Order number: ..../Faculty/UKMO/2024

PEOPLE'S DEMOCRATIC REPUBLIC OF ALGERIA

Ministry of Higher Education and Scientific Research

University of Kasdi Merbah Ouargla

Faculty of Hydrocarbons, Renewable Energies, Earth & Universe Sciences

Petroleum Production Department

Sector: Hydrocarbons

End of Studies Thesis

In order to obtain a

MASTER'S DEGREE

Presented by

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Option: Professional Petroleum Production Engineering

Topic

Optimization of the Net Present Value for Hydraulic Fracturing Treatments

Graduated in: 06/06/2024

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2023/2024

Final Studies Project

Reservoir Performance

Hydraulic Fracturing

Optimization of the Net Present Value for Hydraulic Fracturing Treatments

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Acknowledgment

I begin by expressing my deepest gratitude to God, the Almighty for granting me the strength, patience, and faith throughout this whole journey. Without divine guidance, none of this would have ever been possible.

*To **my dear parents, grandparents, dear sister Romaissa & brother Nouh and cousin Amina**, Thank you for your unwavering support and love, I will forever be indebted to you.*

*I would like to acknowledge my university advisor **MR. Djamel Eddine Chetti** for his support and continuous guidance throughout my university life.*

*My special thanks go to my dear Mentor **Haithem Abdelmoumene Segmane** for his guidance, kindness and sincere dedication. Your mentorship has not only shaped my academic pursuits but also my personal and professional growth and I will forever be grateful I got to have a mentor as caring as you are.*

*I would also like to thank my beloved, **Hadjer Khelkhal**, your continuous support, time, kind and motivating words are what gave me the strength to finish my thesis and I am so happy I got to meet a beautiful person inside and out such as yourself.*

*My thanks go to my dearest Managers **Fouzi Rouina & Badreddine Guerziz,** thank you for believing in me, for the precious advices you continuously give me, for providing the perfect and safest environment for one to grow and learn. I will forever be proud I got the chance to meet both of you.*

*I extand my heartfelt appreciation and love to all of the SLB Frac Team, both those I have had the pleasure of meeting and those I have yet to meet, and all of the Lab Team, **Samia, Louai, Oussama, Ilyes, Hichem, Uncle Djamel**, my days with you in the lab have been nothing short but enjoyable and valuable, I admire each and every one of you.*

*My sincere thanks go to all of the **PCO SPE Student Chapter** friends, my journey with you will forever be the most special memory from university, thank you **Narimene, Chahla, Youcef, Smail, Abdallah, Anis, Amine, Imed, Zaki** and especially **Yasser** , I will always be indebted to you for your help.*

*To my dear friends **Tarek, Ahlem, Radouane and Rania** Thank you for always being there for me, I absolutely adore each one of you.*

To all those whose names may not be mentioned but have contributed in ways seen and unseen, thank you.

Dedication

This work is dedicated to

My dear ***Grandparents.***

Abstract

Hydraulic fracturing optimization is very necessary to achieve the best stimulation results. This dessertation aims to optimize the hydraulic fracturing treatment parameters by optimizing the Net Present Value which is directly linked to the fracture geometry. This study introduces a different approach into optimization, using a set of previous historical data from various wells to obtain a collection of charts that illustrate the liaison between the production and the optimal ranges of both the fracture geometry & conductivity and proppant distribution. We then proposed a tool developed in excel using the Generalized Reduced Gradient optimization method which resulted in obtaining the base cases and case study for this dissertation and acquire the fracture geometry parameters while focusing firstly on optimizing the revenues and costs separately in the first two cases in a way to simulate the operator's usual approach, then secondly simultaneously optimizing the revenues while taking into consideration the operation costs which represents our strategy. Following that, case study validation is conducted using Petrel to demonstrate the application of the previous optimization strategy coupled with the historical data on well X and show that in fact this method can achieve optimal NPV results and meet both the service company and the operator's demands.

Key words:

Net Present Value (NPV), Hydraulic Fracturing (HF), Optimization, Geometry, Fracture conductivity (Cf), Generalized Reduced Gradient (GRG), Revenues and Costs.

Résumé

L'optimisation de la fracturation hydraulique est indispensable pour obtenir les meilleurs résultats de stimulation. Cette dessertation vise à optimiser les paramètres de traitement de la fracturation hydraulique en optimisant la valeur actuelle nette qui est directement liée à la géométrie de la fracture. Cette étude introduit une approche différente de l'optimisation, en utilisant un ensemble de données historiques provenant de différents puits pour obtenir une collection de graphiques qui illustrent la liaison entre la production et les plages optimales de la géométrie et de la conductivité des fractures et de la distribution des agents de soutènement. Nous avons ensuite proposé un outil développé sous Excel en utilisant la méthode d'optimisation du gradient réduit généralisé qui a permis d'obtenir les cas de base et l'étude de cas pour cette thèse et d'acquérir les paramètres de géométrie de fracture tout en se concentrant d'abord sur l'optimisation des revenus et des coûts séparément dans les deux premiers cas de manière à simuler l'approche habituelle de l'opérateur, puis en optimisant simultanément les revenus tout en prenant en compte les coûts d'exploitation, ce qui représente notre stratégie. Ensuite, la validation de l'étude de cas est effectuée à l'aide de Petrel pour démontrer l'application de la stratégie d'optimisation précédente couplée aux données historiques du puits X et montrer que cette méthode permet d'obtenir des résultats optimaux en termes de VAN et de répondre aux demandes de la société de services et de l'opérateur.

Mots clés :

Valeur actuelle nette (NPV), fracturation hydraulique (HF), optimisation, Géométrie, conductivité de la fracture (Cf), gradient réduit généralisé (GRG), Revenus et coûts.

الملخص

التكسير الهيدروليكي الأمثل ضروري للغاية لتحقيق أفضل نتائج التحفيز. تهدف هذه الدراسة إلى تحسين معلمات معالجة التكسير الهيدروليكي من خلال تحسين صافي القيمة الحالية المرتبطة مباشرةً بهندسة الكسر. تقدم هذه الدراسة نهجًا مختلفًا في التحسين، باستخدام مجموعة من البيانات التاريخية السابقة من آبار مختلفة للحصول على مجموعة من الرسوم البيانية التي توضح الارتباط بين الإنتاج والنطاقات المثلى لكل من هندسة الكسر والتوصيل وتوزيع المواد المساعدة. ثم اقترحنا بعد ذلك أداة تم تطويرها في برنامج إكسل باستخدام طريقة تحسين التدرج المخفض المعمم والتي أسفرت عن الحصول على الحالات الأساسية ودراسة الحالة لهذه الرسالة والحصول على معلمات هندسة الكسر مع التركيز أولاً على تحسين الإيرادات والتكاليف بشكل منفصل في الحالتين الأوليين بطريقة تحاكي النهج المعتاد للمشغل، ثم ثانيًا تحسين الإيرادات في وقت واحد مع الأخذ في الاعتبار تكاليف التشغيل التي تمثل استراتيجيتنا. بعد ذلك، يتم إجراء التحقق من صحة دراسة وإظهار أن هذه X لإثبات تطبيق استراتيجية التحسين السابقة مقترنة بالبيانات التاريخية للبئر Petrel الحالة باستخدام الطريقة يمكنها في الواقع تحقيق نتائج مثلى لصافي القيمة الحالية وتلبية متطلبات كل من شركة الخدمات والمشغل

الكلمات المفتاحية

صافي القيمة الحالية ، التكسير الهيدروليكي ، التحسين ، الهندسة ، موصلية الكسر، التدرج المخفض المعمم، والإيرادات والتكاليف

List of Abbreviation

2D	Two-dimensional
BHST	Bottom Hole Static Temperature
Cl	Hydrochloric acid
CMHPG	Carboxymethyl hydroxypropyl guar
DCA	Decline Curve Analysis
GOR	Gas Oil Ratio
GRG	Generalized Reduced Gradient
H_2S	Hydrogen sulfide
HC	Hydrocarbon
HF	Hydraulic Fracturing
HPG	Hydroxypropyl guar
ISIP	Instantaneous Shut-In Pressure
KGD	Khristianovic-Geertsma-de Klerk
LWD	Logging-While-Drilling
MD	Measured Depth
NPV	Net Present Value
NWB	Near Well-Bore
OBM	Oil Based Mud
P3D	Pseudo three-dimensional
PCM	Precision Continuous Mixer
pH	Potential of Hydrogen
PKN	Perkins-Kern-Nordgren
PPA	Proppant Pound per Added Volume
POD	Programmable Optimum Density
PVT	Pressure Volume Temperature
RCS	Resin Coated Sand
SP	Spontaneous Potential
TCV	Treatment Control Vehicle
TVD	True Vertical Depth
UCS	Uniaxial compressive strength

Nomenclature

Sign	Name	Unit
K	Permeability of the reservoir	mD
Ks	Permeability of the damaged zone	mD
Kf	Fracture Conductivity	mD
φ	Porosity	%
Φ eff	Effective Porosity	%
Φ N	Porosity From Neutron	%
Φ D	Porosity From Density	%
Φ S	Porosity From Sonic	%
Sw	Water Saturation	%
q	Flow rate	Bbl/day
Q'	Flow rate of the Post-frac	Bbl/day
Q0	Flow rate of the Pre-frac	Bdl/day
Qi	Initial Rate	Bdl/day
Di	Initial decline rate	Bdl/day
μ	Viscosity	cP
Bo	Formation Volume Factor	Unitless
S	Skin	Unitless
Sf	Skin results from a Fracture	Unitless
MD	Measured Depth	m
h	Reservoir height	ft
rw	Radius of the well	ft
rs	Radius of the damaged zone	ft
L0	Original Length	ft
L	Length after an external load is applied	ft
Δd	Latitudinal Strain	ft
Xf	Fracture Half-length	ft
Wf	Fracture Width	in
Hf	Fracture Height	ft
PI	Productivity Index	Bbl/d/psi
Pr	Reservoir Pressure	Psi
Pwf	Dynamic Bottom Hole Pressure	Psi

P net	Net Pressure	Psi
P	Pore Pressure	Psi
$\boldsymbol{\sigma}$	Stress	Psi
$\boldsymbol{\sigma'}$	Effective Stress	Psi
$\boldsymbol{\sigma}$**v**	Vertical stress or Overburden	Psi
$\boldsymbol{\sigma}$**H**	Maximum Horizontal Stress	Psi
$\boldsymbol{\sigma}$**h**	Minimum Horizontal Stress	Psi
ε**h**	Tectonic Minimum Stress Constant	Psi
εH	Tectonic Maximum Stress Constant	Psi
ρ	Density	Kg/m^3
ρma	Matrix Density	g/cc
ρb	Measured Density	g/cc
ρf	Fluid Density	g/cc
v	Poisson’s ratio	Unitless
α	Biot Constant	Unitless
ε	Strain	%
E	Young’s Modulus	GPa
G	Shear Modulus	GPa
K	Bulk Modulus	GPa
Δt	measured transit time of the formation	µs/ft
Δtf	measured transit time in well bore Fluids	µs/ft
Δtma	measured transit time in rock Matrix	µs/ft
DTS	Transit Time of Shear waves	µs/ft
DTC	Transit Time of Compressional waves	µs/ft
Rw	Water Resistivity	Ohm.m
Rt	Uninvaded Formation True Resistivity	Ohm.m
n	Saturation Exponent	Unitless
m	Cimentation Exponent	Unitless
a	Archie cementation constant	Unitless
CFD	Dimentionless Fracture Conductivity	Unitless
Ppf	Perforation Frictions	Psi
D	Diameter of Perforation	in
N	Number of Perforation	Unitless

C	Discharge Coefficient	Unitless
FOI	Folds of Increase	Unitless
b	The degree of curvature of the line	Unitless
R	Revenues	$
Mp	Proppant Mass	Kg
P rp	Proppant Price	$/kg
Vf	Fluid Volume	m^3
P rf	Fluid Price	$/m^3
NF	Number of Fractures	Unitless
FC	Cost of Equipment	$
AC	fixed and miscellaneous costs	$
η	Fluid Efficiency	Unitless
V pad	Volume of Pad	m^3
V i	Total Volume of fluid requirements	m^3
n	Flow Behavior Index	Unitless
GR	Gamma Rey	gAPI
CAL	Caliper	in
RHOB	Bulk Density	g/cc
NPHI	Neutron Porosity Hydrogen Index	Ft3/ft3
PHE	Photoelectric Effect	b/e-
Sp	Spurt Loss Coefficient	m
β	Constant	Unitless
Cl	Leak off Coefficient	m/s^0.5
Di	Discount Rate	year
ta	Total Assests	day
NPC	Net Present Cost	$
DPI	Direct Project Investment	Unitless
OPEX	Operating Expenses	$
CAPEX	Capital Expenditures	$

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General Introduction

General Introduction

Algeria, like many other countries throughout the world, is confronted with a pressing issue brought on by the growing demand for hydrocarbons against a backdrop of diminishing production. The need for hydrocarbon resources has increased significantly in Algeria in recent years as a result of the nation's expanding industrialization, urbanization, and patterns of energy use. The hydrocarbon sector in Algeria is being greatly impacted by this rising demand, necessitating for creative solutions to meet the country's energy needs while resolving production issues. **[1]**

The combination of falling production rates and rising hydrocarbon demands creates a complex issue that needs broad solutions. Given this, applying modern methods such as hydraulic fracturing is a viable way to deal with Algeria's hydrocarbon problems. Fracking is a well stimulation process that creates a conductivity to make it easier to extract oil and gas by injecting high-pressure fluid into rock formations to cause fractures. **[4]**

Optimal fracture design plays a critical role in successful economical production from oil reservoirs. However, many complex parameters such as fracture half-length, width and conductivity make fracturing treatments costly and uncertain. To improve fracking design, it is essential to determine reasonable and optimal ranges for these parameters and to evaluate their effects on well performance and economic feasibility. **[2]**

The foundation of our approach is the creation of a tool designed especially for hydraulic fracturing. The main goal of this approach is rigorous design to maximize the Net Present Value (NPV) of HF projects, consequently minimizing operational expenses and increasing production rates. Our approach of evaluation of the project's economic viability and long-term profitability is net present value (NPV). The core of our methodology involves the thorough gathering and examination of data from fifty wells located in field Z. This directs us into defining the important factors that affect production and their optimum ranges and allows us to adapt our optimization algorithm to the specific geological and operational features of this field. Through the utilization of this vast information, our principle goal is to generate a strategy that can lead to long lasting profitability and efficiency of hydrocarbon production.

Therefore, the main objective of this study is to develop a strategy able to enhance the production with minimal cost and to prove its efficiency by evaluating it using the Net Present Value evaluation method.

Hence, the problematic that can arise from this objective is:

How can this strategy enhance production and reduce hydraulic fracturing operational cost simultaneously? How does the NPV influence fracking parameters? How can previous data be employed into optimizing a HF job?

In order to highlight this strategy and respond to the problematic raised, the following plan was realized. This thesis is divided into five distinct chapters:

Chapter one discusses formation damage, its definition, types, origin, effect on production and permeability, and ways into its identification.

Chapter two focuses on formation evaluation, it is divided into two seperate sections respectively are: Basics of geomechanics and Use of petrophysics in HF. This chapter is indispensable to understand how the HF design is chosen.

Chapter three emphasizes on the explanation of the hydraulic fracturing design, from fluid and proppant selection, fracture modeling and geometry, equipment choice and pumping schedule to testing.

Chapter four, Net Present Value modeling addresses the definition of the NPV, its application in HF, factors affecting it, explanation of some economical terms used in the study and finally a clarification of the GRG excel method used in our optimization strategy.

Chapter five presents the case study of our optimization method with its application on a well, its simulation and NPV results, along with the developed excel tool.

Chapter one
Formation Damage

Introduction

Formation damage is a generic term that refers to the impairment of the permeability of petroleum bearing formations by various adverse processes. Formation damage is an undesirable operational and economic problem that can occur during the various phases of oil and gas recovery from subsurface reservoirs,including drilling, production, hydraulic fracturing, and workover operations. **[4]**

This chapter aspires to give a comprehensive point of view regarding the concept of formation damage, its locations, origin and mechanisms, backed by a brief discussion on identification methods.

1.1. Theory of damage

Normally, impurities and fines attached to the pore surface are stabilized. However, change in temperature, pressure, chemical and stress states can provoke and disturb these particles resulting in all kind of issues such as, precipitation, movement or dissolution of fines. **[1]**

Well operations can damage the formation from the moment the drill bit first penetrates a permeable formation which will continue to end its productive life. Formation damage is defined as a partial or complete plugging of the near-wellbore area, which reduces the initial permeability of the formation. This damage can be anything that obstructs the normal flow to the surface. **[3]**

1.2. Formation damage locations

The Figure below shows some common types of damage, which can occur anywhere in the production process from the wellbore to perforation and into the formation. Such a distinction is usually not made because most plugging phenomena are rarely found in only one section of the flow system.

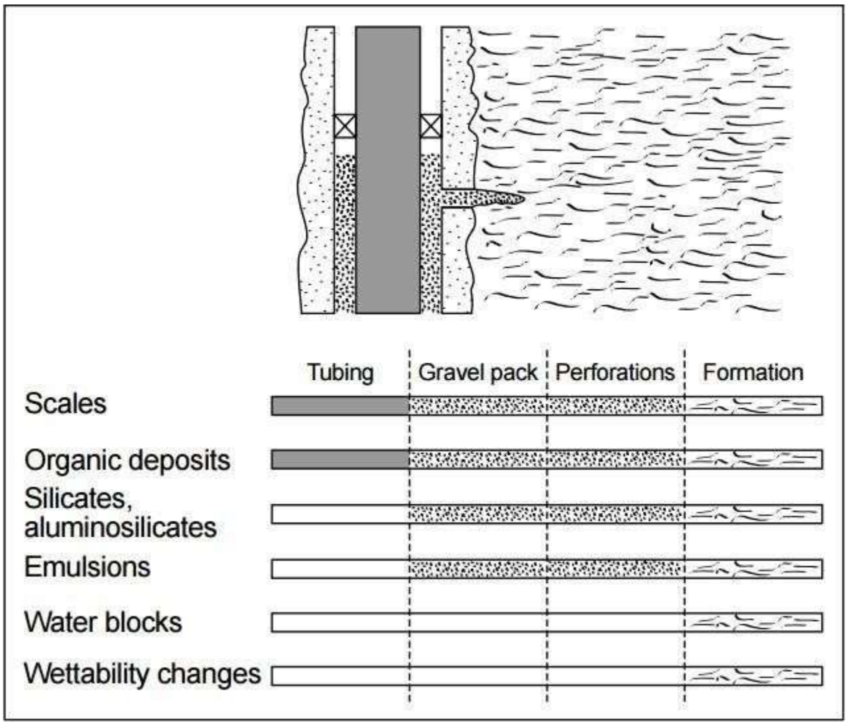

Figure 1-1 Location of various types of damage [1]

1.3. Origin of formation damage

Typical well operations including drilling, cementing, completion, gravel packing, production, stimulation and injection for enhanced oil recovery are all potential sources of damage.

1.3.1. Drilling

1.3.1.1. Drilling Mud Solids Invasion

Materials like clays, cuttings, weighting agents, and lost-circulation agents in drilling fluids have the potential to cause damage. If these materials enter the pay zone, they can fill the reservoir rock's pores, significantly reducing permeability around the wellbore area. **[2]**

1.3.1.2. Drilling Fluid Filtrate Invasion

Filtrate damage is a significant cause of production issues, but its severity varies based on the formation's sensitivity to the filtrate. Generally, high-permeability clean sandstones remain unaffected if their connate water is chemically compatible with the filtrate. **[2]**

1.3.2. Cementing

1.3.2.1. Washers and spacers

The primary aim of a cementing operation is to create a strong, impermeable seal in the well annulus to isolate different zones effectively. It involves removing drilling mud completely, usually achieved through washers, spacers, casing movements, and turbulent flow. Proper mud removal is crucial because it helps protect the formation rocks against filtrate invasion during the cementing.

1.3.2.2. Cement slurries

There are three situations where this invasion can cause significant permeability issues:

- **Formation clay sensitivity**: The cement slurry's relatively high pH can harm clay minerals in theformation.

- **Interaction with connate brines:** When cement filtrate encounters formation water with high calcium concentrations, it may lead to the precipitation of substances like calcium carbonate, lime, or calcium silicate hydrate.

- **Over dispersed slurries:** Slurries that are over dispersed, lacking a yield value, can separate rapidly, causing cement particles to settle at the bottom and water at the top. This separation may result in significant invasion of free water, leading towater blockage with potential permeability issues.

1.3.2.3. Perforation damage

Perforating is always a cause of additional damage in formation rocks, whether it is performed overbalanced or underbalanced, it always compacts the rock around the perforations and produces a zone with an average thickness where the permeability decreases. **[2]**

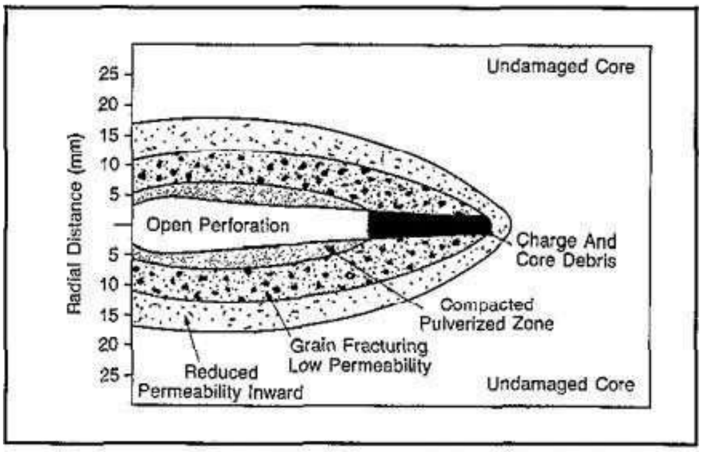

Figure 1-2 Damage caused by perforations. [1]

1.3.3. Completion and work-over fluids damage

The various types of damage from completion and work-over fluids arc basically similar to the ones described above.

1.3.4. Damage in Gravel packs

Gravel packs may experience various issues, including improper placement leading to sand intrusion, contamination from formation particles during placement, the introduction of foreign substances like dope, paint or polymer residues, potential invasion of formation fines due to inadequate gravel size, and problems with screen slots either being too large or too narrow. These challenges can compromise the effectiveness of gravel packs and impact well productivity. **[2]**

1.3.5. Damages during production

In some reservoirs, high flow rates or large drawdowns can cause permanent damage that reduces production efficiency. Loose silts and clays in the formation, when set in motion by rapid flow rates or the production of multiple fluids, can block pore throats or migrate toward the wellbore, affecting productivity.

Excessive drawdown may lead to wellbore filling by formation sand, particularly in poorly cemented sandstones. Damage can also occur due to precipitation of organic or inorganic materials resulting from changes in pore pressure or cooling during gas expansion. **[2]**

1.3.6. Damage during stimulation treatments

1.3.6.1. Wellbore cleanup

During well cleaning processes aimed at removing deposits or corrosion from tubing, there is a risk of introducing high concentrations of harmful materials into the pay zone. It is crucial to exercise extreme caution to avoid pushing these substances into the porous rock. Rust in acidic solutions or paraffin in hot oil are common examples of substances that can dissolve in the wellbore and then re- precipitate in the formation, leading to significant, severe, and often irreversible damage. **[2]**

1.3.6.2. Acid treatments

During acidizing treatments, potential damaging processes include oil-wetting of the reservoir by surfactants, leading to emulsion blocks, water blocks, and asphaltene/paraffin deposition with large acid volumes. Poorly designed acidizing treatments can cause specific production impairments, such as sludge formation from acid-asphaltene reactions, deconsolidation of formation rock due to excessive cement dissolution, precipitation of by-products from acid-mineral reactions, permeability issues from residues of corrosion inhibitors or thermal degradation of polymers. **[2]**

1.3.6.3. Fracture treatments

Hydraulic fracturing damage takes two forms: proppant-pack damage within the fracture and fracture-face damage extending into the reservoir. The severity depends on reservoir permeability, with proppant-pack damage becoming crucial as permeability increases. Proper selection of fracturing fluids, polymer concentrations, and breakers is vital. High-permeability reservoirs may suffer severe damage due to polymer-based gels and inefficient fluid-loss agents. Poor load-fluid recovery during treatment can lead to fluid trapping in smaller pores. **[2]**

1.4. Mechanisms of formation damage

Formation damage is generally categorized as either natural or induced. Damages classified as natural arise mostly from the process of producing reservoir fluid. A well's exterior operations, including as drilling, well completion, repairs, stimulation treatments, or injection operations,might cause induced damages. Additionally, natural damage mechanisms may be triggered by certain completion activities, induced damages, or design flaws.

1.4.1. Natural damages include

1.4.1.1. Fines migration

Formation damage may arise due to particle migration within the produced fluid, leading to the formation of bridges across pore throats near the wellbore. This bridging can result in a reduction in well productivity. Migrating fines encompass various materials, including clays and silts, Kaolinite platelets are considered prevalent among migratory clays. **[1]**

1.4.1.2. Swelling clays

Clays can change volume based on the saltiness of the fluid in the formation. This phenomenon is linked to factors like ion exchange and salt concentration. Changes in how easily fluids move through the formation happen because of the amount, type, and location of clay minerals. **[1]**

1.4.1.3. Water-formed scales

Scale usually consists of precipitates formed from mixing incompatible waters or upsetting the solution equilibrium of produced waters. They can be present in the tubing, perforations and formation.

Table 1-1 Types of scales that can be formed [6]

Acid Soluble Scale	
Calcite ($CaCO_3$)	Both calcium and bicarbonate in the formation brine
Siderite ($FeCO_3$)	Corrosion products and bicarbonate in the formation brine
Pyrite (FeS, FeS_2)	Corrosion products and sulfate reducing bacteria
Iron Oxide (Fe_2O_3, Fe_3O_4)	Corrosion products and oxygen rich injected water
Acid Insoluble Scale*	
Barite ($BaSO_4$)	Barium in formation water and sulfate in injected seawater
Celestite ($SrSO_4$)	Strontium in formation water and sulfate commonly in injected seawater
Anhydrite (> 110 °C) Gypsum (< 110 °C), $CaSO_4$	Calcium in formation water and sulfate commonly in injected water
Mixed Barium/ strontium sulfate ($(Ba, Sr) SO_4$)	Barium and strontium in formation water and sulfate in injected sea water

1.4.1.4. Organic deposits

Organic deposits are heavy hydrocarbons (paraffins or asphaltenes) that precipitate as the pressure or temperature is reduced. This is a form of distillation. They are typically located in the tubing, perforations or formation. Although the formation mechanisms of organic deposits are numerous and complex, the main mechanism is a change in temperature or pressure in the flowing system. **[1]**

Figure 1- 3 An example of a paraffin deposit. [6]

1.4.1.5. Mixed organic/inorganic deposits

Mixed organic/inorganic deposits consist of a combination of organic compounds, scales, or fines and clays. In a sandstone reservoir experiencing heightened water production, migrating fines undergo a shift in wettability, becoming oil-wet. **[1]**

1.4.1.6. Emulsions

Emulsions are combinations of two or more immiscible fluids (including gas) thatdon't normally disperse into each other. All natural emulsions are formed becauseof the presence of an energy source that produces mixing and most of these emulsions break when such source is removed, unless a stabilizing force is acting to keep the fluids emulsified. **[6]**

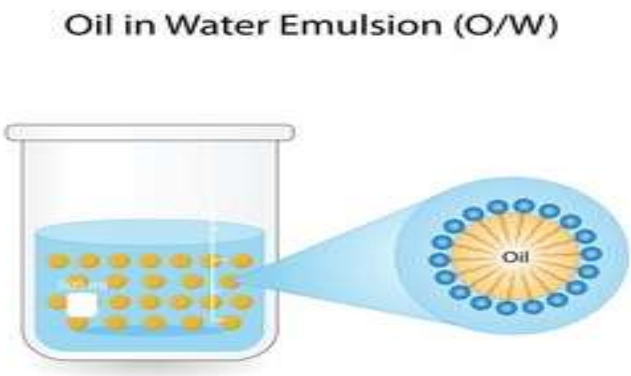

Figure 1- 4 A diagram depicting the process of an emulsion. [6]

1.4.2. Induced damages include

1.4.2.1. Plugging by entrained particles

Damage caused by particles in injected fluids occurs in the vicinity of the wellbore, leading to the obstruction of formation pore throats. Issues associated with this damage encompass the formation of bridges within pores, the filling of perforations and the substantial loss of high-solid content fluid into natural fractures or propped fracture systems. **[2]**

1.4.2.2. Wettability change

The term ‘wettability alteration’ refers to the process of oil wetting rock containing hydrocarbon deposits, primarily asphaltene, or the adsorption of an oleophilic surfactant (one that attracts oil) from drilling fluid or stimulation fluid dispersants. There is an extra pressure drop surrounding the wellbore as a result of the formation’s increased permeability to water and decreased permeability to oil. **[1]**

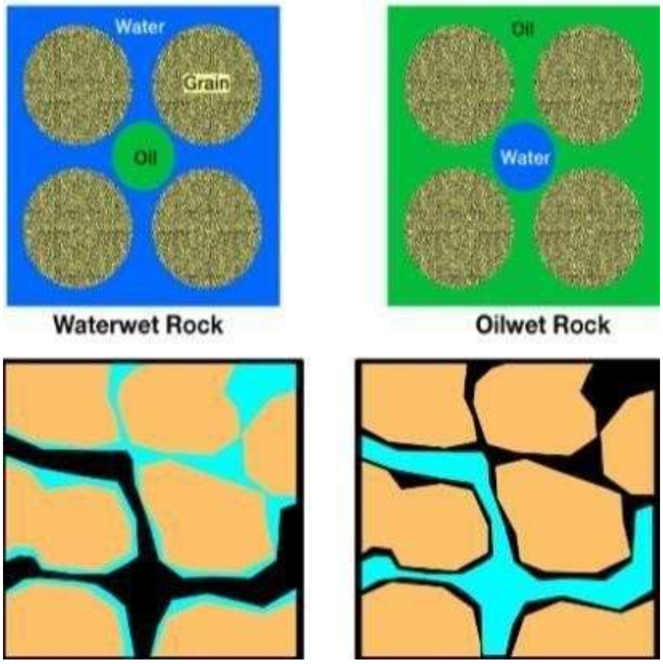

Figure 1- 5 Water wet vs. Oil wet Rock, Fluid behavior in geological structures.[6]

1.4.2.3. Acid reactions and acid reaction by-products

Acidizing treatments may encounter various issues, including damaging materials from tubing entering the formation, oil-wetting of the reservoir by surfactants, waterblocks, and asphaltene or paraffin deposition with large acid volumes. Poorly designed acidizing treatments can lead to additional production impairments, such as sludges formed by acid-asphaltene reactions and by-products precipitated by acid reactions with formation materials. **[1]**

1.4.2.4. Bacteria

Bacteria can be a serious problem in production operations because of what they consume and their by-products. Bacteria can grow in many different environments and conditions:

temperatures ranging from 12°F to greater than 250°F [–11° to >120°C], pH values ranging from 1 to 11, salinities to 30% and pressures to25,000 psi. **[1]**

The bacteria most troublesome in the oilfield are:

Table 1-2 Types of Bacteria present in the oil field and their impact [1].

Bacteria type	Impact
Sulfate Reducing Bacteria	H_2S generation and fracturing fluids viscosity reduction.
Iron Oxidizing Bacteria	Production of gelatinous ferric hydroxide, which is highly insolubleand precipitates out of water.
Slime Forming Bacteria	Produce mats of high-density slime that cover surfaces, protection of colonies of sulfate-reducing bacteria and pore plugging.
Polymer Attacking Bacteria	Rapid bacteria growth and formation Plugging.

Prevention of polymer destruction by bacteria is usually handled with biocides and tank monitoring. **[1]**

1.4.2.5. Water blocks

Water can cause blocking in low-permeability rocks. Water blocks are a special case of relative permeability problems.

The most severe cases of water blocks are usually observed in low-pressure, low permeability, gas-producing formations after treatment with water that has a high surface tension.

1.4.2.6. Incompatibility with drilling fluids

Oil-base mud is the preferred drilling fluid for highly deviated wells and formations sensitive to water-base mud. OBMs, especially those with densities over 14 lbm/gal, often contain enough solids to form stable emulsions with high-salinity brines or acids, causing significant and long-lasting damage. In some cases, this damage can be so severe that it leads to a considerable decrease in well productivity. Additionally, the use of powerful wetting surfactants in OBM can alter formation wettability leading to reducing permeability. **[1]**

1.5. Quantifying formation damage

The type, extent, and location of the damage must all be taken into account when calculating the severity of formation damage. Pressure transient analysis is one such technique that determines the skin factor. Furthermore, depending on reservoir characteristics and flowing bottomhole pressure, the productivity index compares the well's actual productivity to its theoretical productivity.

1.5.1. The Skin Factor

A numerical value used to analytically model the difference from the pressure drop predicted by Darcy's law due to skin. Typical values for the skin factor range from -6 for an infinite conductivity massive hydraulic fracture to more than 100 for a poorly executed gravel pack. This value is highly dependent on the value of kh. **[5]**

$$\boldsymbol{S = \left(\frac{Kh}{141.2\, q\, \mu\, Bo}\right) \Delta P\ Skin} \qquad \textbf{(1-1)}$$

Where,

k: Permeability in mD; **h:** Reservoir Height (ft); **q:** Oil Flow in bottom hole conditions (bbl/day); $\boldsymbol{\mu}$**:** Oil Viscosity (cP); **B:** Volumetric Factor (bbl/ST); $\boldsymbol{\Delta P\ Skin}$**:**the pressure drop.

The figure below illustrates how limitations in flow near the wellbore can elevate the pressure gradient, leading to an extra pressure decline attributed to formation damage(Δpskin).

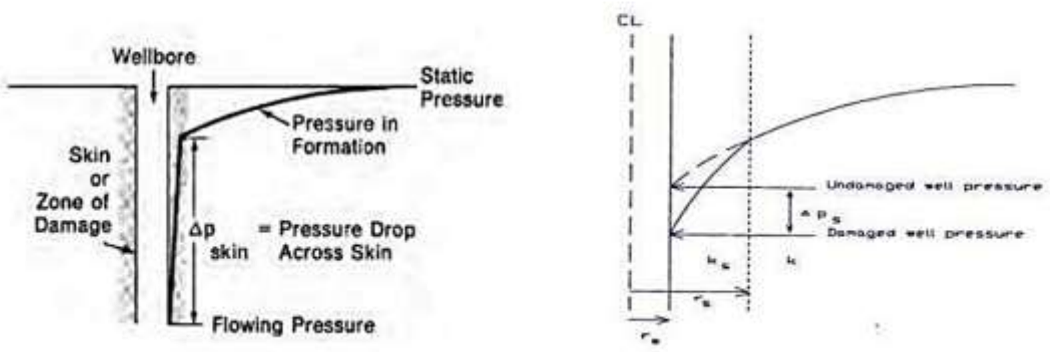

Figure 1- 6 Pressure profile in the NWB region for an ideal well and a damaged well [10]

1.5.2. Effect of Skin on permeability

This effect is represented by the Hawkins' formula below:

$$S = \left[\frac{K}{Ks} - 1\right] ln \frac{rs}{rw} \qquad \textbf{(1-2)}$$

S: skin; **k**: permeability of the reservoir (mD); **ks**: permeability of the damaged zone (mD)**rs**: radius of the damaged zone (ft); **rw**: radius of the well (ft)

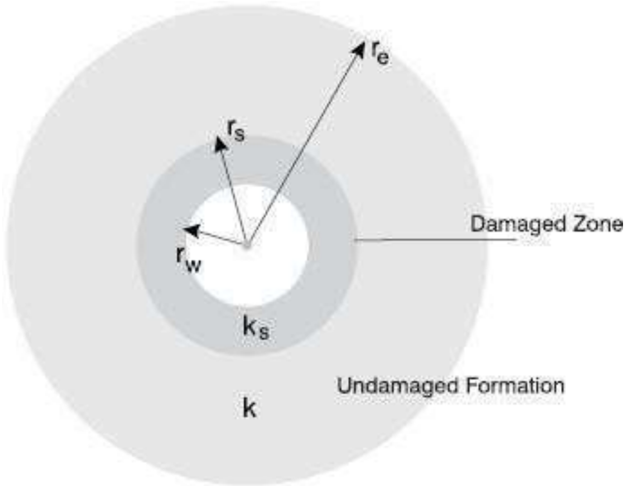

Figure 1- 6 Damaged vs. undamaged zones. [6]

If:

- S > 0: The permeability of the wellbore vicinity is lower than that of the restof the formation (indicating damage);
- S < 0: Corresponds to a stimulation;
- S = 0: Ke = K (no damage).

1.5.3. Effect of Skin on productivity index

The productivity index, a frequently utilized metric for well performance, is defined as the flow linked to the pressure decrease between the reservoir and thewellbore. It represents the potential of a well under conditions of steady-state, circular radial flow for liquids. **[3]**

$$PI = \frac{Q}{Pr-Pwf} \qquad \textbf{(1-3)}$$

Understanding the PI and Hawkins' equation is essential to comprehend the impact of formation damage on well productivity.

For an oil well, the PI equation is:

$$Q = \frac{kh\,(Pr-Pwf)}{141.2\,q\,\mu\,B\,(\,ln\frac{re}{rw}+S)} \qquad (1\text{-}4)$$

Q: Oil rate in bottom hole conditions bbl/d; **K**: Permeability mD; **h**: Reservoir height ft; **μ**: Oil viscosity cp; **Pr**: Reservoir pressure psi; **Pwf**: Bottom hole pressure psi; **re**: drainage radius ft; **rw**: well radius ft; **S**: Total skin; **Bo**: Volumetric factorbbl/st.

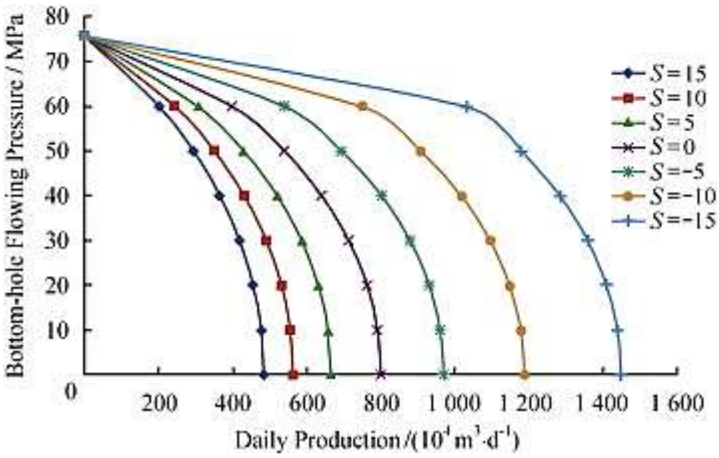

Figure 1- 7 Effect of Skin on Productivity

1.5.4. Formation damage vs. pseudo damage

The skin of mechanical origin is called pseudo damage, while the one truly originating in the formation is called formation damage. A treatment can only, at best, suppress formation damage. It has no effect on any skin of mechanical origin. Pseudo damage is considered "pseudo" because it arises from factors such as wellbore geometry, completion design, production conditions or operational issues rather than actual reservoir damage. This type of damage must be subtracted from the total skin value to estimate the true skin associated with real formation damage.**[2]**

1.6. Identifying formation damage

1.6.1. Well history

Drilling, completion, and work over records serve as fundamental documentation for engineering operations. They lay the foundation for the initial identification of potential issues, such as drilling challenges, the utilization of loss agents, perforation characteristics, and details about the kill fluid. Additionally, these records establish the groundwork for designing laboratory tests aimed at evaluatingpotential damage. **[8]**

1.6.2. Well tests

The skin factor can be estimated from well testing data by using analytical or numerical models that relate the pressure and flow rate at the wellbore to the reservoir properties and the skin factor. Some common methods to estimate theskin factor are the Horner plot, the pressure derivative plot, and the type curve matching. **[9]**

1.6.3. Open hole or production logs

Open-hole wireline logs serve as valuable tools for identifying various features, including anomalies like out-of-gauge wellbores, wellbore breakout, fluid invasiondepth, stratigraphy, and natural fractures. These logs, readily accessible, are effective for assessing potential issues like oversized cement sheaths. Additionally,cased-hole logs offer insights into flow distribution post-stimulation treatments and factors impacting well performance, such as cement bond quality (poor cement jobs leading to positive skins due to cross flow behind the casing). **[8]**

1.6.4. Production records

Patterns in production performance can provide insights into evolving changes linked with damaging processes like waxing or scaling, as well as the impacts ofworkovers. **[8]**

1.6.5. Core analysis

Core analysis involves taking core samples from the reservoir to measure their permeability before and after exposure to drilling fluids or other agents. The ratio of initial to final permeability is called the damage ratio, which ranges from 0 to 1.A lower value indicates a higher degree of formation damage. **[3]**

Conclusion

To enhance well performance, the pathways from the formation to the pipeline need to have minimal pressure resistance. This means having a well completion designed effectively and addressing any formation damage. Various techniques and chemicals are accessible for stimulation and damage removal.

Chapter Two
Formation Evaluation

Introduction

Hydraulic fracturing is a commonly used technique for increasing the productivity ofoil and gas wells by generating fissures in reservoir rock. However, building an optimum fracturing treatment requires a thorough knowledge of the formation's characteristics, including porosity, permeability, stress, mineralogy, and fluid composition.

This chapter is divided into two distinct sections. The main focus in the first part will be clarifying the fundamental principles of geomechanics and explaining their significance in HF operations and the direct relevance of geomechanics to the successof HF processes. Following this, the second section will explore the area of petrophysics in fracking. The discussion will cover various petrophysical aspects and highlight the principal logs indispensable for a comprehensive analysis of hydraulic fracturing jobs.

2.1. Basics of Geomechanics

The objective of rock mechanics is to characterize the behavior of rocks using quantifiable parameters, including the stress field, elasticity, and plasticity parameters.A significant number of these parameters are commonly used to specify the physical state of the rock. **[16]** In this section, some definitions, principles, and relationships of the mechanical properties measured will be presented.

2.1.1. Elasticity

The majority of materials possess a capacity to withstand and rebound from deformations induced by external forces, this ability is referred to as elasticity.

The theory of elasticity is based on the two concepts of stress and strain**. [11]**

2.1.1.1. In situ stresses

Stress refers to the force applied per unit area on a material. It is a measure of the internal forces within a solid body that can cause that can cause deformation or strain. The formula for stress is given by:

$$\boldsymbol{\sigma} = \frac{\boldsymbol{Force\ (lb)}}{\boldsymbol{Area\ (in^2)}} \qquad (\mathbf{2-5})$$

2.1.1.2. Underground stresses

Subsurface layers are confined and stressed. In this Figure, we see how stress is divided into three main types.

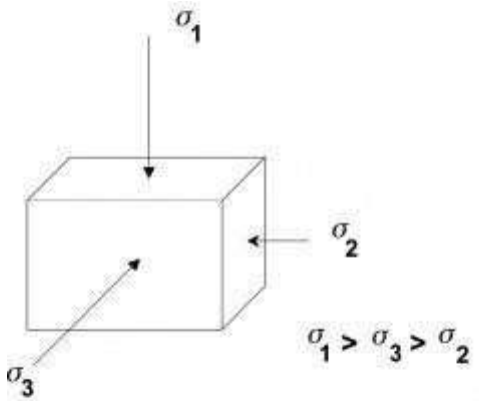

Figure 2-8 Underground Stresses [2]

- σ_1 is the vertical stress
- σ_2 is the minimum horizontal stress
- σ_3 is the maximum horizontal stress

Typically, an underground formation bears the load of the overlying formations.The vertical stress at a depth 'z,' induced by a uniform column of material aboveit, is expressed as σv = ρgz, where ρ denotes the density of the material and 'g' isthe acceleration due to gravity. In cases where density varies with depth, the vertical stress at depth 'z' takes on a different form: **[11]**

$$\sigma v = \int_0^z (\rho z)\, g dz \tag{2-6}$$

Note: A hydraulic fracture will propagate perpendicular to the minimum principalstress. For the minimum and maximum horizontal stresses, they can be estimated with:

$$\sigma H = \frac{v}{1-v}(\sigma v - \alpha p) + \alpha p + \frac{E}{1-v^2}\varepsilon H + \frac{vE}{1-v^2}\varepsilon h \tag{2-7}$$

$$\sigma h = \frac{v}{1-v}(\sigma v - \alpha p) + \alpha p + \frac{E}{1-v^2}\varepsilon h + \frac{vE}{1-v^2}\varepsilon H \tag{2-8}$$

$\boldsymbol{\sigma h}$ = the minimum horizontal stress, $\boldsymbol{\sigma H}$ = the maximum horizontal stress,

ν = Poisson's ratio, σ_v = overburden stress, α = Biot's constant,

p = pore pressure,and σ_h, σH = tectonic stresses constants.

These stresses are nonhomogeneous, anisotropic, and compressive, which suggests that the compressive stresses on the rock are not equal and change in magnitude depending on direction. **[2]**

2.1.2. Strains

Strain is a measure of the deformation of a material under the influence of an external force. It is defined as the ratio of the change in length of a material to its original length. **[12]**

$$S = \frac{L-L0}{L0} \qquad \textbf{(2-9)}$$

Strain (ε) is the percentage change in length or another dimension; **L** is the length of the material after an external load is applied; **L0** is its original length measured in the same units as "L".

There are three main types of deformations, defined as follow:

- Elastic deformation is a reversible deformation of materials.
- Plastic deformation is an irreversible deformation of materials.
- Fracture is the formation of a permanent fracture plane in the material.

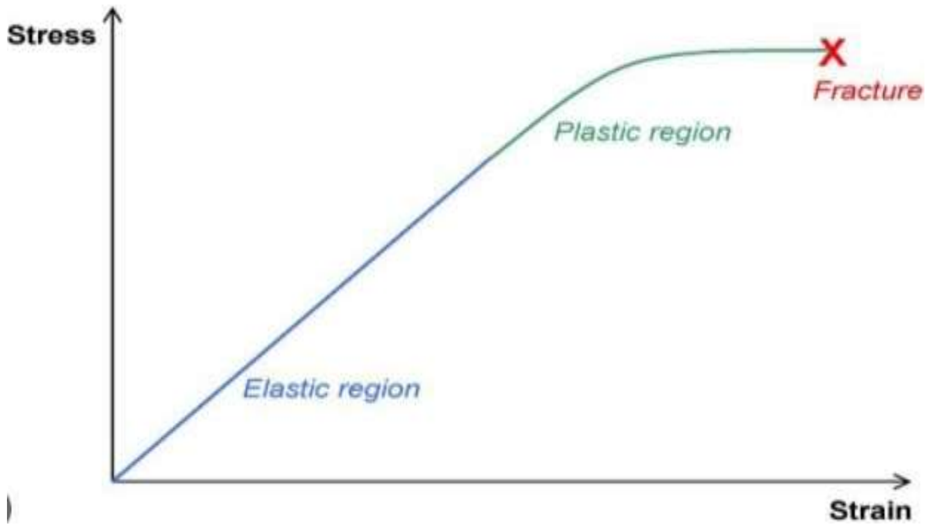

Figure 2-9 Deformation Types

2.1.3. Stress/Strain relationships

The relationship between stresses and deformations illustrates the behavior ofa material subjected to solicitations and is defined by intrinsic curves describing the material model used (stress/strain).

Real bodies such as rocks are never perfectly elastic, plastic. In the general case, they combine properties of all three fundamental types. The transition from elastic behavior to plastic behavior is called hardening; in thiscase, rocks undergo irreversible modifications in their structures. Rock deformation can remain ductile but increase over time, even though the stress value remains constant; this is known as creep. In other cases, and at a given stress, fracture may occur, causing the rock to become brittle and break. **[16]**

2.1.4. Principle mechanical rock properties

2.1.4.1. Uniaxial compressive strength UCS

Uniaxial compressive strength represents the ultimate strength of a rock underuniaxial loading and is the most commonly used property in rock mechanics. This property is expressed in MPa. It signifies the highest stress (peak strength) applied to the sample.

2.1.4.2. Young’s modulus

Young's modulus describes how stiff a material is, determined by the slope of its stress-strain graph in the elastic range. It is calculated by dividing the stress value byits corresponding strain value.

$$\mathbf{E} = \frac{\boldsymbol{Stress}}{\boldsymbol{Strain}} \qquad \textbf{(2-10)}$$

The term "elastic modulus" denotes the relative stiffness or rigidity of a material. In other words, a material with high stiffness will have a high elastic modulus, whereas a flexible material will exhibit a low elastic modulus. The unit of elastic modulus is giga-newton/m^2 (GN/m^2). **[13]**

2.1.4.3. Shear modulus

It represents how Earth's materials react to shear deformation. It is determined by the ratio of shear stress to shear strain. This critical property provides insight into a material's resistance to shearing deformation. A material that strongly resists shearingwill efficiently transmit shear energy. **[15]** It resembles Young's modulus, except the material undergoes shear instead of compression or torsion.

$$\boldsymbol{G} = \frac{\boldsymbol{E}}{\boldsymbol{2(1+v)}} \qquad \textbf{(2-11)}$$

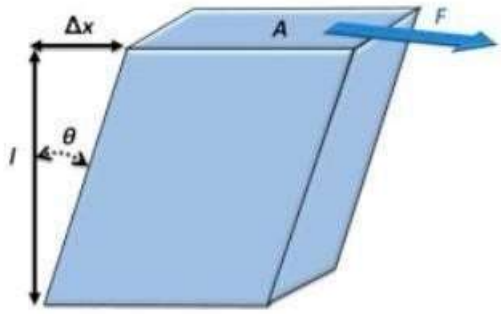

Figure 2- 10 Shear Modulus Effect on earth's materials.

2.1.4.4. Bulk modulus or incompressibility modulus (K)

Applying a hydrostatic stress P in the three orthogonal axes results in a volumechange ΔV, experimentally defined by the bulk modulus K.**[16]**

This modulus is expressed in GPa and calculated based on the Young's modulus (E) and Poisson's ratio (ν) according to the following relationship:

$$K = \frac{E}{3(1-2v)} \tag{2-12}$$

2.1.4.5. Poisson’s ratio

An elastic constant that is a measure of the compressibility of material perpendicularto applied stress, or the ratio of latitudinal to longitudinal strain. **[14]**

$$v = \frac{\Delta d/d}{\Delta l/l} \tag{2-13}$$

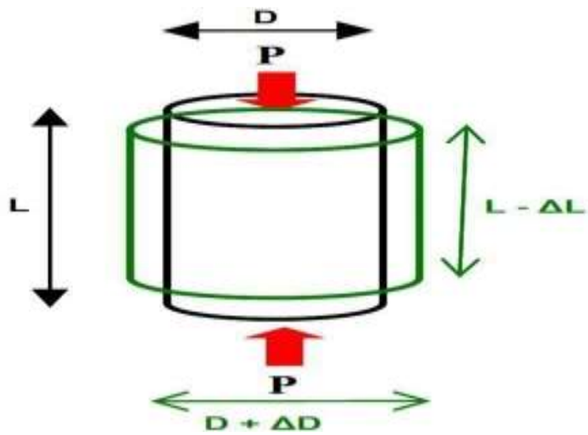

Figure 2- 11 Rock Deformation due to Applied Stress

2.1.5. Influence of pore pressure

Pore fluids within the reservoir rock are significant as they bear a portion of the overall applied stress. Consequently, the rock matrix carries only a portion of the totalstress, specifically the effective stress component. **[2]**

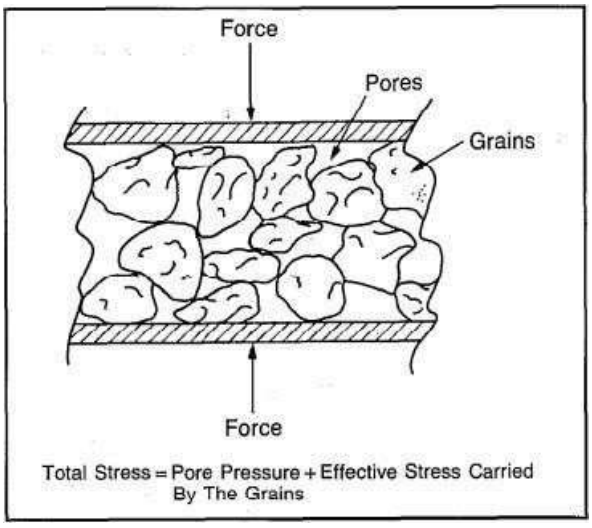

Figure 2- 12 Influence of Pore Pressure on the Overburden Stress.

For that, the concept of the effective stress is introduced and defined as follow:

$$\boldsymbol{\sigma' = \sigma - a\, Pp} \qquad \textbf{(2-14)}$$

Where,

$\boldsymbol{\sigma}$ is the total applied stress; $\boldsymbol{\sigma}$**'** is the effective stress governing the failure of thematerial; **Pp** is the pore pressure; and $\boldsymbol{a}$ is the Biot's constant.

2.1.5.1. Biot constant

The poroelastic constant α, ranges from 0 to 1 and serves as a parameter characterizing the efficiency of fluid pressure in counteracting the total applied stress.Its value relies on both pore geometry and the physical properties of the solid system'sconstituents. **[1]**

2.1.6. Rock failure

When a solid material undergoes significant stress, some form of failure is inevitable.In other words, upon stress relief, the rock does not revert to its original state. The type of failure is dependent on the stress state, material type, and rock geometry. **[11]**

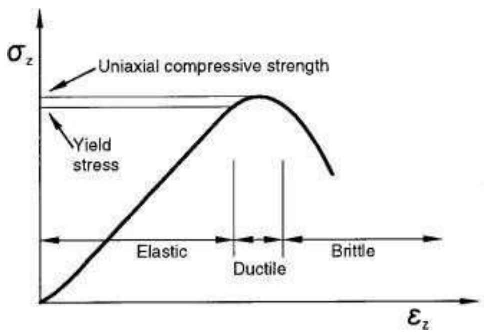

Figure 2- 23 Rock Failure Curve. [11]

2.1.7. Lab testing

2.1.7.1. Uniaxial Compression Test

Applying a uniaxial load (stress) to a standardized rock sample results in a volume change reflected in changes to the sample's dimensions (diameter and length). In a uniaxial compression test, the loading is applied to the transverse surface of the sample (in the vertical or axial direction), until the sample fractures. This change undergoes several phases during the test until the sample ruptures. **[16]**

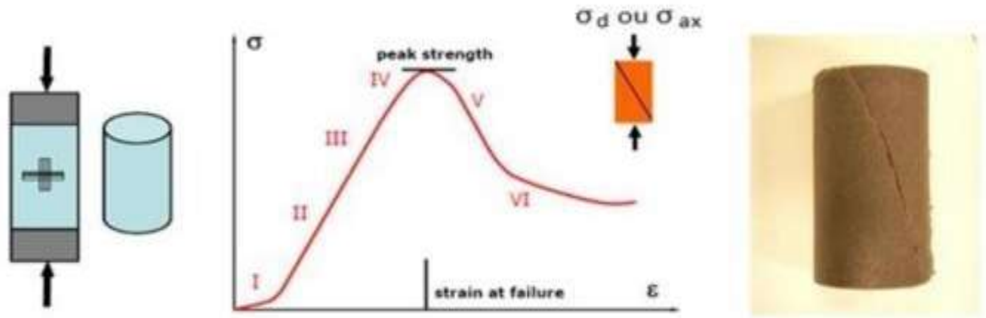

Figure 3- 14 Uniaxial Compression Test

2.1.7.2. Triaxial Compression Test

In the subsurface, rocks experience axial and radial stresses (triaxial conditions), and the compressive strength is stronger under triaxial conditions. The true triaxial compression state involves three different principal stresses. For simplicity, it is oftenassumed that the two radial stresses are equal to the minor principal stress, representing the confinement pressure (Pc) in triaxial tests. **[16]**

The behavior of the rock in triaxial compression changes with increasing confinementpressure (see Figure 2- 15):

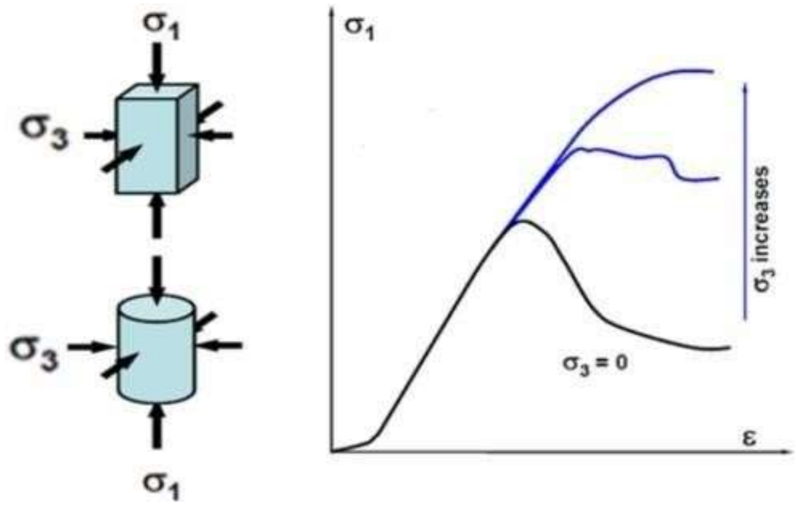

Figure 2- 15 Triaxial Compression Test [16]

a) The maximum strength increases.

b) The post-peak behavior gradually shifts from brittle to ductile.

2.1.7.3. Scratch Test

The scratch test is primarily used to quickly, simply, and continuously estimate the uniaxial compressive strength. The test involves creating a groove on the sample's surface at a fixed shallow cutting depth (d) and a constant speed throughout the test. The test is conducted using a synthetic diamond knife with a width W and an inclination at an angle θ, the knife moves at a constant speed V throughout the entiretest. **[16]**

2.1.7.4. Brazilian Test

Also known as the splitting test, is used to measure tensile strength, where the central part of the sample is subjected to both compressive and tensile stresses. The principle of the test is to crush a standardized cylindrical sample between two platens of a presswith forces uniformly distributed along two diametrically opposed generatrices. **[16]**

2.2.Petrophysics in hydraulic fracturing

2.2.1. Depth

TVD is measured straight down from a zero reference point. On the other hand, Measured Depth (MD) is the distance along the wellbore path, which is not always exactly vertical. During drilling, it's the length of the pipe that goes into the ground,while during wireline logging, it's the length of the cable that goes into the ground. Another way to measure it is from the LWD data. **[1]**

2.2.2. Temperature

The temperature of the formation is critical for the performance of both matrixstimulation products and hydraulic fracturing fluids.

The mud temperature obtained during wireline logging is commonly used to estimate the formation temperature. However, this method may underestimate the actual formation temperature by up to 30°F [15°C]. Despite this limitation, wireline temperature remains the only continuous temperature measurement available. For more precise measurements, discrete point temperature readings can be acquired during fluid sampling using formation testers. **[1]** Thermologs are also used to monitor the fracture growth.

2.2.3. Properties related to the diffusion of fluids

The diffusion of fluids is controlled by factors such as porosity, permeability, pore pressure, and the characteristics of fluids present in the formation. This part explains methods for extracting these parameters from logs.

- **Porosity φ**

The percentage of pore volume or void space, or that volume within rock that can contain fluids. Porosity is divided into two types: **Primary porosity** is the original space between grains. And **secondary porosity** is the space that was created due to tectonic forces and waterdissolution.

Another important point lies between total porosity (φ total) and effective porosity(φeff).

Total porosity represents the volume unoccupied by solid rock. However, aportion of the total porosity volume is filled with fluid that is immobile, known as bound water. Effective porosity is the volume filled by mobile fluids and is the porosity of major concern. **[14]**

- **Porosity from density**

Density tools measure the electron density of a formation, which closely approximatesits bulk density (ρb). By knowing the density of matrix components (ρma) and pore fluid (ρf), total porosity from density can be determined through volume balance: **[14]**

$$\boldsymbol{\theta = \frac{\rho ma - \rho b}{\rho ma - \rho f}} \qquad \textbf{(2-15)}$$

Where, **ρb** is determined from log, **ρma** is determined from the lithology and **ρf** is taken from the mud filtrate.

- **Porosity from neutron**

Neutron tools measure how much hydrogen is in the formation. If there's no hydrogenin the rock and the hydrogen index of the fluid is known, the neutron porosity (φN) gives us an idea of the total porosity. Neutron porosity is not sensitive to the presence of oil in the sampled volume because water and liquid hydrocarbons have similar hydrogen indices. However, if gas is present, neutron porosity may underestimate thetotal porosity. The differences between neutron porosity (φN) and density porosity (φD) tend to balance out, and by averaging them, we can get a good estimate of effective porosity. **[1]**

$$\boldsymbol{\Phi\ \mathrm{eff}} = \frac{\mathbf{1}}{\mathbf{2}}(\boldsymbol{\Phi}\mathbf{N} + \boldsymbol{\Phi}\mathbf{D}) \qquad ((\mathbf{2-16}))$$

- **Porosity from sonic**

Porosity can be estimated using sonic tools by analyzing the travel times of acoustic waves through the formation. Sonic tools typically provide measurements related to the slowness of sound, and these measurements can be used to infer porosity as follow:

$$\boldsymbol{\theta s = A\,\frac{\Delta t - \Delta tma}{\Delta tf - \Delta tma}} \qquad \textbf{(2-17)}$$

Where

A is a constant and $\Delta\mathbf{t}$ denotes the measured transit time of a sonic wave in theformation. The transit time in the matrix $\Delta\mathbf{tma}$ is known from the lithology.

Porosity from sonic logs is only sensitive to primary porosity, not to the secondaryporosity.

2.2.4. Lithology and saturation

Lithology and saturation are important parameters for designing stimulation treatments. For hydraulic fracturing, saturation is used to estimate the compressibilityof the formation fluid.

2.2.4.1. Saturation

The product of saturation and porosity defines the hydrocarbons volume in place. Inaddition to that in stimulation operations, these properties are also of need because they control the flow of water based fluids in a porous medium. **[1]**

Water saturation Sw is the fraction of the pore volume occupied by water.

By definition, 1 – Sw is the fraction of the pore volume occupied by hydrocarbons.

The irreducible water saturation Swi is the fraction of the pore volume occupied bywater bound to the formation.

The value of Sw is obtained mainly through resistivity measurements.

$$Sw = \left(\frac{a\ Rw}{\theta^m Rt}\right)^{\frac{1}{n}} \qquad \textbf{(2-18)}$$

Rw can be determined from water catalogs, samples or SP measurements, the resistivity of the virgin formation **Rt**; m is the cementation exponent; n is the saturation exponent; θ is the porosity.

2.2.4.2. Lithology

The objective of lithological analysis is to acquire a volumetric distribution ofminerals and fluids within the formation, correlated with depth.

- **Gamma Ray Logs:** Gamma ray logs are sensitive to the presence of certain minerals.Peaks in gamma ray values can indicate the presence of shale, while lower values maysuggest sandstone or limestone.

- **Density Logs:** Density logs help differentiate between formations with varying densities, aiding in identifying lithology.

Analyzing a reservoir thoroughly usually requires combining data from differentsources and using diverse techniques to gain an understanding of lithology and reservoir properties.

- **Volume of Shale:** Calculate the Gamma Rey Index IGR which also equals to the volume of shale using the following formula:

$$IGR = VSH = \frac{GR - GR\ clean}{GR\ shale - GR\ clean} \qquad \textbf{(2-19)}$$

Where,

GR: Gamma ray reading at a specific depth.

GR clean: gamma ray value in clean formations.

GR shale: gamma ray value in shale.

- There is a second method that uses both density and neutron logs, the difference between the neutron and density porosity at the same depth should be calculated, after that the following formula is applied:

$$V\ SH = \frac{NPor\ Den\ Diff - (NPor\ Den\ Diff)\ clean}{(NPor\ Den\ Diff) shale - (NPor\ Den\ Diff) clean} \qquad \textbf{(2-20)}$$

Where,

NPor Den Diff: the value of the difference between the porosity from density and neutron logs at a specific depth.

(NPor Den Diff) clean: the NPor Den Diff in clean formations.

(NPor Den Diff) shale: the NPor Den Diff in shale formations.

2.2.4.3. Permeability

Permeability is a measure of how easily fluids, such as liquids or gases, can flowthrough a porous material. **[1]**

- **Types of permeability**

Effective permeability

The ability to preferentially flow or transmit a particular fluid when other immiscible fluids are present in the reservoir. The relative saturations of thefluids as well as the nature of the reservoir affect the effective permeability. In contrast, absolute permeability is the measurement of the permeability conductedwhen a single fluid or phase is present in the rock.

Relative permeability

Relative permeability is the ratio of effective permeability of a particular fluid at aparticular saturation to absolute permeability of that fluid at total saturation.

- **Indirect measurements of permeability:**

4A. Permeability-porosity correlations

Three well-know relations of permeability and porosity are

Labrid (1975) $$\frac{k_i}{k} = \left(\frac{\phi_i}{\phi}\right)^3 \quad \text{(4A-1)}$$

Lund and Fogler (1976) $$\frac{k_i}{k} = \exp\left[7.5 \times \frac{(\phi_i - \phi)}{0.08}\right] \quad \text{(4A-2)}$$

Lambert (1981) $$\frac{k_i}{k} = \exp\left[45.7 \times (\phi_i - \phi)\right]. \quad \text{(4A-3)}$$

Figure 2- 16 Permeability-Porosity Correlations.

- **Direct measurements**

- **Formation testers**

Measure how easily fluids move through a specific part of the rock. In the testingprocess, the part is isolated and fluid is slowly drawn out from it. After that, the pressure is let to return to a stable level. **[1]**

- **Well tests**

The same procedure as that used for formation testing is used during well testing.

2.3.2.1. Pore pressure

Pore pressure is the pressure of the fluid in the formation. After production, its value can decrease significantly from one layer to another.

The pore pressure also strongly influences the state of stress in a formation and is therefore a critical piece of information for designing hydraulic fracturing treatments. **[1]**

- **Pore pressure measurement**

In addition to being measured by well tests, pore pressure can be measured by formation testers.

Conclusion

Both the petrophysical and geomechanical evaluations are indispensable while planning for a successful hydraulic fracturing job since its parameters are mainly based on the formation and reservoir properties.

Chapter Three
Hydraulic Fracturing Design

Chapter Three: Hydraulic Fracturing Design

Introduction

Since its commencement in the late 1940s, Hydraulic fracturing has changed how we harness energy and became a primary engineering tool for improving well productivity. It involves creating a conductive channelto bypass near-wellbore damage or act as a control measurement for sand production. Fracking is considered to be a complex operation, its complexity lies in it being tied to diverse disciplines such as production engineering, rock mechanics, fluid mechanics, selection of optimum materials and operational disciplines all while taking into account field and well limitations. **[1]**

This chapter aims to introduce hydraulic fracturing, the execution fromstart to finish including the design and its evaluation, the fluid and proppant selection, equipment, pumping schedule, calibration... etc.

3.1.Objectives of hydraulic fracturing

In general, hydraulic fracture treatments are used to increase the productivity index of a producing well or the injectivity index of an injection well.

Hydraulic fracturing serves various purposes, such as enhancing the flow of oil or gas from reservoirs with low permeability, restoring wells that have suffered damage, establishing connections between natural fractures and the wellbore, reducing pressure drops around the well to prevent sand production, improving the placement of gravel-packing sand,minimizing issues with asphaltene and/or paraffin deposition, expanding the drainage area, and linking the entire vertical span of a reservoir to a slanted or horizontal well. Most hydraulic fracturing treatments are carried out for these specific reasons. **[17]**

3.2.Elements of hydraulic fracturing

3.2.1. The physics of hydraulic fracturing

The dimensions and alignment of a fracture, along with the pressure required for its formation, are influenced by the in situ stress field of the formation. This stress field is characterized by three primary compressive stresses that are mutually perpendicular (see figure 3-17).The values and directions of these three principal stresses are influenced by the tectonic conditions in the area, along with factors such as depth, pore pressure, androck properties. These factors play a crucial role in determining how stressis transmitted and distributed among formations. **[19]**

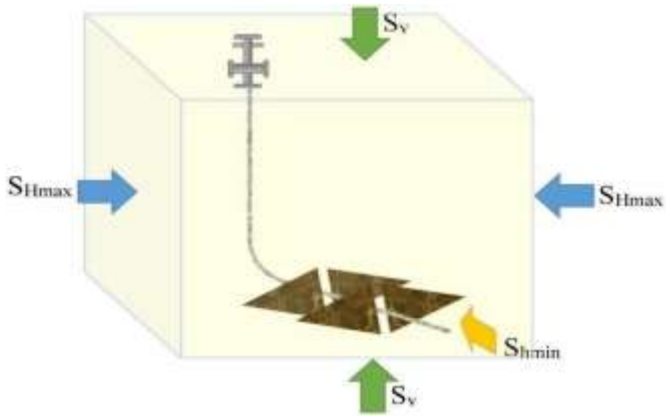

Figure 3-17 In situ stresses and hydraulic fracture propagation.

The three principal compressive stresses are a vertical stress and a maximum and minimum horizontal stress Hydraulic fractures open in the direction of the least principal stress and propagate in the plane of the greatest intermediate stresses. **[19]**

3.2.2. Post fracture initiation

At the surface, a sudden pressure drop signals the initiation of a fracture as the fluid penetrates the fractured formation. Breaking the targeted interval requires the fracture initiation pressure to surpass the sum of the minimum principal stress and the tensile strength of the rock. Determining the fracture closure pressure involves allowing the pressure to decrease until indicating that the fracture has closed again (Figure 3-18). Engineers ascertain the fracture reopening pressure by pressurizing the zone until a pressure leveling suggests the fracture has reopened. Both closure and reopening pressures are influenced by minimum principal compressive stress. **[19]**

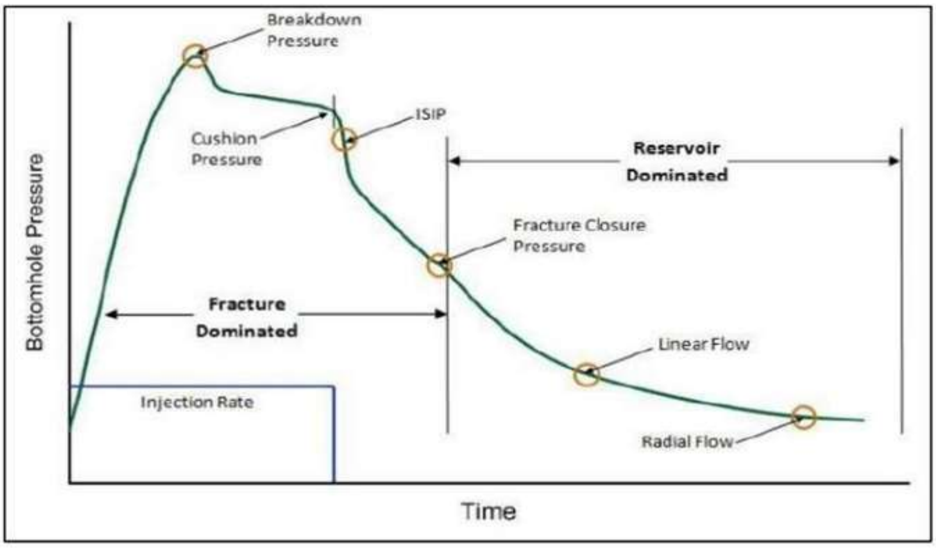

Figure 3-18 Evolution of Hydraulic Fracturing Pressure Curve with time.

Chapter Three: Hydraulic Fracturing Design

During a stimulation treatment, engineers pump fluid into the targeted stimulation zone at a prescribed rate, and pressure builds to a peak at the breakdown pressure, then it drops, indicating the rock around the well has failed. Pumping stops and pressure decreases to below the closure pressure.

Following fracture initiation, pressure is applied to the zone for the scheduled stimulation treatment. Throughout this treatment, the zone is pressurized to the fracture propagation pressure, surpassing the fracture closure pressure. The net pressure, indicating the sum of frictional pressure drop and fracture-tip resistance to propagation, is determined by the difference between these two pressures. **[19]**

3.2.3. Keeping fractures open

Throughout this process, the zone undergoes pressurization until it reaches the fracture propagation pressure,exceeding the fracture closure pressure. The net pressure, encompassing the frictional pressure drop and the fracture-tip resistance, leads to fracture growth, establishing a width for the fracturing slurry—composed of fluid and proppant. Once pumping concludes, internal pressures in the fracture decline, leading to closure. **[19]**

The stimulation treatment is considered done either upon completion of the scheduled pumping or when a sudden rise in pressure signals a screenout occurrence. A screen out refers to a blockage formed by the bridging—accumulation, clumping, or lodging—of proppant across the fracture width, impeding fluid flow into the hydraulic fracture. **[19]**

3.3.Design considerations and primary variables

3.3.1. Design goals

Traditionally, the focus in fracturing low-permeability reservoirs has been on the productive fracture length (xf). However, in higher permeability reservoirs, the conductivity (kfwf) becomes equally or more crucial, and a balance is struck between the two factors, considering the formation permeability (k). **[1]**

$$\boldsymbol{Cfd = \frac{Kf\,Wf}{K\,Xf}} \qquad \textbf{(3-21)}$$

Where,

Cfd: fracture conductivity dimensionless

Kf: fracture permeability (mD)

K: formation permeability (mD)

Wf: propped fracture width (ft)

Xf: fracture half-length (ft)

This dimensionless conductivity is the ratio of the ability of the fracture tocarry flow divided by the ability of the formation to feed the fracture. In general, these two production characteristics should be in balance. **[1]**

The conductivity of the fracture can be reduced during the life of the wellbecause of:

- Increasing stress on the Proppant agents.
- Proppant crushing.
- Damage resulting from gel-residue or fluid-loss additive.**[3]**

3.3.2. Design primary variables

The primary design variables in hydraulic fracturing include fracture half-length, which affects the contact area with the reservoir, and fracture width, which influences fluid and proppant flow. Proppant concentration and distribution are crucial for keeping fractures open and maintaining conductivity. Fluid viscosity impacts fracture creation and propagation, while injection rate (pump rate) determines the pressure and extent of fracturing. Pad volume, sets the stage for proppant placement. Fluid efficiency, the percentage of fluid that stays in the fracture, these are all important factors in optimizing fracturing treatments for enhanced production and economic returns.

3.4.Fracturing fluids types and components

The fracturing fluid is an essential component of the hydraulic fracturing procedure. Its primary roles include opening the fracture and transporting the propping agent along its length. The viscosity characteristics of a fluid are typically considered the most essential. For hydraulic fracturing to be effective, the fluids must possess additional qualities. **[2]**

3.4.1. Water-base fluids

Water-based fluids are the most widely used fracturing fluids because oftheir low cost, high performance, and ease of handling. **[3]**

- **Polymers**

Water-soluble polymers can create a viscous solution suitable for suspending particles. Polymers are molecules that have a high molecular weight.

Guar gum was among the first polymers used to thicken water forfracturing. **[2]**

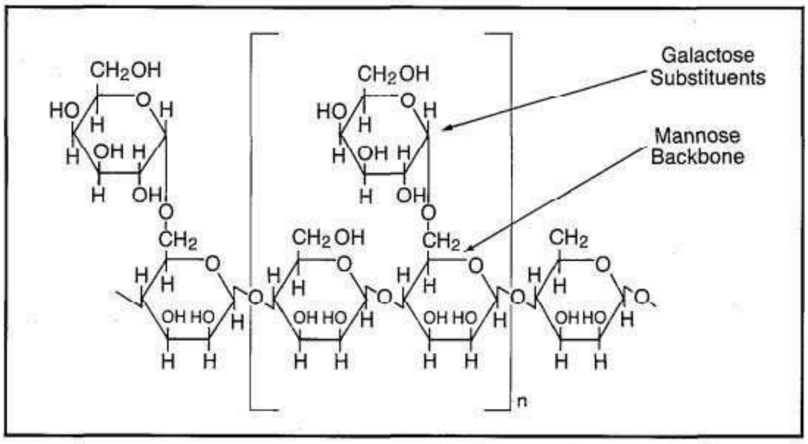

Figure 3- 19 Structure of Guar [2]

The process used to produce guar powder does not completely separatethe guar from other plant materials, which are not soluble in water. To minimize this problem, guar can be derivatized with propylene oxide toproduce HPG. The additional processing and washing removes much ofthe plant material from the polymer, so HPG typically is less damaging and more stable. Another derivative is CMHPG. **[21]**

- **Crosslinkers**

Gels are crosslinked into a network via intermolecular connections to dramatically increase the elastic response of the fluid and develop enoughviscosity to transport proppant through the hydraulic fracture. Polymer chains are interconnected at the crosslink sites as shown in the figure. **[21]**

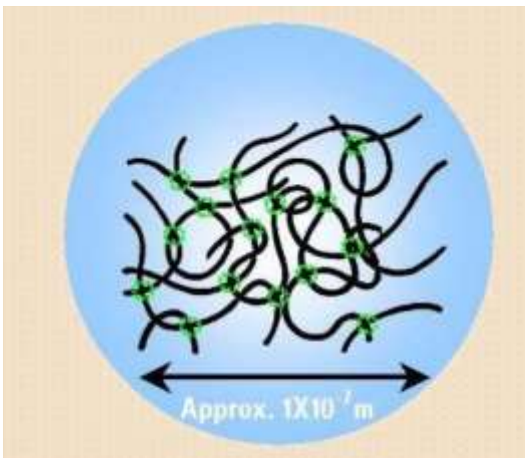

Figure 3- 20 An Illustration of the Cross Linked Fluid on the Microscopic Level [21]

A number of metal ions have been used to crosslink water-soluble polymers.Borate, Titanium (IV), and Zirconium (IV) are by far the mostpopular. Aluminium (IJI) is sometimes used to crosslink CMHPG. [2]

The characteristics of the commonly used crosslinked fluids are summarized in Table:

Table 3- 3 Characteristics of the Commonly Used Crosslinked Fluids.

Borate	Ti and Zr Complexes
Fast crosslinking	Controlled crosslinking rate
Crosslinking reversible	Crosslinking permanent
No shear degradation	Shear-sensitive
Upper temperature limit: 200° to 225°F	Upper temperature limit: 300° to 325°F
High friction pressure	Friction pressure reduced by delayed crosslinking
pH 8 to 10 required concentration	Variable pH

3.4.2. Oil-base fluids

Heavy oils were initially utilized as fracturing fluids due to their supposedless harmful effect on hydrocarbon-bearing formations compared to
Water-based fluids. Their intrinsic viscosity makes them more appealingthan water. Oil-based fluids are costly and difficult to handle. Therefore, they are now used exclusively in formations that are particularly water-sensitive. **[1]**

3.4.3. Acid-based fluids

Acid fracturing is a well stimulation procedure that injects HCl at high pressure into a carbonate formation to fracture or open existing fractures.As the acid runs along the fracture, parts of the fracture face dissolve. **[1]**

3.4.4. Multiphase fluids

Standard water-base, oil-base, or acid-based fluids can sometimes benefitfrom adding a second phase to improve their characteristics. Gas is addedto the fluid to produce foams.
Oil and water are combined to generate emulsions. **[20]**

3.4.5. Fracturing fluid Components

- **Gelling Agent**

Gelling agents are added to the Fracturing fluid to increase viscosity, which increases fracture width and improves proppant movement while decreasing friction pressure. In addition, the chemical structure of gelling agents enables crosslinking. Guar was one of the earliest polymers utilizedto vicosify water in fracturing applications. It is a long chain, high molecular weight polymer made up of mannose and galactose sugars. Theguar polymer has a very high affinity for water. When the powder is added to water, guar particles swell and hydrate. **[20]**

- **Additives**

A fracturing fluid is more than just a liquid and viscosifying material, likewater and HPG polymer or diesel oil and aluminum phosphate ester polymer. Additives are used to regulate pH, manage microorganisms, improve high-temperature stability, break the fluid after use, minimize formation damage, and limit fluid loss.

Table 3- 4 Additives Types and Their Purpose. [3]

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

The fracturing process involves combining the previous chemistry withsand, mixing, and pumping equipment to achieve the required propped fracture. The fracturing fluid or additive created in a laboratory settingmay not always be applicable in the field.

Quality assurance procedures must be applied to fluids for a comprehensive fluid evaluation. **[2]**

3.5.Proppant Types and properties

A proppant is a solid material, typically sand, treated sand, or a manufactured ceramic material that is designed to prevent and keep an induced hydraulic fracture open during and after a fracturing treatment sothat the fracture does not collapse and close. **[22]**

3.8.1. Types of proppant

Because propping agents play a critical role in keeping the fracture openafter the pumps are turned off and the fracture starts closing, the optimalpropping agent should possess strength, resistance to crushing and corrosion, low density, and be easily accessible at a low cost.

- **Silica Sand**

Due to its relatively low cost and availability, Sand is the most commonlyused proppant, especially in reservoirs with a low closure pressure of less than 6000 Psi. **[3]**

- **Resin-coated proppant**

Resin-coated proppant, usually silica sand coated with resin, serves two primary purposes. First, it enhances the resistance to crushing of silica sand particles by spreading the pressure load more uniformly. Second, it helps maintain the integrity of fractured pieces subjected to high closure stress from downhole pressure and temperature. This prevents broken pieces from flowing into the borehole and ensures they don't return to the surface during flowback production operations.

There are two main types of resin-coated proppants: precured and curable. In the precured resin-coated proppant technology, resin is coated onto silica sand grains, and the resin is fully cured before injection into fractures. Conversely, the curable resin-coated proppant technology involves incomplete curing of the resin before use. During downhole pumping, the curing process is completed in the fractures due to the downhole pressure and temperature. **[22]** It is used in operations where the closure pressure is less than 8,000 Psi.**[23]**

- **Manufactured Ceramic Proppant**

It involves the use of manufactured ceramic materials typically nonmetallurgic bauxite or kaolin clay. In the manufacturing process, theceramic proppant is prepared by sintering bauxite mixed with other additives, and the mineral composition of ceramic proppant is aluminumoxide, silicate, and iron, with some titanium oxide.

Ceramic proppants are generally uniform in round shape and character, which gives the proppant much higher strength than quartz sand and RCSso that it is suitable for the fracturing of deep oil and gas reservoirs with high closure pressure. **[22]**

There are three main types of ceramic proppant: Light weight (LWP),Intermediate Strength (ISP), and high Strength (HSP) **[23]**

- **Rod Shaped Proppant**

This type is a new propping agent which integrates two main features: enhanced proppant pack conductivity and improved proppant flowback control. **[23]**

Figure 3- 20 Rod Shaped Proppant [23]

3.8.2. Proppant properties

The main Proppant properties that affect fracture conductivity include:

- **Shape and Size**

Proppant shape is typically defined by two main attributes: roundness and sphericity. Roundness refers to the smoothness of the proppant, while sphericity describes how closely it resembles a sphere.

The size of the proppant is a crucial factor in the design process, determined by factors such as stress levels, desired conductivity, andachievable fracture width. To ensure quality control, proppant size distribution is tested using the sieve analysis. **[22]**

- **Stress**

Proppants need to be selected to withstand closure stress without crushing.And to do so, crush resistance tests are required.

The small particles that break off the surface of proppants reduce pack porosity and permeability and cause major degradation in the conductivityof proppant packs. When proppant fines migrate down the proppant pack toward the well bore, they accumulate and reduce flow capacity. **[22]**

- **Pack Rearrangement**

Proppant pack rearrangement in the fracture can cause a significant reduction in propped width, which can also lead to reduced fracture flow capacity and connectivity to the wellbore. **[22]**

- **Embedment**

Proppant embedment occurs as a result of the proppant embedding into the fracture face, especially in soft shale formations, leading to reduced fracture width and lower fracture flow capacity. In the embedment process, the proppant partially or completely sinks into a formation through displacement of the formation around the grain. **[22]**

- **Flowback**

Proppant flowback is the movement of proppants back to the wellbore.The higher the velocity of the pump, the more the chance of flowback happening.

There are many mechanisms for flowback control, from which are: Rod-shaped proppant, Fibers and Resin-coated proppant.

- **Fracture Conductivity**

Fracture conductivity is determined by the proppant type and size, fracturing fluid system, and placement technique. **[22]**

3.6.Surface main equipment of hydraulic fracturing

Surface equipment for hydraulic fracturing is essential for the successful execution of fracturing operations. This equipment comprises a range of specialized components and machinery designed to handle the complex processes involved in hydraulic fracturing. The main components include:

3.9.1. Hydration unit ‘Precision Continuous Mixer’

The precision continuous mixer is a machine that mixes dry polymer additives with water from tanks to make a linear gel. It includes C-pumps,tanks, a polymer storage bin, and four liquid additive systems. This equipment is designed to save both time and money on-site by reducing delays between mixing and pumping.

Figure 3- 21 Precision Continuous Mixer 'PCM' [25]

3.9.2. The blender: Programmable optimum density

Blenders are the heart of the Hydraulic Fracturing job, they precisely combine proppant, fracturing fluid, and additives in a vortex at a set density in an automated mode. This density is measured by a radioactive densitometer, which gauges the absorption of gamma rays by the fluid. Detectors then capture these gamma rays transmitted through the fluid, converting the signal into an electrical one. An electronic panel processesthis electrical signal to indicate density. Subsequently, the slurry is pumped through the low-pressure line of the manifold. **[1]**

Figure 3- 22 POD Blender [25]

3.9.3. High pressure pumps

The fracturing pump has the following major components:

A reciprocating pump sends the fracturing fluid at high pressure and rate to the well in the high pressure line of the missile. High-pressure pumps should be installed close enough to the blender so that the discharge pumps on the blender can easily feed slurry to the intake manifolds on thepumps. **[3]**

Components: engine, transmission, power end, fluid end, lubricationsystem, suction manifold, suction stabilizer, pneumatic systems and hydraulic systems. **[25]**

Figure 3- 23 High Pressure Pump [25]

3.9.4. Treatment Control Vehicle

Known as ‘FRAC CAT’, it is a PC-based system specialized in data acquisition and control, tasked with monitoring pumping, mixing, and blending equipment**. [3]**

SMS-505 FracCAT Skid

Figure 3- 24 Treatment Control Vehicle 'TCV' [25]

3.9.5. Treating iron

High-pressure pipes and connections called treating iron, used on a treatment between the high pressure pumps and the wellhead isolator. **[3]**

3.9.6. Annulus pump

It applies pressure within the annulus to maintain underbalanced pressure,which helps prevent the collapse of tubing under the high pressures experienced during hydraulic fracturing operations. **[3]**

3.7.Fracture Geometry

-Length (L): Radial distance from the wellbore to the outer tip of afracture penetrated by the well.

-Width (W): It is the distance between the two vertical faces of the fracture along the normal direction. It can be determined by acousticimaging and conventional logs.

-Height (H): the distance measured vertically between the two pointsassociated with a zero thickness. It can be determined by thermolog.

3.11.1. Fracture modelling

Fracture geometry is influenced by various factors such as initial reservoir stress conditions and rock properties. To model this complex system, Bi- and Tri-dimensional models are utilized, relying on simplifying assumptions to approximate realistic values. **[3]**

- **Two-Dimensional Fracture Propagation Models**

a) The Perkins-Kern-Nordgren and Khristianovic-Geertsma-de Klerkmodels

The PKN geometry is typically applied when the fracture length significantly exceeds the fracture height, as depicted in Figure. Conversely, the KGD geometry, illustrated in Figure 3-34, is utilized when the fracture height surpasses the fracture length. In some formations, either model can effectively guide hydraulic fracture design. The key lies in using models, regardless of type, to inform decisions rather than striving for precise dimension calculations. Design evaluations should consistently compare actual outcomes with model predictions. Through "calibrating" the 2D model with field data, adjustments can be made to enhance the success of stimulation treatments. **[32]**

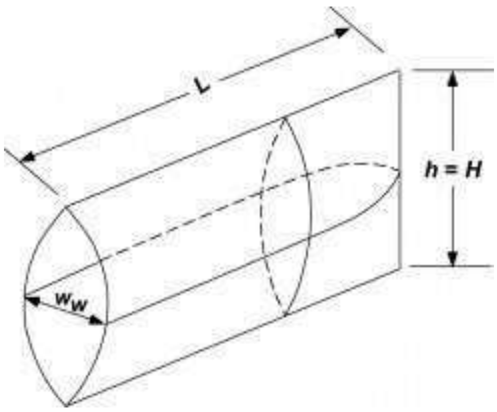

Figure 3- 25 PKN geometry for a 2D fracture. [32]

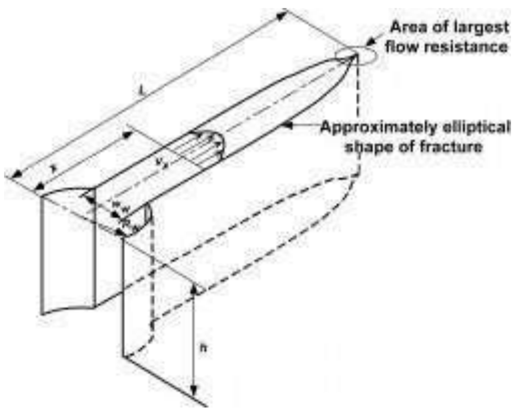

Figure 3- 26 KGD geometry for a 2D fracture. [32]

b) Radial Model

In this scenario, the height of the fracture equals its width. Both the PKN(1961) and GDK (1969) methods have examined radial fractures, which develop in an open environment, originating from a point source. This model is applicable when there are no obstacles hindering vertical growthor in the case of a horizontal fracture. **[33]**

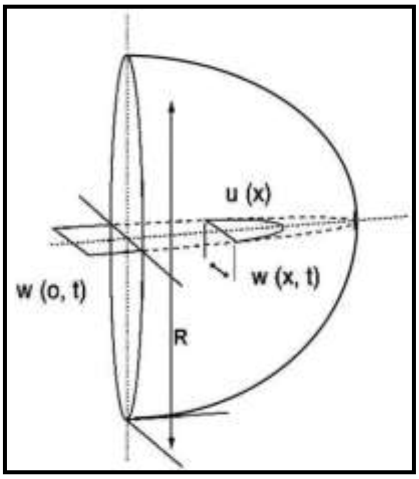

Figure 3- 27 Radial Model [36]

- **Three-dimensional fracture propagation models**

Most fracture design engineers prefer to utilize pseudo-three-dimensional(P3D) models. These models offer advantages over 2D models in most scenarios. Unlike 2D models, P3D models factor in the data for the pay zone along with all the rock layers above and below the perforated interval. Consequently, P3D models can more accurately compute the distribution of fracture height, width, and length. **[32]**

3.8. Hydraulic fracturing design

3.12.1. Data collection

- **Reservoir information**

It includes: (In-situ Stresses, type of formation & lithology, permeability& porosity, initial Reservoir Pressure & BHST, rock mechanical properties, the skin factor and damage mechanism. **[35]**

- **Well information**
  - Hole survey
  - Completions (casing & tubing)

- Perforations

3.12.2. Perforations

Perforating is the only way to establish conductive tunnels that link oil and gas reservoirs to steel-cased wellbores which lead to surface. **[30]** However, perforating also damages formation permeability around perforation tunnels. This damage and perforation parameters- formation penetration, hole size, number of shots and the angle between holes- havea significant impact on pressure drop near a well and. Optimizing these parameters and mitigating induced damage are important aspects.

Many perforating techniques exist: Shaped Charge, bullet perforating, abrasive jetting, or high-pressure fluid jetting. **[30]**

$$Ppf = \frac{0.2369\, Q^2 \rho}{D^2\ C^2\ N^2} \qquad \textbf{(3-22)}$$

P_{pf} = Perforation Friction (psi)

Q = Flow rate (bpm)

ρ = Fluid density (lb/gal)

D = Diameter of perfs (inches)

N = Number of perfs taking fluid

C = Discharge Coefficient 0.6

3.12.3. Fluid selection

The major considerations for fluid selection are viscosity (for width, proppant transport or fluid-loss control) and cleanliness (after flowback) to produce maximum post fracture conductivity. Other considerations thatmay be important for specific cases are: **[1]**

- Compatibility with reservoir fluids and reservoir rock
- Compatibility with reservoir pressure (e.g., foams to aid flowback inlow-pressure reservoirs)
- Surface pump pressure or pipe friction considerations
- Cost
- Compatibility with other materials
- Safety and environmental concerns

3.12.4. Proppant selection

When selecting proppant, it's important to consider its conductivity underin-situ stress conditions, which affects proppant permeability.

Additionally, proppant size plays a crucial role. It must align with proppant admittance criteria, both within the perforations and inside the fracture. Lastly, determining the maximum in-situ proppant concentration at shut-in is essential as it dictates the extent to which the hydraulic width created during the fracture treatment will be maintained as propped width once thefracture closes. **[1]**

3.12.5. Fracture model selection

The fracture propagation model is chosen based on in situ stresses and laboratory studies to accurately represent formation properties and pressure behavior. Clearly, a fracture geometry model is used to producethe final schedule. Using a calibrated fracture geometry model allows fornumerous scenarios to determine the best treatment for a given application. **[3]**

3.12.6. Diagnostic testing

Before the main treatment starts, there may be a series of diagnostic teststhat are done to evaluate the formation properties and design the final fluid volumes for the main treatment.

3.10.5.1. Initial Breakdown and Instant Shut-In Pressure

This test is often done with either water or acid. Recording the first break-down pressure and instant shut-in pressure (ISIP) is important for understanding rock hardness and in-situ stress levels. The ISIP taken at this moment should be compared to the final ISIP once the primary treatment is completed. **[34]**

3.10.5.2. Step-Rate Test

This test involves injecting into the formation at various “constant” rates both below and above the pressure required to fracture the well. The test provides two data points. The first is the fracture parting/closure pressureand the second is the fracture extension pressure or pressure required to drive the fracture deeper into the formation. **[34]**

3.10.5.3. Diagnostic Fracture Injection Test Calibration & redesign

This test involves injecting a small volume of clean fluid into the formation and watching the decline for various changes in the pressuredecline response. This pressure decline gives an indication of fracture closure pressure, secondary pressure-dependent leakoff, and height recession (critical stress) behaviors. **[34]**

3.10.5.4. Minifrac or Datafrac

This test evaluates the fluid efficiency and leakoff coefficient for the primary treatment pad design. It's important to use the exact fluid and ratefor the intended treatment. To fracture rock, a huge amount of fluid is often used to contact the majority of the surface. **[34]**

3.12.7. Pumping schedule

A fracturing job has several stages, which falls as follow:

- **Pre-pad:** low viscosity fluid (linear gel) is pumped before the fracturingtreatment to initiate the fracture. This fluid cools the casing and tubularsand reduces the high temperatures that may degrade the fracturing fluid.
- **Pad Stage:** a higher-viscosity fluid is pumped down the borehole at highrate leads to breaking down the formation.
- **Slurry:** is a mixture of the fracturing fluid and proppant that keeps the fractures open and should have a compressive strength to bear stresses from the formation, normally it consists of several sub-stages each withdifferent proppant concentration.
- **Flush:** Clear fluid (linear gel) is pumped to displace the slurry out of thewellbore. **[3]**

3.12.8. Folds of increase FOI

FOI for steady-state flow can be defined as the post fracture increase inwell productivity compared with pre-fracture productivity.

$$\boldsymbol{FOI = \frac{Q'}{Q^0} = \frac{Ln\, {}^{re}/_{rw}}{Ln^{re}/_{rw} + Sf}} \qquad \textbf{(3-23)}$$

Where**,**

Q'= the flow rate of the Post-frac (stb/day-psi);

Qo= the flow rate of thePre-frac (stb/day-psi);

re= the well drainage or reservoir radius;

rw= thenormal wellbore radius;

Sf = is any prefracture skin effect

Conclusion

The propagation of hydraulic fractures obeys the laws of physics, in situstresses control the pressure and direction of fracture initiation and growth. The engineering part lies in well understanding of these uncontrollable factors in order to better monitor and regulate the controllable ones and achieve a successful HF job.

Chapter Four
Net Present Value Modeling

Introduction

As it was mentioned in the previous chapter, Hydraulic fracturing is a complex operation with many parameters that can control and influence its success. For that theNet Present Value concept has been introduced to get the optimum of these linked variables.

In this chapter, the Net Present Value concept will be introduced, along with the effect of HF parameters on it and the GRG optimization tool used in our study.

4.1. NPV in Hydraulic fracturing:

This evaluation method assesses the economic viability of fracking projects by comparing the present value of expected revenues from oil or gas production with the present value of investment costs, operational expenses, etc…

The NPV is directly related to Xf and indirectly to other factors such as formation andwell characteristics, fracture propagation model, fluid, and proppant qualities. That is,to maximize the NPV, one must optimize these diverse parameters. **[37]**

NPV can be optimized considering fracture parameters, well production, and treatment total costs.

A positive NPV indicates that the project is expected to generate more value than itscosts, making it financially successful.

4.1.1. Quantifying the NPV

The Net Present Value is determined by the following formula:

NPV= $\sum_{n=1}^{N} \frac{Rn}{(1+i)^n} - Cost$ **(4-24)**

Where,

R: Revenues

n: Period of time yearly

i: Discount rate

In the case of HF:

Cost is defined as follow:

$CHF = nf(\ FC + Prp * Mp + Vf * PrF) + AC$ **(4-25)**

Where,

Mp is the proppant mass [kg],

P rp is the proppant price [$/kg],

P rF is the fluid price[$/m3],

VF is the volume of the fluid [m3],

Nf is the number of fractures,

FC is the cost of equipment, e.g. pumping [$],

AC is the fixed and miscellaneous costs [$].

AC is considered 0 in this case.

i: The discount rate, also known as the interest rate, exchange rate, or cost of money,is used to adjust all future cash flows to the current dollar. In our study the discount rate is negligible.

The rules of thumb for NPV projects are as follow:

1. Accept independent projects if the NPV is positive.

2. Reject any project that has a negative NPV.

3. Pick the highest positive NPV in projects that would add the most value.

4. NPV must be considered along with other capital budgeting criteria to makeeducational decisions.[41]

4.1.2. Hydraulic fracturing variables affecting the NPV:

To better understand how each of the factors mentioned above influence the fracking job and the NPV, the figure below offers a comprehensive explanation:

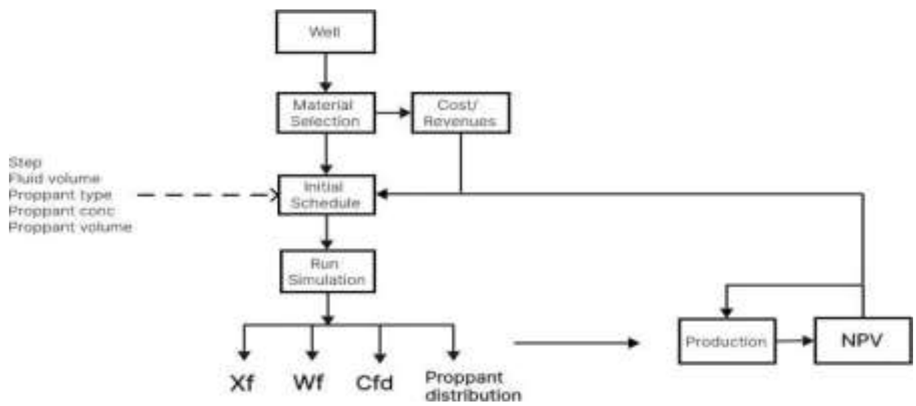

Figure 4- 28 Flow Chart of the NPV Components.

4.1.3. Factors affecting Revenues

In the oil and gas industry, revenue refers to the amount of money earned from everyday business activities, such as selling hydrocarbons and providing services tooperating firms. For example, selling hydrocarbons contributes significantly to an operational company's revenue. It's important to distinguish between revenue and profit. Revenue refers to a company's gross earnings and excludes project expenses.

a. Production:

The basic assumption for the pseudo-steady-state production model is that the pressure at the reservoir boundary declines at a constant rate with time.

The following equation is used to determine the production rate:

$$q = \frac{kh\,(p_e - p_{wf})}{141.22\,\mu\,\mathrm{B}\,\left[log_e\left(\frac{r_e}{r_w}\right) + S\right]} \qquad \textbf{(4-26)}$$

The next equation is used to estimate the production rate from a hydraulically fractured well:

$$q = \frac{kh(P^2 - Pwf^2)}{142\mu g\;Zg\;T} * \frac{1}{\ln\left(\frac{0.472\,re}{Xf}\right) + (Sf + ln\frac{Xf}{rw'})} \qquad \textbf{(4-27)}$$

- **Inflow Performance Relationship:**

IPR is a curve of producing rates plotted against well bottomhole pressure for oil, water and gas wells. It shows productive capacity and well performance, it is used for well nodal analysis for production systems design, analysis and optimization.

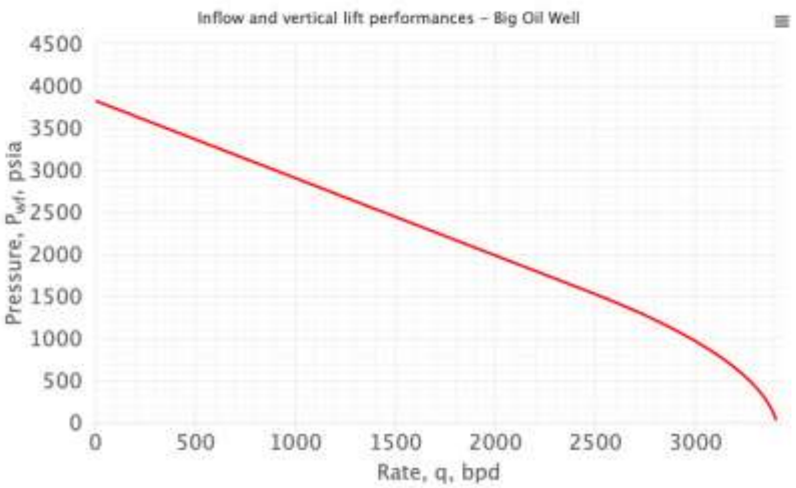

Figure 4- 29 Inflow Performance Relationship

- **Decline Curve Analysis:**

Used to estimate reservoir performance based on historical production data, it plots the production rate versus a period of time.

There are mainly three DCA models, the one used in this study is the hyperbolic with the following equation:

$$\mathbf{Q} = \frac{\mathbf{qi}}{(\mathbf{1+bDit})^{\frac{1}{\mathbf{b}}}} \qquad \textbf{(4-28)}$$

Where,

Qi: The initial rate.

Di t: Initial decline rate at t time.

b: The degree of curvature of the line.

b. Price of Hydrocarbon

Crude oil prices are dictated by worldwide supply and demand. Economic growth is a major factor influencing petroleum product (and thus crude oil) demand. Growing economies result in increased need for energy in general, particularly for moving commodities from producers to consumers.

4.1.4. Factors affecting costs

Can be divided into two parts, controllable and non-controllable factors.

a. Non controllable factors

- **Formation properties:**

Characteristics of the reservoir are non-controllable, they affect deeply directly or indirectly the hydraulic fracturing parameters thus the NPV. The main affecting factors include:

- **PVT properties:**

Reservoir fluid properties like bottom-hole temperature, oil viscosity, GOR and specific gravity influence the flow behavior of these fluids consequently leading to change in production rates and eventually the ultimate recovery, plus the selection offracturing fluids depends on their compatibility with those of the formation.

- **Geomechanics properties:**

Rock properties have an important role in impacting the controllable factors and the NPV. The principal in situ stresses affect the net pressure that needs to be applied, andthe propagation of the fracture by controlling the fault regimes in the area, in addition to controlling the choice of the appropriate proppant type depending on the closure stress.

Other rock characteristics such as the strength, deformability, elasticity and failure arealso important to consider while executing the job.

- **Reservoir properties:**

Reservoir characteristics have a significant impact on hydraulic fracturing, they control the proppant type used, the hydrocarbon production and the completion used.

b. Controllable factors

- **Fluid properties:**

The major considerations for fluid selection are usually viscosity (for width, proppant transport or fluid-loss control) and cleanliness to produce maximum postfracture conductivity which are controlled by the gel loading.

Another important factor is the fluid volume which is linked to the pad volume which ties to the efficiency of the fluid by:

$$\mathbf{V\ pad = Vi\ \left(\frac{1-\eta}{1+\eta}\right)} \qquad \mathbf{(4\text{-}29)}$$

Excessive fluid loss limits fracture propagation because of the accumulated insufficient fluid volume within the fracture. As a result, the fracturing fluid with the lowest fluid loss (leak-off) coefficient should be used.

A fluid viscosity that is too high can cause excessive injection pressure during the treatment. However, in some circumstances, other factors may also be important. These include compatibility with reservoir fluids and rock, compatibility with other materials, compatibility with operational pressure and temperature, and safety and environmental considerations. [38]

- **Proppant properties:**

Major concerns in proppant selection are the strength of the proppant which should be greater than the minimum horizontal stress and the proppant size, permeability of the sand increases with bigger sizes but perforation diameters should be kept into consideration, which concludes that proppant selection depends highly on formation and well characteristics. The figure below 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. **[38]**

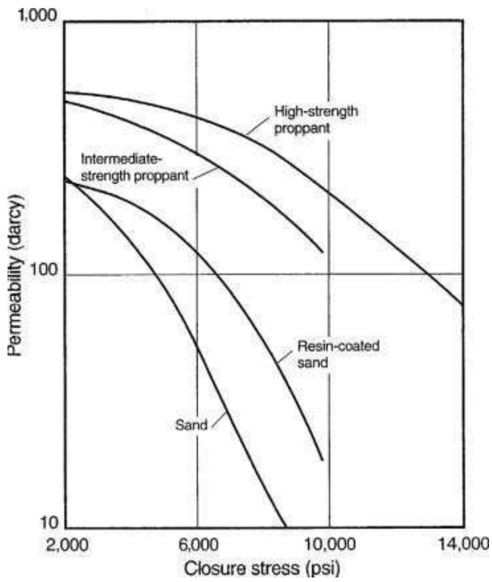

Figure 4-30 Effect of fracture closure stress on proppant pack permeability

Another important point is, concentrations of the proppant. Higher proppant concentrations can lead to increased fracture conductivity, thus higher production rates of hydrocarbons. The optimal proppant concentration can vary depending on the reservoir's geology, such as its permeability, porosity, and fluid properties. A concentration that matches the reservoir's characteristics well can enhance NPV.

- **Fracture geometry**

Fracture height

This is the most challenging characteristic to quantify during hydraulic fracturing design. To compute fracture height. However, for practical purposes, one can rely on existing 2D models. To properly construct a fracture therapy using a 2D model, it's important to accurately estimate the fracture height.

Fracture width

The fracture width can be computed using the following formula, this calculation aids in designing efficient fracturing treatment to well performance.

$$Wf = 9.15^{\frac{1}{2n+2}}\, 3.98^{\frac{n}{2n+2}} \left[\frac{1+2.14n}{n}\right]^{\frac{n}{2n+2}} K^{\frac{1}{2n+2}} \left(\frac{qi^n\, hf^{1-n}\, Xf}{E'}\right)^{\frac{1}{2n+2}} \qquad \textbf{(4-30)}$$

The average width is calculated as below:

$$Wa = {}^{\pi}/_{5}\, Wf \qquad \textbf{(4-33)}$$

Fracture half-length Xf

The Half-length can be obtained using this correlation that couples average width with the fracture height, initial flow and other parameters.

$$\boldsymbol{Xf = \frac{(Wa+2Sp)qi}{4\,Ci^2\pi\,hf}\left[\,exp\,(\beta^2)erfc\,(\beta) + \frac{2\,\beta}{\sqrt{\pi}} - 1\right]} \qquad \textbf{(4-31)}$$

- **Fracture Conductivity**

Fractured well productivity is determined by two steps: (1) collecting fluids from formation and (2) transferring them to the well bore. Typically, the first step's efficiency is determined by fracture dimensions (length and height), whereas the second step's efficiency is influenced by fracture permeability.

- **Proppant Distribution**

Proppant distribution is the amount of proppant in one cubic feet, it is controlled by the concentrations of proppant.

4.2. The GRG method

The Generalized Reduced Gradient (GRG) method is an optimization technique used to find the best solution for a problem by iteratively adjusting the solution based on the direction that reduces the cost or increases the profit the most. Starting with an initial guess, GRG modifies the solution step by step until the changes become very small, indicating that it's close to the optimal solution. This method is particularly useful for nonlinear problems.

- Objective Function and Constraints: The GRG method is used to minimize (or maximize) an objective function subject to constraints. The objective function is the quantity that needs to be optimized (minimized or maximized), while the constraints are conditions that the solution must satisfy.
- Iterative Process: The GRG method is an iterative process that starts with an initial feasible solution. A feasible solution is one that satisfies all the constraints of the problem.
- Reduced Gradient: At each iteration, the algorithm calculates the reduced gradient of the objective function with respect to the variables. The reduced gradient measures the rate of change of the objective function when one unit change is made in the variable values, while keeping the constraints satisfied.
- Search Direction: Based on the reduced gradient, the algorithm determines a search direction that suggests how to adjust the variable values to improve the objective

function without violating the constraints.

- Line Search: Once the search direction is determined, the algorithm performs a line search to find the optimal step size along that direction. This step ensures that the solution moves towards the minimum (or maximum) of the objective function while staying within the feasible region defined by the constraints.
- Update Variables: After finding the optimal step size, the algorithm updates the variable values accordingly and checks if the updated solution still satisfies all the constraints. If not, additional adjustments are made to ensure feasibility.
- Convergence: The process continues iteratively until certain convergence criteria are met, such as reaching a specified tolerance level for the objective function or the variables.

4.3.1. GRG in Excel:

The figure below shows the Solver function in Excel from where the optimization method is chosen (in our case the GRG). In this window, one get to choose the objective function, to maximize or minimize it, the constraints and variables.

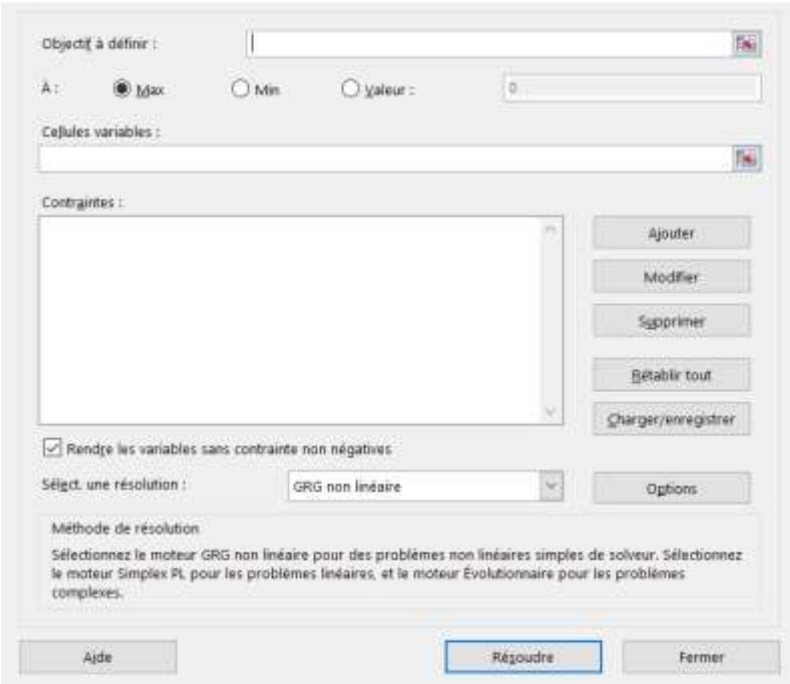

Figure 4- 31 GRG Method in Excel.

This thesis couples the optimization of both revenues and cost, thus the parameters affecting them from Proppant type, concentrations and volume to fluid volume and step rate. To get the optimum of these factors, the GRG method was used by putting PVT, geomechanics and reservoir data as inputs, Proppant and fluid properties as variables and Xf, Wf, Cfd and proppant distribution as constraints.

Conclusion

This chapter discusses the fundamentals of the NPV evaluation method, which is the most commonly used strategy for project analysis. Investors prefer this method because it is easy to calculate and reinvest cash flows.

This chapter also focused on explaining the basics of the GRG method and its use in our study.

Chapter Five

Case Study and Simulation Results

Chapter Five: Case Study and Simulation Results

Introduction

As outlined in the previous chapters, hydraulic fracturing success is based on numerous factors. To achieve optimal stimulation results, it is essential to optimize these parameters. Various optimization strategies exist, including completion optimization, fracture spacing optimization, geometry optimization, treatment parameter optimization, and optimization for different reservoir types.

This thesis focuses on the geometry optimization. The conventional treatment optimization is to obtain optimal treatment parameters in order to maximize the production or minimize cost only, where finding an optimum solution that balances both is rarely considered. That is why our main focus in this study is to develop an optimum case that takes into consideration both cases and offers the highest Net present value.

In this chapter, NPV is used as the optimization objective, the technique developed will be presented and applied to well X, along with the results obtained from the simulation and the NPV analysis.

5.1. Problem definition

Fracture conductivity and geometry are both crucial in determining the success of a fracturing treatment, they are influenced by a variety of factors such as proppant type, size, concentrations, fluid type, gel loading, temperature, formation stress, and so on. And here lies the difficulty in optimizing the job: with so many aspects influencing it, it's challenging to experiment with one factor without affecting another.

The main goal of this thesis is to achieve an optimum productivity hence better NPVby developing a new strategy to choosing the most suitable fracturing design parameters based on various previous data while focusing on maximizing the NPV and not only the production.

5.2. Work flow solution

The first step of the study involved gathering data from past wells on formation parameters, well properties, PVT, fracturing parameters and other factors. These data were organized and analyzed in order to determine whether there was a relationship between these parameters and production, which resulted in the creation of optimum ranges of Xf, Wf, Cf, proppant concentrations, and proppant distribution for production improvement charts. Following that, a tool in Excel was constructed, which uses the data results to achieve an optimal scenario that meets the needs of both the operator and the service firm through optimizing both the revenues and costs.

For the simulation of our strategy well X was chosen, we started with the formation evaluation study where we got the petrophysical and geomechanical data, then it was put in the excel tool to get the results for the optimal case. After that, Petrel was used toget the fracture simulation and schedule for each case, after that the NPV for each case was calculated.

This software takes charts with optimum ranges and sets them as maximum and minimum values that cannot be exceeded; these are the limit values of Xf, Wf, and Cf,and it then begins experimenting with these three parameters to obtain the estimated revenues and minimal cost and NPV.

After that, simulation must be performed; the first step is to build the MEM; for this, the well data is attached to obtain the stress profile and fracture geometry; after that, we can begin thejob design; we select the fluid parameters and proppant parameters, as well as the pumping schedule, to calculate the cost of the entire job; once the revenues and costs are estimated, we can calculate the NPV for each of the three situations and compare them to validate the optimal financial performance of the optimized case.

5.3. Solution Implementation

5.3.1. Data collection

Previous fracturing treatment data were collected, organized and analyzed to be usedfor this study. The main purpose of this step is to determine the main parameters affecting the production.

Building a data-driven revenue- cost model requires a significant number of data (logs, reservoir properties, production, etc.) as inputs, the data used in this study were collected from fifty different oil and gas wells in field Z, the data included reservoir, PVT information and well logs, it was then put in excel where we were able to conclude and plot a set of charts linking the production improvement with the main factors influencing it.

5.3.2. Formation evaluation

5.3.2.1.Petrophysics

To begin, Client Data is provided which is a combination of these raw logs: Gamma Ray, Caliper, Density and Neutron, Resistivity and Sonic logs as the image shows. These set of data is then used to acquire the following parameters:

- **Borehole Quality**

Analyzing borehole quality is done by examining gamma ray and caliper well logs to understand the conditions inside the borehole. Gamma ray readings indicate the type of rock surrounding the borehole, with higher values often signaling shale or clay-rich formations and lower values suggesting cleaner sandstone or limestone. Caliper data, on the other hand, reveals the diameter of the borehole and any irregularities in its shape. By looking for patterns or sudden changes in gamma ray and caliper data, we can identify potential issues such as unstable formations, washouts, or borehole collapse and obtain a clear image of the borehole shape as the image shows.

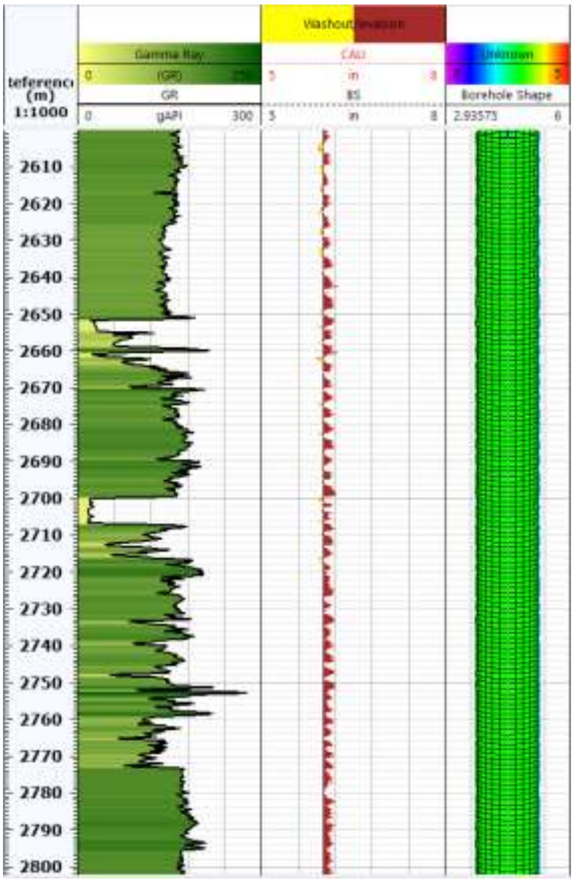

Figure 5-32 Borehole Quality and Shape log.

- **Volume of Shale**

For the first method, the Gamma Ray Index is applied, which compares the GR response of shale to that of clean formations using the equation (2-19)

For the second method, the difference between the neutron and density porosity at the same depth should be calculated, after that the formula (2-20) is applied.

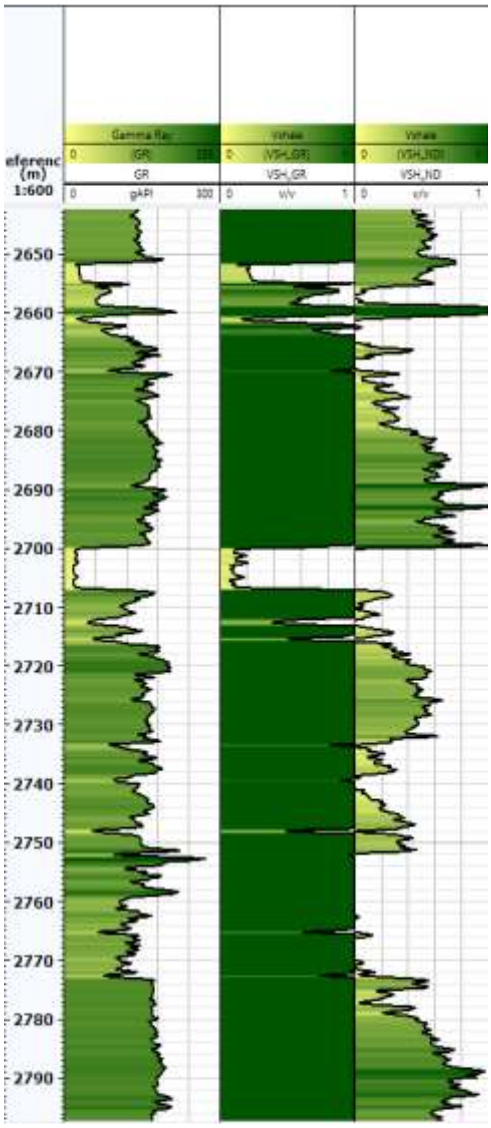

Figure 5-33 Volume of Shale Calculation

- **Porosity from Density log RHOZ**

The total density porosity is obtained using formula (2-15)

- **Porosity from Sonic log DTC**

The total porosity is obtained using formula (2-17)

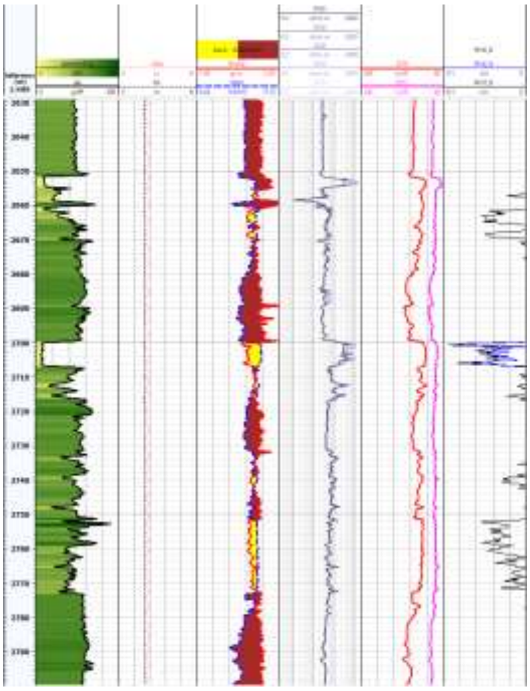

Figure 5-34 Porosity from Density log

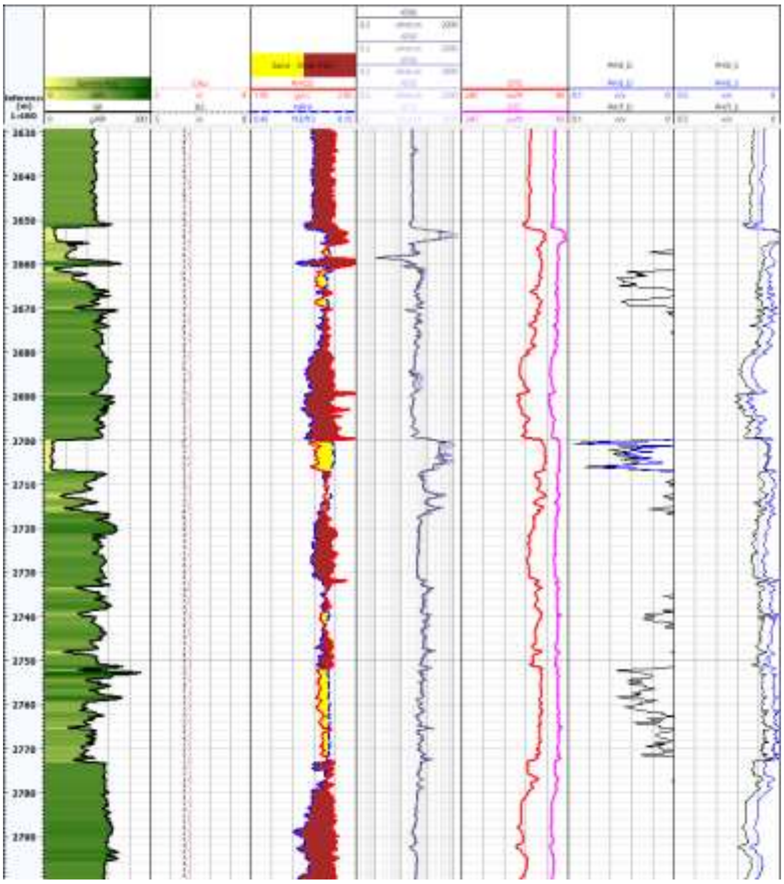

Figure 5-35 Porosity from Sonic Log

- **Effective Porosity**

To determine effective porosity from each log (sonic, density or neutron logs) the formula below should be applied.

$$\theta E = \theta T - Vsh * \theta Tsh \qquad \textbf{(5-32)}$$

Where,

θE: Effective Porosity.

θT: Total Porosity.

Vsh: Volume of Shale.

θTsh: Total Porosity of Shale.

- **Average Porosity**

To attain the average porosity, we use equation (2-16) at each depth.

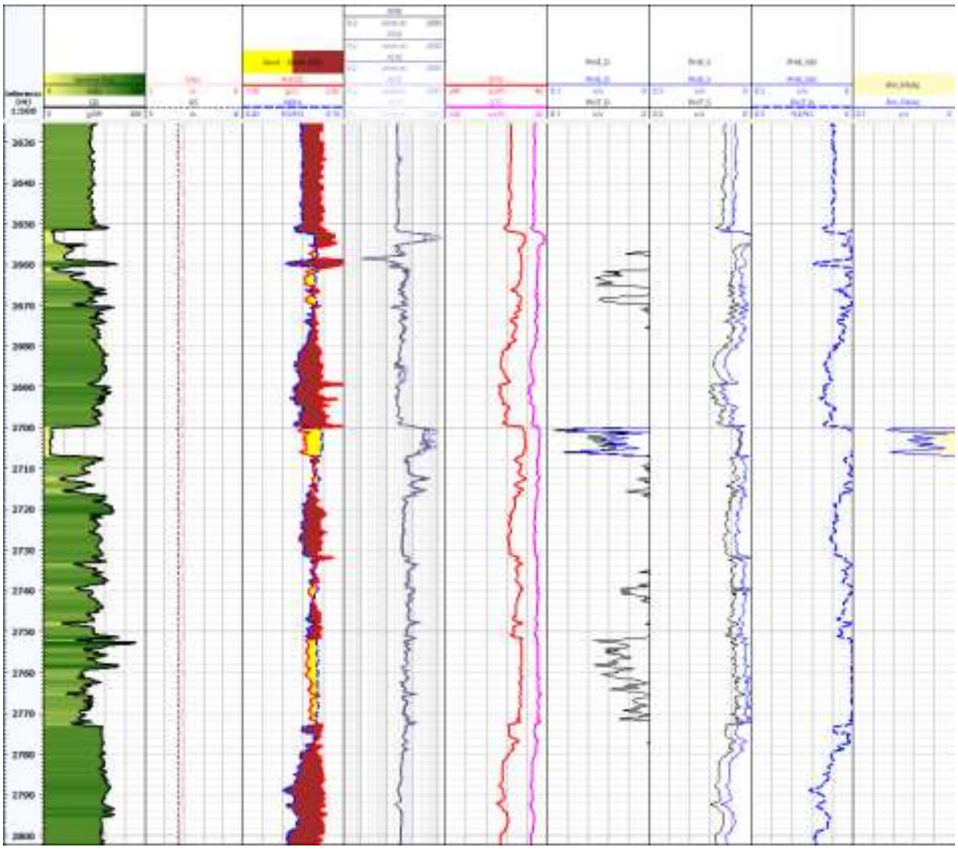

Figure 5-36 Average Porosity Log

- **Permeability**

To estimate permeability from well logs and average porosity, empirical relationships or models are used that correlate porosity, lithology, and fluid properties to permeability. The one used is the COATE equation.

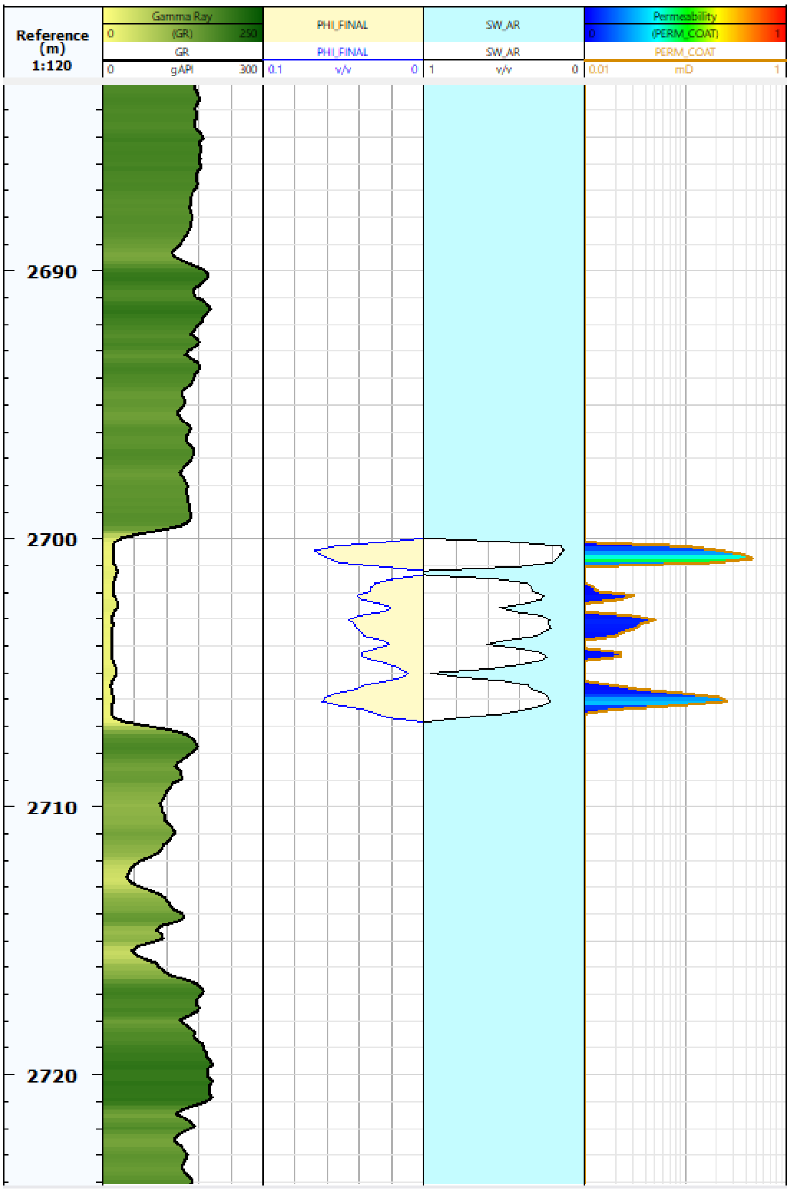

Figure 5-37 Permeability Log

- **Water Saturation**

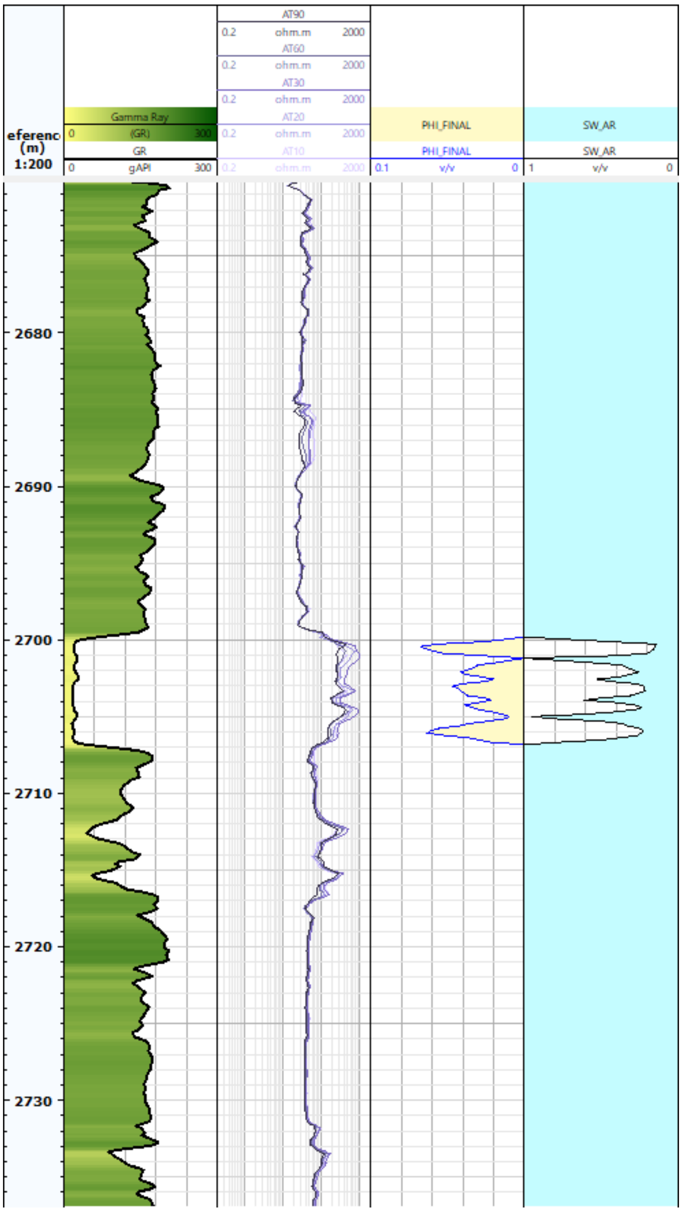

Figure 5-38 Water Saturation

The water saturation is calculated using the Archie's equation that relates water saturation to resistivity, porosity, and a formation factor. The general form of Archie's equation is showed in (2-18).

- **Final Petrophysical logs**

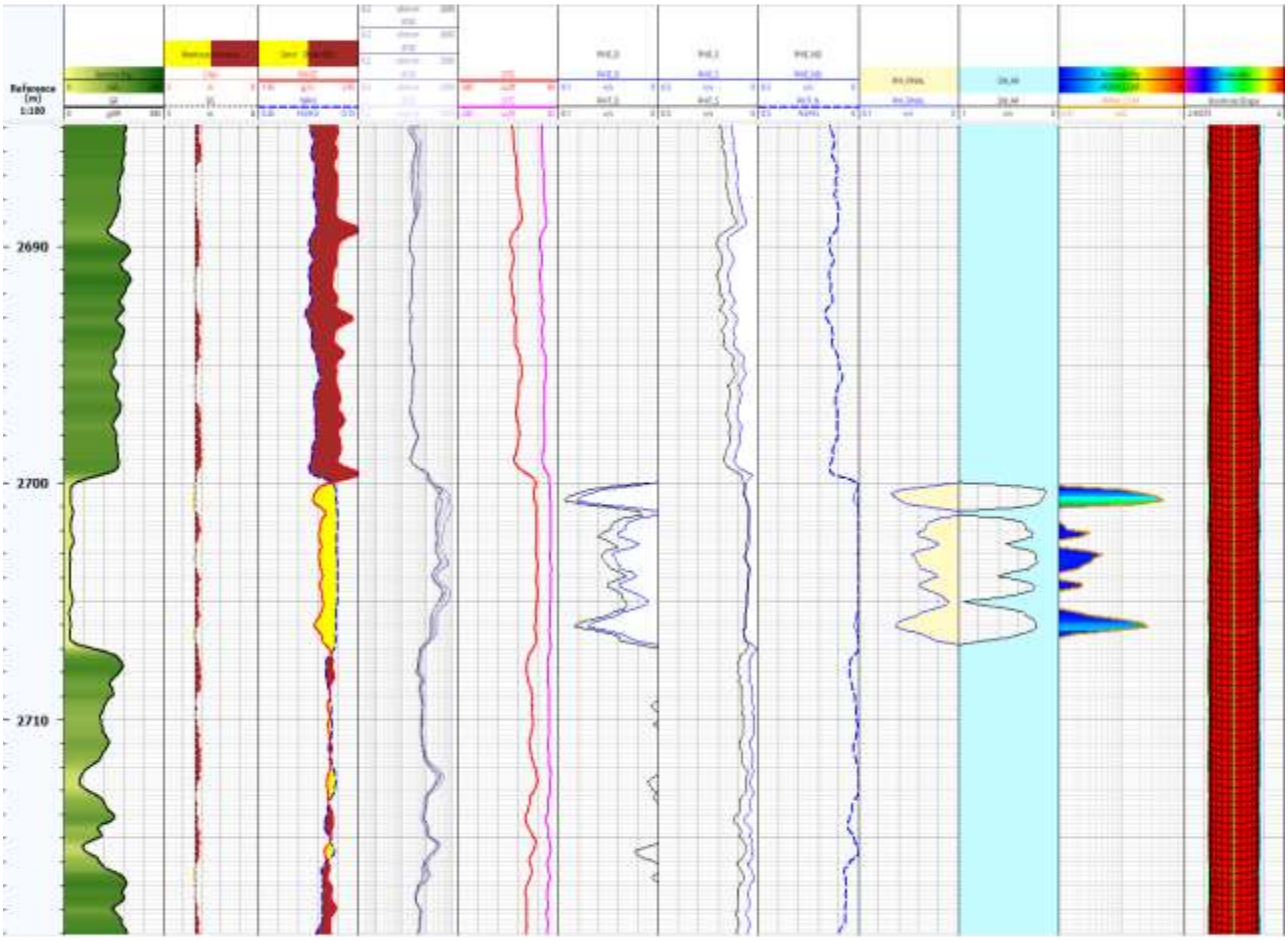

Figure 5-39 Final Petrophysical Evaluation

5.3.2.2. Geomechanics

- **Vertical Stress**

The vertical stress is calculated using the equation (2-6).

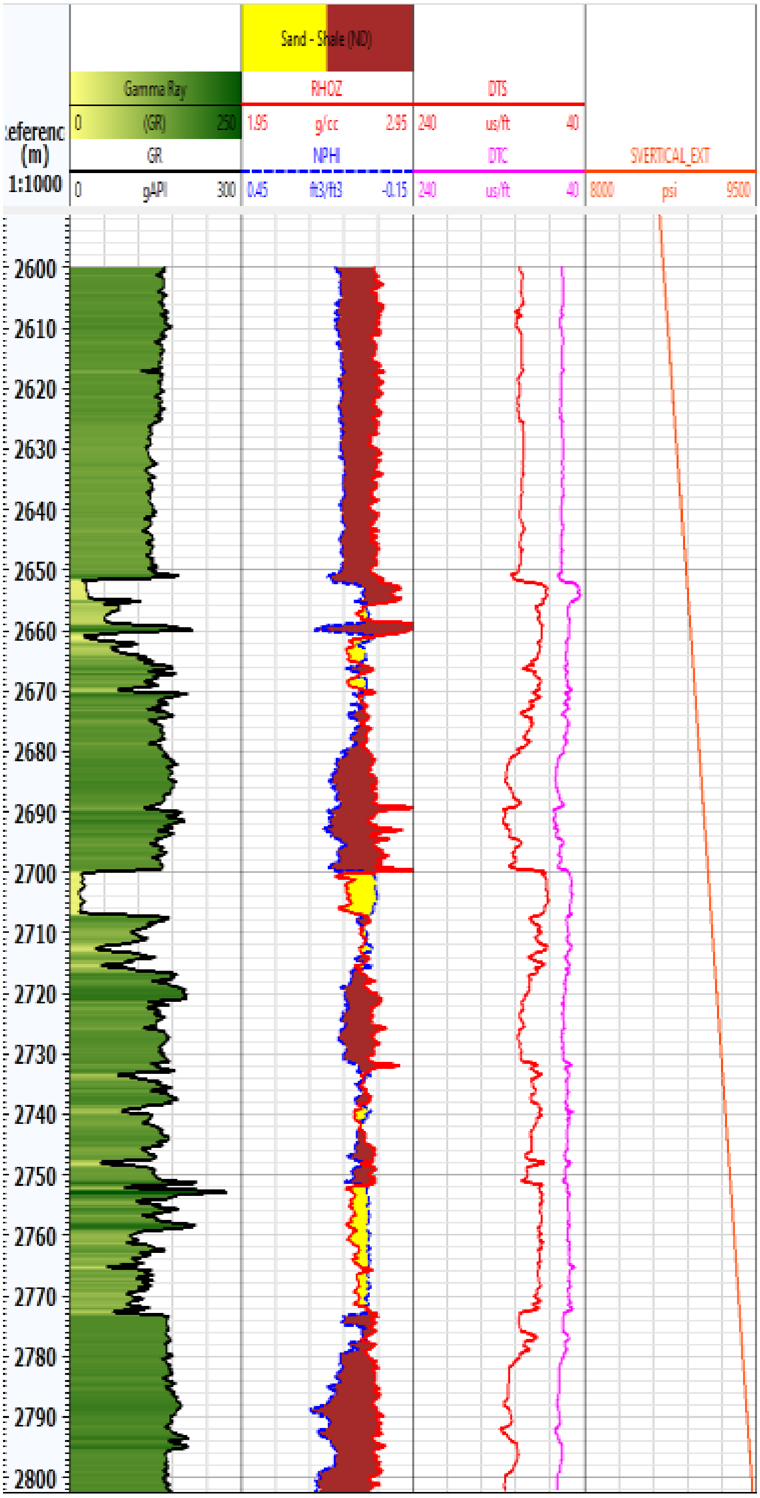

Figure 5-40 Vertical Stress Log

- **Dynamic Properties**

Geomechanical parameters obtained from logs, such as Young's modulus, Poisson's ratio, and shear modulus can be established from client logs and they play an important role in analyzing the mechanical behavior of the rock.

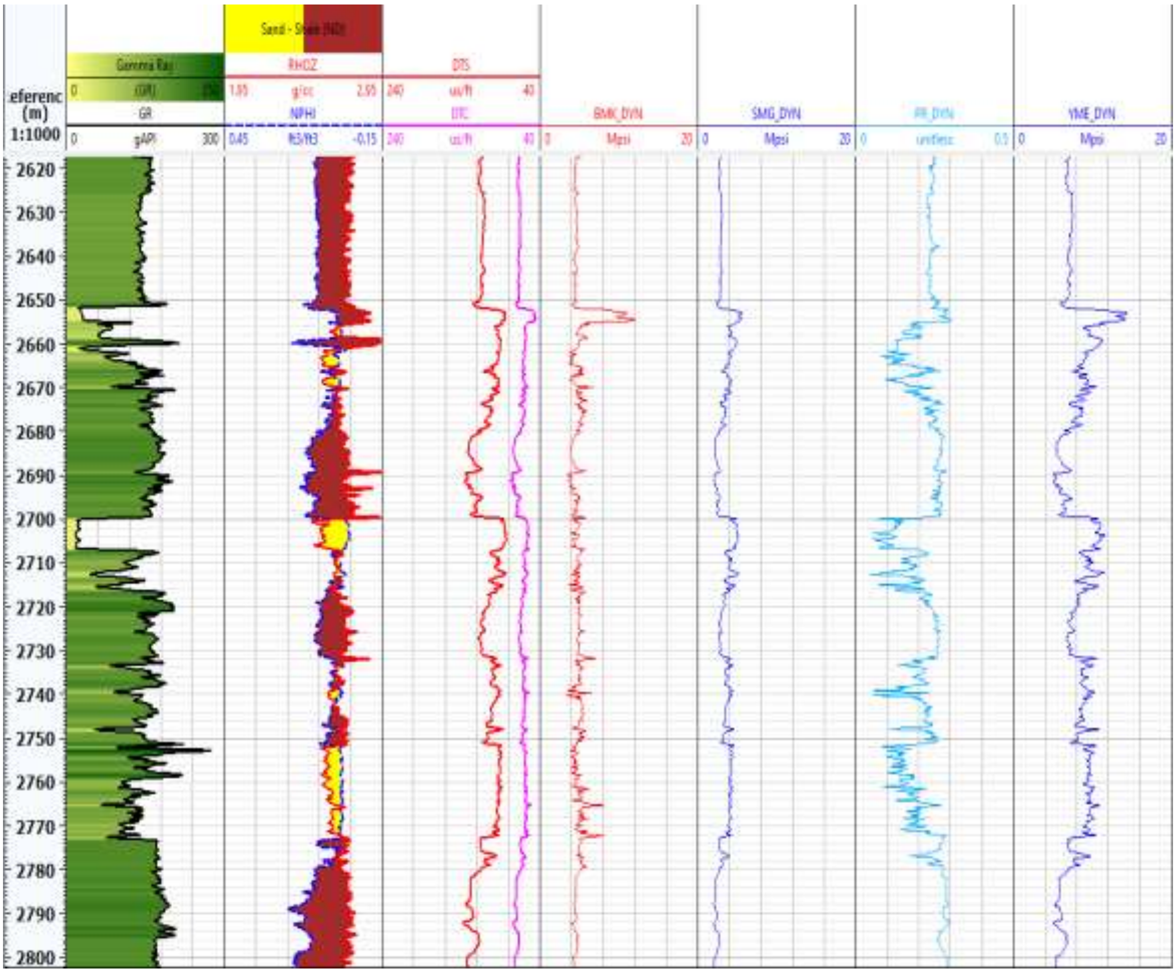

Figure 5-41 Dynamic Properties Log

- **Static Properties**

Many correlations can be used to convert the dynamic properties into static.

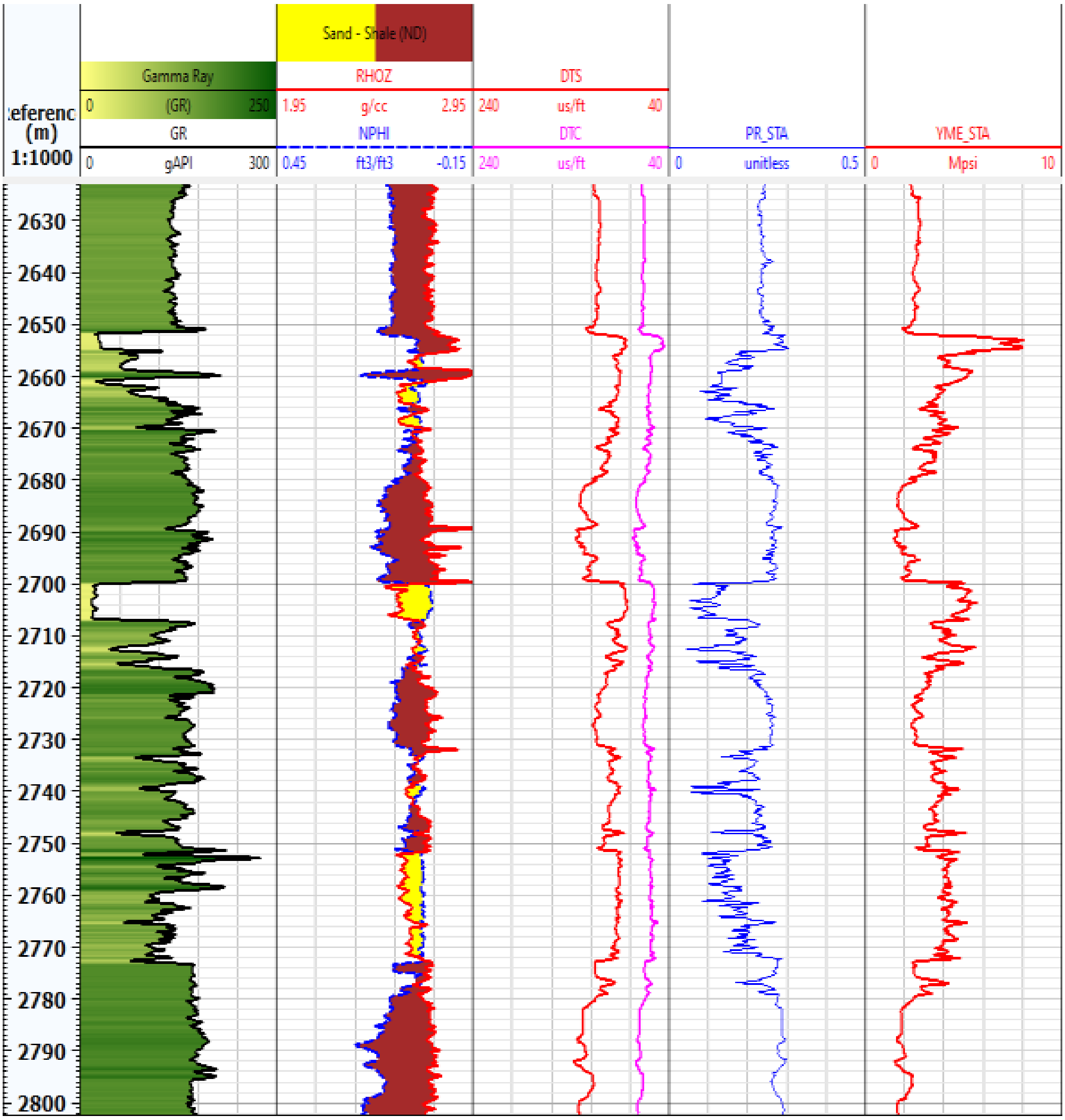

Figure 5-42 Static Properties Log

- **Horizontal Stresses**

Maximum and Minimum horizontal stresses are achieved using formulas (2-7) (2-8).

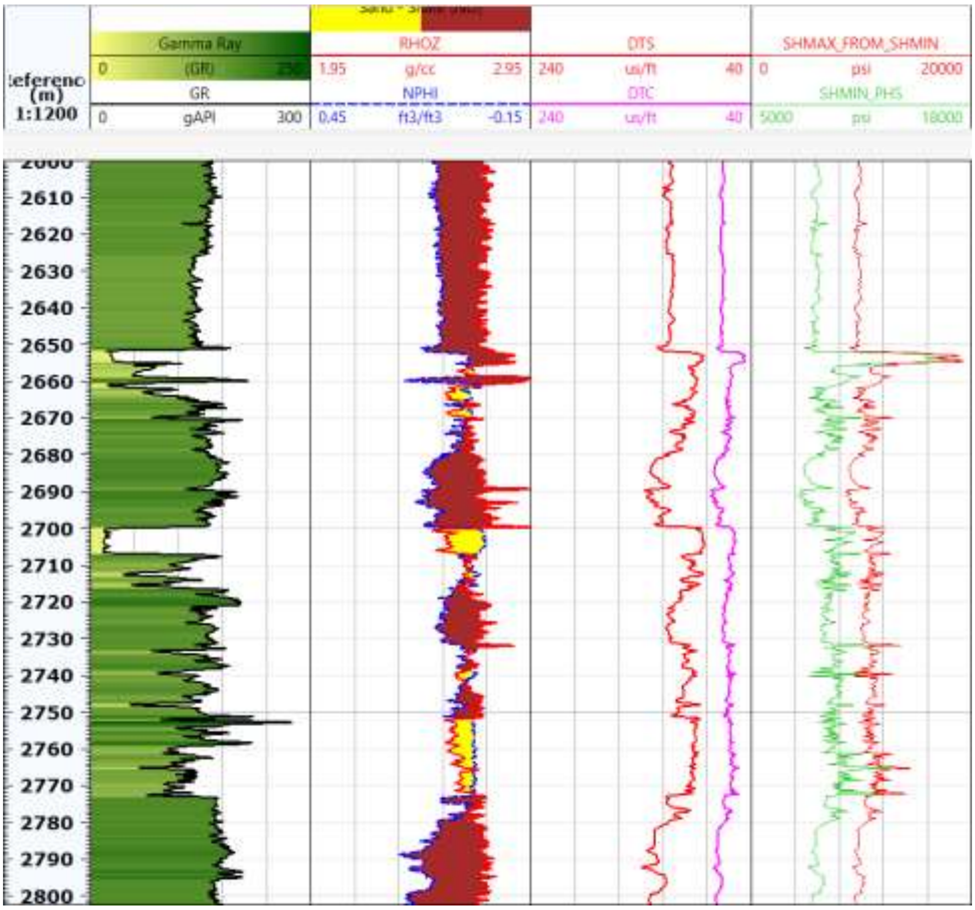

Figure 5-43 Horizontal Stresses Log

- **Faulting Regime**

And finally, after having the horizontal and vertical stresses values, the faulting regime can be identified.

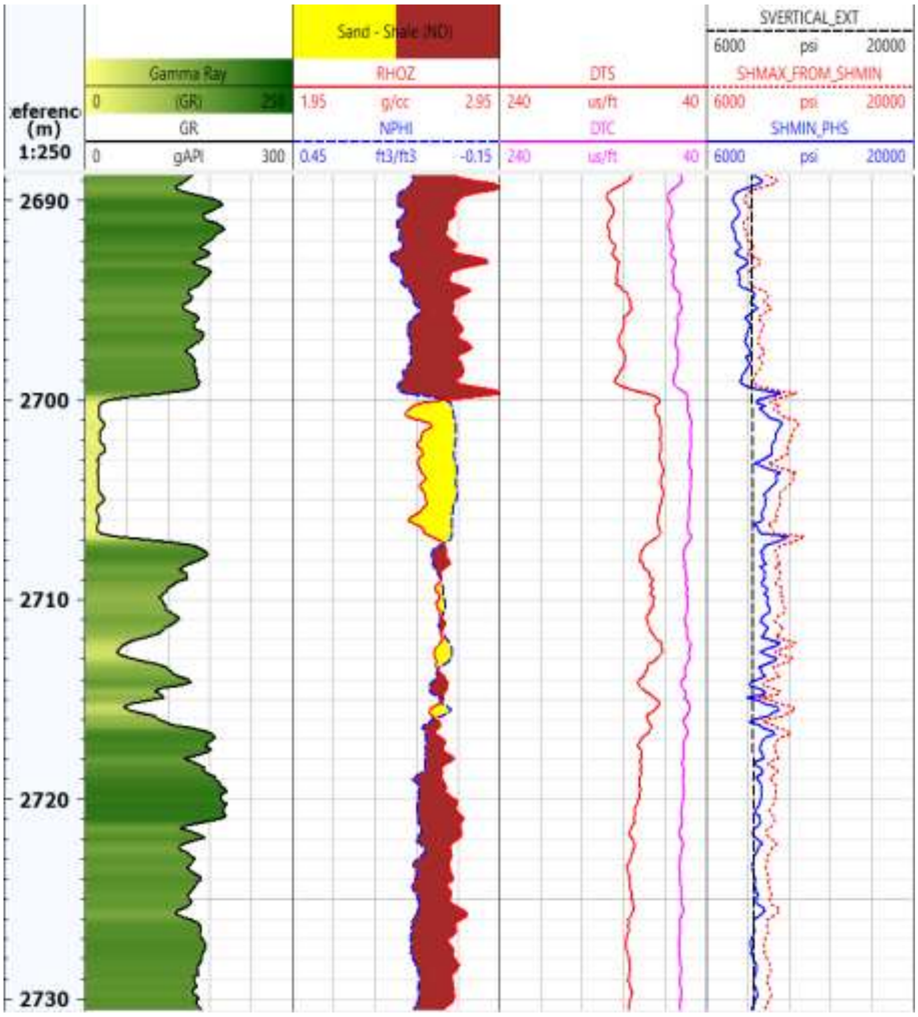

Figure 5- 44 Faulting Regime

- **Mechanical Earth Model**

The MEM is then computed to simulate the geomechanical behavior of rock formation. It incorporates all the data to build a model that predicts how the rock would react to stress and pressure.

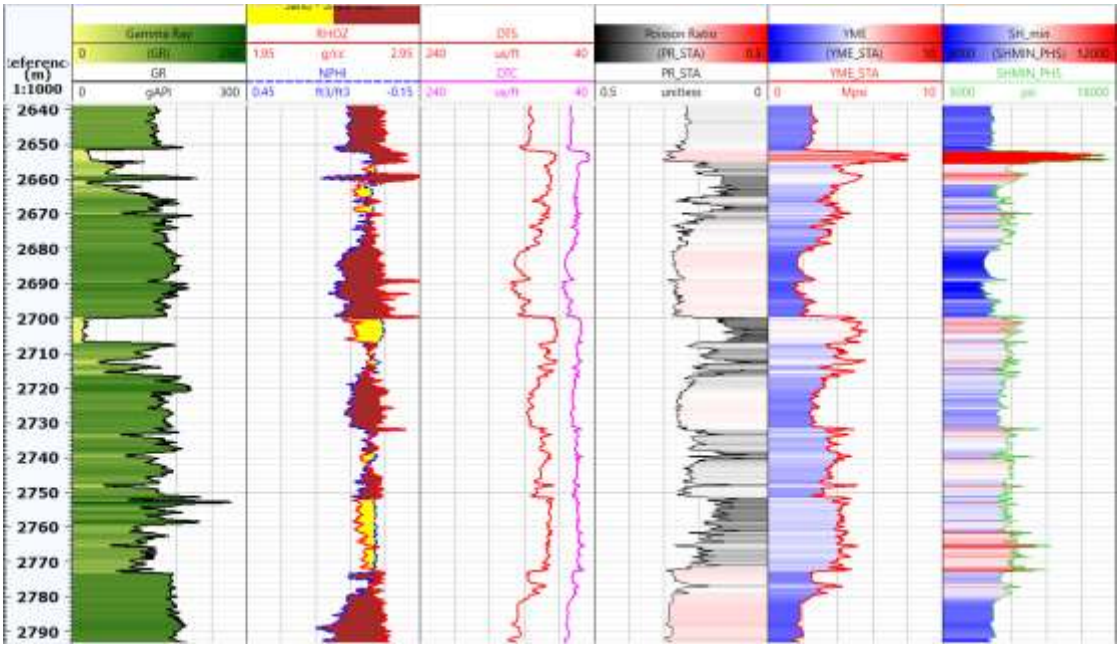

Figure 5-45 Mechanical Earth Model

5.3.3. Initial Production Estimate

The curve demonstrates the production decline while the flowing bottomhole pressure vary, as it is seen the production starts declining as the Pwf decreases until it reaches 300 STB/D which is a moderate production value

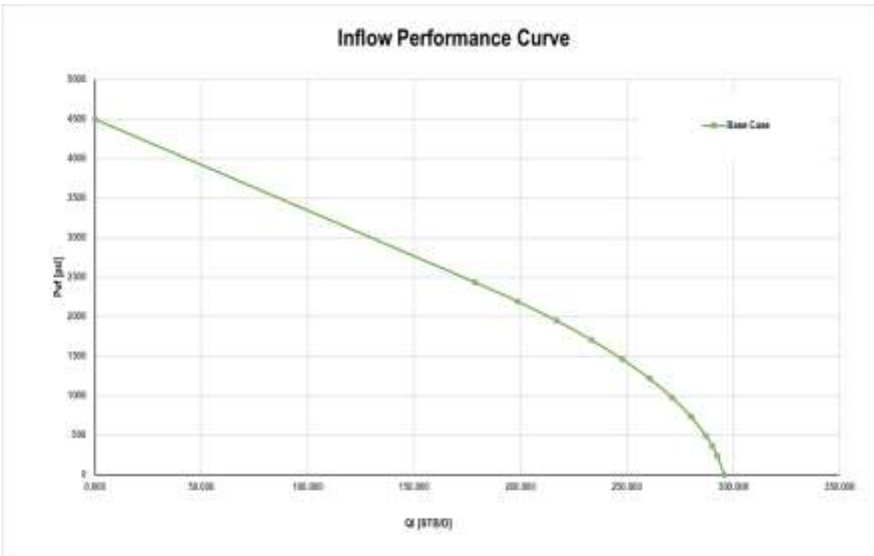

Figure 5- 46 Inflow Performance Curve Pre-Frac

5.3.4. Fracturing design

The process of designing a hydraulic fracturing treatment is based on several steps.Firstly, reservoir analysis is conducted to understand the formation properties alongside geological assessments to determine optimal fracturing strategies.

Following this, a well is selected based on geological data, production history, and economic factors. Fracture modeling is then performed to simulate fracture propagation and estimate dimensions. Fluid selection involves choosing a suitable fracturing fluid considering reservoir conditions, formation compatibility, then proppant selection involves determining the proppant type, concentration, and size distribution. Designing the treatment needs specifying injection rates, pressures, and pumping schedules based on reservoir properties and desired fracture geometry, withmonitoring, testing and calibrations during the process.

Optimization is a continuous process that aims at improving efficiency. In this case, it begins with analyzing data gathered from previous fracturing jobs. This information is used to identify patterns and areas for improvement. Iterative modeling techniques are then employed to optimize fracturing designs and treatment parameters.

5.3.4.1.Import data

The well X data was put in Petrel in order to obtain the MEM and define where the perforation zones should be.

- **Building the Mechanical Earth Model with Petrel:**

Petrel is a software platform used in the exploration and production sector of the petroleum industry. It enables the user to determine fracture geometry, interpret seismic data, perform well correlation, build reservoir models, visualize reservoir simulation results, calculate volumes, produce maps and design development strategies to maximize reservoir exploitation. Risk and uncertainty canbe assessed throughout the life of the reservoir. Although some other oil servicing companies hire the services of this software, Petrel is developed and built by SLB. **[41]**

After filling the software with the coordinates of the well (GR, Caliper, RHOB, pressure ...), Petrel generates the profiles of Young’s modulus, Poisson ratio, andstress between the different layers (zones), from which it is better to analyze the formation to select the different pay zones.

5.3.4.2. Zoning

Using the same software, reservoir boundaries and perforation interval are chosen based on this set of logs, the perforation placements should take into account all ofthese logs, in our case the perforations are set to be in this interval [2775 m- 2760 m]

Treatment Schedule

The treatment schedule include choosing the fluid type and concentrations, theproppant type and size and injection rate

- **Case 01: Maximizing production**

In this case which is considered a base case, the aim was to only focus on maximizing the production in a way to simulate the operator's point of vue to only aim for an optimal production that usually results in a bigger size of a job with high cost and lower NPV.

As the picture shows, after choosing to maximize the production, the tool finds a solution that achieves the objective while not surpassing the treatment limits.

The treatment parameters for Case 01 are:

Table 5- 7 Case One Parameters.

Xf, ft	Wf, in	Cf, mD	FCD, ~	Revenue, $	Cost, $
500	0.15	5000	0.30	31,365.08	5,679.45

The pumping schedule & simulation

After obtaining the treatment parameters, selection of fluid and proppant and creating the pumping schedule as the table shows, the fracture simulation, proppant distribution and fracture width profile can be concluded in Petrel.

Table 5- 8 Pumping Schedule for Case One

Bottomhole schedule

	Step name	Pump rate (bbl/min)	Fluid name	Fluid volume (gal)	Proppant	Prop. conc (PPA)	Prop. mass (lb)	Slurry volume (bbl)	Pump time (min)	Step type
1	Pad	36.00	YF135HTD	19000.00	None	0.00	0.00	452.38	12.57	Pad
2	1 PPA	36.00	YF135HTD	7000.00	30/50 HSP	1.00	7000.00	172.08	4.78	Slurry
3	2 PPA	36.00	YF135HTD	7000.00	30/50 HSP	2.00	14000.00	177.80	4.93	Slurry
4	3 PPA	36.00	YF135HTD	7000.00	30/50 HSP	3.00	21000.00	182.92	5.08	Slurry
5	3 PPA	36.00	YF135HTD	7000.00	20/40 ISP	3.00	21000.00	185.51	5.15	Slurry
6	4 PPA	36.00	YF135HTD	7000.00	20/40 ISP	4.00	28000.00	191.79	5.33	Slurry
7	5 PPA	36.00	YF135HTD	7000.00	20/40 ISP	5.00	35000.00	198.07	5.50	Slurry
8	6 PPA	36.00	YF135HTD	7000.00	16/30 ISP	6.00	42000.00	203.36	5.65	Slurry

Totals

	Fluid volume (gal)	Prop. mass (lb)	Slurry volume (bbl)	Pump time (min)
Total	68000.00	168000.00	1763.60	48.99

% Pad clean: 20.00 %

% Pad dirty: 26.00 %

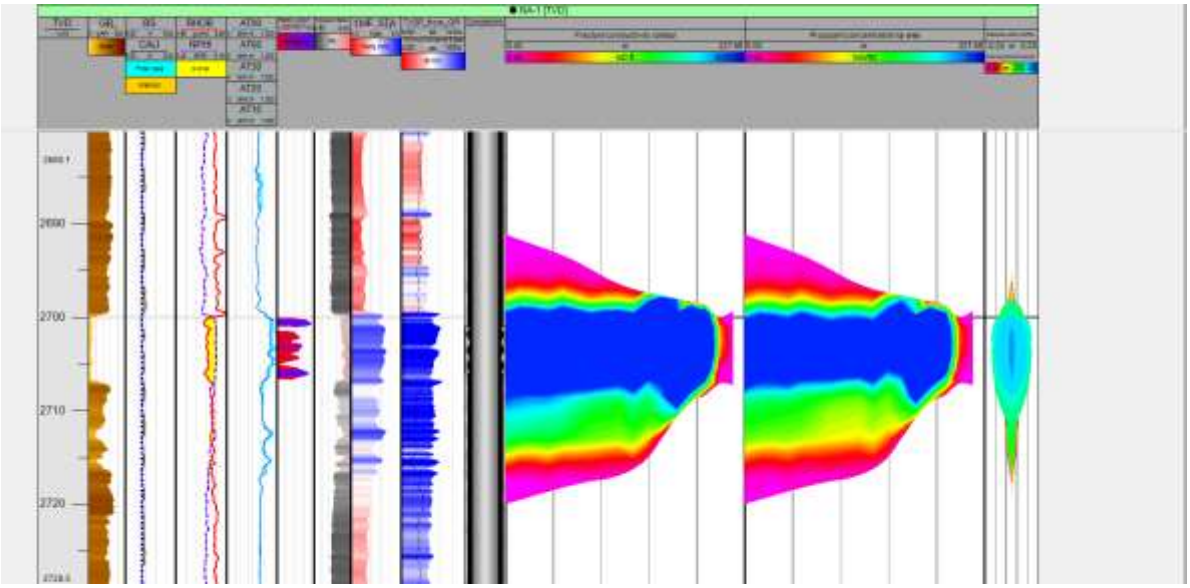

Figure 5-47 Simulation Results for Case One

- **Case 02: Minimizing Cost**

  For the second base case, we chose to only minimize cost in order to demonstrate its effect on both the operation parameters and production and toprove the importance of taking cost into consideration while optimizing a HFjob.

Table 5 - 9 The treatment parameters for Case Two

Xf, ft	Wf, in	Cf, mD	FCD, ~	Revenue, $	Cost, $
200	0.10	2500	0.33	24,212.24	852.07

The pumping schedule & simulation

Table 5 - 10 Pumping Schedule for Case Two

Bottomhole schedule

	Step name	Pump rate (bbl/min)	Fluid name	Fluid volume (gal)	Proppant	Prop. conc (PPA)	Prop. mass (lb)	Slurry volume (bbl)	Pump time (min)	Step type
1	Pad	20.00	YF135HTD	7000.00	None	0.00	0.00	166.67	8.33	Pad
2	1 PPA	20.00	YF135HTD	1500.00	30/50 HSP	1.00	1500.00	36.87	1.84	Slurry
3	2 PPA	20.00	YF135HTD	1500.00	30/50 HSP	2.00	3000.00	38.04	1.90	Slurry
4	3 PPA	20.00	YF135HTD	1500.00	30/50 HSP	3.00	4500.00	39.20	1.96	Slurry
5	3 PPA	20.00	YF135HTD	1500.00	20/40 ISP	3.00	4500.00	39.75	1.99	Slurry
6	4 PPA	20.00	YF135HTD	1500.00	20/40 ISP	4.00	6000.00	41.10	2.05	Slurry
7	5 PPA	20.00	YF135HTD	1500.00	20/40 ISP	5.00	7500.00	42.44	2.12	Slurry
8	6 PPA	20.00	YF135HTD	1500.00	16/30 ISP	6.00	9000.00	43.58	2.18	Slurry

Totals

	Fluid volume (gal)	Prop. mass (lb)	Slurry volume (bbl)	Pump time (min)
Total	17500.00	36000.00	447.64	22.38

% Pad clean: 40.00 %
% Pad dirty: 37.00 %

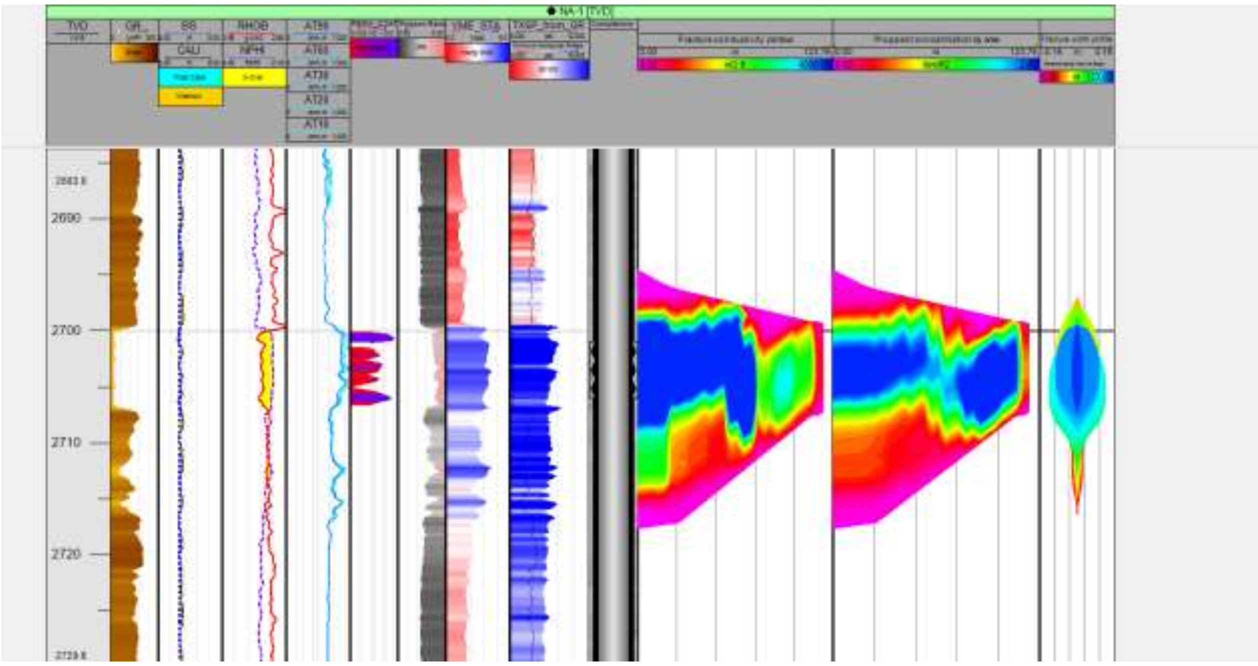

Figure 5-48 Simulation Results for Case Two

Comparison between Cases One and Two shows that concentrating on production improvement results in longer, wider fractures with high conductivity, but it also requires large volumes of fluid and proppant, which drives up costs. Conversely, concentrating on cost only results in shorter, less wide fractures with a conductivitythat is also nearly half as high, but the cost is of course more reasonable. The conclusion drawn from this comparison is that revenues and costs cannot be separated; both must be considered while optimizing to get the best results from any HF job.

5.3.5. Net Present Value optimization

As it was concluded in the previous cases, it is crucial to look into both production and cost in any optimization project, which is what this study has focused on. In thesenext titles the optimization algorithm process will be presented along with its simulation and NPV results.

5.3.5.1.Optimization algorithm

GRG in its most basic form, is a solver method that looks at the gradient or slope of the objective function as the input values (or decision variables) change and determines that it has reached an optimum solution when the partial derivatives equalzero.

Steps:

1- The GRG model starts by choosing a starting point (initialization).
2- It calculates the gradient at that specific starting point.
3- It takes a step in the same (or opposite when minimizing) direction to the gradient.
4- Repeats step two and three until one of the criteria is met:
  - Maximum number of iteration is reached.
  - Step size is smaller than the tolerance.

The function that we are going to maximize is as follow:

F(x)= Revenues – Cost

F(x)= Oil (bbl/d). Oil price * $(\boldsymbol{FC} + \boldsymbol{Prp} * \boldsymbol{Mp} + \boldsymbol{Vf} * \boldsymbol{PrF}) + \boldsymbol{AC}$

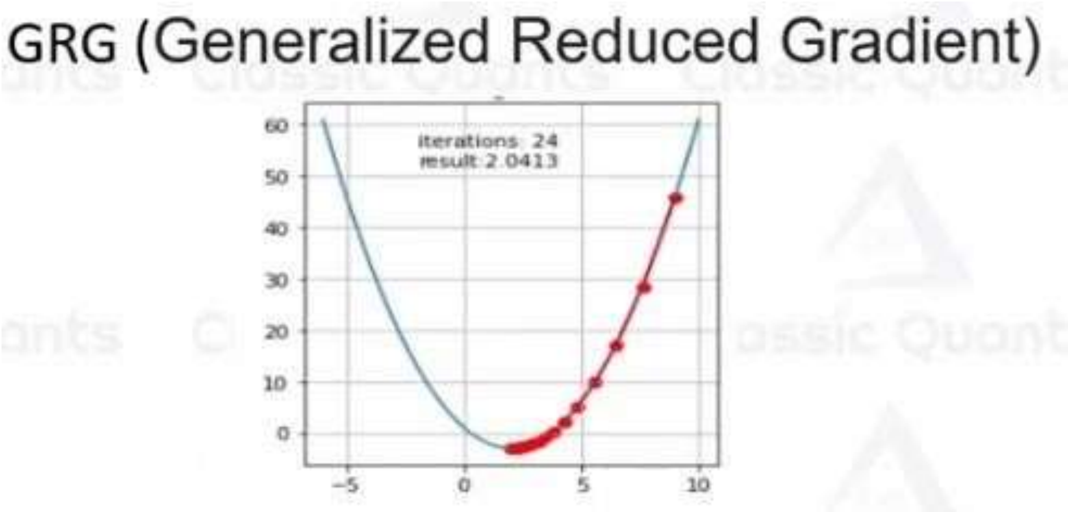

Figure 5-49 Generalized Reduced Gradient Method.

When the message “Solver found a solution” appears, it means that the GRG method has found a locally optimal solution – there is no other set of values for the decision variables close to the current values that yields a better value for the objective function.

5.3.5.2.Design constraints

Five charts were obtained from historical data analysis. These charts, were used for establishing the maximum and minimum ranges of these crucial parameters for a greater production and achieve the study's goal in enhancing optimization methodologies and establish an effective approach that maximizes production whileminimizing costs.The charts are presented below:

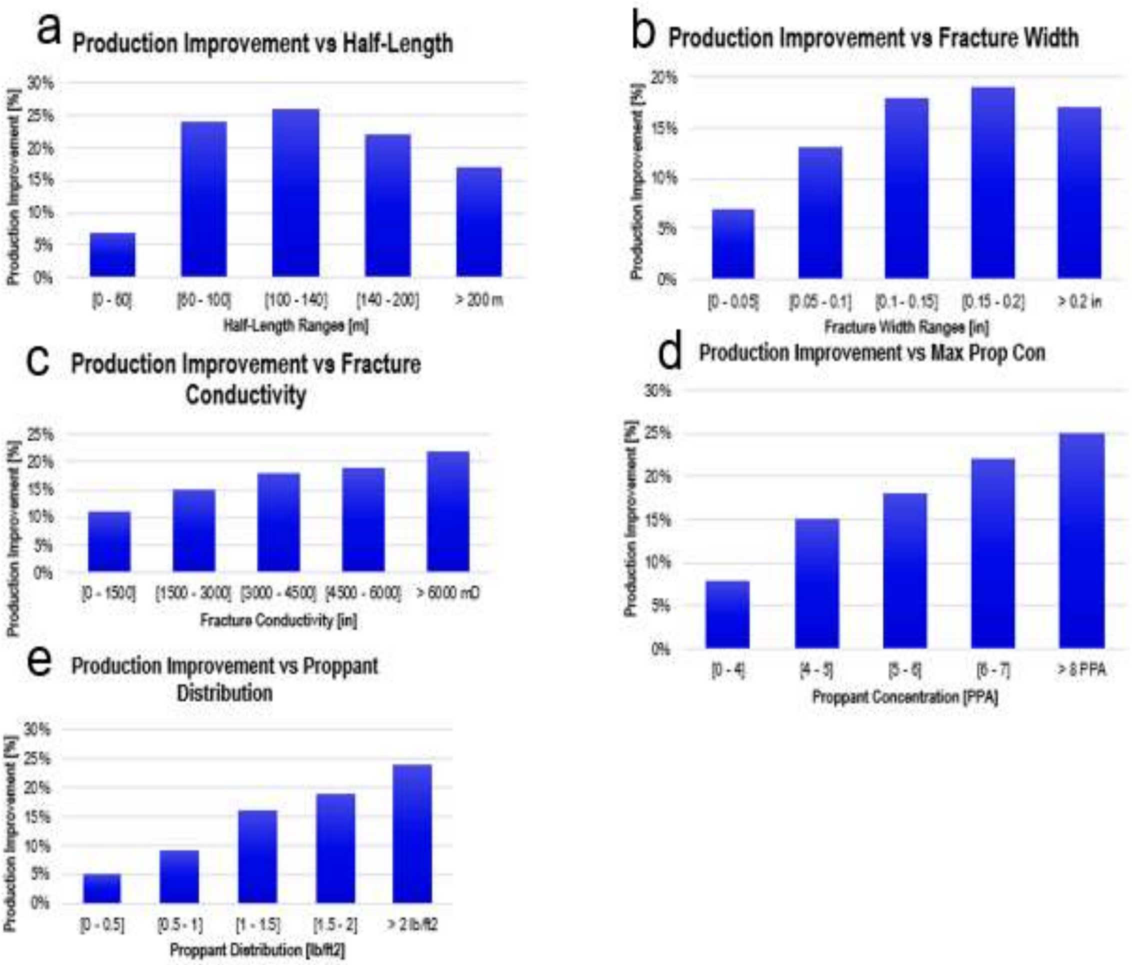

Figure 5-50 Optimum Ranges Charts

The figure above shows the impact fracturing parameters have on the cumulative production and its improvement. Figure a and b show the effect of fracture half-lengthXf and Fracture width Wf on production improvement, the longer the Xf/Wf the better the production until the optimum range is achieved [60m-200m]for Xf and [0.1in-0.2in]for Wf, after that the production starts to decrease due to the influence of other parameters like fluid volume, fracture conductivity. Figure c illustrates the effect of fracture conductivity on the production, it shows clearly that the higher the Cf more improvement is acquired. And so is the case for Figure d and e that show

Respectively the influence of proppant concentration and distribution on production improvement.

5.3.5.3. Optimization process

The first step of the study involved gathering data from past wells on formation parameters, well properties, PVT, and other factors. These data were organized and analyzed in order to determine whether there was a direct or indirect relationship between these parameters and production, which resulted in the creation of optimumranges of Xf, Wf, Cf, proppant concentrations, and proppant distribution for production improvement charts. Following that, a tool in Excel was used, which uses the data results to achieve an optimal scenario between that maximizes revenues and minimizes cost so that it meets the needs of both the operator and the service firm.

This tool takes charts with optimum ranges and sets them as maximum and minimum values that cannot be exceeded; these are the limit values of Xf, Wf, and Cf,and it then begins experimenting with these three parameters to obtain the estimated i)maximal revenues, ii) minimal cost. After that, simulation must be performed; the first step is to build the MEM; for this, the well data is attached to obtain the stress profile and fracture geometry; after that, we can begin thejob design; we select the fluid parameters and proppant parameters, as well as the pumping schedule, to calculate the cost of the entire job; once the revenues and costs are estimated, we can calculate the NPV for each of the three situations and compare them to validate the optimal financial performance of the optimized case.

5.3.5.4. Fracturing design

Following the same procedure as in Cases one and two, the well data were entered into the excel tool, however at this point the goal is to find an optimal example that maximizes production while spending the fewest costs possible.

The results are shown below:

Table 5- 11 The treatment parameters for The Optimum Case

Xf, ft	Wf, in	Cf, mD	FCD, ~	Revenue, $	Cost, $
250	0.13	4000	0.63	27,616.99	1,296.88

Treatment schedule & Simulation Results

Table 5- 12 Treatment Schedule for the Optimum Case

Bottomhole schedule

	Step name	Pump rate (bbl/min)	Fluid name	Fluid volume (gal)	Proppant	Prop. conc (PPA)	Prop. mass (lb)	Slurry volume (bbl)	Pump time (min)	Step type
1	Pad	36.00	YF135HTD	13000.00	None	0.00	0.00	309.52	8.60	Pad
2	1 PPA	36.00	YF135HTD	2300.00	30/50 HSP	1.00	2300.00	56.54	1.57	Slurry
3	2 PPA	36.00	YF135HTD	2300.00	30/50 HSP	2.00	4600.00	58.32	1.62	Slurry
4	3 PPA	36.00	YF135HTD	2300.00	30/50 HSP	3.00	6900.00	60.10	1.67	Slurry
5	3 PPA	36.00	YF135HTD	2300.00	20/40 ISP	3.00	6900.00	60.95	1.69	Slurry
6	4 PPA	36.00	YF135HTD	2300.00	20/40 ISP	4.00	9200.00	63.02	1.75	Slurry
7	5 PPA	36.00	YF135HTD	2300.00	20/40 ISP	5.00	11500.00	65.08	1.81	Slurry
8	6 PPA	36.00	YF135HTD	2300.00	16/30 ISP	6.00	13800.00	66.52	1.86	Slurry

Totals

	Fluid volume (gal)	Prop. mass (lb)	Slurry volume (bbl)	Pump time (min)
Total	29100.00	55200.00	740.35	20.57

% Pad clean: 45.00 %
% Pad dirty: 42.00 %

Flush

Step name	Pump rate (bbl/min)	Fluid name	Flush to depth (m)	Flush volume (bbl)	Underdisplacement volume (bbl)	Flush time (min)
Flush	36.00	WF130	2701.00	142.62	0.00	3.96

c. **Simulation results**

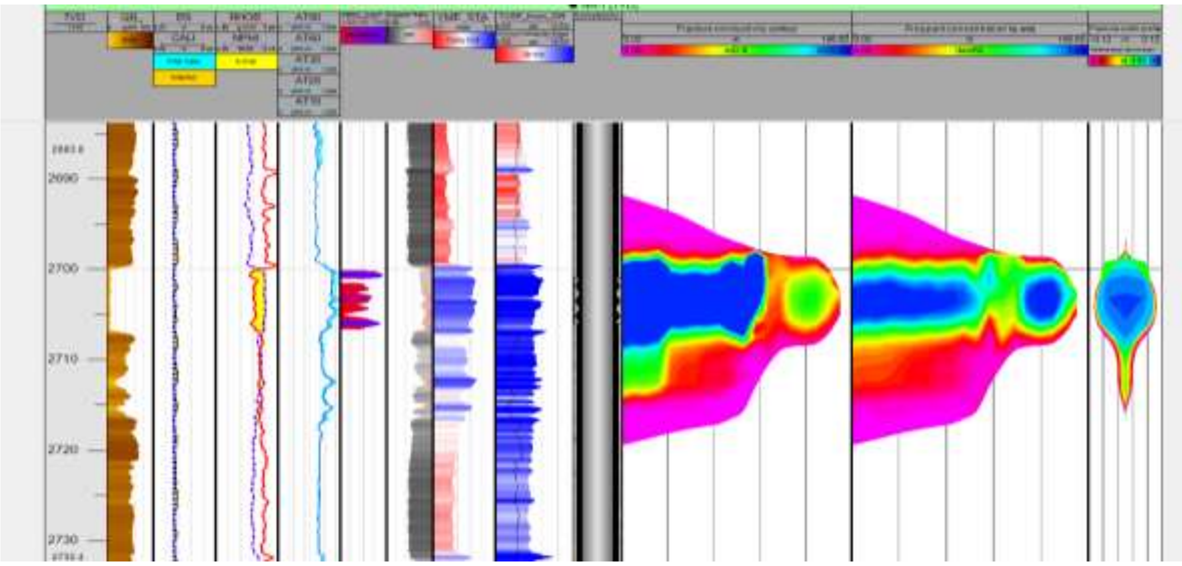

Figure 5-51 Simulation Results for the Optimal Case

As deducted from the simulation of case three, when focusing on optimizing both the production and the cost, the results obtained regarding the fracture geometry are optimal in addition to a maximized production and minimized cost.

5.3.6. Post fracturing results

The IPR curve shows the different production rates that can be achieved for a given bottomhole pressure for our three cases.

The first two when the operator chooses to maximize production or minimize costs either have high revenues with really high expenses or having reduced costs but not being able to increase production.

But with our optimum case, we were able to achieve a production that's almost the same as the maximize production case with the lowest costs possible.

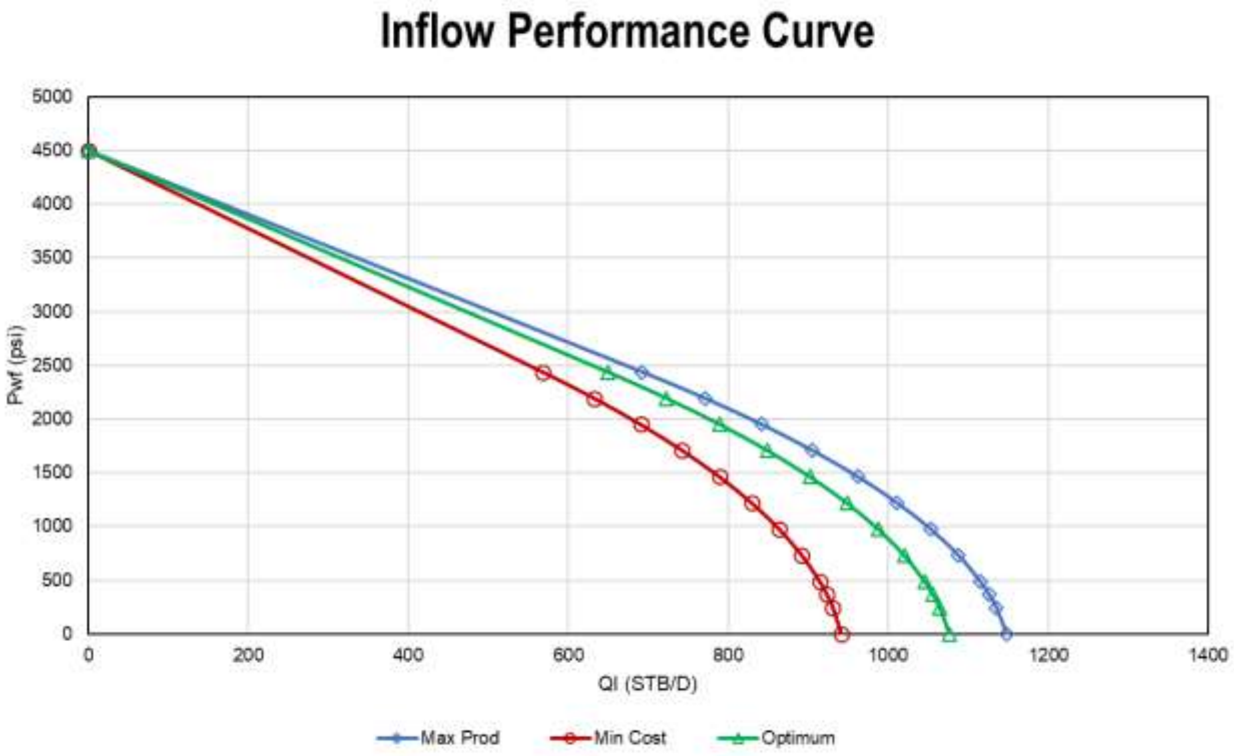

Figure 5-52 Inflow Performance Curve - With Optimization

The results of the three cases are summarized here, as it appears.

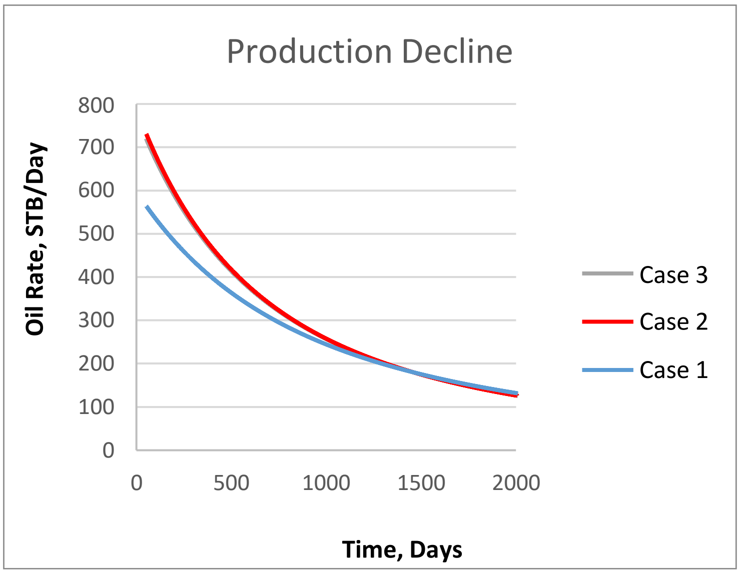

Figure 5-53 Production Decline for the Three Cases

The graph shows on the x-axis Time, Days and the y-axis Oil Rate, STB/Day.

The curves show a decline in oil production over time as the reservoir pressure naturally decreases as oil is extracted.

In this specific well, oil production starts at a rate of 750 STB/d for the max production and optimum cases and around 580 STB/d for the min cost case. It then steadily declines over time until they reach a lowest value of 120 STB/d in an estimated period of 2000 days.

These result show the efficiency of the optimum case from the technical side and how we were able to achieve almost the same production decline profile with less cost and higher revenues.

5.3.7. NPV analysis & comparison

The following table depicts the results of the calculated NPVs for the three cases along with a base case before fracking.

Table 5- 13 NPV Comparison

Case	qi, stb/d	Di, ~/yr	Di, ~/d	ta, d	qa, stb/d	Npa, stb	NPV, $
Base	300	0.2000	0.0005	4155	0	579,506	11,661,823
Frac_1 Min Cost	565	0.3996	0.0011	4135	54	713,089	17,706,878
Frac_2 Max Prod	732	0.5273	0.0014	3829	53	741,399	19,158,520
Frac_3 Optimum	720	0.5184	0.0014	3848	53	739,777	21,075,063

The following charts represent a comparison between the NPV values for the 4 cases where the highest NPV was achieved by our optimal case with a value of more than 20 million dollars.

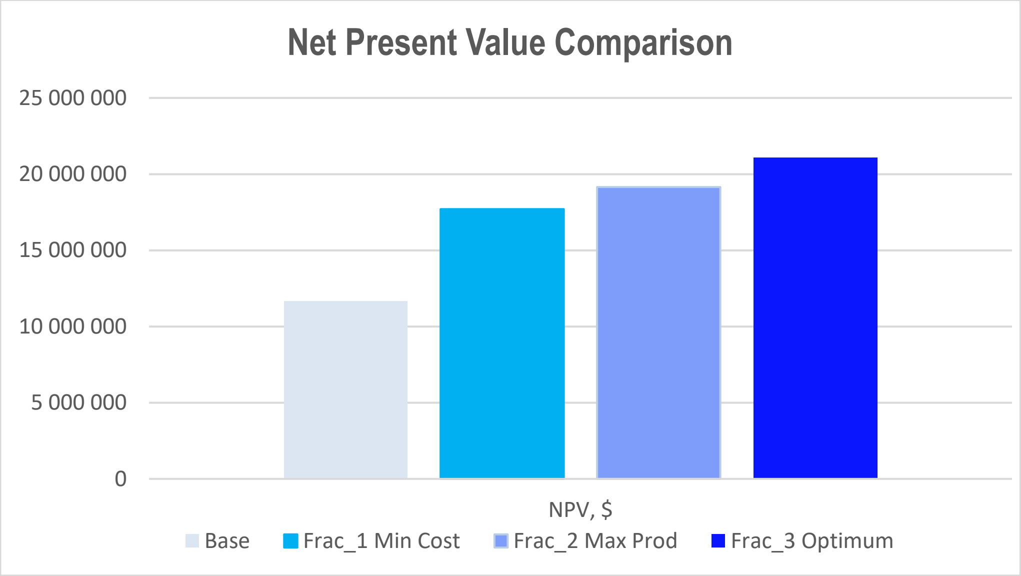

Figure 5- 54 Net Present Value Comparison

Conclusion

In this last chapter, we studied the case of the well X where the optimization method was applied to. The results obtained confirmed the success of our strategy thus achieving a successful hydraulic Fracturing job, as a result; increasing NPV and more specifically revenues while reducing costs. Implementing this proposition shows clear evidence of the enhancement of fracturing parameters resulting in an optimum design that’s not achievable with the ordinary design.

Conclusion & Recommendations

This dessertation was accomplished in an attempt to introduce our approach for hydraulic fracturing treatment optimization in order to achieve the highest Net Present Value possible which translates to the highest revenues possible while simultaneously minimizing costs.

The workflow of our approach has been established and presented with an application on Well X, where we were able to prove the viability of our strategy with accurate and precise results.

Our strategy was mainly based on collecting diverse previous experience data, use it to obtain optimum ranges of the main parameters affecting production. After that, selecting a candidate well where the multi-objective method that's the Generalized Reduced Gradient can be applied to the well, The NPV was then calculated for the optimal case and the base cases, comparison showed clear evidence of the success of our method.

The main results from our method that prove its success can be resumed in the following points:

- Production growth by 4 times.
- Cost reduction by 38 %
- Recovery factor increase by 4.7 %
- Net Present Value rise by 23%

Recommendations

The accuracy of the optimization tool is highly dependent on the collected data, their quantity and quality. For that reason, it is essential to filter it from any flawed values and gather as much as possible.

The optimum ranges acquired are only designated for wells from field Z or fields that have similar properties. If not, new data needs to be collected and used alternatively.

Due to the of this topic, focus was only set on fracture geometry and conductivity. Therefore, future research should expand the scope into other parameters such as fluid chemistry and selection, proppant selection, treatment rate to have broader optimization models.

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Appendices

Appendix 01 Chapter Three

Proppant Types

Figure A 6- 1 Silica Sand [23]

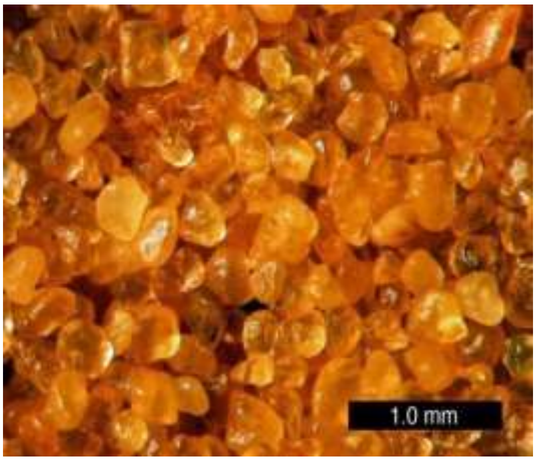

Figure A 3- 2 Resin-coated proppant [23]

Figure A 3- 3 Manufactured Ceramic Proppant [23]

Appendix 01 Chapter Three

Equipment

Figure A 3-4 Frac Tanks [25]

Figure A 3- 5 Sand Chief [25]

Figure A 3- 6 Missile [25]

Figure A 3- 7 Tree Saver [25]

Appendix 03 Chapter Five

Excel tools

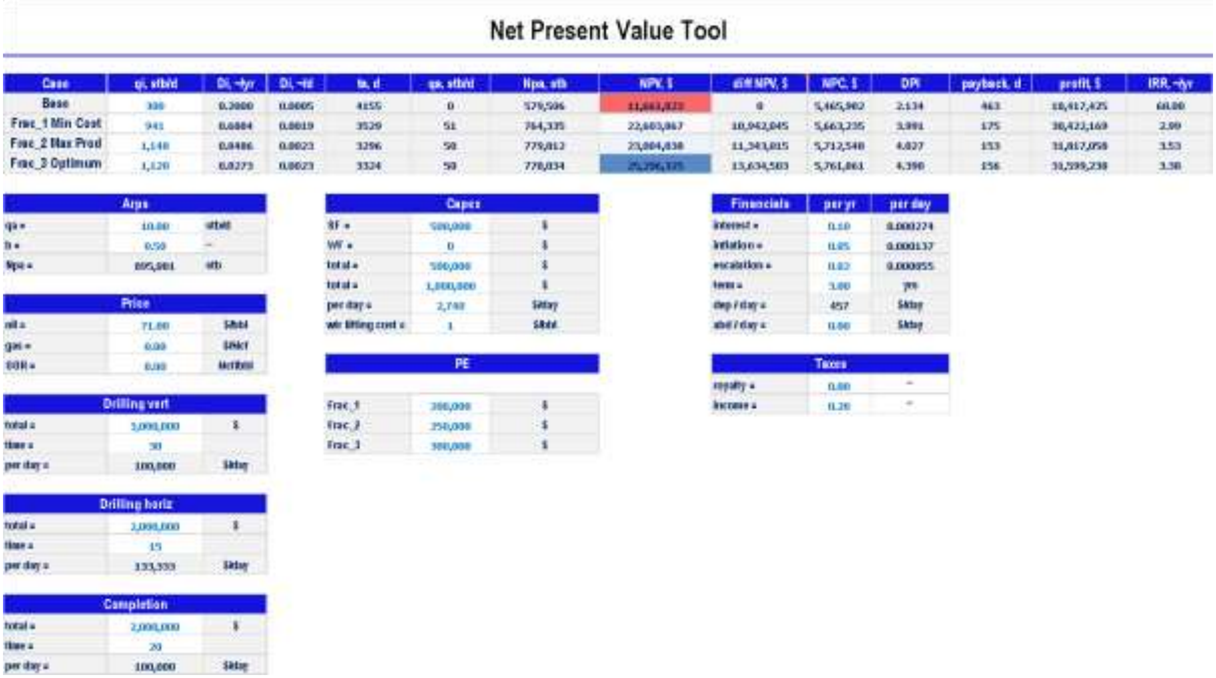

Figure A 5-8 Net Present Value Calculation Tool

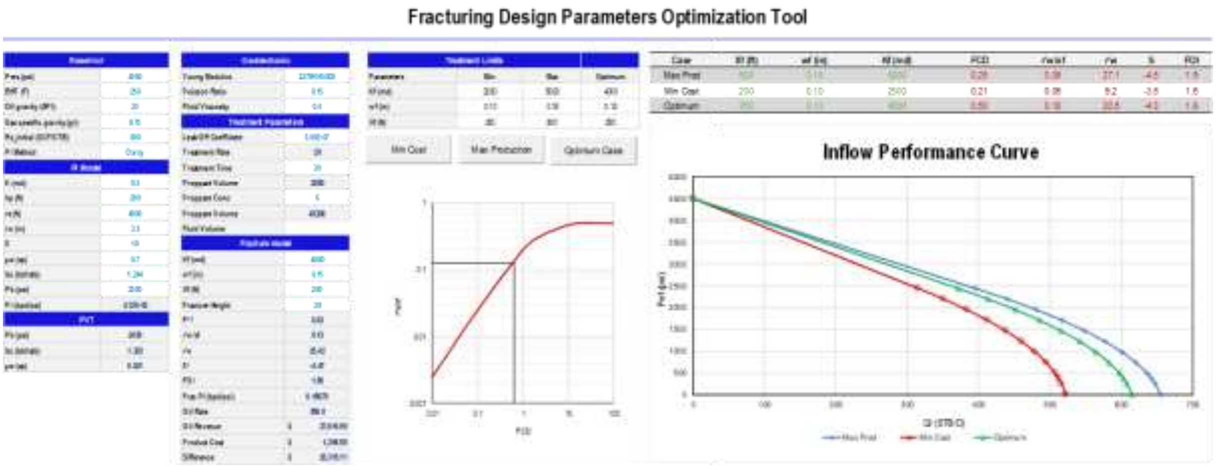

Figure A 5-9 Fracturing Design Parameters Optimization Tool