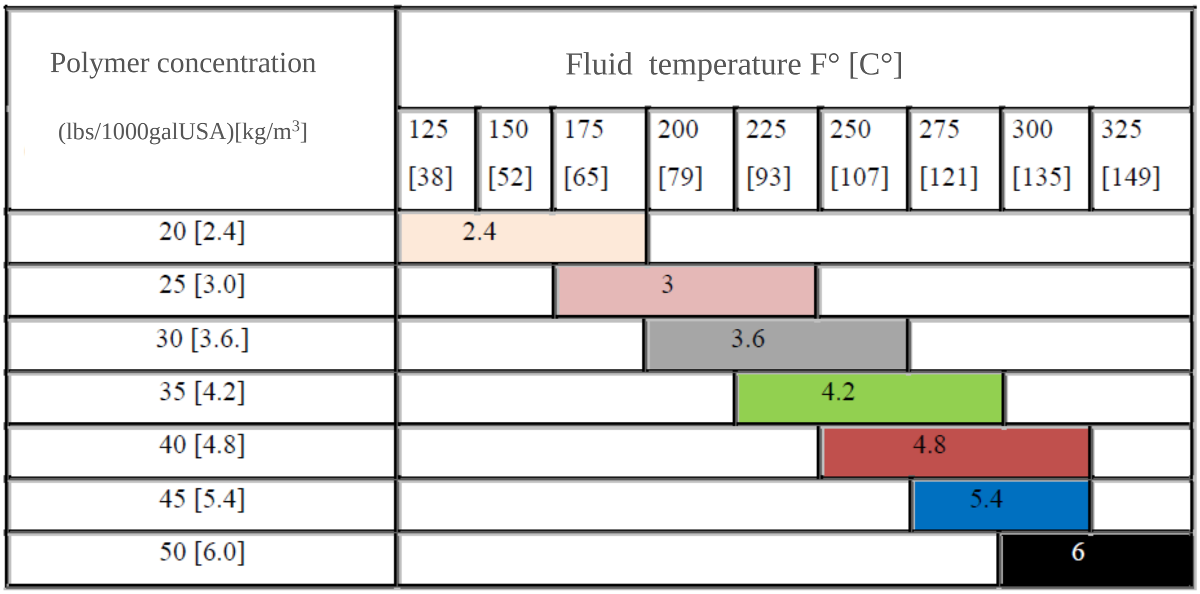


**Figure III.9:** Relation between polymer concentration and reservoir temperature [22]

From this figure and (figure II.13), we deduce the adequate polymer concentration with reservoir temperature, which is of the order of **35 lb / 1000gal**. The linear gel and the crosslinked gel corresponding to this loading are respectively: **#35 linear gel** and **Hybor H35#**. While proppant type deduced is the Intermediate Strength Proppant (**ISP**).

### III.3.2 Fracture Geometry Calculations using Nolte Method:

Thermometric recordings are generally made right after the mini frac, they allow precise indications of the fracture to be obtained in the immediate vicinity of the well (height and orientation). In the case of IRS-A, thermometry could not be performed so we rely on the offset wells indications. (Annex 3)

The following parameters are calculated from Stage number one indications:

**Table III-7:** Deduced parameters from offset wells

| Parameter | Value | Unit |
|---|---|---|
| Upper Frac Height | 3282 | m |
| Lower Frac Height | 3245 | m |
| Total frac height | 37 | m |

- **Fracture area estimation :**

$$A_{frac1} = \frac{(1-\eta)V_{inj}}{2g(\Delta t_D=0)(C_L r_P\sqrt{t_{inj}})} \qquad A_{frac1} = \frac{(1-0.4)5264.06}{2\times\frac{4}{3}(0.009\times0.48\times\sqrt{37.5})} = 43312.48 \text{ ft}^2$$

$$A_{frac} = A_{frac1} \times 2 \qquad A_{frac} = 43312.48 \times 2 = 86624.96 \text{ ft}^2$$

- **Length estimation :**

The half-length of the fracture for the PKN model is given by the following relation:

$$X_f = \frac{A_{frac1}}{2h_f} \qquad X_f = \frac{43312.48}{2\times114.83} = 188.6 \text{ ft}$$

- **Width estimation:**

$$\overline{W}_f = \frac{2g(\Delta t_D=0)(C_L r_p\sqrt{t_{inj}})\eta}{(1-\eta)} \qquad \overline{W}_f = \frac{2\times\frac{4}{3}(0.009\times0.48\times\sqrt{37.5})0.41}{(1-0.41)} = 0.04 \text{ ft}$$

$$= 0.5 \text{ in}$$

**Table III-8:** Resume of fracture geomerties parameters.

| Parameter | Symbol | Value | Unit |
|---|---|---|---|
| Fracture surface | $A_f$ | 86625 | Ft |
| Fracture half-lenght | $X_f$ | 188.6 | Ft |
| Fracture width | $W_f$ | 0,5 | In |

### III.3.3 Treatment design:

The treatment is designed to connect the created fractures to a productive fault, where the the half-length of the fracture is the distance between the frac-Sleeve and the productive fault. (Annex 4)

**Table III-9:** Distance between each frac-Sleeve and the productive fault [21]

| Stage | Xf (m) |
|---|---|
| Stage 1 | 40 |
| Stage 2 | 74 |
| Stage 3 | 147 |
| Stage 4 | 225 |
| Stage 5 | 332 |

- **Fracture width:**

Fracture width is estimated by using many formules and equations, from Minifrac results:

$E' = \frac{E}{(1-\nu^2)}$ $E' = \frac{6700000}{(1-0.15^2)}$ =6854220 Psi

$W_{fo} = \frac{2P_{net}h_f}{E'}$ $W_{fo} = \frac{2\times1607\times114.83}{6854220} = 0.054\ \text{ft} = 0.65\ \text{in}$

$\overline{W}_f = \frac{\pi}{5}W_{fo}$ $\overline{W}_f = \frac{\pi}{5}\times 0.65 = 0.4\ \text{in}$

- **Fracture Area:**

$A_f = 2x_fh_f$ $A_f = 2\times 114.83\times 131.24$ =60283.8 ft$^2$

- **Fracture volume:**

$V_{frac} = A_f\overline{W}_f$ $V_{frac} = 60283.8\times 0.4 = 2052.5\text{ft}^3$

$= 15354.81$ gal

- **Injection time and volume:**

To estimate the injection time, a second-degree equation must be solved:

$$q_{inj}t_{inj} = A_f\overline{W} + 2K_LC_LA_tr_p\sqrt{t_{inj}}$$

Where:

$K_L = \frac{1}{2}\left[\left[\frac{8}{3}\eta + \pi(1-\eta)\right]\right]$ ; $K_L = \frac{1}{2}\left[\left[\frac{8}{3}0.4 + \pi(1-0.4)\right]\right]$ =1,47

$\eta = \frac{G_c}{2+G_c} = \frac{1.4}{2+1.4} = 0.41$

Next, we find the injection time that allows estimating the injection volume:

Taking: $T = \sqrt{T_{inj}}$ ;

$q_{inj}T^2 = A_f\overline{W} + 2K_LC_LA_tr_pT \quad \Leftrightarrow \quad q_{inj}T^2 - A_f\overline{W} - 2K_LC_LA_tr_pT = 0$

$129.112T^2 - 201.79T - 1818.47 = 0 \quad \Leftrightarrow \quad t_{inj} \approx 56.38 \text{ min}$

And then, we can calculate the injection volume:

$V_{inj} = q_i t_i \qquad V_{inj} = 25 \text{ bpm} \times 56.38\text{min} = 1409.7\text{bbl}$

$= 59207.1$ gal

- **Pad volume and time:**

$\varepsilon = \frac{1-\eta}{1+\eta} \qquad \varepsilon = \frac{1-0.4}{1+0.4} = 0.41$

$V_{pad} = V_{inj}\left(\frac{1-\eta}{1+\eta}\right) \qquad V_{pad} = 59207.1 \times 0.42 = 24774.6 \text{ gal}$

$t_{pad} = t_{inj}/2 \qquad t_{pad} = \frac{t_{inj}}{2} = 28.2 \text{ min}$

- **Proppant concentration schedule:**

$$C_p(t) = C_f\left(\frac{t - t_{pad}}{t_{inj} - t_{pad}}\right)^{\varepsilon}$$

$C_f$ is the final proppant concentration desired.

$C_p(t) = C_f\left(\frac{t-t_{pad}}{t_{inj}-t_{pad}}\right)^{\varepsilon} \qquad C_p(28.2 \text{ min}) = C_f\left(\frac{28.2-28.2}{56.3-28.2}\right)^{0.41} = 0 \text{ ppg}$

$C_p(56.3 \text{ min}) = C_f\left(\frac{28.2-28.2}{56.3-28.2}\right)^{0.41} = 5 \text{ ppg}$

- **Predict propped fracture width:**

Propped fracture width can be estimated from proppant weight and moyen proppant concentration as below:

$W = \frac{C_p}{(1-\phi_p)\rho_p} \qquad \phi_p = 35\% \qquad \rho_p = 112.3 \text{ lbs/ft}^3$

$\overline{C_p} = \frac{C_f}{1+\eta}$ $\overline{C_p} = \frac{5}{1+0.4} = 3.52 \text{ ppg}$

$M_p = \overline{C_p}(V_{inj} - V_{pad})$ $M_p = 3.52(59207.1 - 24774.6) = 121374.5 \text{ lbs}$

$$W = \frac{3.52}{(1-0.35)\times 112.3} = 0.05 \text{ ft} = 0.6 \text{ in}$$

**Table III-10:** Resume of main treatment parameters.

| Parameter | Symbole | Stage 1 | Stage 2 | Stage 3 | Stage 4 | Stage 5 | Unit |
|---|---|---|---|---|---|---|---|
| **Max. Width** | $W_{fo}$ | 0.054 | 0.054 | 0.054 | 0.054 | 0.054 | ft |
| **Moy. Width** | $W_f$ | 0,034 | 0.034 | 0.034 | 0.034 | 0.034 | ft |
| **Fracture total surface** | $A_f$ | 6283.8 | 111525 | 221542.9 | 339096.27 | 500355.81 | $ft^2$ |
| **Total injection Time** | $T_{inj}$ | 56.38 | 85.87 | 191 | 148.13 | 162.73 | min |
| **Total injection volume** | $V_{inj}$ | 59207.1 | 72131.07 | 160473 | 124434 | 136696 | gal |
| **Pad volume** | $V_{pad}$ | 24774.6 | 30182.5 | 67148.27 | 52068.53 | 57199.01 | gal |
| **Moy. Proppant concentration** | $\overline{C_p}$ | 2.3 | 2.7 | 3.52 | 3.52 | 3.48 | ppg |
| **Proppant Weight** | Mp | 121374.5 | 147868.7 | 328969.6 | 255091.68 | 280226.7 | lbs |
| **Proppant concentration** | Cp | 5.2 | 5.4 | 7.5 | 7.8 | 7.6 | $lbs/ft^3$ |
| **Predicted propped fracture** | Wfp | 0,05 | 0.036 | 0.04 | 0.02 | 0.01 | ft |

### III.3.4 Productivity of fractured well:

$$F_{CD} = \frac{k_f w}{k x_f} = \frac{900 \times 0.04}{0.1 \times 170} = 2.1$$

The productivity of the stage way shall be up to **2,1**.

### III.3.5 Main treatment design using MeyerFrac software:

The fracture treatment was designed using the three-dimensional fracture simulator MFrac. The lithology was modeled with reference to the open-hole logs and offset fracture treatment reports. The lithology and derived permeability profile was entered into a lumped parameter three dimensional fracture simulator, MFrac, to predict fracture dimensions and proppant distribution to design the treatment. (Annex 5) (Annex6)

**Table III-11:** MeyerFrac main treatment design.

| Stage Number | Description | Fluid System | Clean Volume (gal) | Slurry Volume (gal) | Prop Conc Start (lb/gal) | Prop Conc End (lb/gal) | Prop Type |
|---|---|---|---|---|---|---|---|
| 1 | Pre-Pad | Linear Gel 35# | 1000 | 1005 | 0.00 | 0.00 | |
| 2 | Pad | Hybor H 35# | 20000 | 20236 | 0.00 | 0.00 | |
| 3 | 1 ppg SLF | Hybor H 35# | 8000 | 8422 | 1.00 | 1.00 | 20/40 ISP |
| 4 | 2 ppg SLF | Hybor H 35# | 7000 | 7679 | 2.00 | 2.00 | 20/40 ISP |
| 5 | 3 ppg SLF | Hybor H 35# | 5000 | 5708 | 3.00 | 3.00 | 20/40 ISP |
| 6 | 4 ppg SLF | Hybor H 35# | 5000 | 5927 | 4.00 | 4.00 | 20/40 ISP |
| 7 | 5 ppg SLF | Hybor H 35# | 1000 | 1230 | 5.00 | 5.00 | 20/40 ISP |
| 8 | Flush | Linear Gel 35# | 7078 | 7078 | 0.00 | 0.00 | |
| 9 | Shut-In | | 0 | 0 | 0.00 | 0.00 | |
| **Total** | | | **54078** | **57285** | | | |

- **Stage Number 1 design (3268.24m MD):**

The main treatment of the first stage, include injection of **1312 gals** of Pre-pad stage (35# Gel) using HP pumps with a minimum rate of **2 bpm** and brought it up to **25 bpm**. A total volume of **46709 gals** of Cross-linker (Hybor H 35) was pumped to transport a volume of **70320 lbs** of proppant (Wanli ISP 20/40). Finally, **7181 gals** of linear gel (35# Gel) was used to clean out fracturing fluid, and achieve a $F_{CD}$ greater than 2.

**Table III-12:** Stage Number 1 treatment volumes summary.

| Fluid Summary | Fluid Type | Volume (gals) |
|---|---|---|
| Pre-Pad | 35# Gel | 1312 |
| Pad | Hybor H 35 | 19955 |
| Fluid for Proppant | Hybor H 35 | 26574 |
| Displacement | 35# Gel | 7181 |
| **Proppant Summary** | **Proppant Type** | **Volume (lbs)** |
| Proppant Volume, Surface | Wanli ISP 20-40 | 70320 |
| Proppant Volume In Formation | Wanli ISP 20-40 | 68612 |

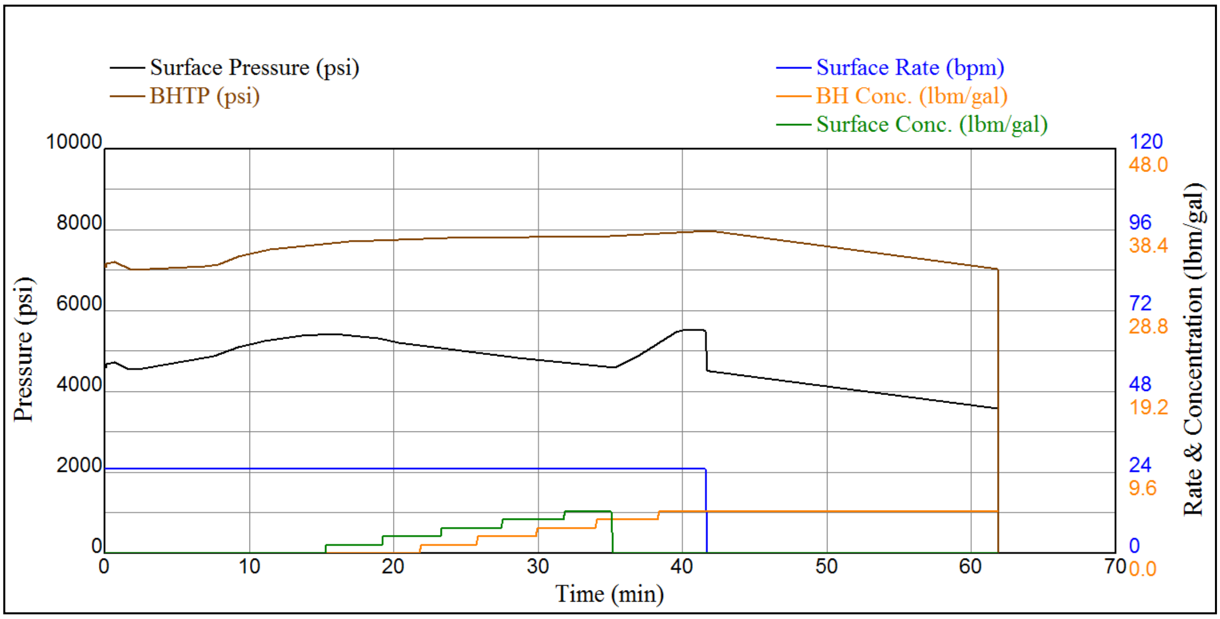


**Figure III.10:** Stage 1 Main Frac Treatment Pressure [21]

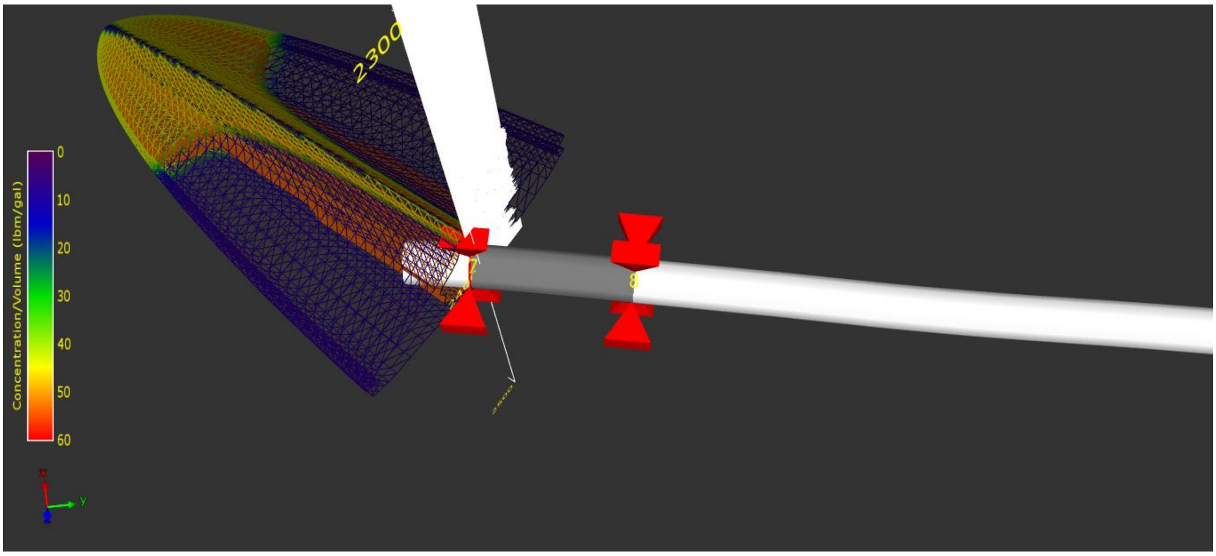


**Figure III.11:** Stage 1 Simulated Fracture Dimensional Results

- **Stage number 2 treatment design (3233.8m):**

The main treatment of the first stage, include injection of **1145 gals** of Pre-pad stage (35# Gel) using HP pumps with a minimum rate of **2 bpm** and brought it up to **20 bpm**. A total volume of **62402 gals** of Cross-linker (Hybor H 35) was pumped to transport a volume of **112640 lbs** of proppant (Wanli ISP 20/40). Finally, **6625 gals** of linear gel (35# Gel) was used to clean out fracturing fluid, and achieve a $F_{CD}$ greater than 2.7.

**Table III-13**: Stage 2 treatment volumes summary.

| **Fluid Summary** | **Fluid Type** | **Volume** (gals) |
|---|---|---|
| Pre-Pad | 35# Gel | 1,145 |
| Pad | Hybor H 35 | 24,975 |
| Fluid for Proppant | Hybor H 35 | 37,427 |
| Displacement | 35# Gel | 6,625 |
| **Proppant Summary** | **Proppant Type** | **Volume** (lbs) |
| Proppant Volume, Surface | Wanli ISP 20-40 | 112,640 |
| Proppant Volume In Formation | Wanli ISP 20-40 | 110,088 |

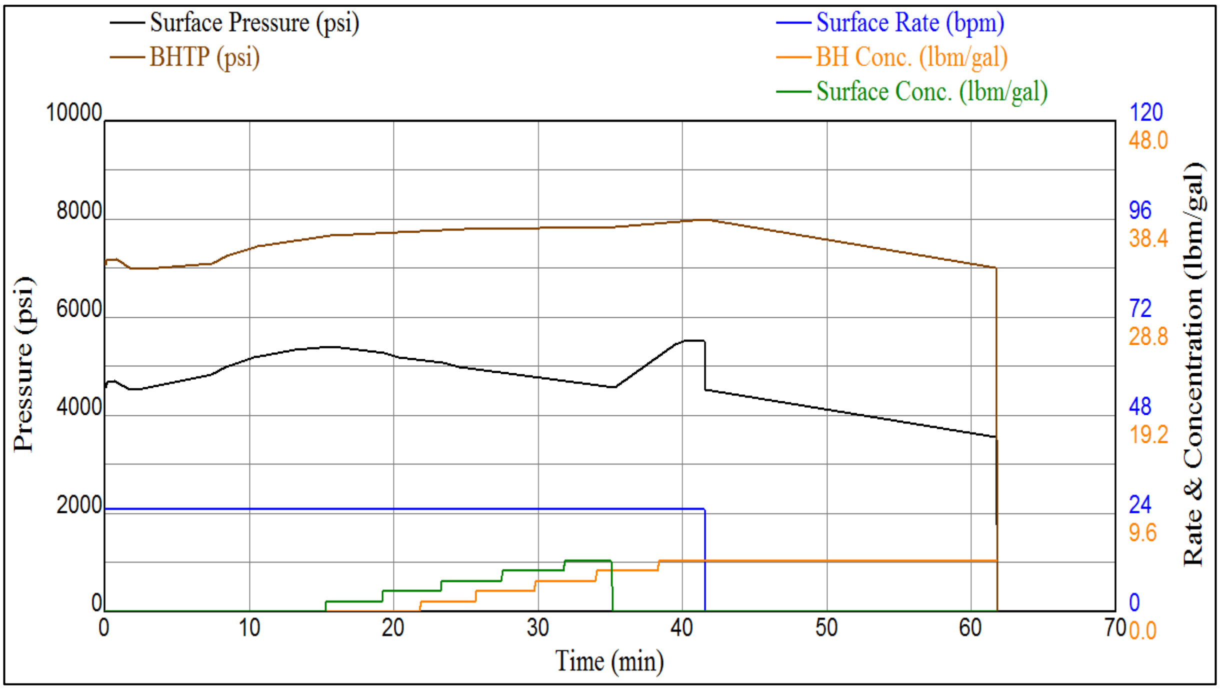


**Figure III.12:** Stage 2 Main Frac Treatment Pressure [21]

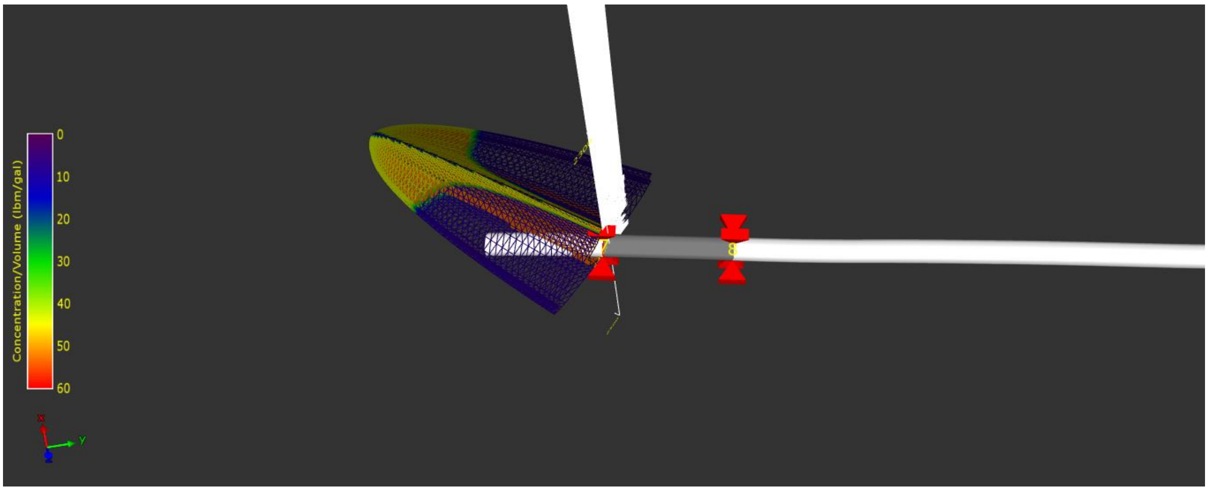


**Figure III.13:** Stage 2 Simulated Fracture Dimensional Result

- **Stage 3 main treatment design (3160.2 m MD):**

The main treatment of the first stage, include injection of **1159 gals** of Pre-pad stage (35# Gel) using HP pumps with a minimum rate of **2 bpm** and brought it up to **20 bpm**. A total volume of **83652 gals** of Cross-linker (Hybor H 35) was pumped to transport a volume of **172532 lbs** of proppant (Wanli ISP 20/40). Finally, **6491 gals** of linear gel (35# Gel) was used to clean out fracturing fluid, and achieve a FcD greater than 1.05.

**Table III-14**: Stage 3 treatment volumes summary.

| **Fluid Summary** | **Fluid Type** | **Volume** (gals) |
|---|---|---|
| Pre-Pad | 35# Gel | 1159 |
| Pad | Hybor H 35 | 35012 |
| Fluid for Proppant | Hybor H 35 | 48640 |
| Displacement | 35# Gel | 6491 |
| **Proppant Summary** | **Proppant Type** | **Volume** (lbs) |
| Proppant Volume, Surface | Wanli ISP 20-40 | 172532 |
| Proppant Volume In Formation | Wanli ISP 20-40 | 169097 |

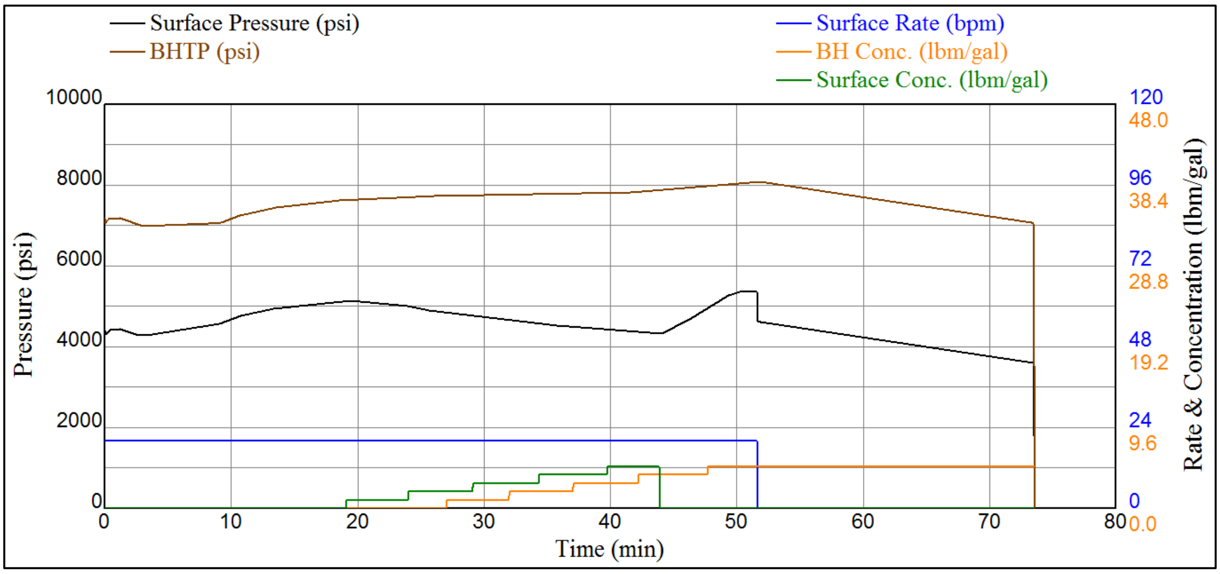


**Figure III.14:** Stage 3 Main Frac Treatment Pressure [21]

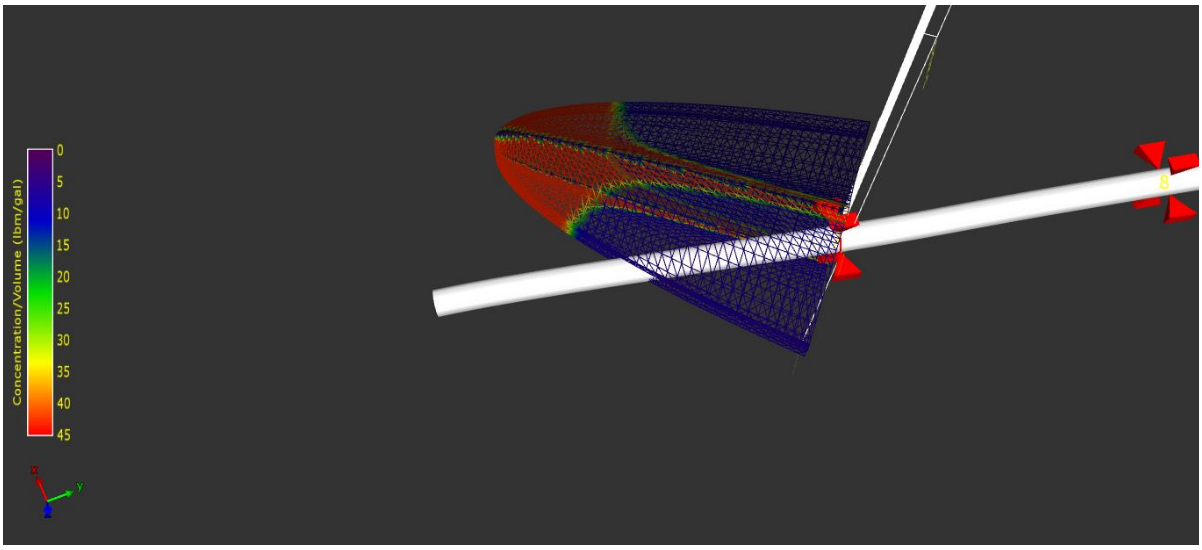


**Figure III.15:** Stage 3 Simulated Fracture Dimensional Results

- **Stage 4 treatment design (3082.8 m MD) :**

The main treatment of the first stage, include injection of **802 gals** of Pre-pad stage (35# Gel) using HP pumps with a minimum rate of **2 bpm** and brought it up to **20 bpm**. A total volume of **90515 gals** of Cross-linker (Hybor H 35) was pumped to transport a volume of **210913 lbs** of proppant (Wanli ISP 20/40). Finally, **6558 gals** of linear gel (35# Gel) was used to clean out fracturing fluid, and achieve a $F_{CD}$ greater than 0.97

**Table III-15**: Stage 3 treatment volumes summary.

| **Fluid Summary** | **Fluid Type** | **Volume** (gals) |
|---|---|---|
| Pre-Pad | 35# Gel | 802 |
| Pad | Hybor H 35 | 37842 |
| Fluid for Proppant | Hybor H 35 | 52673 |
| Displacement | 35# Gel | 6558 |
| **Proppant Summary** | **Proppant Type** | **Volume** (lbs) |
| Proppant Volume, Surface | Wanli ISP 20-40 | 210913 |
| Proppant Volume In Formation | Wanli ISP 20-40 | 207987 |

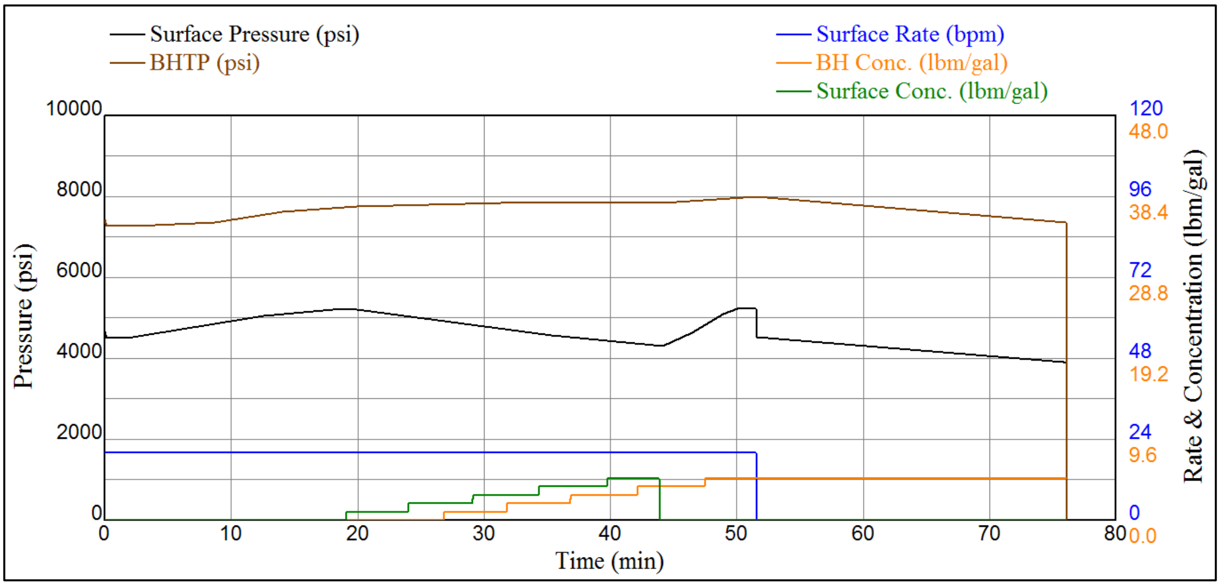


**Figure III.16:** Stage 4 Main Frac Treatment Pressure [21]

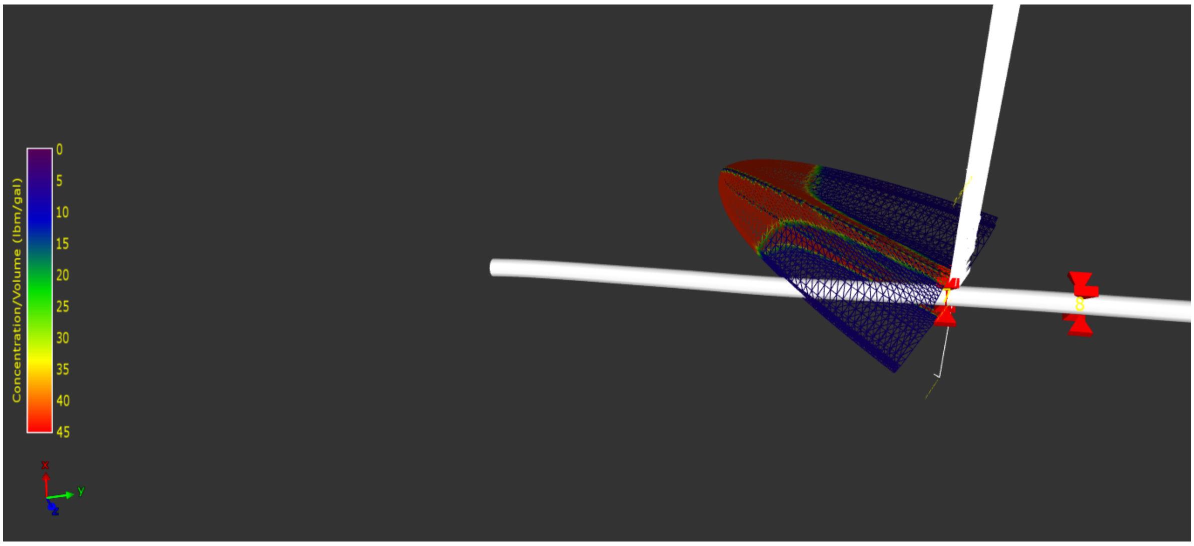


**Figure III.17:** Stage 4 Simulated Fracture Dimensional Results

- **Stage 5 treatment design (2975.7 m MD):**

The main treatment of the first stage, include injection of **1147 gals** of Pre-pad stage (35# Gel) using HP pumps with a minimum rate of **2 bpm** and brought it up to **20 bpm**. A total volume of **80473 gals** of Cross-linker (Hybor H 35) was pumped to transport a volume of **178585 lbs** of proppant (Wanli ISP 20/40). Finally, **5852 gals** of linear gel (35# Gel) was used to clean out fracturing fluid, and achieve an $F_{CD}$ of 2.7.

**Table III-16:** Stage 5 treatment volumes summary.

| **Fluid Summary** | **Fluid Type** | **Volume** (gals) |
|---|---|---|
| Pre-Pad | 35# Gel | 1147 |
| Pad | Hybor H 35 | 33007 |
| Fluid for Proppant | Hybor H 35 | 47466 |
| Displacement | 35# Gel | 5852 |
| **Proppant Summary** | **Proppant Type** | **Volume** (lbs) |
| Proppant Volume, Surface | Wanli ISP 20-40 | 178585 |
| Proppant Volume In Formation | Wanli ISP 20-40 | 175065 |

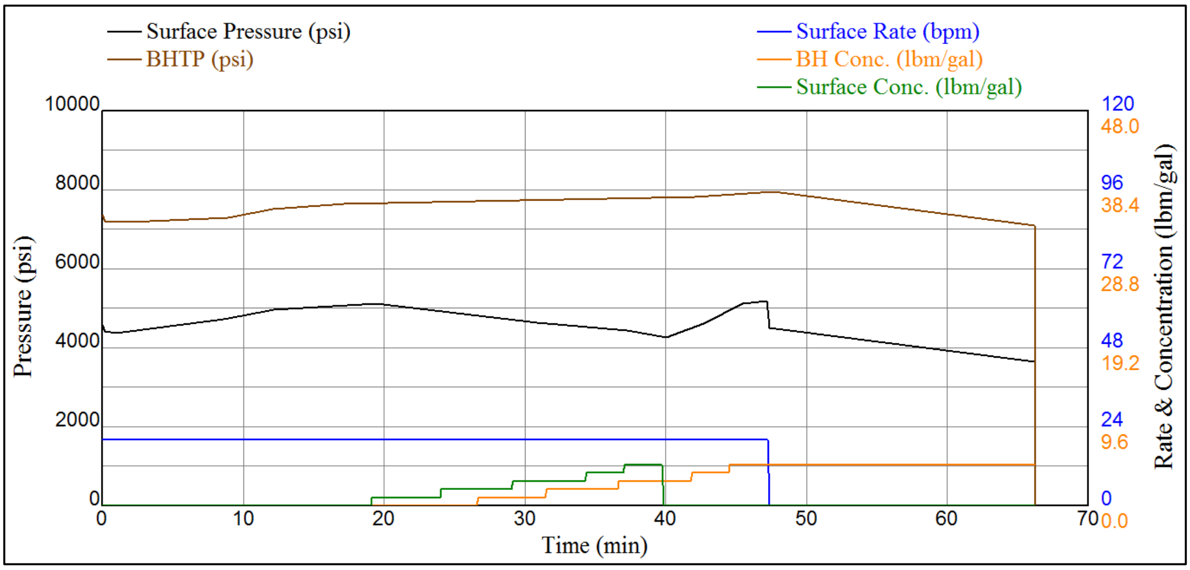


**Figure III.18:** Stage 5 Main Frac Treatment Pressure [21]

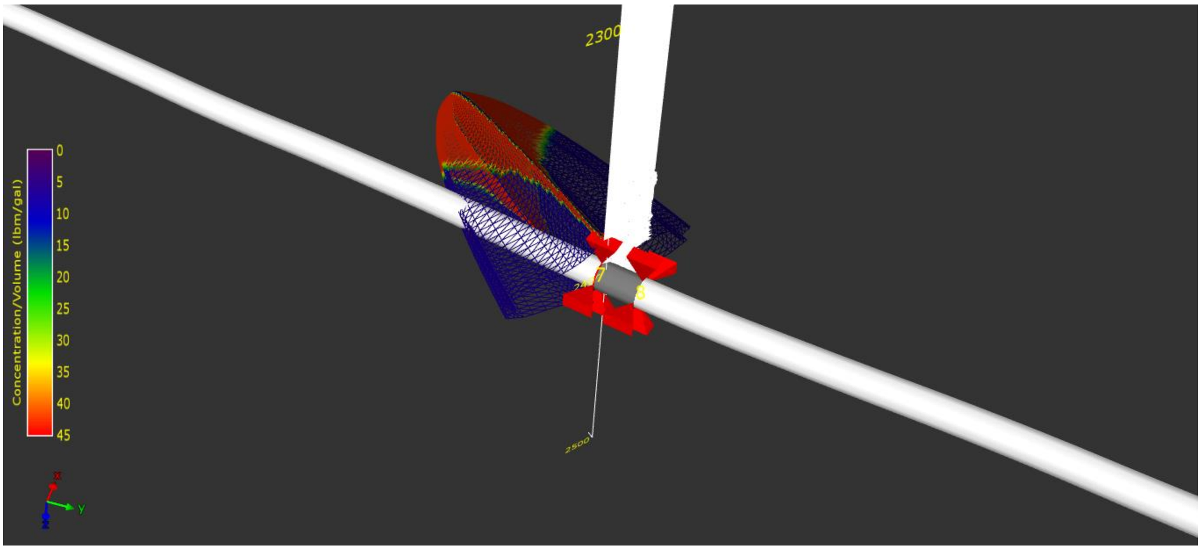


**Figure III.19:** Stage 5 Simulated Fracture Dimensional Result

## III.4 Economic evaluation of the fracturing operation:

In order to assess the contribution of hydraulic fracturing, an economic evaluation is necessary to enable us to decide whether or not to continue with the main treatment of the fracturing. In order to evaluate the costs of this operation, we can consider the cost associated with the hydraulic fracturing operation and the period for its pay out time.

**The estimated flow after fracturing: Q After frac = 500000 $m^3$/jour.**

**The total cost of the IRS-A well operation: 1 600 000 $**

**Calculation of volume cost:**

If we take the average price of a MBTU of natural gas in 2020 is 3$.

So the price of the $m^3$ is 0.10$

$$\text{The cost in equivalent volume } (m^3) = \frac{\text{The total cost of the operation}}{\text{The price of } m^3}$$

$$\text{the cost in equivalent volume } (m^3) = \frac{1600000}{0.10} = 16000000 \text{ m}^3$$

**Pay out time:**

$$\text{Pay out time} = \frac{\text{The cost in equivalent volume}}{\text{Q}}$$

$$\text{Pay out time} = \frac{16\ 000\ 000}{500000} = 32 \text{ days}$$

**Table III-17:** Operation cost in equivalent volume

| IRS-A well | Total cost of the operation $ | $m^3$ price 0,10 $ | Pay out time |
|---|---|---|---|
| The cost in equivalent volume ($m^3$) | 1 600 000 | 16 000 000 | 32 days |

**Conclusion**:

According to the results of the economic evaluation, the recovery time for 500,000 $m^3$ is ranging to 32 days for a price of 0.10$ per cubic meter. In addition, this well is estimated to produce with this rate for almost 3 years.

Thus, the gain of the operation is very important and the operation in general is so gainful.

## Conclusion:

It is evident now that the Evaluation and development of unconventional resources are more complex than for conventional resources, from this study we can conclude the following:

- The application of horizontal wells has a significant impact on production and the potential of unconventional reserves recovery.

- The necessity and the importance of Multistage Hydraulic fracturing with horizontal wells in unconventional reservoirs to be economically exploited by increasing the initial permeability which improve the productivity of the wells.

- The role of geomechanics studies in unconventional resources development relates to the design and modeling of hydraulic fracturing stimulation, safe and efficient drilling of horizontal wellbores, and identification and characterization of sweet spots within the reservoir.

- The success of the operation is conditioned, first by a good analysis of the minifrac Data and pretreatment formation evaluation using different sources of data of the well or from offset wells and second by an adequate design which ensure more efficiency of the operation.

The safe development of these resources provides economic benefits and advantage, but on the other hand it also has some disadvantages, the major disadvantages of these operations are the very high cost and the huge logistic job plus the risk of the negative impact of the environment.

## Recommendation:

The application of multistage fracturing in the unconventional reservoirs improve the potential of the exploited wells, but this technique is still very valuable and expensive, which is why we recommend the following:

- The mini frac test in horizontal wells is generally pumped only in the first stages due to the same characteristics of the reservoir. While the injection test is applied in all stages to ensure the connection between the wellbore and the formation.

- The acid injection is recommended to decrease the High friction value.

- The Mini frac shut-in pressure decline was analyzed using G-Function, and confirmed by Square root method to estimate the closure pressure.

- A major concern of the drilling engineers is keeping the borehole wall from falling in or breaking down by drilling the well in the direction of the minimum horizontal stress to ensure its stability.

- The numerical simulation of the operation gives the operator more choices, presents fracture propagation scenarios and roughly forecasts the gain in production. Therefore, the optimization of the technique.

- The image log of IRS-4 maximum stress orientation indicates that the well was not drilled in direction of minimum horizontal stress, It was drilled close to the middle of both principal horizontal stresses "minimum and maximum" which may generate both types of fracture (transvers and longitudinal) after stimulation.

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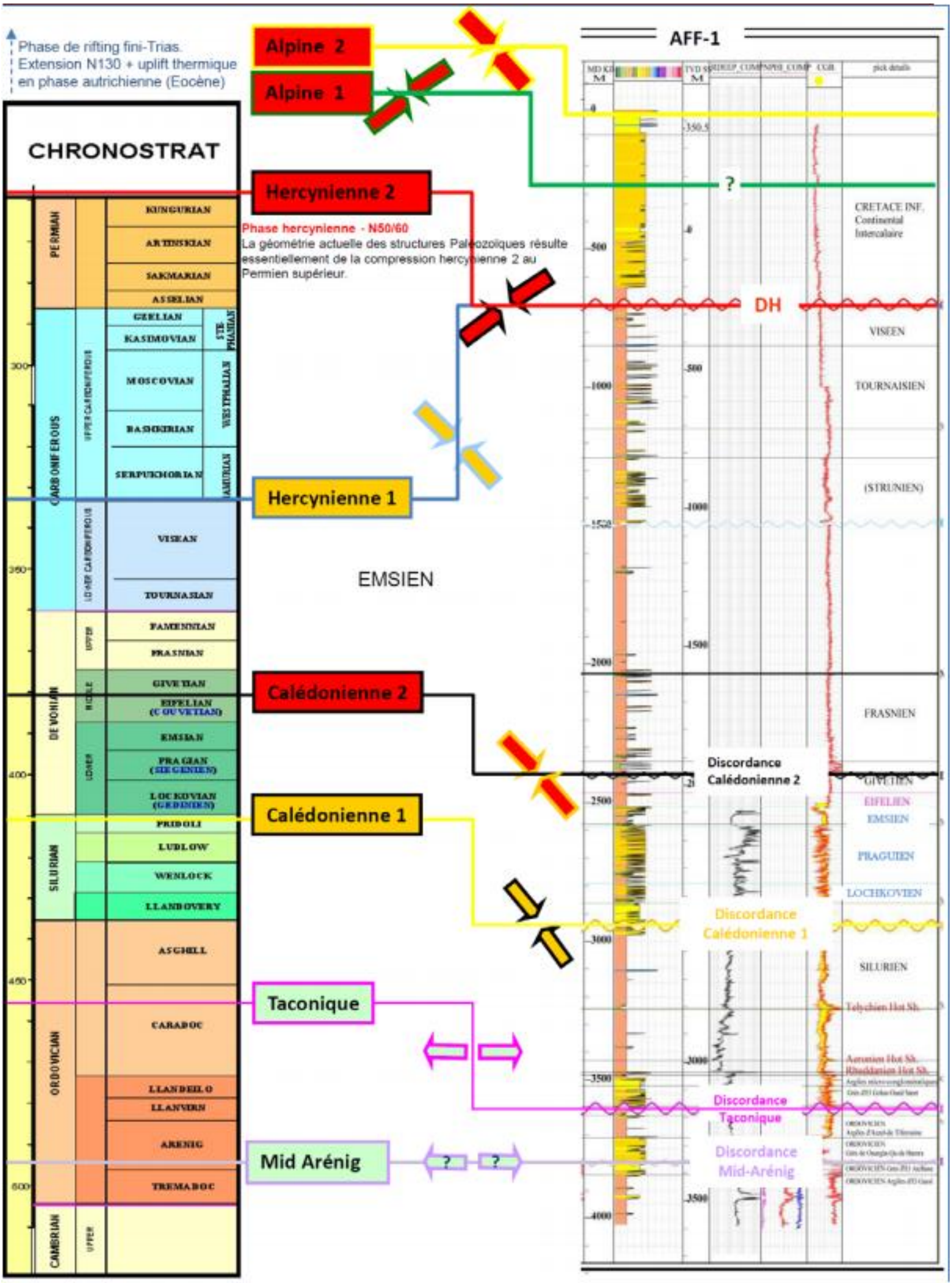
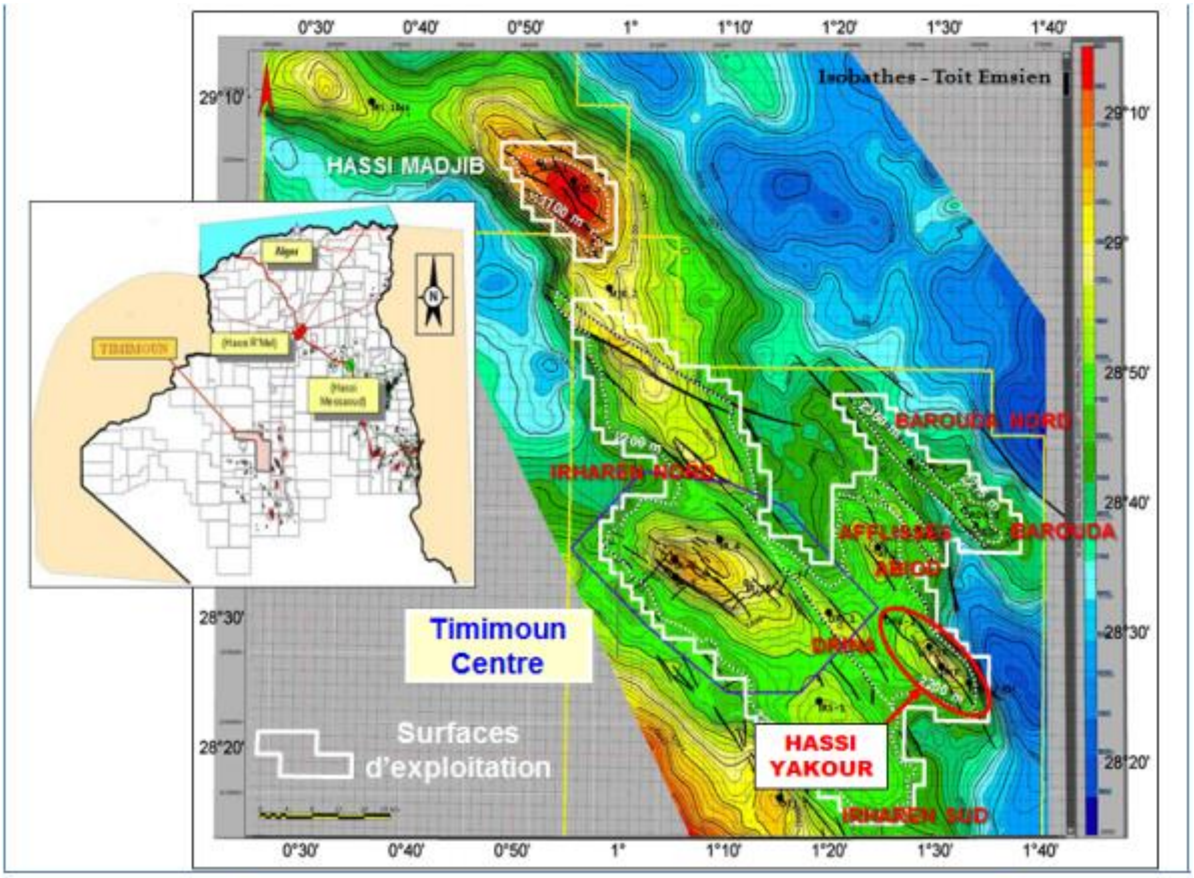
# Annex

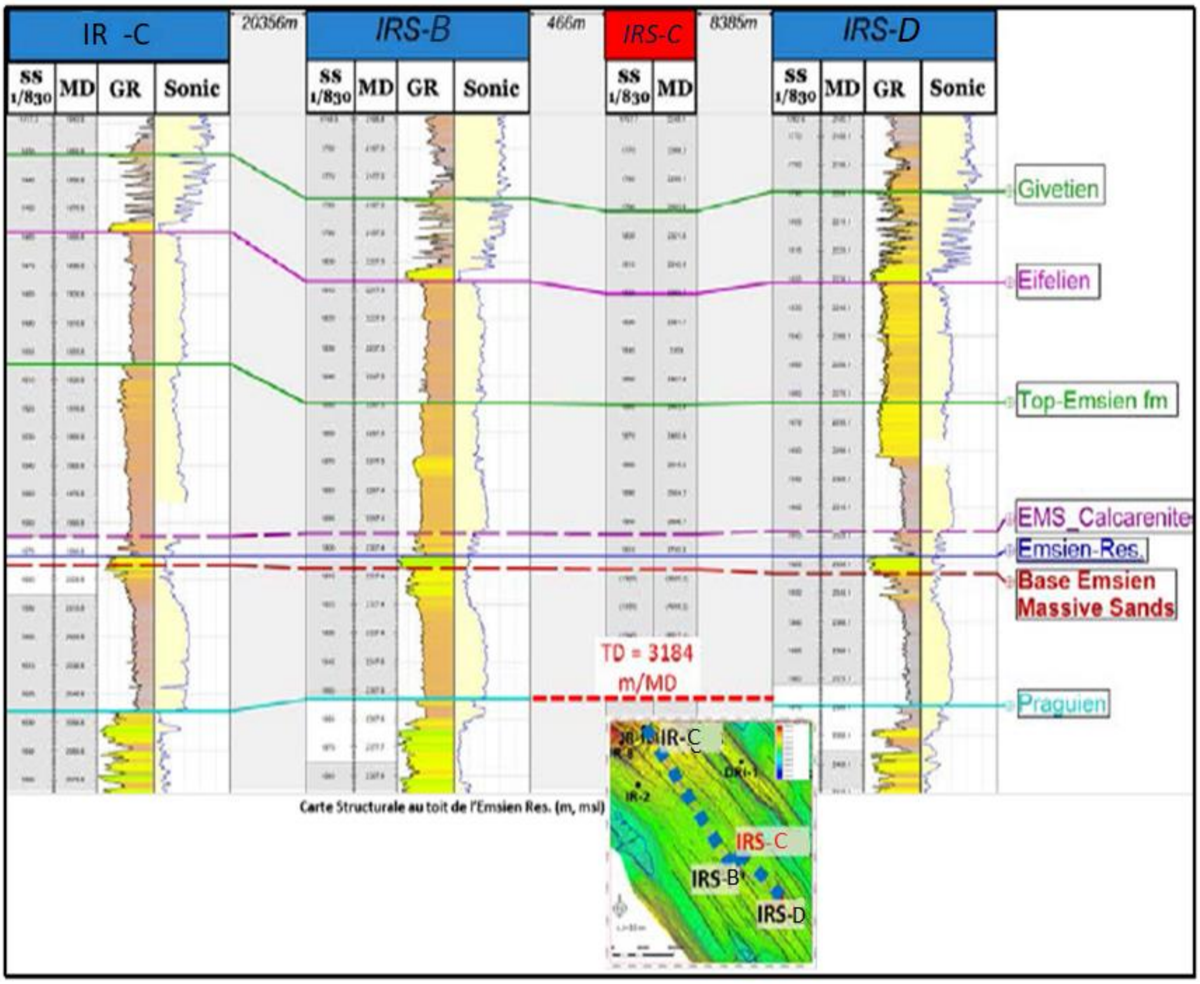
## Annex 1: Regional chronostratigraphic charts



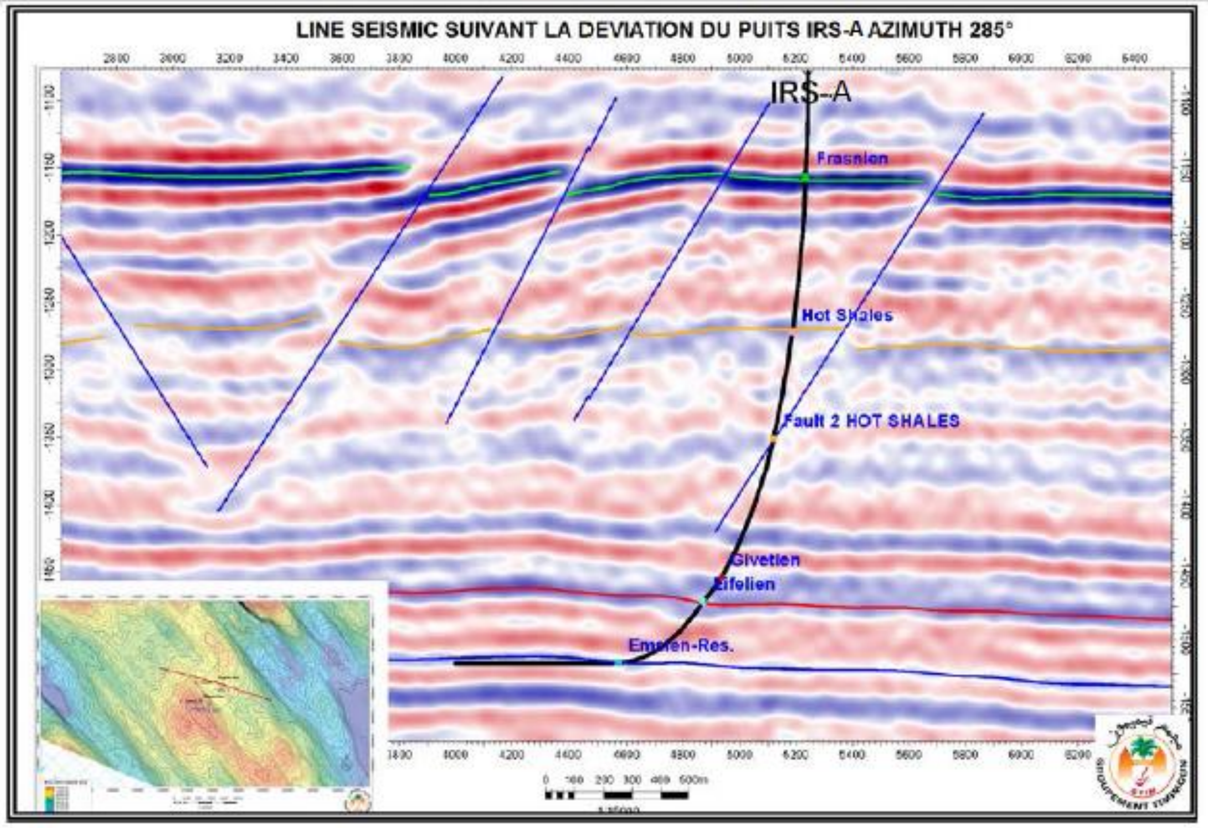
## Annex 2: Location map of Irhan structure within the Timimoun development area



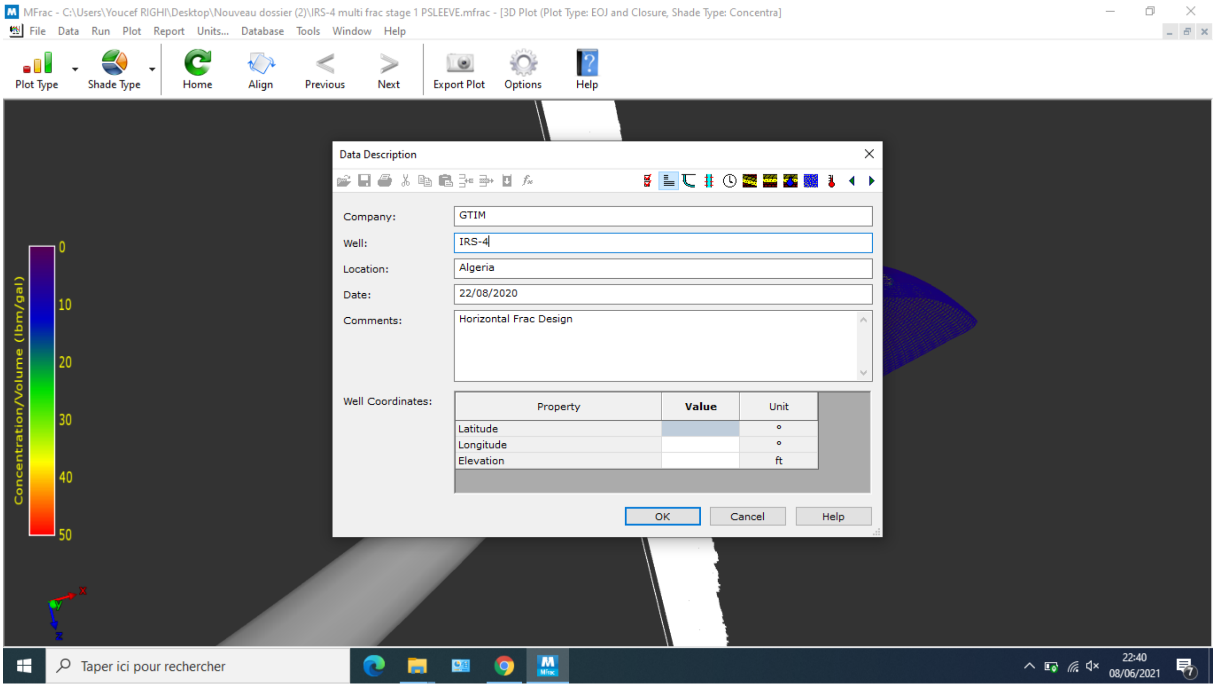
## Annex 3: Emsien reservoir Log



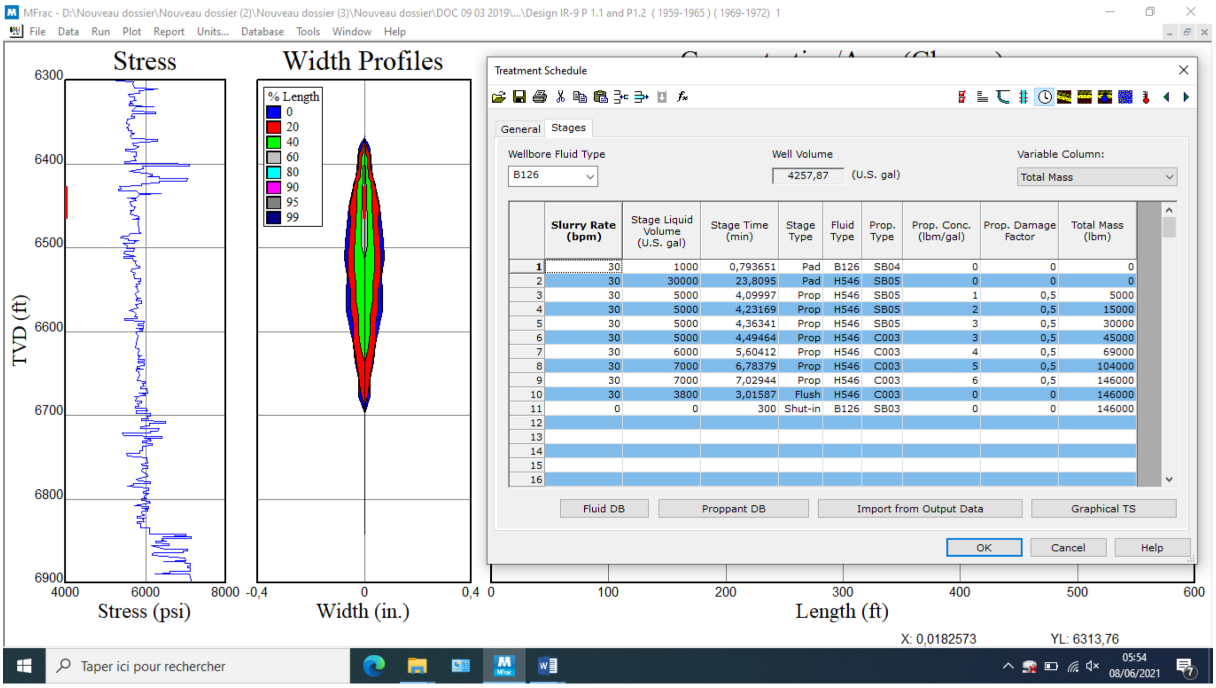
## Annex 4: Sismic section of IRS-A well



# Annex 5: Mfrac input data




# Annexe 6: treatment schedule



# Annex 7: IRS-A completion diagram

## Completion Multi Stage Frac

**All depths are related to ST15 RT**

Lat: 28° 25' 19.58"N

Long: 01° 19' 41.46" E

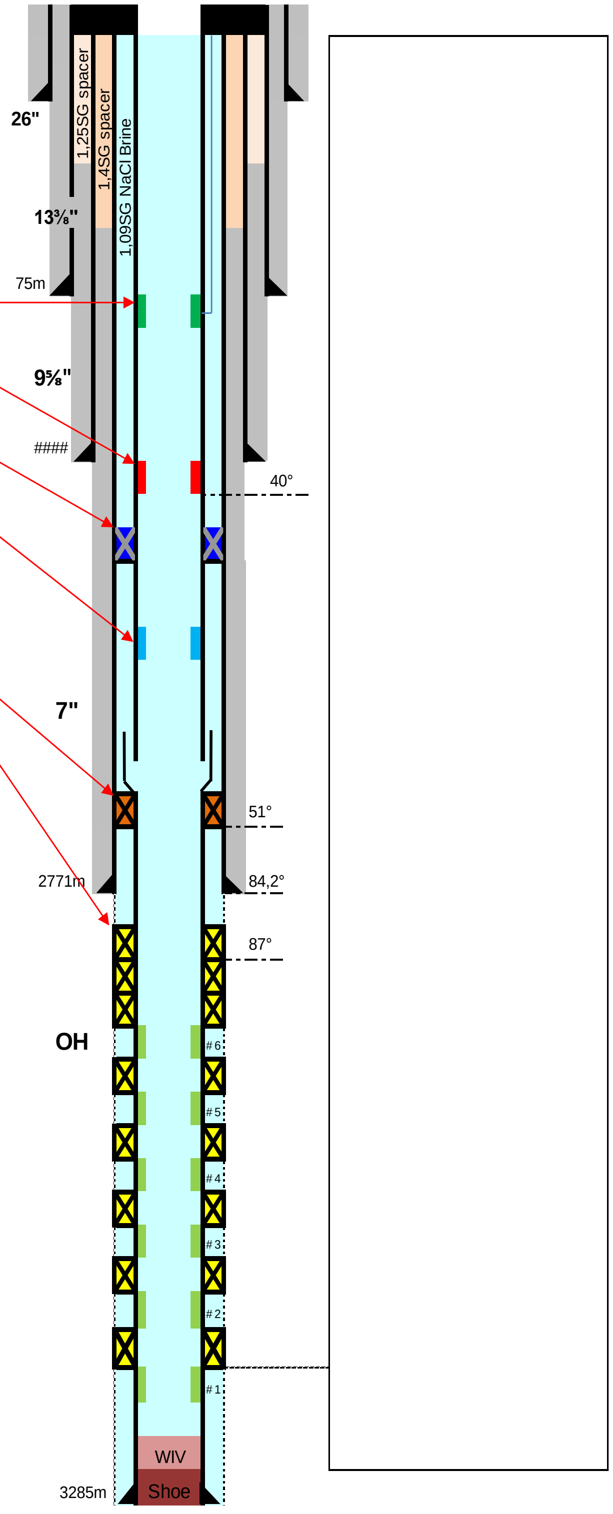
KOP: 1706m

Z Ground : 402,5m

ZG - RT : 9,14m

| Component | ID (in) | Top (m) | Bot (m) |
|---|---|---|---|
| 26" CP | | 0,00 | |
| 13⅜" 68ppf K55 BTC | 12,415 | 0,00 | 75,00 |
| 9⅝" 47ppf L80 HSC | 8,681 | 0,00 | 717,00 |
| 7" 29ppf P110 HSC | 6,184 | 0,00 | 2771,00 |

| UPPER COMPLETION | | | Depth to tops | |
|---|---|---|---|---|
| **Qty** | **Element** | **I.D.** | **Length** | **Top** |
| 1 | Hanger w/ FMC BPV profile | | 0,18m | 8,7m |
| 8 | 4½" 13.5# 13Cr L80 NV TBG+PJ | 3.920" | 56,46m | 8,8m |
| 1 | ASSY Thunder 8E TRSSSV w/ BA 3.75" 13.5# 13Cr 80 Ksi V-Top B x P | 3,75" | 2,44m | 65,3m |
| 174 | 4½" 13.5# 13Cr L80 NV TBG+PJ | 3,920" | 2089,73m | 67,7m |
| 1 | 3,688" AOF Nipple Top No Go | 3.688" | 0,69m | 2157,5m |
| 2 | 4½" 13.5# 13Cr L80 NV PJ | 3.920" | 5,10m | 2158,2m |
| 1 | Size 831-387 Premier Packer. | 3,761" | 3,22m | 2163,3m |
| 2 | 4½" 13.5# 13Cr L80 NV PJ | 3,920" | 5,11m | 2166,5m |
| 1 | 3.688" AOR Nipple BTM No Go | 3,633" | 0,59m | 2171,6m |
| 12 | 4½" Pup Jnt 13.5# 13Cr L80 NV | 3,920" | 130,22m | 2172,2m |
| 1 | WEG (top) | 3.920" | 3,11m | 2302,4m |
| | WEG (bottom) | | | 2305,5m |
| **LOWER COMPLETION - MULTI STAGE FRAC** | | | **Length** | **Top** |
| 1 | Hydraulic set Csg packer Assembl | 3,870" | 6,22m | 2304,6m |
| 45 | 4½" 13,5# P110. V-Top TBG+PJ | 3,920" | 579,49m | 2310,8m |
| 3 | Self Energize Swell Packer | 3,883" | 18,24m | 2890,3m |
| 2 | 4½" PJ P110 V-Top | 3,920" | 5,02m | 2908,6m |
| 1 | Frac Sleeve #6 | 3,812" | 1,66m | 2913,6m |
| 4 | 4½" PJ P110 V-Top | 3,920" | 14,03m | 2915,2m |
| 1 | Self Energize Swell Packer | 3,883" | 6,08m | 2929,3m |
| 7 | 4½" 13,5# P110. V-Top TBG+PJ | 3,920" | 40,46m | 2935,3m |
| 1 | Frac Sleeve #5 | 3,812" | 1,66m | 2975,8m |
| 6 | 4½" 13,5# P110. V-Top TBG+PJ | 3,920" | 51,35m | 2977,5m |
| 1 | Self Energize Swell Packer | 3,883" | 6,00m | 3028,8m |
| 7 | 4½" 13,5# P110. V-Top TBG+PJ | 3,920" | 48,02m | 3034,8m |
| 1 | Frac Sleeve #4 | 3,812" | 1,66m | 3082,8m |
| 7 | 4½" 13,5# P110. V-Top TBG+PJ | 3,920" | 37,97m | 3084,5m |
| 3 | Self Energize Swell Packer | 3,883" | 6,08m | 3122,5m |
| 4 | 4½" PJ P110 V-Top | 3,920" | 31,72m | 3128,5m |
| 1 | Frac Sleeve #3 | 3,812" | 1,66m | 3160,3m |
| 5 | 4½" PJ P110 V-Top | 3,920" | 43,90m | 3161,9m |
| 1 | Self Energize Swell Packer | 3,883" | 6,08m | 3205,8m |
| 4 | 4½" 13,5# P110. V-Top TBG+PJ | 3,920" | 21,97m | 3211,9m |
| 1 | Frac Sleeve #2 | 3,812" | 1,66m | 3233,9m |
| 3 | 4½" 13,5# P110. V-Top TBG+PJ | 3,920" | 18,60m | 3235,5m |
| 1 | Self Energize Swell Packer | 3,883" | 6,09m | 3254,1m |
| 3 | 4½" 13,5# P110. V-Top PJ | 3,920" | 8,05m | 3260,2m |
| 1 | Frac Sleeve #1 | 3,812" | 1,66m | 3268,3m |
| 3 | 4½" 13,5# P110. V-Top PJ | 3,920" | 10,82m | 3269,9m |
| 1 | WIV | | 4,34m | 3280,7m |
| 1 | Double valve float shoe | | 0,68m | 3285,1m |



# Annex 8: IRS-A Completion ( frac-sleeves position)