

People's Democratic Republic of Algeria
Ministry of Higher Education and Scientific Research

Serial N°:/2026

Kasdi Merbah Ouargla University



Faculty of Hydrocarbons, Renewable Energies, Earth and Universe
Sciences

Department of Hydrocarbon Production

MASTER'S THESIS To obtain the Master's Degree

Option: Professional Production

Presented By:

BEN AMOR Saadeddine, GUARRICHA Ahmed Yacine

-TITLE-

Investigation of Acidizing Techniques for Productivity Index
Improvement (Hassi Messaoud region).

Defended on: 07 / 06 / 2026 before the examination committee

Jury:

President:	Mr. DADEN Abdelghafour	M.A.A	Univ. Ouargla
Supervisor:	Mr. SID ROUHOU Hadj Mohamed	M.C.B	Univ. Ouargla
Examiner:	Mr. GHALI Ahmed	M.A.A	Univ. Ouargla

Academic Year 2025/2026



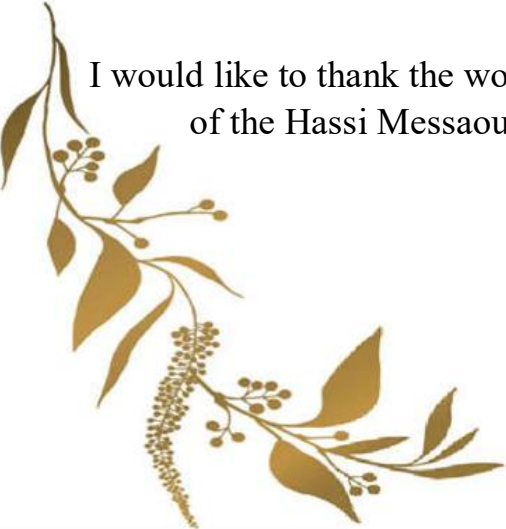
Acknowledgement

All my thanks go first and foremost to Almighty God for the health, willpower and patience he gave me throughout all my years of study.

I would like to thank my mother and father, who have supported me throughout my life and helped me achieve my dreams.

I would like to thank my sister and brothers, my friends who encouraged me to be stronger than the circumstances and to achieve my goal.

I would like to express my gratitude to all those who contributed to the completion of this work. In particular, Mr.Sid Rouhou Hadj Mohamed for his guidance, direction, and trust in the scientific direction of this thesis also Sincere thanks Production Department Employees.



I would like to thank the workers of Department of the Engineering and Production Directorate of the Hassi Messaoud Regional Directorate for helping me complete this project.



Thank you again to all...



Dedication

Would like to dedicate this project to my beloved ones my family,

To my father, for his support, advice, and sacrifices throughout my life, for who
I am today. May God bless him.

To my mother, without whom I would be nothing, who always gives me hope for
life and who has never stopped sacrificing herself for me so that I can succeed in
my life, for her prayers and encouragement in difficult times. May God bless her.

And to my brothers Lamine, Anas, Hicham, and my sister Chiraz.

And I extend my sincere greetings to all the employees of the Well Techniques
Department of the Engineering and Production Directorate in the Hassi Messaoud
Regional Directorate, and especially to Kamal Mekkeri and Mohcen Boufaghas
for their support during my training period and for providing me with the
necessary information for the success of this project.

BEN AMOR Saadeddine





Dedication

This monumental achievement is not mine alone; it truly belongs to every individual who stood firmly by my side. With a heart full of pride and deep gratitude.

I dedicate this project:

To my beloved parents, for their unwavering belief in my potential, their countless silent sacrifices, and the unconditional love that has been my ultimate anchor.

To my wonderful family and friends, for being my safe sanctuary, my constant source of joy, and the strength that lifted me throughout this long journey.

To my fellow students, for the unforgettable memories we created, the heavy challenges we shared, and the mutual support that turned every obstacle into a stepping stone

GUERRICHA Ahmed Yacine



Abstract

Various types of **formation damage** can occur in oil and gas wells, resulting from either continuous production or well intervention operations such as workovers, completions, and stimulations. **acidizing** is a primary stimulation technique implemented to enhance well productivity or injectivity. This is achieved by injecting tailored acid systems into the formation at a pressure strictly below the formation fracturing pressure to effectively dissolve near-wellbore impairment Especially **Matrix Acidizing** . Based on our field case study of two wells in **Hassi Messaoud** and **Bir Berkine**, which exhibit distinct reservoir rock **mineralogies** and **petrophysical** properties, each well required a specific acid formulation to optimize damage removal. This targeted treatment successfully restored flow capacity, leading to a substantial increase in the well **flow rate** and a significant improvement in the **Productivity Index (PI)**.

Key words: damage, Matrix acidizing, flow rate, Productivity Index.

Résumé

Divers types d'endommagement de la formation peuvent survenir dans les puits de pétrole et de gaz, résultant soit de la production continue, soit des opérations d'intervention sur les puits telles que les workovers, les complétions et les stimulations. **L'acidification** est une technique de stimulation primaire mise en œuvre pour améliorer la productivité ou l'injectivité des puits, Cela est réalisé en injectant des systèmes d'acide spécifiques et adaptés dans la formation à une pression strictement inférieure à la pression de fracturation de la roche, afin de dissoudre efficacement les restrictions d'écoulement près du puits En particulier L'acidification Matricielle. sur la base de notre étude de cas sur site de deux puits à **Hassi Messaoud** et **Bir Berkine**, qui présentent des **minéralogies** et des propriétés **pétrophysiques** de roche réservoir distinctes, chaque puits a nécessité une formulation d'acide spécifique pour optimiser l'élimination de l'endommagement. Ce traitement ciblé a permis de restaurer avec succès la capacité d'écoulement, entraînant une augmentation substantielle du **débit** du puits et une amélioration significative de **l'Indice de Productivité (PI)**.

Mots clés : endommagement, acidification matricielle, débit, l'Indice de Productivité.

المخلص

تتعدد أنواع **الأضرار** التي قد تلحق بالتكوين الإنتاجي لأبار النفط والغاز، وتنتج إما عن عمليات الإنتاج المستمر أو خلال عمليات التدخل في الأبار مثل عمليات الإصلاح، والإكمال، والتحفيز. ويُعد التحميص تقنية تحفيز أساسية تُطبق لتحسين إنتاجية الآبار أو قدرتها على الحقن؛ ويتم تحقيق ذلك عن طريق ضخ منظومات حمضية مصممة خصيصاً داخل التكوين الإنتاجي عند ضغط أقل تماماً من ضغط تشقق الصخور لإزالة الانسدادات والأضرار القريبة من جدار البئر بشكل فعال وخاصة **التحميص المصفوفي**. وبناءً على دراسة حالة ميدانية لبئرين في كل من **حاسي مسعود** و**بئر بركين** اللذين يظهران اختلافاً واضحاً في المعادن المكونة لصخور المكنم وخصائصها البتروفيزيائية، تطلّب كل بئر تركيبة حمضية نوعية ومحددة لتحقيق الاستجابة المثلى في إزالة الضرر. وقد نجحت هذه المعالجة الموجهة في استعادة القدرة الانتاجية لتدفق السوائل، مما أدى إلى رفع **معدل تدفق البئر** بشكل ملحوظ وتحقيق تحسن كبير في **مؤشر الإنتاجية**.
الكلمات المفتاحية: أضرار، تحميص المصفوفي، معدل تدفق، مؤشر الإنتاجية.

Table of Content

Acknowledgement	I
Dedication	II
Abstract	III
List of Figures	V
List of Tables	IV
List of Symbols	IIV
General Introduction.....	1

Chapter I: Notions of Damage.

I.1. Introduction.....	3
I.2. Damage concept.....	3
I.3. Origin and causes of the damage	3
I.3.1. Damage due to the formation	3
I.3.2. Damage due to perforation.....	5
I.3.3. Cement filtrate invasion	5
I.3.4. Damage due to stimulation	5
I.3.5. Damage due to well operations (Drilling, Work-Over and Snubbing)	5
I.3.6. Damage due to water injection	6
I.4. Damage Location.....	7
I.4.1. At the bottom of the well.....	7
I.4.2. At the wellbore well.....	7
I.4.3. Around the wellbore	7
I.4.4. Particle build-up	7
I.5. Detection of damage	8
I.5.1. Laboratory sampling and analysis	9
I.5.2. Complete well history	9
I.5.3. Well Test.....	9
I.5.4 Analysis of the production system	9
I.5.5 Production logging (PLT)	9
I.6.Skin effect	9

I.6.1. Definition	9
I.6.2. The origin of skin	10
I.6.2.1. Perforations.....	10
I.6.2.2. Partial Penetration.....	10
I.6.2.3. Overall damage	11
I.6.2.4. Stimulation treatments.....	11
I.6.2.5. Mechanical effects	11
I.6.3. The skin effect on permeability	11
I.6.4. The effect of skin on productivity	12
I.7. Expression of damage.....	13
I.7.1. Ideal well	13
I.7.2. Damaged well.....	14
I.8. Conclusion:	15

Chapter II: Notions of Acidizing.

II.1. Introduction	16
II.2. The main types of stimulation	16
II.2.1. Hydraulic fracturing	16
II.2.2. Acid Fracturing	16
II.2.3. Acidizing	16
II.3. Theory of Acidizing.....	16
II.3.1. Definition	16
II.3.2. Objectives of Acidizing.....	17
II.3.3. Candidate Selection for Acidizing.....	18
II.3.4. Criteria and Steps for an Acidizing Operation.....	19
II.3.5. The Operational Stages of an Acid Treatment.....	20
II.3.5.1 Tubing and Perforation Cleaning.....	20
II.3.5.2. The Matrix Treatment Process	21
II.3.5.3. Well Flowback	22
II.3.5.4. Fluid Placement	22
II.3.5.5. Treatment Diversion	22
II.4. Chemical of acidizing.....	23
II.4.1. Main Types of Acids Used	23
II.4.1.1. Hydrochloric Acid (HCl)	23

II.4.1.2. Hydrofluoric Acid (HF)	23
II.4.1.3. Mud Acid (HCl-HF Mixture)	24
II.4.1.4. Organic Acids	24
II.4.1.5. Organic Clay Acid (OCA)	24
II.4.1.6. Clay Acid (Fluoboric Acid - HBF ₄).....	25
II.4.2. Acidizing on Carbonate reservoirs.....	25
II.4.2.1. Characteristics of Carbonate Formations.....	25
II.4.2.2. Action of Acids on Carbonates	25
II.4.3. Acidizing on Sandstone reservoirs	26
II.4.3.1. Characteristics of Sandstone Formations	26
II.4.3.2. Action of Acids on Sandstone Reservoirs	27
II.4.4. Secondary Reactions	29
II.4.5. Acid Additives	31
II.4.5. Acid Selection Criteria	32
II.4.6. Laboratory Studies.....	33
II.5. Conclusion.....	35

Chapter III: Evaluation of Matrix Acidizing on Productivity Result.

III.1. Introduction.....	36
III.2. Well presentation	36
III.2.1. Well N°1:	36
III.2.1.1. Geological and petrophysical aspect	36
III.2.1.2. Reservoir aspect	37
III.2.1.3. Completion aspect.....	38
III.2.1.4. Production aspect.....	38
III.2.1.5. Well intervention aspect.....	39
III.2.1.6. Offset well perspective	40
III.2.2. Well N°2:	40
III.2.2.1. Geological and petrophysical aspect.....	41
III.2.2.2. Reservoir aspect	42
III.2.2.3. Completion aspect	42
III.2.2.4. Production aspect	43
III.2.2.5. Well intervention aspect	43
III.2.2.6. Offset well perspective	43

III.3. Discussion and treatment recommendation	43
III.4. Job needs and acid composition	45
III.5. Matrix Acidizing Job Procedure	51
III.6. Treatment job execution.....	59
III.7. Evaluation of production result	62
III.8. Economical Evaluation	64
General Conclusion.....	67
Recommendation	
Reference Bibliography	
Annex	

List of Figures

Figure I.1: Different zone of Damage.....	8
Figure I.2: Zone of Skin	10
Figure I.3: The influence of skin on permeability.....	12
Figure I.4: The influence of skin on permeability.....	13
Figure I.5: Evolution of bottom hole pressure after well shut-in (case of the ideal well)	14
Figure I.6: Evolution of bottom hole pressure after well shut-in (case of the damaged well)	15
Figure II.1: Matrix Acidizing.....	17
Figure II.2: Typical constituents of Sandstone.....	27
Figure III.1: Production Performance of Well N°1.....	39
Figure III.2: 10 % Acitic Acid Composition.....	46
Figure III.3: Organic Acid Composition	47
Figure III.4: Preflush/Overflush Acid Composition	48
Figure III.5: Mud Acid Composition	48
Figure III.6: Sample Test of Acid	50
Figure III.7: Step of Matrix Acidizing in the field	51
Figure III.8: Coiled Tubing Site (Equipment Spotting)	51

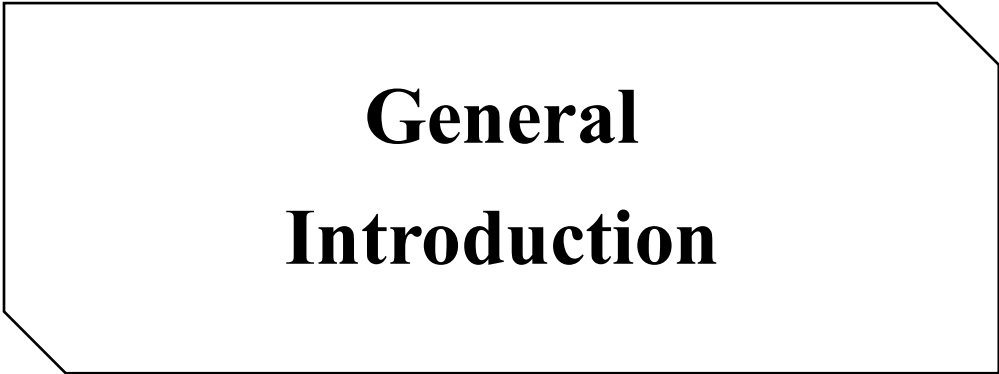
List of Tables

Table III.1: The petrophysical characteristics of well N°1	37
Table III.2: Well Test Data of well N°1	37
Table III.3: Completion Data of well N°1.....	38
Table III.4: Production Data of well N°1	38
Table III.5: The petrophysical characteristics of well N°2.....	41
Table III.6: Well Test Data of well N°2.....	42
Table III.7: Completion Data of well N°2	42
Table III.8: Test detail and results 10% Acetic Acid	49
Table III.9: Test detail and results Organic Acid	49
Table III.10: The Step of Tube Clean well N°1	52
Table III.11: The Step of using Organic Acid on Squeeze well N°1.....	54
Table III.12: The Step of Tube Clean well N°2	56
Table III.13: The Step of using Mud Acid on Squeeze well N°2	59
Table III.14: The Production Data after Treatment well N°1	63
Table III.15: The Production Data after Treatment well N°2	64
Table III.16: The Gain of Production after Operation.....	63
Table III.17: The job costs of the wells.....	65
Table III.18: The Production Data of wells after Operation	65
Table III.19: The payout of Operation wells.....	66

List of Symbols

PLT: Production Logging Tools
HMD: Hassi Messaoud
WO: Work Over
CTU: Coiled Tubing Unit
SF: Sif Fatima
TD: Total Depth (m)
Pi: Reservoir Pressure (kg/cm ² or bar)
BHP: Bottom Hole Pressure (kg/cm ² or bar)
HPJT: High Pressure Jetting Tool
SNJT: Standard Nozzle Jetting Tool
SGS: Static Gradient Survey
FGS: Flow Gradient survey
RIH: Run In Hole
POOH: Pull Out on Hole
SNJT: Standard Nozzle Jetting Tool
WHP: Well Head Pressure (kg/cm ² or bar)
MAOWP: Maximum Allowable Operating Working Pressure (kg/cm ² or bar)
MWWP: Maximum Wellhead Working Pressure (kg/cm ² or bar)
DFCV: Double Flapper Check Valve
TW: Treated Water
WOR: Water Oil Ratio
GOR: Gas Oil Ratio
HCl: Chlorhydric Acid
HF: fluorhydric Acid
CaCO₃: Calcium carbonates
BaSO₄: Barium sulfates
S: Skin

Q: Oil flow rate under bottom water conditions (bbl/day)
μ: Oil viscosity (cp)
H: Reservoir height (ft)
r: Drainage radius (ft)
rs: Damaged zone radius (ft)
rw: Well radius (ft)
β: Bottom water volume factor (bbl/STB)
T: Reservoir temperature ($^{\circ}\text{C}$)
S: Skin dimension
Sp: Partial skin
Sc: Pseudo skin
Se: Flow restriction due to partial penetration
K: Reservoir permeability (undamaged zone) (md)
Ks: Damaged zone permeability (md)
PI: Productivity Index ($\text{m}^3/\text{j/kg}/\text{cm}^2$)



General Introduction

The extraction of hydrocarbon resources from subsurface formations is of utmost importance in meeting global energy demands, well stimulation techniques play a critical role in optimizing production rates and recovering additional reserves. Among these techniques, acidizing has emerged as a highly effective method for improving well productivity and reservoir permeability by addressing damage.

However, during the life of a deposit, well productivity decreases after a certain period of production, and this is due either to natural depletion or to the eventual damage to the reservoir rock.

Formation damage is one of the main causes of low well productivity, particularly in sandstone reservoirs where the presence of clays and fine particles can significantly alter permeability. In sandstone and especially shaly sandstone formations, damage mechanisms are often associated with drilling fluid invasion, clay swelling, fines migration and pore throat plugging. These issues can lead to severe reduction in near-wellbore permeability and, in some cases, completely prevent the well from producing after drilling. In such conditions, Matrix acidizing is commonly applied as an effective remediation technique to restore formation productivity and improve hydrocarbon flow by removing formation damage around the well and restoring the formation's original permeability.

The goal of acidizing treatment is to eliminate formation damage around the well and restore the original permeability of the seam. injecting acid into a sedimentary formation often results in improved production. Conversely, injecting acid without prior thorough analysis can cause much more severe damage that can only be removed through very costly treatments.

This thesis begins by addressing the problem of well damage, which poses a challenge to well productivity and reservoir performance. Understanding the different types and causes of well damage such as drilling mud invasion, formation damage during drilling and completion operations, fine migration, scale deposition, and organic matter accumulation, is crucial. Learning acidizing techniques helps us make the best decisions for the success of the process by exploring the theories and chemistry of acidizing, this involves selecting suitable wells for the process and the necessary preparation steps, followed by preparing an operational report for the well. The appropriate acid is then selected based on the reservoir to avoid adverse reactions that could negatively impact the reservoir and future production.

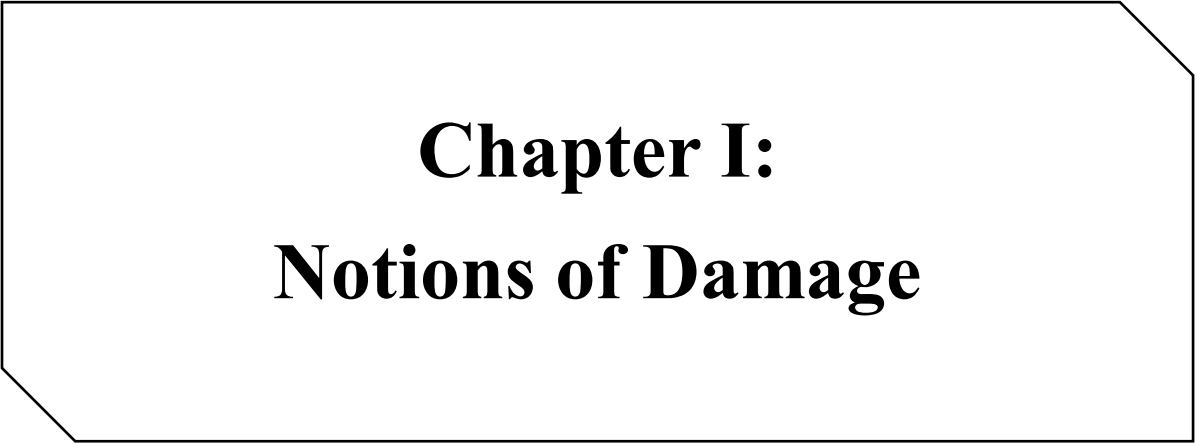
The objective of this final year project is to study the impact of well stimulation using acidizing on well productivity in detail, with a particular focus on the use of acidic fluids in the stimulation process. This will be achieved by examining the condition of two wells in the Hassi Messaoud region before and after acidizing to determine the success of this experiment, the conditions that enable its success.

In this context, our project will address several ideas, including: a case study of the types of acid solutions used in different types of Sandstone reservoir rocks in the Hassi Messaoud and Bir Berkine oil fields; an analysis of the types of damage and a discussion of fluid treatment methods; defining the implementation process, procedures, and final report; the results of this treatment; and an economic evaluation of this experience for determining its success.

These challenges highlight first the need of selecting the effective stimulation techniques that could restore formation permeability by dissolving right damaging materials and improving reservoir-wellbore connectivity. However, the success of this technique in sandstone reservoirs depends heavily on the appropriate selection of the treating fluid system, its compatibility with reservoir rock and fluids as well as the procedure how it placed in the reservoir.

The main problematic addressed in this study can therefore be formulated as follows:

How can appropriate acidizing treatment be selected and optimized to effectively restore or initiate production in wells completed in sandstone and shaly sandstone reservoirs affected by severe formation damage?



Chapter I:

Notions of Damage

I.1. Introduction

Damage reduces the well production or injection capacity, and the removal of damage is one of the major goals of petroleum engineers. This chapter identifies and quantifies formation damage and includes ideas on treatment strategy. It is important to note that not all types of formation damage require a removal treatment. Some types of damage will clean up during production, and others can be removed by changes in operating practices. In addition, some producible impairment is misconceived as damage.

I.2. Damage concept

Damage represents all incrustations, whether mineral or that can alter the natural permeability by their deposition inside the reservoir or by sealing perforations or even the production tubing. This damage can be located in the different parts of the effluent, from the reservoir to the surface. [1]

Damage is an undesirable operational and economic problem that can occur during the various phases of oil and gas recovery from subsurface reservoirs including production, drilling, hydraulic fracturing, and work over operations, damage indicators include:

- ✓ Permeability impairment.
- ✓ Skin damage.
- ✓ Decrease in well performance.

I.3. Origin and causes of the damage [2]

A proper understanding of the origin and mechanisms of formation damage is essential for selecting effective remedial treatments. Formation damage may result from several factors, which can be classified into the following categories:

I.3.1. Damage due to the formation

Damage originating from the formation itself is considered one of the main contributors to productivity decline. It is mainly characterized by its **composition** and **location**, both of which play a key role in determining the success of stimulation operations such as acidizing. The selection of suitable fluids and appropriate placement techniques is therefore critical, several types of damage may develop within the reservoir and may require acidizing or other treatment methods, including:

- Salt deposits.

- Organic deposits (asphaltenes)
- Paraffin deposits.
- Sulfate deposits.
- Fines migration.
- Clay swelling. [2]

a. Salt deposits

Variations in pressure and temperature during production can lead to salt precipitation from highly saline formation water. Such deposits may plug the formation matrix, perforations, or even production tubing. In many cases, salt can be dissolved by injecting fresh water. However, if the injected water is incompatible with the formation water, it may lead to secondary precipitation such as barium sulfate (BaSO_4).

b. Organic deposits (asphaltenes)

Asphaltenes are complex organic compounds that may precipitate from crude oil under changes in pressure, temperature, or fluid composition. Their accumulation in the formation or production equipment can severely restrict flow and reduce productivity. Mitigation strategies include the use of solvents, dispersants, surfactants, or operational adjustments to prevent precipitation.

c. Paraffin deposits

Paraffin deposits are a type of organic deposit that can form in oil and gas wells. Paraffins are naturally occurring hydrocarbons that are present in crude oil, and they can precipitate out of the produced fluids and accumulate in the formation or on the production equipment, causing formation damage and reduced productivity. Paraffin deposits can be especially problematic in cold environments, as the paraffins can solidify and become more difficult to remove. To mitigate paraffin deposits, various techniques can be used, such as the use of chemical solvents or mechanical methods to dissolve or remove the deposits. Additionally, proper selection of production fluids and procedures can be done to prevent the formation of paraffins and reduce the risk of deposition.

d. Sulfate deposits

Sulfate scale results from precipitation of sulfate minerals present in formation water. These deposits may form hard and resistant scale, especially at high temperatures. Chemical scale inhibitors or dissolution treatments are often required, in addition to mechanical removal when necessary.

e. Fines migration

Fines migration occurs when small particles in the reservoir rock become dislodged by fluid flow and move toward the wellbore. These particles may accumulate and block pore throats, resulting in reduced permeability and production decline. [2]

f. Swelling and dispersion of clays

Water-based fluids used during drilling, completion, or workover may disrupt the equilibrium between clays and formation water. This can cause clay minerals to swell or disperse, leading to significant permeability reduction. Minerals such as kaolinite, illite, and chlorite may also become mobilized and obstruct pore channels.

I.3.2. Damage due to perforation

Many drilling operations are conducted under overbalanced conditions, which encourages the formation of filter cake and filtrate invasion into perforation tunnels. This can lead to near-wellbore plugging, increased pressure drops, and additional skin effect.

I.3.3. Cement filtrate invasion

During liner cementing operations, cement filtrate may invade the formation. Although cementing is essential for zonal isolation and structural support, filtrate invasion can alter the formation properties and cause permeability impairment near the wellbore.

I.3.4 Damage due to stimulation

Although stimulation treatments such as acidizing and hydraulic fracturing are intended to improve well productivity, they may also create damage if not properly designed. Improper stimulation fluids or reactions may alter rock properties, generate fines, or cause precipitation that reduces permeability.

I.3.5. Damage due to well operations (Drilling, Work-Over and Snubbing)

For safety purposes, drilling and workover operations often require killing the well by circulating heavy fluids, typically oil-based muds. While this procedure prevents uncontrolled flow, it may also result in severe formation damage due to filter cake formation and permeability reduction.

a. perforation plugging

When performing workover or snubbing operations, it's common for filter cakes to form in the perforations, which can cause perforation plugging and reduce well productivity. To manage the effects of filter cakes in the perforations, a range of strategies may be employed, such as using chemical treatments to dissolve or remove the plugging material, or using mechanical methods to clean out the perforations.

b. wettability alteration

Wettability significantly influences oil recovery. In water-wet reservoirs, oil tends to remain trapped, whereas in oil-wet conditions, oil flows more easily. Wettability alteration may occur due to fluid invasion, chemical exposure, or changes in reservoir conditions, and can negatively affect production.

c. Water block

Water block occurs when water saturation increases near the wellbore, reducing hydrocarbon relative permeability and limiting flow. This phenomenon may result from poor completion practices or uncontrolled water invasion. Treatments include surfactant injection, polymer usage, or mechanical stimulation to bypass the blocked zone.

d. Emulsification

Emulsification refers to the formation of stable mixtures between immiscible fluids such as oil and water. The presence of emulsifying agents may create persistent emulsions that restrict flow and complicate separation processes.

I.3.6. Damage due to water injection

Water injection is widely used to maintain reservoir pressure and improve recovery. However, improper injection practices may lead to near-wellbore water saturation and cause water block, thereby reducing production performance.

I.4. Damage Location

Damage is defined as an obstacle preventing the flow of fluids from the reservoir to the well; the areas of damage location are illustrated, taking into account the well configuration.

I.4.1. At the bottom of the well

Deposits of various origins may accumulate at the bottom of the well, including formation particles, corrosion products, salts, paraffins, and asphaltenes. [3]

I.4.2. At the wellbore well

- **External cake**

External cake is a layer formed on the wellbore wall during drilling operations. It is composed of solids from drilling fluids and plays a role in stabilizing the wellbore but may also restrict flow. [3]

I.4.3. Around the wellbore

a. Internal cake:

Internal cake refers to fine particles that penetrate and accumulate inside the formation close to the wellbore, often originating from drilling mud, cement, or completion fluids. [3]

b. The invaded zone:

The invaded zone refers to the area beyond the internal cake that is invaded by the filtrates from the drilling mud and cement. This area can modify the natural environment of the porous formation and can result in various effects such as:

- Change in wettability.
- Formation of emulsions.
- Swelling and/or disintegration of clays.
- Precipitation of various minerals and sometimes organic materials in the case of incompatibility between the filtrate and the fluids in place. [3]

I.4.4. Particle build-up

Particle build-up in oil wells refers to the accumulation of solid particles, such as sand, silt, clay, and other minerals, in the wellbore or on the production equipment. These particles can come from several sources, including the reservoir rock, drilling fluids and muds, formation fines, and corrosion products. [3]

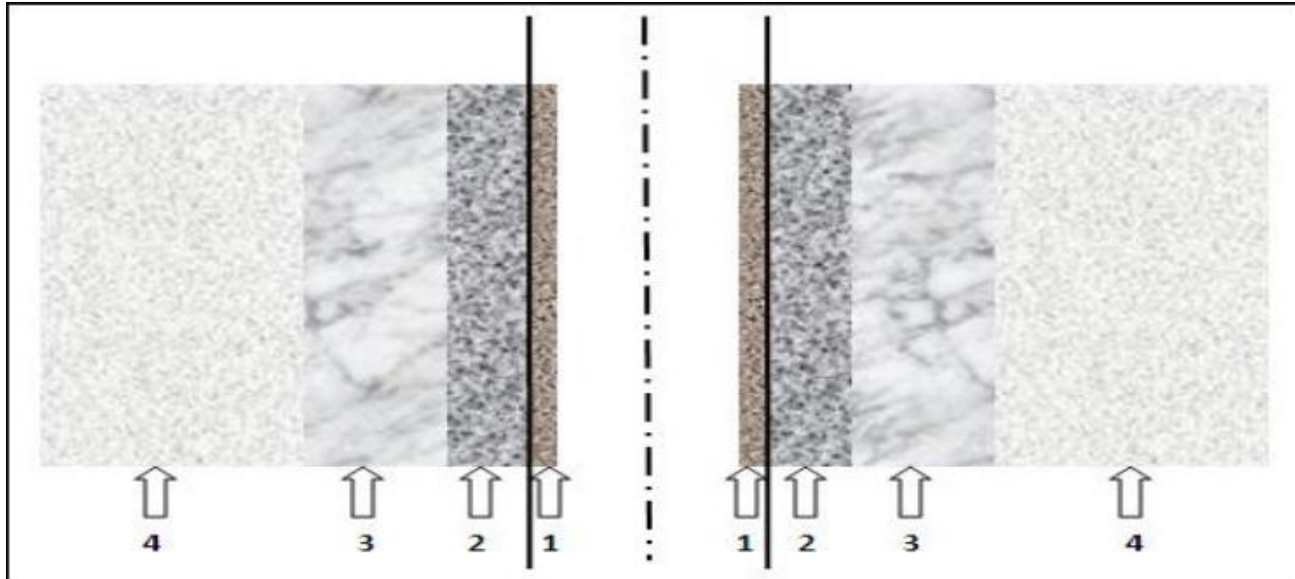


Figure I.1: Different zones of damage. [4]

- **Zone 1:** External cake lining the walls of the wellbore.
- **Zone 2:** Internal cake composed of solids that have penetrated the porous formation.
- **Zone 3:** zone invaded by the sludge filtrate.
- **Zone 4:** Virgin zone where the permeability is not affected.

I.5. Detection of damage

Several commonly used methods are available, including: [5]

- Laboratory sampling and analysis.
- Complete well history.
- Well testing.
- Analysis of the production system.
- Production logging PLT.

I.5.1. Laboratory sampling and analysis

Detailed analysis of formation cores is essential for designing an effective treatment to eliminate formation damage, Core analysis techniques used in matrix treatment include petrophysical evaluations to measure porosity as well as absolute and relative permeability. In addition, flow tests are conducted on the cores to assess the rock's permeability response during the injection of various fluids.

I.5.2. Complete well history

A well's history is a crucial source of information of all kinds to help detect the causes, nature, and types of damage likely to be found in the well to create a complete well history, one must examine all operations and changes made from the drilling phase through the entire production phase, up to the present day.

I.5.3. Well Test

Well tests are a key source of information for assessing whether reservoir production is restricted. However, it is known that the total skin effect (S) includes parasitic factors (pseudo-skin) that must be subtracted to determine if actual clogging is present. Well tests also provide other crucial information: an assessment of reservoir pressure and the productivity index.

I.5.4 Analysis of the production system

The analysis of a production system involves evaluating the various components of the system to identify potential issues or opportunities for optimization. This can include the reservoir wellbore, completion, production facilities, and any associated infrastructure.

I.5.5 Production logging (PLT)

Production logs play a very important role in detecting damage. For example, PLT allows us to determine the contribution of each drilled bench to the total well production, thus providing accurate localization of the damage. [6]

I.6.Skin effect

I.6.1 Definition

The skin factor is a dimensionless parameter obtained from well testing. It represents the total additional pressure drop occurring near the wellbore, Skin includes both actual formation damage and pseudo-skin effects caused by completion configuration. [7]

It represents an additional pressure loss (ΔP_{skin}) located near the well.

- $S > 0$: Damaged reservoir.

- $S < 0$: Stimulated reservoir.

- $S = 0$: Undamaged reservoir.

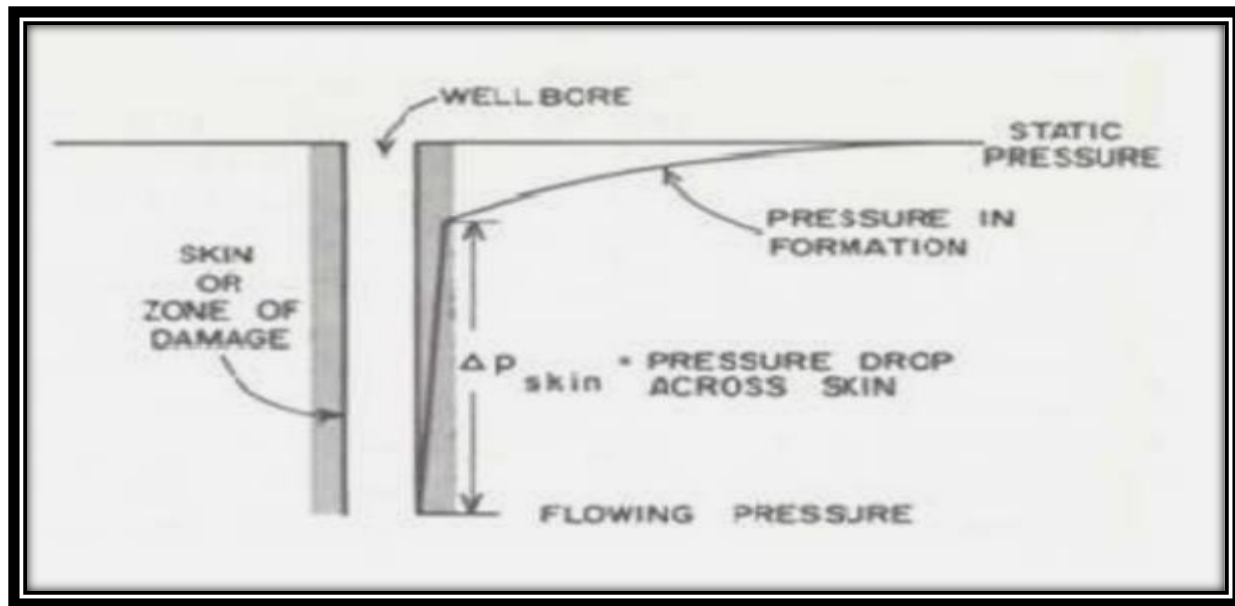


Figure I.2: Zone of skin. [4]

I.6.2 The origin of skin [7]

The skin has several origins, the most important of are

I.6.2.1 Perforations

The ideal well model assumes that its contact with the formation extends over 360° , but with perforations, it is easy to see that production is forced only through the openings. This results in a pressure drop, which is expressed as the skin " S_p ," called the partial effect coefficient, and which depends on the number of perforations and their distribution.

I.6.2.2 Partial Penetration

Perforating only a portion of the wellbore restricts flow lines near the wellbore. This contributes to the existence of a positive skin (pseudo-skin " S_c ") which varies depending on the formation thickness, wellbore diameter, and drilled depth.

I.6.2.3 Overall damage

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

$$S = S_e + S_p + S_c \dots \dots \dots (I.1)$$

- S_e : the real damage around the wellbore (matrix)
- S_p : the pressure loss due to perforations
- S_c : the choke of the flow due to partial penetration.

All of these contribute to increased pressure losses and flow restrictions, resulting in an overall positive skin factor. The measured skin is the net result of all these separate skin components.

I.6.2.4 Stimulation treatments

Treatments like acidizing and fracturing are done to improve well productivity but they can also leave an altered zone around the wellbore, contributing to skin.

I.6.2.5 Mechanical effects

Issues like pipe eccentricity, improper well completion, solids deposition etc. can lead to mechanical effects that increase skin.

I.6.3 The skin effect on permeability [8]

The radius (r_e) and permeability (K_e) of the damaged zone are related to the skin factor (S) by Hawkins' expression:

$$s = \left(\frac{k}{k_s} - 1 \right) \ln \frac{r_s}{r_w} \dots \dots \dots (I.2)$$

s : skin.

k : reservoir permeability (md).

k_s : permeability of damage (md).

r_w : the outer radius of the damaged zone.

r_s : the inner radius of the damaged zone.

Hawkins' expression can be used to estimate the skin factor based on the radius and permeability of the damaged zone. A positive skin factor indicates that the near-wellbore region is damaged and has reduced permeability, while a negative skin factor indicates that the near-wellbore region has been stimulated and has increased permeability. The magnitude of the skin factor will depend on the extent and nature of the damage or stimulation around the wellbore.

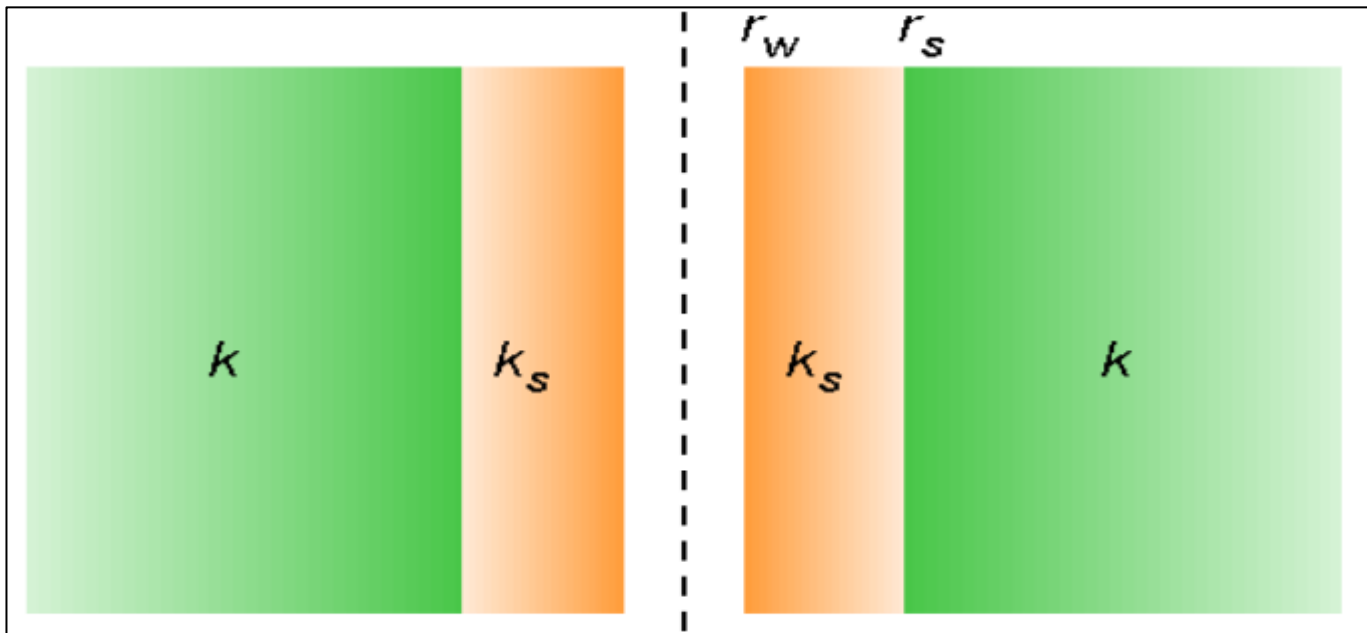


Figure I.3: The influence of skin on permeability. [6]

I.6.4 The effect of skin on productivity [9]

Understanding the IPR (Inflow Performance Relationship) curve and Hawkins' equation is essential to understand how formation damage (skin) affects well productivity.

For an oil well, the IPR equation is written as:

$$Q = \frac{k h (P_g - P_{wf})}{141.2 \mu \beta (\ln \frac{r_e}{r_w} + s)} \dots\dots\dots (I.3)$$

Q = Oil flow rate at bottomhole conditions (STB/day).

k = Permeability (mD).

h = Reservoir net pay (ft).

Pi = Reservoir pressure (psi).

P_{wf} = Flowing bottomhole pressure (psi).

μ = Oil viscosity (cp).

β = Oil formation volume factor (RB/STB).

r_e = Drainage radius (ft).

r_w = Wellbore radius (ft).

S = Skin factor.

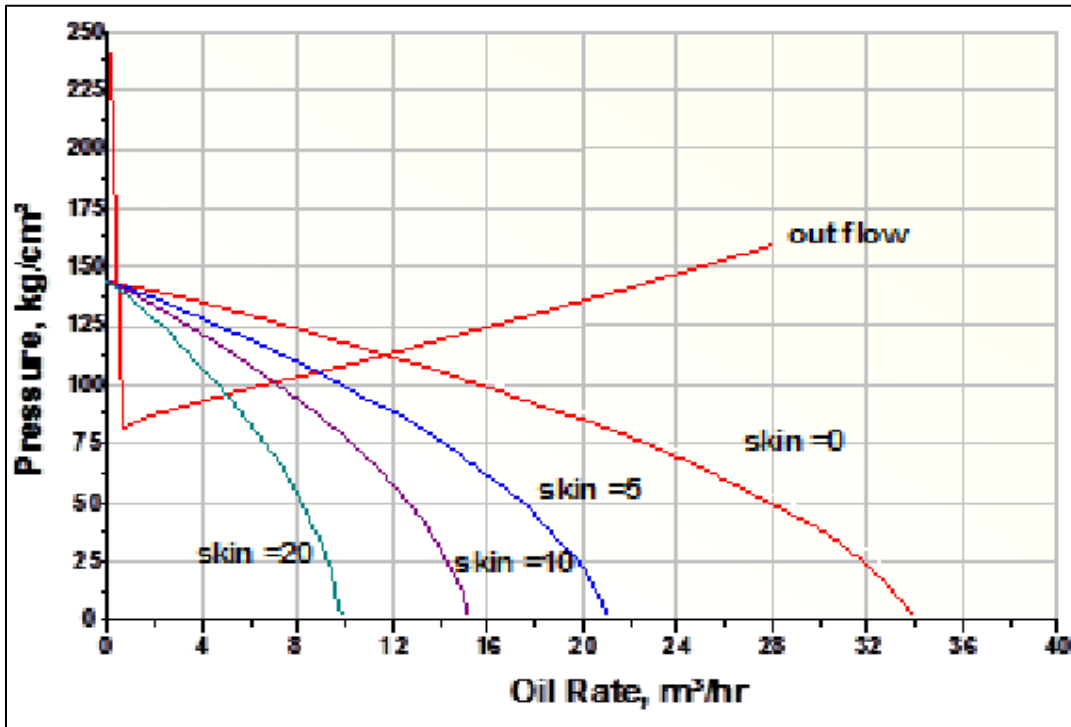


Figure I.4: Influence of the skin on productivity. [6]

The above graph represents the influence of skin on productivity, by plotting the pressure curve as a function of flow rate. It can be observed that the relationship between flow rate and skin is an inverse relationship.

I.7 Expression of damage

I.7.1. Ideal well [9]

An ideal well is defined as a well with a radius of a , open over the entire height h of the layer whose permeability K has not been altered. If, after a time T of production at a constant flow rate Q_F , the well is shut-in, the evolution of the bottomhole pressure $P_{WF}(t)$ at time $(T+\Delta t)$ can be expressed as follows

$$P_{wf} = P_g - \frac{\mu Q F}{4\pi h k} \ln\left(\frac{T + \Delta t}{\Delta t}\right) \dots\dots\dots (I.4)$$

The graphical representation in semi-logarithmic coordinates of the variation of pressure is a straight line whose slope allows for the calculation of the reservoir's transmissibility.

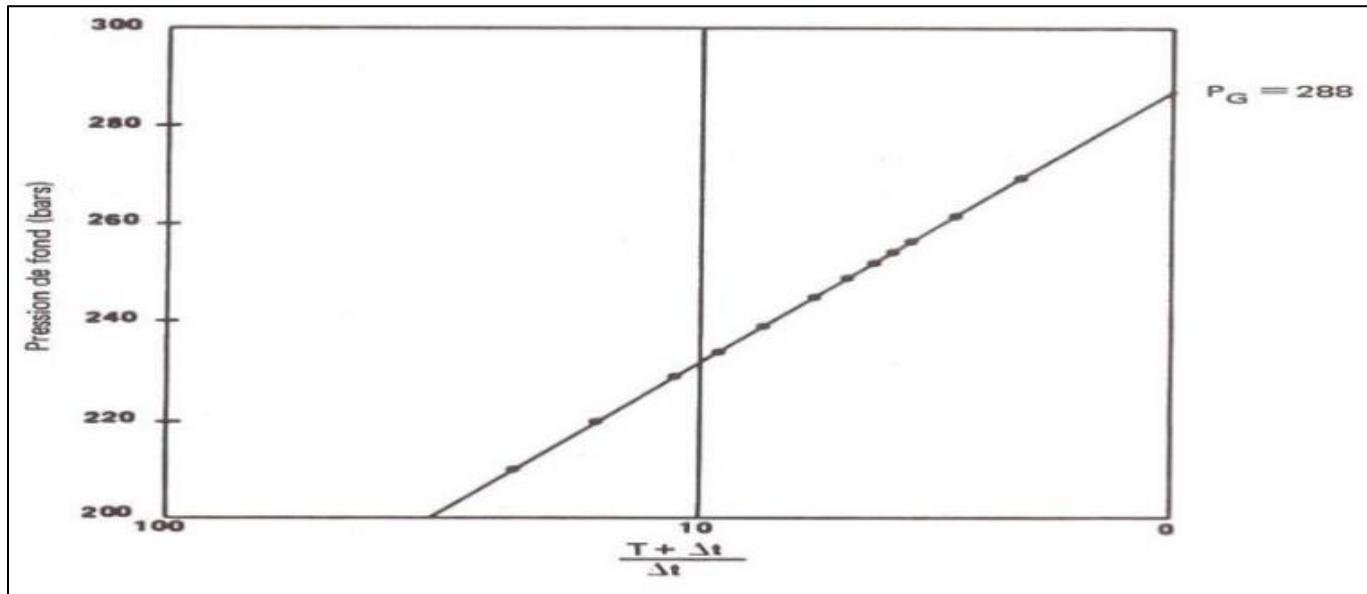


Figure I.5: Evolution of bottomhole pressure after well shut-in (case of the ideal well). [4]

I.7.2. Damaged well [9]

In the case of a damaged well, the transmission of pressure is not uniform throughout the reservoir and is affected by local heterogeneity in the immediate vicinity of the well (3 to 5 ft), meaning that the permeability near the wellbore, K_S , becomes different from the far-field permeability.

As a result, any decrease in permeability will have a similar effect to an additional pressure drop " ΔP_s " in the near-wellbore region due to the skin effect (boundary effect).

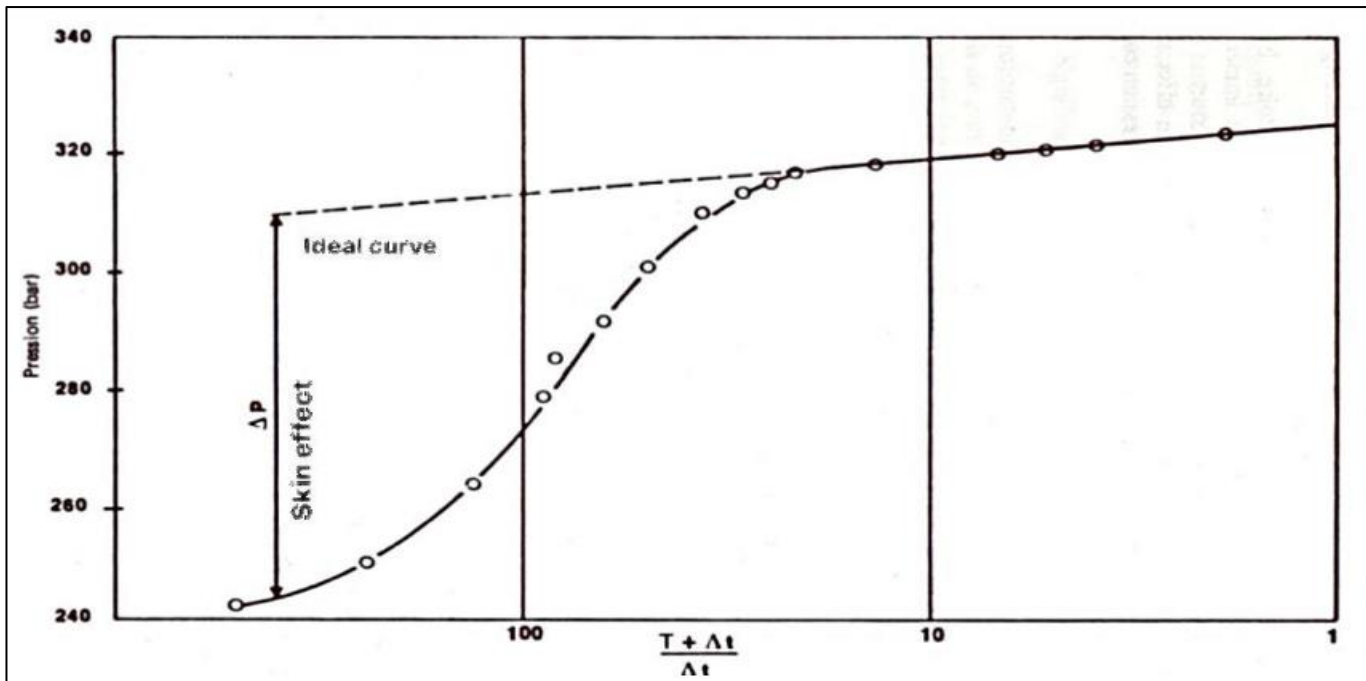


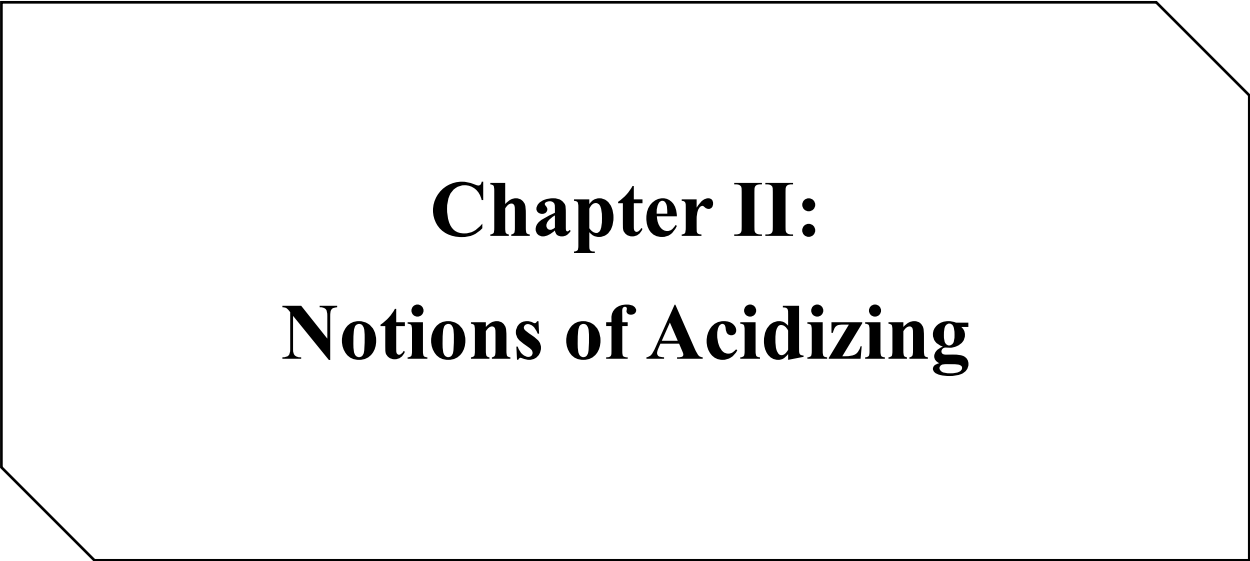
Figure I.6: Evolution of bottomhole pressure after well shut-in (Case of the damaged well). [4]

From this graph, the pressure evolution is not uniform throughout the reservoir; it is affected by the local heterogeneity found in the immediate vicinity of the well.

This is due to the presence of damage that negatively affects reservoir pressure. Consequently, any decrease in permeability will have an effect similar to an additional pressure drop " ΔP_s " near the well due to the wall effect (skin effect). In practice, the pressure curve of a well will not coincide with the curve of an ideal well.

I.8. Conclusion:

To maximize well performance for achieving a well-designed completion and the elimination of damage. The tools are an array of stimulation and damage removal techniques and chemicals that are readily available. Still, although formation damage removal seems easily achievable, the goal of a damage-free completion can be elusive.



Chapter II:

Notions of Acidizing

II.1. Introduction

Matrix stimulation is a technique in which a solvent is injected into the formation to dissolve some of the materials present and hence recover or increase the permeability in the near-wellbore region. The most common matrix stimulation treatment is acidizing, in which an acidic solution is injected to dissolve minerals in the formation. However, other solvents are also used. The next most common fluids are organic solvents aimed at dissolving waxes, paraffins, asphaltenes or other organic damaging materials.

This chapter focuses on matrix acidizing; however, the reader should keep in mind that many of the theories and calculation procedures presented here can also be applied to nonacid solvent treatments.

II.2. The main types of stimulation [11]

II.2.1. Hydraulic fracturing

It consists of injecting a treatment fluid at a pressure higher than the formation fracture pressure. This creates cracks or fissures in the formation, opening channels with very high permeability. These channels allow the effluent to flow much more easily, thereby increasing the overall permeability and resulting in a boost in productivity.

II.2.2. Acid Fracturing

In this method, the fracturing fluid is an acid injected at high pressure to create a fracture. The acid dissolves the fracture faces in a non-uniform manner, creating "dissolution channels" (etching). These channels remain open even after the pressure is released, which significantly increases permeability.

II.2.3. Acidizing

This involves injecting a volume of acid containing chemical additives at an injection pressure lower than the fracture initiation pressure. The purpose of the acid is to:

- Dissolve specific particles blocking the formation pores.
- Solubilize certain compounds of the rock matrix itself.
- Modify the physicochemical state of the near-wellbore area.

II.3. Theory of Acidizing

II.3.1. Definition [1]

Acidizing is a stimulation technique designed to enhance the productivity of oil and gas wells, or the injectivity of water and gas injection wells.

In Matrix Acidizing, acids are injected into the formation to eliminate near-wellbore damage (Skin Effect) that restricts fluid flow. This technique is most effective when the rock possesses good natural permeability.

The treatment fluids are injected at pressures strictly below the formation fracture pressure to ensure a uniform radial penetration and to avoid bypassing the damaged zones through induced fractures.

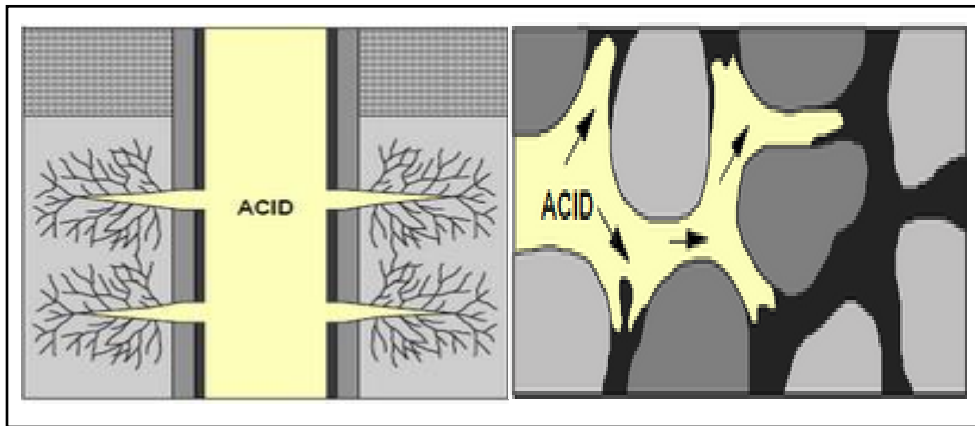


Figure II.1: Matrix Acidizing. [11]

II.3.2. Objectives of Acidizing

The primary goal of an acid restoration operation is to clear blocked pathways. To achieve this, the acid performs the following functions:

- **Dissolution of Plugging Particles:** Dissolving solids that are clogging the pore throats of the reservoir rock.
- **Matrix Attack (Liberation of Insoluble Fines):** If the plugging particles are insoluble, the acid attacks the surrounding rock matrix to release these particles and allow them to be produced back.
- **Physicochemical Modification:** Altering the state of particles, such as treating clay swelling issues to restore flow area.
- **Wellbore Remediation (Skin Removal):** Eliminating the "Skin Effect" (Pellicular effect) to reduce the pressure drop around the wellbore.

- Deep Formation Treatment: Extending the treatment deeper into the formation to facilitate a smoother flow of fluids toward the wellbore. [11]

II.3.3. Candidate Selection for Acidizing

Acidizing a well does not guarantee a production gain unless critical data is analyzed. To select the right candidate and the appropriate treatment, the following reports must be evaluated:

A. Geological Report

Sedimentological and petrophysical analyses provide information on:

- Rock Lithology: The mineral composition of the reservoir.
- Clay Content and Type: Crucial to avoid clay swelling or migration issues.
- Natural Fractures: Presence of existing fissures that might divert the acid. [14]

B. Field Production Report

This report focuses on the reservoir's dynamic behavior:

- Production History: Analyzing the dispersion of permeability values and the Productivity Index (PI).
- Reservoir Study: Data on porosity ($\emptyset$), permeability (K), and fluid saturations (S_w , S_g , S_o).
- Past Stimulations: Previous types of acids and additives used and their effectiveness. [14]

C. Completion and Drilling Report [14]

- Stratigraphic Position: Using isobath and isopach maps to determine fluid interfaces and assess the risk of water or gas coning.
- Drilling History: Reviewing drilling fluid properties (density, pH, filtrate) to identify potential formation damage or fluid losses encountered during drilling.
- Well Logging: Interpreting tools such as Sonic, Induction, Gamma Ray, and Caliper logs to determine:
 - ✓ Rock and fluid nature, porosity, and shaliness.
 - ✓ Rock mechanical parameters and consolidation state.
 - ✓ Fluid saturation levels.

- ✓ Filtrate Invasion Depth: How deep the drilling fluid has penetrated the formation.
- ✓ Hole Integrity: Identifying washouts (caves) or borehole restrictions.
- Core Analysis
 - ✓ Lithology (Nature of the rock): Determining if the reservoir is Limestone, Dolomite, or Sandstone.
 - ✓ Porosity and Permeability: Measuring the storage capacity and the ability of fluids to flow through the matrix.
 - ✓ Wettability: Understanding the rock's affinity for oil or water, which affects acid reaction and fluid recovery.
 - ✓ Solubility of Plugging Agents or Mineral Particles: Conducting solubility tests (Acid Response) to determine the efficiency of the acid in dissolving minerals or scales.
 - ✓ Iron Content: Identifying the presence of iron minerals (like Siderite or Pyrite) to prevent the precipitation of iron hydroxide ($\text{Fe}(\text{OH})_3$) during treatment, which can permanently plug the formation.

E. Well Test Report

This report provides the dynamic data required to calculate the "Skin Factor" and justify the cost of stimulation:

- Flow Rate (Q): The current production rate of oil, gas, or water.
- Bottom-hole Pressure (P_{wf}) and Wellhead Pressure (P_t): Essential for calculating the drawdown and productivity index.
- WOR (Water-Oil Ratio) and GOR (Gas-Oil Ratio): To ensure the acid won't lead to excessive water or gas production.
- Fluid Analysis: Laboratory analysis of the produced hydrocarbons and water.
- Pressure Build-up (PBU) Interpretation: Analyzing the pressure recovery after shutting in the well to determine:
 - ✓ The Skin Factor (S): To quantify the degree of damage.
 - ✓ Reservoir Pressure (P_i): To ensure there is enough energy to produce after treatment. [14]

III.3.4. Criteria and Steps for an Acidizing Operation

To initiate an acidizing operation, the following steps must be strictly followed:

- Candidate Selection: Confirm that the well is a suitable candidate for matrix stimulation by analyzing the production decline curve.

- **Damage Diagnosis:** Determine the root cause, severity (Skin factor), and location of the damage by reviewing production and intervention histories.
- **Nodal Analysis:** Perform a nodal analysis to justify the intervention. This helps determine the potential well performance and ensure that the restriction is indeed in the formation and not in the completion strings.
- **Fluid Formulation:** Select the appropriate chemical formulation to minimize the risks of failure, such as the formation of secondary precipitates, sludges, or emulsions.
- **Injection Parameters:** Calculate the maximum injection pressure and rate to stay below the formation fracture gradient.
- **Volume Calculation:** Determine the treatment volume required per foot of perforated interval.
- **Diversion Strategy:** If the reservoir is multi-layered or thick, use an appropriate diversion method (chemical or mechanical) to ensure uniform acid distribution.
- **Placement Mode:** Select the most effective placement method based on the specific well completion and configuration.
- **Flowback and Cleanup Plan:** Establish a detailed plan for well cleanup and restarting production to ensure all spent acid and reaction products are recovered.
- **Economic Evaluation:** Assess the profitability of the treatment by estimating the expected increase in the Productivity Index (PI) or Injectivity. [1]

III.3.5. The Operational Stages of an Acid Treatment [15]

The primary objective of an acid treatment is to eliminate formation damage and restore well productivity. The choice of acid type depends mainly on the nature and location of the damage. Once identified, the acid type is selected, and volumes are calculated based on reservoir parameters and laboratory test results.

In the Hassi Messaoud (HMD) field, the main stages of matrix acidizing are as follows:

III.3.5.1 Tubing and Perforation Cleaning

Before any matrix stimulation, a Tube Clean operation is mandatory to clear the production tubing. This process utilizes Coiled Tubing or a concentric string to pump cleaning fluids.

1. Objectives of the Tube Clean

- **Debris Removal:** To flush out all HCl-soluble materials, such as sediments, rust (iron oxides), and scales.
- **Contamination Prevention:** To remove any substances adhered to the tubing and liner walls. This prevents them from being forced (squeezed) into the formation during the main treatment, which would otherwise lead to permanent plugging.

2. Solvent Wash for Asphaltene Management

For wells prone to frequent asphaltene deposits, it is highly recommended to use a solvent like Reformate.

Sequence: The solvent must be circulated before the diluted acid stage.

Reasoning: Asphaltenes are chemically incompatible with acid. Contact between the two can trigger the formation of sludge or rigid emulsions that are extremely difficult to remove from the pore space.

3. Perforation Cleaning Strategy

In wells equipped with cemented and perforated liners, cleaning the perforations is an indispensable step.

- Fluids Used: "Clean Sweep," Reformate, or HCl acid.
- Methodology: To ensure maximum efficiency, multiple passes are made directly across the perforated intervals to mechanically and chemically dislodge obstructions.

4. Underbalanced Cleaning with Nitrification

The nitrification of fluids (mixing treatment fluids with Nitrogen) allows the well to be cleaned in an Underbalanced state.

- Benefit: This reduces the hydrostatic pressure, allowing the formation to "flow back" during the cleaning process.
- Result: It ensures a much more effective evacuation of insoluble debris and scales toward the surface rather than pushing them deeper into the reservoir.

III.3.5.2. The Matrix Treatment Process

The treatment consists of three critical stages, followed by well cleanup and placement strategies:

A. The Preflush

The Preflush is essential in all matrix treatments, particularly in sandstone formations using Mud Acid. The most common fluid used is Hydrochloric Acid (HCl).

Role of the Preflush:

- Carbonate Dissolution: It dissolves carbonate minerals to prevent them from reacting with Hydrofluoric Acid (HF). This minimizes HF consumption and prevents the precipitation of Calcium Fluoride (CaF_2), which is a permanent plugging agent.

- Displacement of Formation Water: It pushes formation water away from the wellbore. This avoids contact between HF and water rich in ions like K^+ , Na^+ , and Ca^{2+} , thereby preventing damage caused by sodium or potassium fluosilicates.

B. The Main Treatment

The Mud Acid (a mixture of HF and HCl) is the primary treatment fluid.

- Composition: Typically a mixture of 6.5% HF and 1.5% HCl (or other ratios depending on the formation), combined with corrosion inhibitors and specialized additives.
- Function: Hydrofluoric acid (HF) reacts with clays, cement filtrate, and drilling mud to dissolve silicates and improve permeability near the wellbore.
- Design: Most treatment volumes are calculated based on a penetration radius of 1 to 1.5 meters.

C. The Overflush

Injected immediately after the main treatment, the Overflush can be HCl or a light hydrocarbon (like diesel or gasoline).

- Objective: To push potential damaging reaction products deep into the formation, away from the critical near-wellbore area. A penetration radius of 4 feet is usually sufficient.
- Additives perform three vital roles:
 1. Facilitate the flowback (dégorgement) of spent acid and reaction products.
 2. Restore the water-wettability of the rock.
 3. Prevent the formation of stable emulsions.

II.3.5.3. Well Flowback

Flowback must be performed immediately after the treatment. The chemical reaction products are often unstable; if they remain in the reservoir, they can transform into secondary precipitates that permanently block the matrix pores.

II.3.5.4. Fluid Placement

The placement of treatment fluids can be done by coiled tubing, concentric or bullheading depending on the application.

II.3.5.5. Treatment Diversion

When acid is injected into a formation, it naturally follows the path of least resistance, penetrating the most permeable pores—which are ironically the ones that need stimulation the least. To overcome this, diverting agents are used to temporarily plug the most open or permeable pores/perforations. This forces the treatment fluid into the lower permeability or highly damaged zones. Diversion allows for the sequential treatment of plugged layers by isolating them from one another.

- **Mechanical Diversion**

This involves setting a packer to physically isolate the zone of interest from risky or high-permeability zones, directing the fluid solely to the target interval. This is a selective treatment typically applied in wells equipped with a concentric string; however, it is not feasible in Open-hole completions.

- **Foam or Particle Diversion (Chemical/Physical)**

This technique involves injecting "slugs" or diverting materials (such as foam or beads) into the fluid. These agents temporarily restrict the flow into the most permeable (less damaged) zones, ensuring a homogeneous distribution of acid across the entire reservoir thickness.

II.4. Chemical of acidizing

II.4.1. Main Types of Acids Used [1]

The chemical properties and reaction rates of acids are the primary factors in selecting the appropriate stimulation fluid. In the Hassi Messaoud field, the following systems are the most commonly utilized:

II.4.1.1. Hydrochloric Acid (HCl)

HCl is a strong mineral acid widely used in various stages of well stimulation.

- Functions: It is used for carbonate fracturing, sandstone matrix acidizing (as a preflush), and perforation washing. It is also effective in removing acid-soluble scales and deposits.
- Matrix Action: It has practically no effect on quartz and very little on clays, but it is highly effective at dissolving carbonates.
- Concentration: Its ionization peaks at approximately 26%, making it a highly reactive choice for carbonate-rich zones.

II.4.1.2. Hydrofluoric Acid (HF)

HF is the only common acid capable of dissolving the silicate framework of sandstone.

- **Functions:** Its primary role is to solubilize fines and silicate particles (clays, feldspars) that are insoluble in HCl.
- **Matrix Action:** It reacts moderately with quartz but aggressively with clays and carbonates.
- **Precaution:** It is never pumped alone because it reacts with carbonates to form Calcium Fluoride (CaF_2), a permanent plugging precipitate.

II.4.1.3. Mud Acid (HCl-HF Mixture)

The industry standard for sandstone matrix stimulation, typically a mixture of 12% HCl and 3% HF or 6.5% HF and 1.5% HCl.

- **Functions:** The HCl component reacts with carbonates and keeps the pH low to prevent precipitation, while the HF dissolves the clays and drilling mud solids.
- **Efficiency:** Approximately 3.79 liters of standard Mud Acid can dissolve 0.10 kg of sandstone.

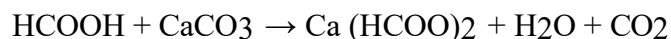
II.4.1.4. Organic Acids

Organic acids are preferred for high-temperature wells or when deep matrix penetration is required due to their low reaction rates.

- A. Acetic Acid (CH_3COOH): Often used at a 10% concentration or as an additive. It is selected for its slow reaction speed and high-temperature stability.



- B. Formic Acid (HCOOH): Stronger than acetic acid but weaker than HCl. It provides a more uniform metal corrosion profile, and with proper inhibitors, it protects tubulars effectively.



II.4.1.5. Organic Clay Acid (OCA)

OCA is a sophisticated retarded acid system composed of Citric acid, Boric acid, HCl, and HF.

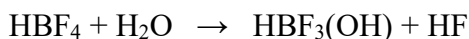
- **Functions:** This system allows for deep matrix penetration and stabilizes suspended clays within the pores.

- **Application:** It is specifically used for poorly consolidated formations containing low concentrations of HCl-sensitive clays at temperatures below 150°C.

II.4.1.6. Clay Acid (Fluoboric Acid - HBF₄)

Fluoboric acid is a unique system that generates HF through a continuous, partial hydrolysis process.

- **Hydrolysis Reaction:**



- **Functions:** Used for treating clay-rich sandstone reservoirs. Beyond its dissolving power, it prevents clay migration by "fusing" or chemically bonding residual clay particles to the pore walls, ensuring long-term permeability.

II.4.2. Acidizing on Carbonate reservoirs

II.4.2.1. Characteristics of Carbonate Formations [16]

Carbonate rocks are sedimentary rocks composed primarily of carbonate minerals. The two most significant types are:

- **Limestone (CaCO₃):** Highly soluble in Hydrochloric Acid (HCl) and organic acids. However, it reacts with Hydrofluoric Acid (HF) to form an undesirable precipitate called Calcium Fluoride.
- **Dolomite (CaMg(CO₃)₂):** Composed of calcium and magnesium carbonates. It is also soluble in HCl and organic acids.

In their pure state, these rocks are almost 100% soluble in HCl. In practice, they may contain associated minerals like Siderite (FeCO₃) or clays (such as Chlorite), but the overall solubility remains extremely high (at least 95% for calcite).

II.4.2.2. Action of Acids on Carbonates

It is crucial to evaluate how each acid interacts with both the rock matrix and the formation damage.

A. Hydrochloric Acid (HCl)

- **Action on the Matrix:**

The chemical reactions produce water-soluble salts and carbon dioxide gas:



HCl is a strong acid and reacts very rapidly, especially with calcite. The reaction with dolomite is slower, particularly at lower temperatures.

- **Action on Damage:**

HCl has a very limited effect on clays or bentonitic mud filtrates. Therefore, it cannot directly remediate plugging caused by these solids, which can often be significant.

B. Hydrofluoric Acid (HF)

- **Action on the Matrix:**



While HF does attack limestone, it results in the formation of Calcium Fluoride (CaF_2), an insoluble precipitate of fine particles. This reaction must be avoided at all costs.

- **Action on Damage:**

Although HF is excellent at dissolving clays and other silicate particles that cause wellbore plugging, the inevitable insoluble precipitate formed when it contacts the carbonate matrix makes it unsuitable for use in carbonate reservoirs.

II.4.3. Acidizing on Sandstone reservoirs [16]

II.4.3.1. Characteristics of Sandstone Formations

These formations result from the accumulation of erosion debris that settles in place or is transported by various agents, eventually becoming cemented or non-cemented after deposition.

From a mineralogical standpoint, the dominant element is Quartz, often representing more than two-thirds of the rock. This quartz is generally accompanied by other minerals, most commonly silico-aluminates.

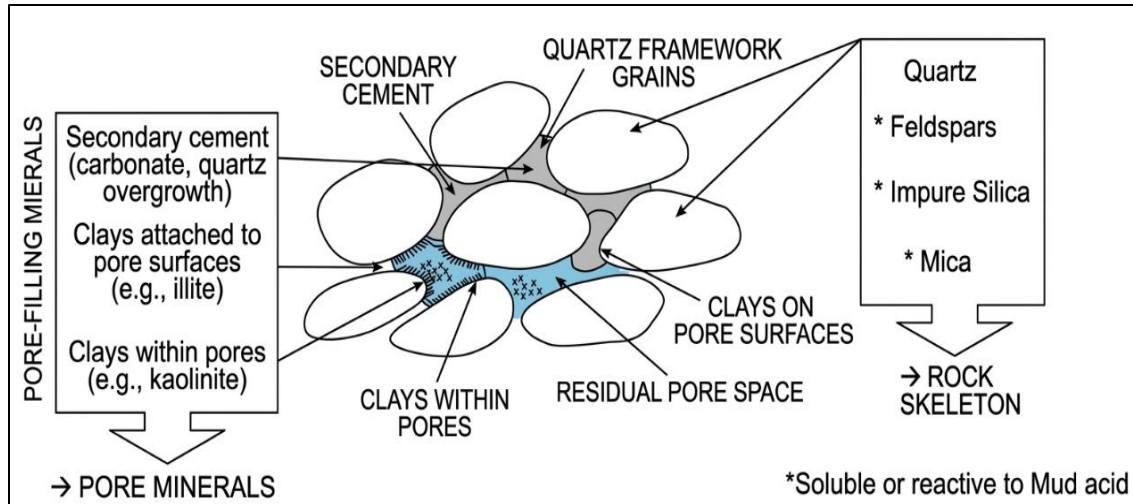


Figure II.2: Typical constituents of sandstones. [11]

Sandstones are composed of several different minerals, namely:

- Quartz: The most dominant element % (50-90).
- Silicates.
- Clays and Micas: (Sheet structure) % (5-30).
- Feldspars: (Three-dimensional structure) % (0-10).
- Carbonates: % (0-10).
- Impurities: Iron, Calcium % (0-3).

While quartz, feldspars, and micas constitute the original skeleton of the rock, the cement is formed by secondary minerals (quartz overgrowth, carbonates, and clays) that precipitated in the pores much later. They are mainly found either attached to the pore surfaces (Chlorite), partially blocking them (Illite), or inside them (Kaolinite).

II.4.3.2. Action of Acids on Sandstone Reservoirs

The acids will:

- Either dissolve certain particles plugging the reservoir rock pores (e.g., Calcium Carbonate).
- Or, if such particles are insoluble, allow their release by attacking the matrix they are plugging.
- Or, finally, lead to a modification of the physicochemical state of these particles (e.g., clay swelling).

1. Hydrochloric Acid (HCl)

Hydrochloric acid is generally used as follows:

- Fracturing of carbonates (fractures and matrix).
- Acidization of sandstones (matrix only).
- Preflush and post flush for HCl-HF mixtures.
- Acidization of sandstones with 15% to 20% carbonate content.
- Removal of acid-soluble deposits.
- Perforation washing.

A. Action of HCl on the Matrix:

It is practically zero on quartz and very weak on clays. Only carbonates are highly soluble, but their solubility rate is not necessarily representative of their exact percentage. Other minerals (impurities) are at least partially soluble in HCl, and their presence must be detected during petrographic studies.

B. Action of HCl on Damage:

In cases where plugging is caused by solid particles from drilling fluids (clays in particular, or unsuitable weighting agents) or completion fluids (various impurities), HCl has a very weak action and cannot effectively participate in their destruction. Otherwise, HCl may have some action in specific cases, such as the dissolution of carbonate used as a bridging or weighting agent, or as a deposit in the well.

2. Hydrofluoric Acid (HF)

Hydrofluoric acid is used with hydrochloric acid to intensify the reaction rate of the system and solubilize the formation, particularly sandstones. Generally, hydrofluoric acid is used as follows:

- Always pumped as an HCl-HF mixture (for the main treatment).
- Matrix acidizing of sandstone formations.
- Solubilizing fines that are not soluble in HCl.
- Concentrations range from 1.5% to 6%.

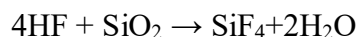
- 3.79 liters of (12% HCl - 3% HF) can dissolve 0.10 kg of sandstone.

A. Action of HF on the Matrix:

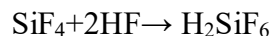
The action is certain, both on quartz (moderate) and on clays (significant) and carbonates (very high).

The reactions are as follows:

- Quartz:

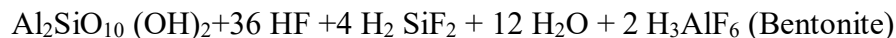


With excess HF:



(This fluosilicic acid (H_2SiF_6) can react in turn).

- Clays (Bentonite):



- Carbonates:



B. Action on Damage:

The high concentration of solid particles, especially clayey ones that have filtered into the near-wellbore area, is specifically targeted by HF, which is capable of dissolving them significantly. This is its frequent and classic use.

II.4.4. Secondary Reactions [16]

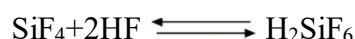
Partial plugging problems are most often caused by secondary reactions. The main types include:

A. Precipitation of Calcium Fluoride (CaF_2)

CaF_2 is produced following the reaction of HF with a matrix containing a percentage of calcite. It is considered the primary cause of plugging after acidification when acid remains in the formation. However, the presence of HCl prevents such a precipitate from forming by maintaining an acidic pH.

B. Precipitation of Fluosilicates

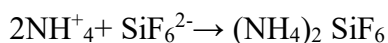
The primary reaction of HF on silica:



This generates **fluosilicic acid**, which can ionize into 2H^+ and SiF_6^{2-} :

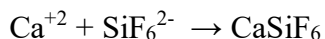
- The H^+ ion contributes to the overall acid reaction with the rock.
- The hexafluorosilicate ion reacts with cations present in the reservoir, such as Calcium, Ammonium, Sodium, and Potassium.

C. Ammonium Hexafluorosilicate



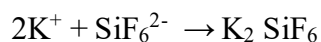
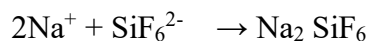
This gel is soluble in both water and acid and is completely removed during the flowback (dégorgement) process. The presence of the NH_4^+ ion is advantageous as it increases the overall solubility of other reaction products.

D. Calcium Hexafluorosilicate



This salt is soluble in water and acid; therefore, it does not pose a plugging problem.

E. Sodium and Potassium Hexafluorosilicates



These products are insoluble and can cause matrix plugging after acidification. These precipitates form and deposit if the acid is left in the formation under static conditions and if the pH increases (the environment becomes less acidic).

Note: In formations containing highly saline water, the risks of precipitate formation are minimized by using a preflush of fresh water or weak hydrochloric acid.

F. Metallic Precipitates

Iron, in various oxidation states, is present in the acid solution and the formation. It originates from:

- The dissolution of rust existing within the tubing, dissolved by the acid during pumping.
- The reservoir rock itself, which contains a percentage of iron that precipitates when the pH of the solution increases.

II.4.5. Acid Additives [14]

While selecting the appropriate treatment fluids is critical to the success of an acid job, the operation may still fail if the correct additives are not used. Their application serves a dual purpose:

- Enhancing stimulation efficiency.
- Mitigating harmful side effects.

Generally, acid solutions are never used without additives, primarily due to their aggressiveness toward wellbore and pumping equipment. The main additives include:

1. Corrosion Inhibitors

These are designed to protect surface and downhole equipment. Their effectiveness is time-limited and depends on temperature, acid type/concentration, and steel grade. They generally function through adsorption onto the metal surface to form a protective film between the metal and the acid.

2. Friction Reducers

The function of this additive is to decrease frictional forces, leading to a reduction in injection pressure and, consequently, decreasing the required pumping power.

3. Clay Stabilizers

These are intended to prevent damage caused by clay swelling resulting from contact between the rock and fresh water. The stabilizing agent works by consolidating clay particles, thereby preventing their migration.

4. Surfactants (Surface Active Agents)

Surfactants have the property of reducing the surface tension of a liquid in contact with a gas by adsorbing at the liquid-gas interface. They can also reduce the interfacial tension between two immiscible liquids (oil and water) or between a liquid and a solid, thus modifying the contact angle and rock wettability.

5. De-emulsifiers and Anti-Sludge Agents

- Sludge consists of a mixture of asphaltenes, resins, paraffin waxes, and high-molecular-weight hydrocarbons originally present in the crude oil. These are flocculated by acids and precipitated at the water-oil interfaces. Once formed, these precipitates are practically insoluble.
- The use of an appropriate surfactant keeps sludges in solution or dispersed within the crude oil.

6. Foaming Agents

Foaming agents are used to generate foams that serve as a medium for transporting and suspending sediments from the bottom to the surface, especially in low-pressure wells.

II.4.5. Acid Selection Criteria [16]

The chemical properties to be considered for acid selection include:

- Dissolving Power: This depends on the acid type and its concentration.
- Reaction Rate: This is influenced by several factors:

A. Pressure

The influence of pressure on the reaction rate of Hydrofluoric Acid (HF) is notable. As HF reacts with sandstones, Silicon Tetrafluoride (SiF_4) is formed. Under reservoir pressure, this compound remains in solution, which results in accelerating the reaction.

B. Temperature

The reaction rate varies according to the temperature during the treatment. As temperature increases, the reaction rate increases, promoting better contact between the acid and the rock.

C. Concentration

- The reaction rate of HCl is a non-linear function of concentration.
- The ionization produced by the acid increases with concentration, reaching its maximum at approximately 26%, before decreasing thereafter.

D. Rock Composition

This is a critical element to consider. It is essential to identify the rock's constituents before treatment. Reservoir characteristics are vital for designing a stimulation treatment and selecting the correct acid formulation. Key factors include:

- Nature of the rock (solubility in different acids).
- Reservoir fluid content.
- Clay content and mineral type.
- Iron content.
- Reservoir temperature.
- Porosity and permeability.
- Water solubility.

Most of these characteristics can be determined through laboratory analyses of core samples.

II.4.6. Laboratory Studies

When a new well is identified as a candidate for stimulation, laboratory tests must be performed on core samples to ensure the compatibility of the treatment products with both the rock matrix and the formation fluids. [6]

The primary objectives of laboratory studies are:

- To analyse the rock and formation fluids.
- To identify the types of formation damage (damage characterization).
- To select the necessary additives and recommend their optimal concentrations.
- To ensure the compatibility of treatment fluids with the rock matrix and formation effluents.

1 .Rock Sample Analysis [6]

Rock sample analyses are categorized as follows:

A. Petrographic Studies

Petrographic characterization of the sample includes fundamental measurements of porosity and permeability to establish a baseline for the reservoir's storage and flow capacity.

B. Core Flow Tests

Flow tests are conducted using high-pressure, high-temperature (HPHT) core flood apparatus. These tests are designed to determine the effects of various fluids on the formation sample by simulating actual downhole treatment conditions.

C. Solubility Tests

The objective is to determine the maximum acid solubility of a rock sample that has been previously crushed, sieved, washed, and dried.

Conditions: These tests are performed under ideal laboratory conditions.

Interpretation: While they indicate the maximum theoretical solubility, the actual effective solubility during field operations may differ significantly.

Results: Limestones and dolomites are entirely soluble in hydrochloric, formic, and acetic acids. However, silicates are insoluble in these acids; therefore, it is necessary to use Mud Acid (with a standard concentration of 12% HCl and 3% HF) to achieve dissolution in sandstone formations.

D. Plugging Test

This test is conducted under downhole conditions and consists of simulating the invasion of rock samples by drilling mud to evaluate the resulting permeability reduction.

E .Acid Response Curve (ARC) Test

The primary objective of this test is to determine the evolution of matrix permeability as a function of the volume of acid injected per unit area.

Procedure: The rock sample is mounted in a core holder (cell) designed to prevent any fluid bypass between the core and the wall.

Saturation: The sample is saturated with formation water or, alternatively, water with controlled salinity that is considered neutral toward the formation. Care must be taken to ensure this reference fluid is compatible with the acids.

Measurement: After establishing the baseline permeability with the reference fluid, the selected acid sequence is injected through the sample. The permeability is then re-measured with the reference fluid after the acid sequences to evaluate the stimulation's effectiveness.

2 .Crude Oil Sample Analysis [6]

A. Emulsion Test

The use of aqueous acid solutions combined with the turbulence generated during pumping can lead to the formation of stable, viscous emulsions.

The primary purpose of this test is to determine the tendency of a surfactant to decrease or increase the emulsion of the system (e.g., Acid + Oil or Brine + Oil).

Methodology: In a high-speed mixer, various proportions of oil and fluid are agitated to form the most viscous emulsion possible. Based on the results, the most effective de-emulsifiers are selected .

B. Precipitation Test (Sludge Test)

The objective of this assay is to detect the tendency of heavy organic products, known as "Sludge," to precipitate when various acid solutions come into contact with the formation's crude oil. Identifying this tendency allows for remediation through the selection of appropriate anti-sludge additives.

Procedure: A volume of the test acid solution (including additives) is mixed with an equal volume of crude oil in a container and agitated vigorously.

Conditioning: The mixture is placed in a water bath at 66°C (150°F) for 4 hours.

Filtration: Finally, the mixture is filtered through a 100-mesh screen to check for any residual solid precipitates.

II.5. Conclusion

In conclusion, acidizing remains a vital stimulation technique for both carbonate and sandstone reservoirs. However, its success is strictly dependent on a precise acid selection process. This selection must integrate multiple critical factors, including formation mineralogy, reservoir temperature, and the specific nature of the damage. Furthermore, ensuring compatibility through rigorous laboratory testing is essential to mitigate secondary risks such as precipitation and emulsion, ultimately maximizing the well's productivity safely and efficiently.

Chapter III:
Evaluation of Matrix Acidizing
on Productivity Result.

III.1. Introduction

This chapter presents a comprehensive analysis of two acid stimulation treatments conducted on two wells drilled and perforated along two different reservoirs, sandstone and shaly sandstone reservoirs. These case studies were selected to investigate the effectiveness of investigation, decision and stimulation procedures adopted to resolve productivity issues related to formation damage, including production decline in one well and the zero production after drilling (non-starting production) in the second well. The comparative nature of this study highlights a deeper understanding of the impact of reservoir types and mineralogical content as well as acid treatment performance.

Overall, this study aims to provide practical insights of a real optimization of acid stimulation strategies in sandstone and shaly sandstone reservoirs, with particular emphasis on well data analysis and investigation process, acid selection, damage mitigation and treatment design under complex geological conditions and a specific well completion.

III.2. Well presentation

III.2.1. Well N°1:

The well N°1 is a vertical oil producer well, it drilled in the border of Berkine basin within the field of Sif Fatima (SF) located around 230 Km of South East of Hassi Messaoud field. It was drilled in 2006 with the objective to reach the lower TAGI formation (lower Triassic Shaly sandstone) under a completion of LCP and tubing 4 "1/2. Since, the well could not be on production until 2018 where it produced from July to October 2018 with an average oil rate of 11 m³/h. After that, a decision has made to convert the well on sidetrack with LCP and tubing 4" ½, the Work Over operation has been conducted from November 2019 to April 2020 (completed with LCP and tubing 4" ½).

The well could not also produce after conversion on Sidetrack for that reason it was a subject of stimulation operation. [17]

III.2.1.1. Geological and petrophysical aspect [18]

The TAGI formation is the main target reservoir targeted by drilling the well N°1, this formation belongs to the Jurassic period era. The Berkine basin's TAGI is divided on three parts, which are defined as upper, middle and lower (upper and basal) and characterized with high presence of clay content and complex

mineralogy (see appendix). The table below shows more details about the TAGI formation. The thickness of the TAGI across the well N°1 is around 90 m.

Table III.1: The petrophysical characteristics of well N°1.

TAGI		H _t (m)	H _u (m)	Ø (%)	Sw (%)
Upper		14	13	16,45	13
Middle		14	12	12	21.6
Lower	(upper part).	5	3,5	13,5	25
Lower	(basal part)	25	11.5	15,4	23

- The overall average porosity (Ø) is moderate (roughly 12–16%), with the best values in the upper part (≈16.5 %) and lower values in the middle. This indicates that the upper zone likely has better storage capacity, while the middle and lower intervals are tighter.
- The water saturation is lower in the upper part compared to the lower part.

III.2.1.2. Reservoir aspect

During drilling phase, the well N°1 was subjected to DST test to evaluate its initial potential, the DST results are presented in the following table:

Table III.2: Well Test Data of well N°1.

Type of Test	Date	Pressure (kg/cm ²)			Flow rate (m ³ /h)		Productivity Index (m ³ /h/kgf/cm ²)	HK			Skin	Choke (mm)	Remark
		Pr	BHFP	WHP				Near	far	(Hw*Kyz)			
SGS	03/06/2018	354.34		127.7				-	-	-			The column content oil
FGS	28/06/2020		278.98	68.8	Oil	7.92		-	-	-		9.53	BHFP/PLT @ - 2926.34m.
BUILD UP	11/11/2020	250	242	57.2	Oil	3.93	.504	2140	-	-	6.54	10	Pr and BHFP@- 2560m

Referring to the BU test performed on November 11, 2020, the reservoir pressure evaluated at 250 kgf/cm² and skin 6.54. Under these conditions, the well has produced an oil rate equal to 3.93 m³/h.

Based on DST data, the well gave a good rate even though it seems damaged. The well test data shows that this well could produce more under targeted and special well intervention.

III.2.1.3. Completion aspect

The well N°1 was completed with LCP and tubing 4 ½, more completion details are presented in table N°III.3

Table III.3: Completion Data of Well N°1.

Completion pieces	Depth
Tubing 4”1/2 New Vam	2775.25 m
OTIS L.Nipple “R” 4”1/2 NV	2753.63 m
OTIS L.Nipple “RN” 4”1/2 NV	2764.63 m
Casing shoe	2941mTR
Botil Packer	2775.25 m
Top Liner	2776.75 m
KOP	2947 mTR
Perforation Interval	(3214 – 3217) (3190 – 3195) (3247.5 - 3250.8) (3163 – 3170) m
Total Depth	3248.64 mTR

III.2.1.4. Production aspect

After conversion on sidetrack (drilling) and completion, the well could not be on production. From June to December 2020, the well produced a good oil rate under well testing operations but a notable production loss when the well opened to production line (December 1, 2020).

The last production rate of the well was evaluated at 1.38 m³/h under choke 9 mm and with low gas production rate. Following production data, it has been decided to perform well intervention operations in order to enhance the well production.

Table III.4: Production Data of well n°1.

Mesurement Date	Choke diameter (mm)	Separati on Unit.	Flow rate (m ³ /h)		GOR	Pressure (kg/cm ²)			Oil Temp. (°C)	K Psi	Water flow rate (l/h)	
			Oil	Gas		WHP	Pipe	separat or			Recovered	Injected
17/10/2018	11	-	12.75	1674.68	131	78.5	53		38	0.4613	0	
13/06/2020	11	1440	2.19	196.51	90	32.6	26.6	26.91	41	1.0359	0	
19/06/2020	11	1440	1.72	112.32	65	61.8	24.7	26.01	36	2.6898	0	
26/06/2020	9.5	1440	7.92	512.32	65	68.8	27.9	28.75	39	0.4997	0	
06/09/2020	9.5	-	3.92	306.13	78	56.4	24.4	24.78	30	0.8278	0	
14/09/2020	9.5	-	3.68	232.20	63	57.2	28.3	28.76	27	0.8938	0	
25/12/2020	9	1440	1.38	70.74	51	50.11	23.38	23.11	16	1.8902	0	



Figure III.1: Production Performance of well N°1.

III.2.1.5. Well intervention aspect

After WO operation achievement (sidetrack conversion), the well N°1 was subjected to the following well interventions:

- **Wireline:**

- On June 21, September 08 and 26, December 10, 2020, wireline control operations were conducted on 2 runs, the first run by using the caliper 96 mm targeting the depth of the first nipple R and the second run by using the caliper 86 mm targeting the well TD. During the three wireline operations, the well TD were reached (3251.50 m RT).

- **Coiled Tubing:**

- May 30, 2020: Clean Out in order to start production: the well was cleaned out with Nitrified Treated Water and Foamed Gel till TD, 2 passes (3247-3250 m) with Foamed Gel and kickoff the well, good result but not sufficient.
- September 10, 2020: Clean Out in order to start production: the well was cleaned out with Nitrified Treated Water till the well TD, 2 passes (3160-3251 m) with 4 m³ of Tube Clean (HCL 7.5%) then 4 m³ Treated Water and kickoff the well, good result but not sufficient.

III.2.1.6. Offset well perspective [17]

The investigation performed about the offset wells of the well N°1 has shown the key points presented below:

- ✓ The well is located in a zone known by the complex mineralogy and salt deposits.
- ✓ From mineralogical aspect, the formation TAGI around the area where the well N°1 is drilled is characterized with complex mineralogy composed mainly of quartz, silt and kaolinite. The intervals with low content of clay minerals are perforated.
- ✓ From the production aspect, the production of the offset wells of the well N°1 oscillates between 2 and 14 m³/h, no water production and low GOR is noted (lower than 150 m³/m³).
- ✓ The range of the reservoir pressure in the area of the well N°1 is above 350 bars, the wells in the area are eruptive wells.

NB: More details of completion, geological and petrophysical, production and well intervention are presented in the Annex 1.

III.2.2. Well N°2:

The well N°2 is a vertical oil producer, drilled in 2023 in Hassi Messaoud Filed within the central zone and targeting the Cambrian rock reservoir. It was drilled on July 17th, 2023 and completed with a 4 1/2" cemented liner, 4 1/2" production tubing up to 3200 m and casing 7" seated at 3315 m.

The well N°2 drilled and potentially tested then completed but could not produce after completion for some reasons related to drilling and completion operations which will be discussed later in this section. [17]

III.2.2.1. Geological and petrophysical aspect [18]

The Hassi Messaoud reservoir field is represented by a sandstone formation series, part of which has been affected by post-Paleozoic erosion in the center of the field. It is subdivided from top to bottom into three main reservoirs, Ri, Ra and R2 and each reservoir is divided into a number of reservoir units.

Regarding the geological aspect of the well N°2, only the two Cambrian reservoirs R1 and R2 are crossed, the Ri is not present in the area of the well (eroded). The main geological characteristics of the reservoirs R1 and R2 are presented below:

Ra: An isometric zone, approximately 120 m thickness, composed of medium to coarse-grained silty-clay-sandstone. It is subdivided into five drains (reservoir units) listed from top to bottom as follows: D4, D3, D2, ID and D1.

R2: Sandstone series with clay cement with an average thickness of 80 m.

The well N°2 is perforated in the reservoir unit D1 and the reservoir R2, the details of which are presented in the table below.

Table III.5: The petrophysical characteristics of well N°2.

Zones	Top	Bottom	Flang name	Gross	Net	Av_Shale volume	Av_Porosity	Av_Water saturation
	(m)	(m)		(m)	(m)	(m3/m3)	(m3/m3)	(m3/m3)
D1	3396.000	3422.000	ROCK	26.000	25.918	0.175	0.072	0.090
			RES	26.000	25.918	0.175	0.072	0.090
			PAY	26.000	25.918	0.175	0.072	0.090
Z_PSG	3422.000	3427.000	ROCK	5.000	4.858	0.368	0.068	0.201
			RES	5.000	4.858	0.368	0.068	0.201
			PAY	5.000	4.858	0.368	0.068	0.201
R2	3427.000	3459.023	ROCK	32.023	18.593	0.285	0.102	0.311
			RES	32.023	18.593	0.285	0.102	0.311
			PAY	32.023	18.593	0.285	0.102	0.311

- The reservoir R2 is thicker than D1.
- The porosity of R2 is slight better than D1.

- The two reservoirs have low clay content.
- The water saturation of the reservoir R2 is higher than R1.
- The composition of the two reservoirs rocks is characterized by quartz minerals dominant.

III.2.2.2. Reservoir aspect [17]

During drilling phase, the well N°2 was subjected to DST test to evaluate its initial potential, the DST results are presented in the following table:

Table III.6: Well Test Data of Well N°2.

Type of Test	Date	Pressure (kg/cm ²)			Flow rate (m ³ /h)		Productivity Index (m ³ /h/kgf/cm ²)	HK			Skin	Choke (mm)	Remark
		Pr	BHFP	WHP				Near	Far	(Hw*Kyz)			
DST	31/07/2023	184.75	125	48.8	Oil	3.02	.0604	83.8	-	-	2.42	9.53	Test carried out in the D4, D3, D2, ID, Di and R2 to TD 3448 m, BHFP @ -3050 m.

The reservoir pressure was estimated 184 kgf/cm² and the skin 2.42. Under these conditions, the well has produced an oil rate of 3.02 m³/h.

Based on DST data, the well gave a good rate even though it seems damaged.

III.2.2.3. Completion aspect [17]

The well N°2 was completed with LCP and tubing 4 ½, more completion details are presented in table N°III.7

Table III.7: Completion Data Well N°2.

Completion pieces	Depth
Tubing 4”1/2 New Vam	3241.85 m
OTIS L.Nipple “R” 4”1/2 NV	3222.85m
OTIS L.Nipple “RN” 4”1/2 NV	3232.85m
Casing shoe	3305 mTR
Botil Packer	3241.85m
Top Liner	3242.85m
Perforation Interval	(3440 - 3439 3438 – 3436) (3430 – 3426) (3415.5 -3409.5) m
Total Depth	3438 mTR

III.2.2.4. Production aspect [17]

After drilling and completion, the well could not be on production. For this reason, it was directly a candidate for more well interventions in order to make it on production.

III.2.2.5. Well intervention aspect [19]

Once the well drilled and completed, it was subjected to the following well interventions:

- **Wireline:**
 - August 23, 2023: the well was controlled by two calipers 98 mm and 92 mm, the first one reached Nipple R depth 3232 m (depth calibration) and the second one reached the depth TD 3447 m which represent the TD of the well.
- **Coiled Tubing:**
 - October 05, 2023: Clean Out in order to start production: the well was cleaned out with Nitrified Treated Water and Foamed Gel till the well TD, 2 passes (3448-3250 m) with Foamed Gel and kickoff the well, negative result.

III.2.2.6. Offset well perspective [17]

The investigation carried out on the offset wells of the well N°2 revealed the following points:

- ✓ The well is located in a zone known by the salt deposits which identified by the high water and oil salinities as well as the good results noted in term of production when the wells are treated with Treated Water.
- ✓ From mineralogical aspect, the formation units (D1 and R2) drilled in the area of the well xx are characterized by high quartz mineral contents, especially in the unit D1. The unit R2 show a small increase in clay mineral content reached in some cases 20%.
- ✓ From the production aspect, the production of the offset wells oscillates between 1 and 4 m³/h, the majority of the wells produce with assisted lifting (GL).
- ✓ The range of the reservoir pressure in the area of the well N°1 is between 160 and 220 bars which justify the use of GL as artificial lift method.

NB: More details of completion, geological and petrophysical, production and well intervention are presented in the Annex 2.

III.3. Discussion and treatment recommendation

1) Well N°1

The well N°1 is a vertical well drilled in and completed with LCP 4 1/2. In 2020, a new wellbore was drilled and it was also equipped with LCP 4 1/2. The reservoir target in this well is the TAGI where the perforations were done on the intervals. The well is a good oil producer; it has experienced during well testing an oil rate ranging between 7 to 1 m³/h.

The reservoir pressure was estimated at 325 kgf/cm² in September, 2006 and 250 kgf/cm² in November, 2020. The Skin was estimated at 6.54 November, 2020 which indicates that the reservoir is damaged, on the other hand the measured BHFP was 242 kgf/cm² (low DD pressure 8 kgf /cm²) with oil production rate of 3.93 m³/h. It most likely seems that the most production comes from reservoir fissures and it has a good reservoir deliverability despite the damage effect on the near wellbore permeability.

Based on PLT data (see figure A.4 Annex 2), it shows that the upper perforation interval (upper TAGI) has the highest production contribution, in terms of lithology is the cleanest reservoir among the other perforated intervals (it has the lowest illite content).

The mineralogy of TAGI layer is characterized with the presence of clay minerals mostly illite and Kaolinite as well as traces of chlorite. These latter, known as migratory clays that could be move with the flow.

The Wire Line job performed on December 10, 2020 indicates that the maximum depth reached by using the caliper 86 mm is 3251 m (TD of the well), no sediment was accumulated in the wellbore.

The fissures in reservoir could be a sign for formation instability that could easily generate buildup of fines in the near wellbore area.

With the available knowledge data of the well, fissured reservoir with complex mineralogy, presence of sensitive migratory clays minerals, the production rate drop could be most likely caused by the clay fines migration plugged in the fissures and block the flow.

Based on the mentioned above, a decision has been made to treat the well with a safe treatment fluid where the reactions are slow with low destabilization effect regarding the fines that could replug the near wellbore. The treatment fluid system selected and adapted to our case was the organic acid known with its slow reaction and low dissolution power. To avoid secondary reactions of acid with organic matters, a treatment of the well with organic solvent is highly recommended prior acid treatment.

2) Well N°2

The well N°2 is an oil producer well drilled on July 07, 2023 in the central zone of HMD field. It's a vertical well completed with 4''1/2 tubing and 4''1/2 LCP completion and perforated from 3409.5 to 3440 m (ED) along the reservoir units D1, ZP and R2.

The mineralogy of reservoir D1 is characterized with high quartz content, and on the other hand, the R2 reservoir has about 30% of Kaolinite clay (Ref. figure A.4, Annex 2). Overall, the reservoir of Hassi Messaoud field is the sandstone dominated rock. the reservoir phase was drilled with OBM mud of 0.88 S. G density. This mud has mainly been prepared by using carbonates as weighting agent.

During the DST, the oil production rate of the well was evaluated at 3.02 m³/h with a skin of 2.42. The reservoir pressure was estimated at 184 kgf/cm² and the BHFP 125 kgf/cm², which means 59 kgf/cm² of Drawdown pressure. The result of DST indicates that the well have a good potential in terms of reservoir deliverability despite the damage effect on the near wellbore permeability. The low reservoir pressure could even favor the mud invasion effect.

After completion phase, the well could not be on production despite good DST results, which most likely indicates that the well was damaged during completion operations.

During the intervention operations, a mud and treating fluids has been observed at return (flare line) which confirm that the reservoir has been damaged by the mud (invasion and loss).

A solubility and damage tests were conducted on the cores of the HMD reservoirs and the best Acid formulation result regarding the rock integrity was obtained with Mud Acid HCL: HF (6%:1.5%).

Based on the previous facts, a matrix treatment with Mud Acid 6:1.5 was highly recommended to improve the near wellbore matrix permeability (near wellbore flow capacity) and allow the well to be on production.

III.4. Job needs and acid composition [19]

All the materials and resources needed for matrix acidizing performed on the two wells (wells N°1 and N°2) are presented as follows:

1. Well N°1 (January 1st-2nd, 2021)

❖ Chemical products used

- 54 m³ Treated Water 3% NH₄CL.
- 06 m³ Tube Clean HCl 7.5% for perforation washing.
- 27 m³ Naphtha for well filling.

- 13 m³ Naphtha/Xylene (50:50) for reservoir treatment.
- 12 m³ 10% Acetic Acid for Preflush/Overflush.
- 12 m³ Organic Clay Acid for reservoir treatment.
- 03 m³ Foam Diversion (2000 scf/bbl) for diversion.
- 16 m³ Liquid Nitrogen.

❖ **Coiled Tubing equipment and Tools**

- One (01) Coiled Tubing Unit.
- One (01) Fluid pumping unit.
- One (01) High pressure N2 convertor.
- Five (05) Tanks for transporting and mixing products.
- One (01) High Pressure Jetting Tool and one (01) Standard Jetting Nozzle Tool.

❖ **The composition of the fluids used**

✓ **Preflush/Overflush: 10% Acetic Acid Chemicals and additives**



Figure III.2 : 10% Acetic Acid Composition.

✓ **Main Acid Treatment: Organic Acid Chemicals and additives**



Figure III.3: Organic Acid Composition.

2. Well N°2 (October 17-18th, 2023)

❖ **Coiled Tubing equipment and Tools**

- One (01) Coiled Tubing Unit.
- One (01) Fluid pumping unit.
- One (01) High pressure N2 convertor.
- Three (03) Tanks for transporting and mixing products.
- One (01) High Pressure Jetting Tool and one (01) Standard Jetting Nozzle Tool.

❖ **Products used**

- 54 m³ Treated Water 3% NH₄Cl for cleaning
- 02 m³ Tube Clean (HCl 7.5%) for perforation washing
- 22 m³ Dead Oil for well filling
- 08 m³ HCl 7.5% for Preflush/Overflush
- 08 m³ Mud Acid (6:1.5) for reservoir treatment
- 02 m³ Foam Diversion (2000 scf/bbl) for diversion
- 16 m³ Liquid Nitrogen

❖ **The composition of the fluids used**

✓ **Preflush/Overflush: HCL 7.5% Chemicals and additives**

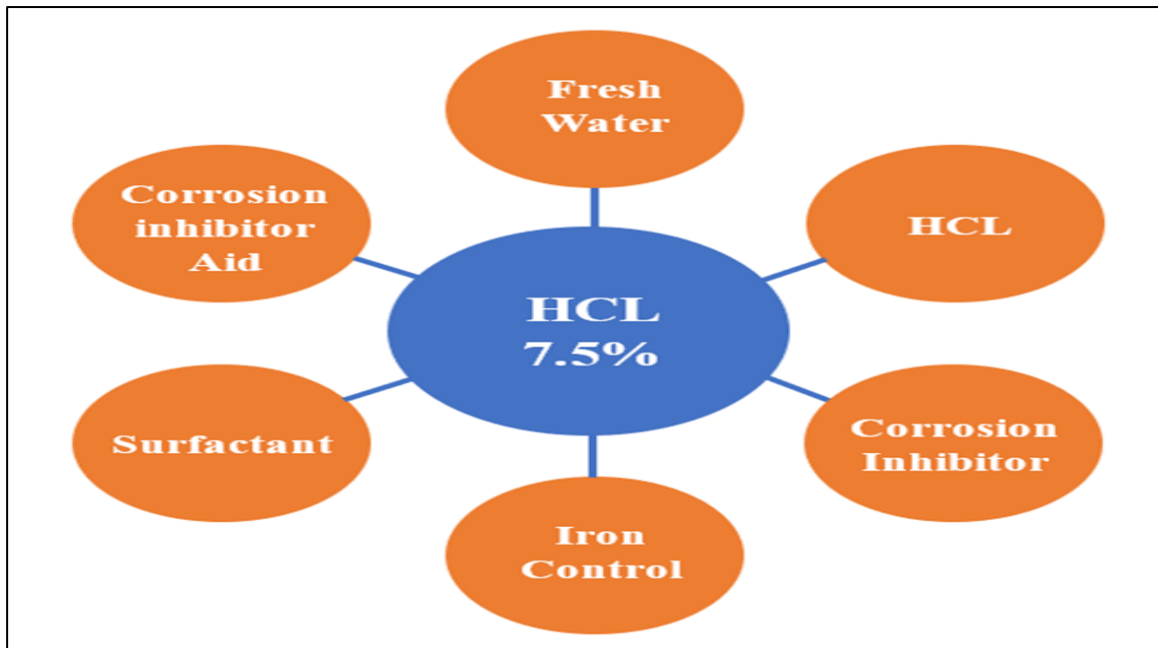


Figure III.4 : Preflush/Overflush Acid Composition.

✓ **Main Acid Treatment: Mud Acid HCL: HF (6:1.5) Chemicals and additives**

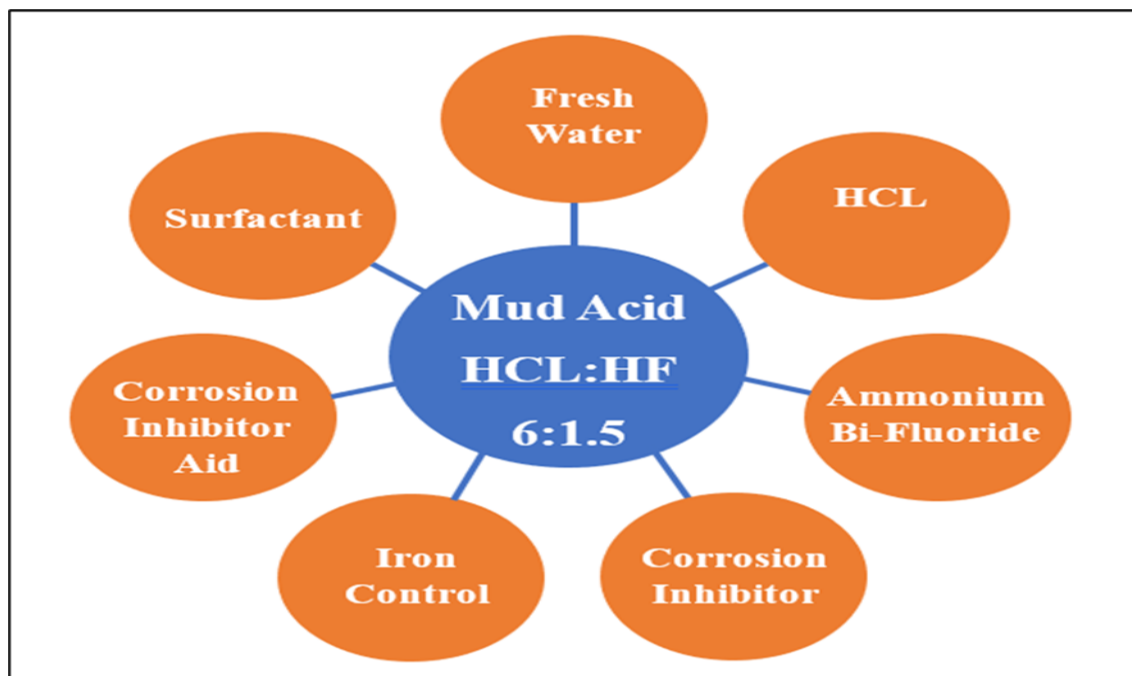


Figure III.5 : Mud Acid Composition.

3. Acid compatibility evaluation

The matrix acidizing jobs are subjected to a rule that before injecting any acid product, the compatibility test should be performed with reservoir fluids, especially with reservoir oil. For our case, the compatibility test was carried out on the two acid types used in the matrix acidizing jobs conducted on the two studied wells, unfortunately, the compatibility test report of the well N°2 could not be found. Therefore, only the compatibility test conducted on the well N°1 is presented in this section.

To run compatibility test, a sample of produced oil should be taken from the well of interest or from a nearest offset well producing from the same reservoir.

For the well N°1, three samples were used to carry out compatibility test: Organic acid, 10% Acetic Acid and oil sample. The tables below present the test details and the results. This latter is supported by samples pictures after test where no sludge or emulsion were observed.

Table III.8: Test detail and results 10% Acetic Acid.

Fluid design	10% Acetic Acid formulation	10% Acetic Acid formulation	10% Acetic Acid formulation
Oil Sample	Well n°1	Well n°1	Well n°1
Test Temperature	85°	85°	85°
Acid : Oil Mixing ratio	25:75	50:50	75:25
Fines added	No	No	No
Emulsion Breakout after 1 min	40%	20%	10%
Emulsion Breakout after 2 min	75%	65%	35%
Emulsion Breakout after 3 min	93%	83%	55%
Emulsion Breakout after 5 min	100%	100%	100%
Emulsion Breakout after 6 min	100%	100%	100%
Emulsion Breakout after 10 min	100%	100%	100%
Stable emulsion formed	No	No	No
Acid oil interface appearance	No	No	No
Oil adhering to glass in acid phase	No	No	No
Sludge tendency	No	No	No

Table III.9: Test detail and results Organic Acid.

Fluid design	OA(H958) Acid formulation	OA(H958) Acid formulation	OA(H958) Acid formulation
Oil Sample	Well n°1	Well n°1	Well n°1
Test Temperature	85°	85°	85°
Acid : Oil Mixing ratio	25:75	50:50	75:25
Fines added	No	No	No
Emulsion Breakout after 1 min	20%	25%	50%
Emulsion Breakout after 2 min	45%	50%	80%
Emulsion Breakout after 3 min	80%	95%	100%
Emulsion Breakout after 5 min	100%	100%	100%
Emulsion Breakout after 6 min	100%	100%	100%
Emulsion Breakout after 10 min	100%	100%	100%
Stable emulsion formed	No	No	No
Acid oil interface appearance	No	No	No
Oil adhering to glass in acid phase	No	No	No
Sludge tendency	No	No	No

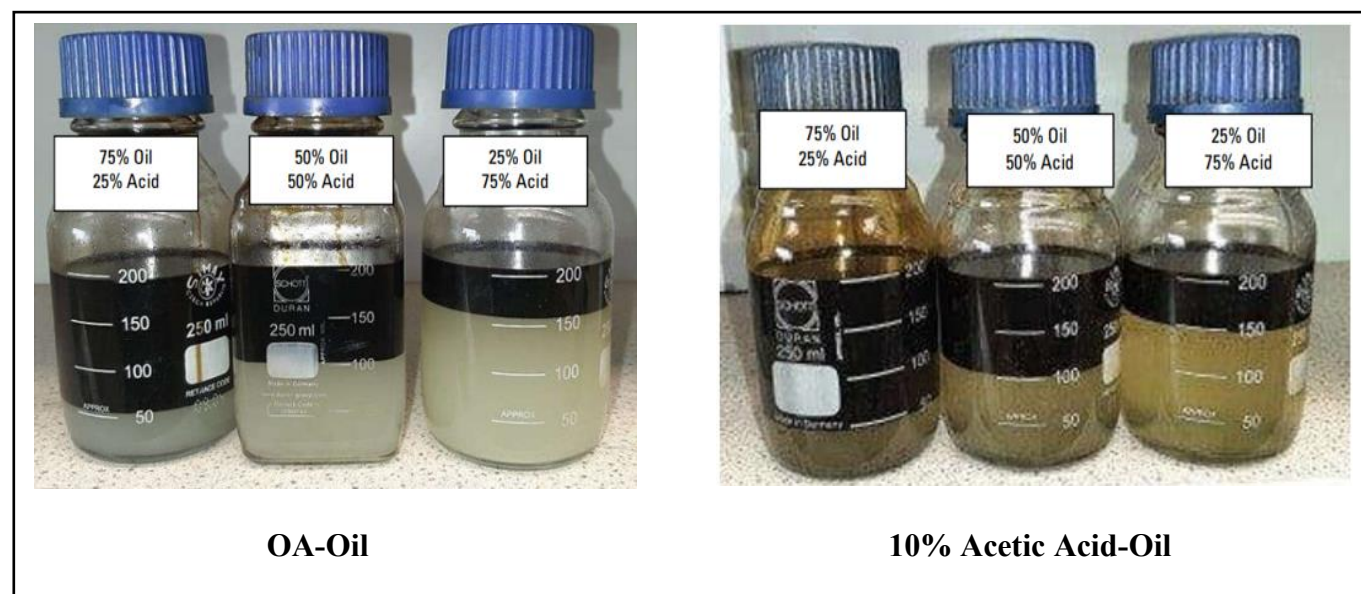


Figure III.6: Sample Test of Acid.

III.5. Matrix Acidizing Job Procedure [20]

In this section, acid job procedure by using Coiled Tubing equipment set will be explained in details powered by additional standardized, operational and best practices information. The safety aspect is also taken into account in this section.

The acidification operation conducted on the wells N°1 and 2 are mainly based on three steps:

- Clean out the wellbore
- Perform the main treatment (acidification)
- Kickoff the well

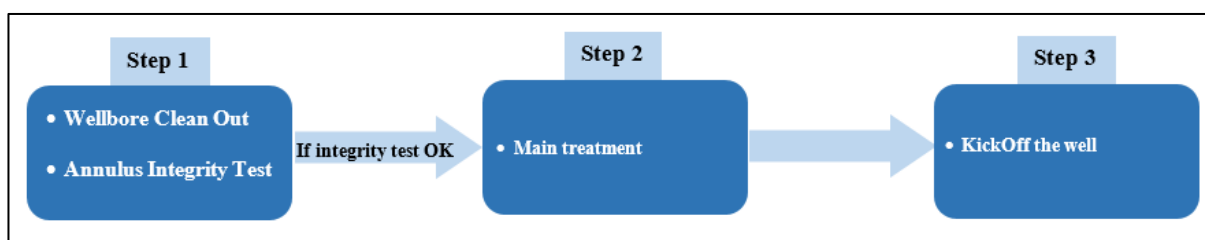


Figure III.7: Step of Matrix Acidizing in the Field.



Figure III.8: Coiled Tubing Site (Equipment spotting).

1) Well N°1

The stimulation operation performed on the well N°1 as mentioned previously is Organic Acid matrix treatment which conducting on three (03) days. The third day is optional in the case if the flow not stabilized during the second day.

• Day 1: Clean Out the wellbore

The main objective of the Coiled Tubing operations performed during the first day is to create wellbore access, clean out the wellbore from any suspected deposits present in the wellbore (minerals and rock grains fines (silts, carbonates and clays, ...), irons and others), perform an intensive washing of perforation interval, test the well annulus integrity and carry out the well injectivity test.

The Coiled Tubing operations during the first day should be performed with respect to the following steps

❖ Surface Site Preparation (area and equipment)

1. Check wellhead, surface connections, the flare line and ensure that there is no leak on site (safety issue). Install the adjustable choke if needed.
2. Spot and rig up coiled tubing, HP pumping unit, N2 unit and tanks for mixed chemicals.
3. Ensure the function test of the fire-pump and the filling of the fire tank (safety issue).
4. Fill all treating lines & CT (Coiled Tubing) with Treated Water (2% NH₄Cl), ensure that the HPJT is not partially or totally plugged (tool function test).
5. Rig up CT Injector on the wellhead then pressure up all lines including the master valve and perform Pressure Test (Ref. See Annex 3: Coiled Tubing Best Practices).

❖ Run In Hole (RIH)

6. Open the well to the flare line and start RIH with High Pressure Jetting Tool, while circulating nitrified Treated Water (2% NH₄Cl) at minimum rates to TD (Total Depth: 3251.50 m Top of cement), increase the rate gradually especially before downhole nipples at 2760.70 m RT.

❖ Perforation interval washing by pumping Tube Clean (TC: HLC 7.5%) + Treated Water (2% NH₄Cl)

7. When the HPJT at TD, start washing the perforation interval (3163-3250 m ER): Electrical Depth Reference) with the respect to POOH/RIH sequences shown in the table below:

Table III.10: The Step of Tube Clean well N°1.

From (m RT)	To (m RT)	Interval length (m)	Fluid System	CT Speed (m/min)	Q (bbl/min)	Time (min)	Volume (m ³)
3250	3163	87	Nitrified TC (HCL 7.5%)	4	1.5	25	6
3166	3250	87	Treated Water	4	1.5	25	6

8. Once the HPJT at TD (3250 m RT), stop Treated Water and favor nitrogen (N₂) at high rate. Keep circulating nitrogen to help unload the spent cleaning fluids at maximum rate to the flare line.

❖ **Well filling by pumping Naphtha fluid**

9. After circulating 1 m³ of N₂, start pumping pure Naphtha at highest possible rate to fill up the well (27 m³), ensure that the well is filled (check return).

❖ **Annulus integrity test**

10. When the well is filled with Naphtha, perform Annulus Integrity Test. Pressure up the annulus **A (4"1/2 x 7") to 55 bars** and **B (7" x 9"5/8) to 35 bars, both during 15 min** (Ref. See Annex 3: Coiled Tubing Best Practices).

❖ **Injectivity test and Matrix Treatment with Reformat**

11. When no annulus communication confirmed, pressure up the annulus (A: 4"1/2 x 7") to 50 bars and (B: 7" x 9"5/8) to 30 bars.
12. Close the well (return) and start injectivity test (Ref. See Annex 3: Coiled Tubing Best Practices) and matrix treatment with 13 m³ of Naphtha/Xylene (50:50) while reciprocating the HPJT (CT) in front of the perforated interval 3163-3250 m ER. Pump at highest possible rate (within the limitation features of the CT and tools) and do not exceed WHP (Wellhead Pressure) of 4800 Psi (MAOWP).
13. When the total volume of treating fluid (Naphtha/Xylene (50:50)) injected, displace it with TW.
14. Once the whole Naphtha/Xylene (50:50) volume out of the nozzle, start pulling the CT out of the hole under pressure with low rate.
15. When HPJT (CT) at surface, close the swab valve and the flare line (secure the well) then bleed off all pressures before starting the rig down. Rig down the CT equipment and leave location. Make sure to bleed off slowly and respectively the two annuluses to atmospheric pressure.
16. Leave the Naphtha/Xylene soaking overnight and prepare for the next day matrix treatment (discuss injectivity test result).

NB: The mixture of Naphtha/Xylene will clean the formation from any organic materials or residue from workover fluids prior Organic Acid treatment.

- **Day 2: Main Acid Treatment**

The main objective of the Coiled Tubing operations performed during the second day is to squeeze the main acid treatment into the matrix safely and to kick off the well.

The Coiled Tubing operations during the second day should be performed with respect to the following steps:

❖ **Surface Site Preparation (area and equipment)**

1. Check wellhead, surface connections, the flare line and ensure that there is no leak on site (safety issue). Install the adjustable choke if needed.
2. Spot and rig up coiled tubing, HP pumping unit, N2 unit and tanks for mixed chemicals.
3. Fill all treating lines & CT (Coiled Tubing) with Treated Water (2% NH₄Cl), ensure that the Standard Nozzle Jetting Tool (SNJT) is not partially or totally plugged (tool function test).
4. Rig up CT Injector on the wellhead then pressure up all lines including the master valve and perform Pressure Test (Ref. See Appendix 3: Coiled Tubing Best Practices).
5. Pressure up the annulus **A (4"1/2 x 9"5/8) to 50 bars** and **B (9"5/8 x 13"3/8) to 30 bars**. Observe pressures and check if there is any doubt of annulus communication.

❖ **Run in hole (RIH)**

6. Open the well to the flare line and start RIH with SNJT, while circulating Naphtha at minimum rates to TD (Total Depth: 3251.50 m RT), break circulation.
7. When the SNJT at TD, check the well filling by observation of the return (needle valve or flare line).
8. When the well filling is confirmed, start pumping the treating fluid of the first stage preflush (acetic acid), organic acid and overflush (acetic acid).

❖ **Main Acid Treatment By pumping Preflush Acid + Main Acid+ Overflush Acid**

9. Once the preflush (acetic acid) reaches the SNJT, close the well and start matrix treatment while reciprocating the SNJT (CT) in front of the first targeted interval 3247.5-3250.8 m (3250 m ER). Pump at highest possible matrix regime rate (within the limitation features of the CT and tools) and do not exceed the MAOWP of 4500 Psi (Ref. See Annex 3: Coiled Tubing Best Practices).

The table below gives more details about the different treating stages:

Table III.11: The Step of using Organic Acid on Squeeze well N°1.

CT	To (m ER)	Interval length (m)	CT Targeted depth (m)	Fluid System	Volume (m³)
3247.5	3250.8	3.3	3250	Preflush (Acetic Acid)	1.5
				Organic Acid	3
				Overflush (Acetic Acid)	1.5
				TW 3% NH ₄ CL (Spacer)	0.5
				Foam Diversion	1
				TW 3% NH ₄ CL (Spacer)	0.5
Chemical Diversion					
3214	3217	3	3215	Preflush (Acetic Acid)	1
				Organic Acid	2
				Overflush (Acetic Acid)	1
				TW 3% NH ₄ CL (Spacer)	0.5
				Foam Diversion	1
				TW 3% NH ₄ CL (Spacer)	0.5
Chemical Diversion					
3190	3195	5	3193	Preflush (Acetic Acid)	1.5
				Organic Acid	3
				Overflush (Acetic Acid)	1.5
				TW 3% NH ₄ CL (Spacer)	0.5
				Foam Diversion	1
				TW 3% NH ₄ CL (Spacer)	0.5
Chemical Diversion					
3163	3170	7	3166	Preflush (Acetic Acid)	2
				Organic Acid	4
				Overflush (Acetic Acid)	2

NB: In order to get best Foam Diversion quality, it recommended to inject N₂ with rate 2000 Scf/bbl.

10. When the total volume of treatment fluid (treating schedule) injected, displace it with 4 m³ TW (low rate).

11. Once the TW at SNJT-CT, open the well to the flare line, start kicking off with N₂ and POOH to the kickoff point (2800 m).
12. Once SNJT (CT) at kickoff point, keep kicking the well and flow back the injected fluids, when the flow is stabilized and clean return is observed in the flare line, pull the CT back to surface.
13. When SNJT (CT) at surface, close the swab valve and the flare line (secure the well) then bleed off all pressures before starting the rig down. Rig down the CT equipment, put the well on the production line and leave location. Make sure to bleed off slowly and respectively the two annulus to atmospheric pressure.

- **Day 3: Kickoff (Optional)**

1. Check wellhead, surface connections, the flare line and ensure that there is no leak on site (safety issue). Install the adjustable choke if needed.
2. Spot and rig up coiled tubing, HP pumping unit, N₂ unit and tanks for mixed chemicals.
3. Fill all treating lines & CT (Coiled Tubing) with Treated Water (2% NH₄Cl), ensure that the Standard Nozzle Jetting Tool (SNJT) is not partially or totally plugged (tool function test).
4. Rig up CT Injector on the wellhead then pressure up all lines including the master valve and perform Pressure Test (Ref. See Annex 3: Coiled Tubing Best Practices).
5. Open the well to the flare line and start RIH CT to Kick off point with Standard Jetting Nozzle Tool while circulating nitrogen to unload the treating fluid and kick off the well.
6. Keep kicking off the well with N₂ and observe the well flow return.
7. Once the well flow is stabilized and clean return is observed, start POOH and pull the CT back to surface.
8. When SNJT (CT) at surface, close the swab valve and the flare line (secure the well) then bleed off all pressures before starting the rig down. Rig down the CT equipment, put the well on the production line and leave location.

2) Well N°2

The stimulation operation performed on the well N°2 as known is Mud Acid (HCL/HF-6:1.5) matrix treatment, this latter is carried out on two (02) days.

- **Day 1: Clean Out the wellbore**

The main objective of the Coiled Tubing operations performed during the first day is to create wellbore access, clean out the wellbore from any deposits presented in the wellbore (minerals, rock grains of fines (silts, carbonates, clays, ...), irons and others), perform an intensive washing of perforation interval and test the well annulus integrity.

The Coiled Tubing operations during the first day should be performed with respect to the following steps:

❖ **Surface Site Preparation (area and equipment)**

1. Check wellhead, surface connections, the flare line and ensure that there is no leak on site (safety issue).
Install the adjustable choke if needed.
2. Spot and rig up coiled tubing, HP pumping unit, N₂ unit and tanks for mixed chemicals.
3. Fill all treating lines & CT (Coiled Tubing) with Treated Water (2% NH₄Cl), ensure that the HPJT is not partially or totally plugged (tool function test).
4. Rig up CT Injector on the wellhead then pressure up all lines including the master valve and perform Pressure Test (Ref. See Annex 3: Coiled Tubing Best Practices).

❖ **Run In Hole (RIH)**

5. Open the well to the line and start RIH with High Pressure Jetting Tool, while circulating nitrified Treated Water (2% NH₄Cl) at minimum rates to TD (Total Depth: 3448 m RT), increase the rate gradually especially before downhole nipples at 2800 m RT.

❖ **Perforation interval washing by pumping Tube Clean (TC: HLC 7.5%) + Treated Water (2% NH₄Cl)**

6. When the HPJT at TD, start washing the perforation interval (3409.5-3440 m ER: Electrical Depth Reference) with the respect to POOH/RIH sequences shown in the table below:

Table III.12: The Step of Tube Clean well N°2.

From (m RT)	To (m RT)	Interval length (m)	Fluid System	CT Speed (m/min)	Q (bbl/min)	Time (min)	Volume (m ³)
3448	3400	48	Nitrified TC (HCL 7.5%)	10	1.2	5	6
3400	3448	48	Treated Water	10	1.2	5	6
3448	3400	48	Nitrified TC (HCL7.5%)	10	1.2	5	6
3400	3448	48	Treated Water	10	1.2	5	6

7. Once the HPJT at TD (3440 m RT), stop Treated Water, favor N₂ and start POOH to Kickoff Point (reduce N₂ rate while POOH in function of need).
8. When the HPJT at Kickoff Point (2800 m RT), continue pumping N₂ as needed to unload the injected cleaning fluids (Tube Clean and Treated Water).
9. When clean return is observed and stabilized Wellhead and Circulating Pressures confirmed, start POOH to the surface.

❖ Annulus integrity test

10. When HPJT (CT) at surface, perform Annulus Integrity Test. Pressure up the annulus **A (4"1/2 x 9"5/8) to 55 bars** and **B (9"5/8 x 13"3/8) 40 bars, both during 15 min** (Ref. See Annex 3: Coiled Tubing Best Practices).
11. When HPJT (CT) at surface, close the swab valve and the flare line (secure the well) then bleed off all pressures before starting the rig down. Rig down the CT equipment and leave location. If the annulus integrity test is positive, prepare for the matrix treatment (Next day).

• Day 2: Main Acid Treatment

The main objective of the Coiled Tubing operations performed during the second day is to fill the wellbore with filling fluid (dead oil), squeeze the Mud Acid (HCL/HF 6:1.5) into the matrix safely and kick off the well. The Coiled Tubing operations during the second day should be performed with respect to the following steps:

❖ Surface Site Preparation (area and equipment)

1. Check wellhead and surface connections, the flare line and ensure that there is no leak on site (safety issue). Install the adjustable choke if needed.
2. Spot and rig up coiled tubing, HP pumping unit, N₂ unit and tanks for mixed chemicals.
3. Fill all treating lines & CT (Coiled Tubing) with Treated Water (2% NH₄Cl), ensure that the Standard Nozzle Jetting Tool (SNJT) is not partially or totally plugged (tool function test).
4. Rig up CT Injector on the wellhead then pressure up all lines including the master valve and perform Pressure Test (Ref. See Annex 3: Coiled Tubing Best Practices).
5. Pressure up the annulus **A (4"1/2 x 9"5/8) to 50 bars** and **B (9"5/8 x 13"3/8) to 35 bars**. Observe pressures and check if there is any doubt of annulus communication.

❖ Run in hole (RIH)

6. Open the well to the flare line and start RIH with SNJT, while circulating dead oil at minimum rates to TD (Total Depth: 3448 m RT), break circulation.

❖ Well filling by pumping Dead Oil fluid

7. When the SNJT at TD, start filling the well with 27 m³ Dead Oil followed by the first stage treatment fluids (2 m³ HCl (7.5%) Preflush, 4 m³ Mud Acid (6:1.5) and 2 m³ HCl (7.5%) Overflush), check the return at the needle valve to ensure that the well is filled.

❖ **Main Acid Treatment by pumping Preflush Acid+Main Acid+ Overflush Acid**

8. Once the HCl (7.5%) Preflush reaches the SNJT, close the well and start matrix treatment while reciprocating the SNJT (CT) in front of the first targeted interval 3426-3440 m (3436 m ER). Pump at highest possible matrix regime rate (within the limitation features of the CT and tools) and do not exceed WHP (Wellhead Pressure) of 4500 Psi (MAOWP). For the second targeted interval 3409.5-3415.5 m, reciprocate the SNJT (CT) in front of the depth 3411 m ER.

Table III.13: The Step of using Mud Acid on Squeeze well N°2.

From (m ER)	To m (ER)	Interval length (m)	Fluid System	Volume (m3)
3426	3440	14	HCL 7.5% (PreFlush)	2
			Mud Acid (6:1.5)	4
			HCL 7.5% (OverFlush)	2
Chemical Diversion			TW 3% NH4CL (Spacer)	0,5
			Foam Diversion	1
			TW 3% NH4CL (Spacer)	0,5
3409.5	3415.5	6	HCL 7.5% (PreFlush)	2
			Mud Acid (6:1.5)	4
			HCL 7.5% (OverFlush)	2

NB: In order to get best Foam Diversion quality, it recommended to inject N₂ with rate 2000 Scf/bbl.

9. When the total volume of treatment fluid (treating schedule) injected, displace it with 4 m³ TW (low rate).
10. Open the well to the flare line, start kicking off with N₂ and POOH to the kickoff point (2800 m).
11. Once SNJT (CT) at kickoff point, keep kicking the well and flow back the injected fluids, when the flow is stabilized and clean return is observed in the flare line, pull the CT back to surface.
12. When HPJT (CT) at surface, close the swab valve and the flare line (secure the well) then bleed off all pressures before starting the rig down.

13. Put the well on the production line, rig down the CT equipment and leave location.

III.6. Treatment job execution [19]

a) Well N°1

The matrix acidizing job performed on the well N°1 by using the OA acid was conducted on 2 days, December 28, 2020 and January 01, 2021. A coiled tubing unit with 1 3/4 tubing diameter was used during the entire job period.

- **First day December 28, 2020: Well Clean Out**

During this day, the well was cleaned out by using the planned cleaning fluids. After Coiled Tubing equipment installation and before opening the well, the following steps were conducted:

- Safety meeting,
- Pressure test,
- The well area was checked as well as the wellhead elements. A wing valve problem was noticed and then it was fixed.

After opening the well, WHP was measured at 500 Psi WHP and Oil and gas was observed in return. A cleaning fluid circulation was ensured by increasing the rate until the well TD and no friction or CT (Coiled Tubing) access problem was encountered during RIH.

When CT at TD, 2 up and down washing passes of perforation interval were performed by using Tube Clean HCL 7.5% and Treated Water. The well was filled with Naphtha followed by annulus integrity and injectivity (pumping Naphtha/Xylene (50:50)) tests, positive results were noticed.

- **Second day January 01, 2021: Main Matrix Acidizing treatment**

The second day of the job was dedicated for matrix acidizing with OA fluid. After checking the well filling during RIH, the well annulus A and B were respectively pressured up to 700 and 500 Psi and the well was closing then matrix acidizing treatment was performed with respect to the following stages:

- Stage 1 (CT at 3250 m): 1.5 m³ of 10% Acetic Acid preflush + 3 m³ of Organic Clay Acid + 1.5 m³ 10% Acetic Acid overflush + 0.5 m³ spacer TW 3% NH₄Cl + 1 m³ Foam Diversion + 0.5 m³ spacer TW 3% NH₄Cl.

- Stage2 (CT at 3215 m): 1 m³ of 10% Acetic Acid preflush + 2 m³ of Organic Clay Acid + 1 m³ 10% Acetic Acid overflush + 0.5 m³ spacer TW 3% NH₄Cl + 1 m³ Foam Diversion + 0.5 m³ spacer TW 3% NH₄Cl.
- Stage3 (CT at 3193 m): 1.5 m³ of 10% Acetic Acid preflush + 3 m³ of Organic Clay Acid + 1.5 m³ 10% Acetic Acid overflush + 0.5 m³ spacer TW 3% NH₄Cl + 1 m³ Foam Diversion + 0.5 m³ spacer TW 3% NH₄Cl.
- Stage 4 (CT at 3166 m): 2 m³ of 10% Acetic Acid preflush + 4 m³ of Organic Clay Acid + 2 m³ 10% Acetic Acid overflush.

When the whole matrix acidizing program executed, the well was opened and kicked off until the injected acid was evacuated. The WHP pressure at the end of job was measured at 410 Psi. The well was left on the flare line to continue disgorging because the fluid return was composed of Naphtha and Oil.

The third day of treatment was cancelled because the well could be on production on the second day of treatment.

b) Well N°2:

The matrix acidizing job performed on the well N°2 by using the Mud Acid HCL: HF (6:1.5) was conducted on 2 days, October 16, 2023 and October 18, 2023. A coiled tubing unit with 1 3/4 tubing diameter was used during the entire job period.

• First day October 16, 2023: Well Clean Out

The first day of job was dedicated for well cleaning by using the planned cleaning fluids. After Coiled Tubing equipment installation and before open the well, the following steps were conducted:

- Safety meeting,
- Pressure test,
- The well area was checked as well as the wellhead elements.

After opening the well, WHP was measured at 0 Psi WHP (sign of no production) and no fluid in return was observed. A cleaning fluid circulation was ensured by increasing the rate until the well TD and no friction or CT access problem was encountered during RIH.

When CT at TD, 4 up and down washing passes of perforation interval were performed by using Tube Clean HCL 7.5% and Treated Water. An annulus integrity test was performed and positive result was noticed.

- **Second day October 18, 2023: Main Matrix Acidizing treatment**

During the second day, a Mud Acid treatment was performed. After filling the well with dead oil, the well annulus A and B were respectively pressured up to 700 and 500 Psi and the well was closing then matrix acidizing treatment was performed with respect to the following stages:

- Stage 1 (CT at 3436 m): 2 m³ HCl 7.5% preflush + 4m³ Mud Acid (6:1.5) + 2 m³ HCl 7.5% overflush + 0.5 m³ TW 3% NH₄Cl + 1 m³ Foam Diversion + 0.5 m³ TW 3% NH₄Cl.
- Stage2 (CT at 3411 m): 2 m³ HCl 7.5% preflush + 4m³ Mud Acid (6:1.5) + 2m³ HCl 7.5% overflush.

When the whole matrix acidizing program executed, the well was opened and kicked off until the injected acid was evacuated. The WHP pressure at the end of job was measured at 150 Psi. The well was left on the flare line to continue disgorging.

III.7. Evaluation of production result [17]

A comparison of the oil production rate related to the wells N°1 and 2 before and after matrix acidizing treatments is shown with production data support.

- **Well N°1**

The well N°1 was producing 1.38 m³/h Oil before matrix acidizing treatment performed on January 01, 2021, but after 11 days from the job execution day (January 12, 2021), the oil production rate has been evaluated under a same condition at 6.09 m³/h. The gas production rate was 347 m³/h equivalent to GOR of 57 m³/m³ and no water production was noticed.

Table III.14: The Production Data after Treatment well N°1.

Measurement day	Choke diameter (mm)	Separator unit	Rate (m ³ /h)		GOR	Pressure (kg/cm ²)			Temp. Oil (°C)	K Psi	Water rate (l/h)		Measurement day
			Huile	Gaz		Tête	Pipe	Sépar.			Récupérée	Injectée	
17/10/2018	11	-	12.75	1674.68	131	78.5	53		38	.4613	0		...
13/06/2020	11	1440	2.19	196.51	90	32.6	26.6	26.91	41	1.0359	0		...
19/06/2020	11	1440	1.72	112.32	65	61.8	24.7	26.01	36	2.6898	0		...
26/06/2020	9.5	1440	7.92	512.32	65	68.8	27.9	28.75	39	.4997	0		...
06/09/2020	9.5	-	3.92	306.13	78	56.4	24.4	24.78	30	.8278	0		...
14/09/2020	9.5	-	3.68	232.20	63	57.2	28.3	28.76	27	.8938	0		...
25/12/2020	9	1440	1.38	70.74	51	50.11	23.38	23.11	16	1.8902	0		...
12/01/2021	9	1440	6.09	347.86	57	44.64	23.5	23.23	26	.3827	0		...

- **Well N°2**

Before performing the matrix acidizing on the well N°2, the well was closed due to zero production (the well could not get on production), however, after 7 days from the job execution day (October 18, 2023), the oil production rate was evaluated at 1.69 m³/h under the choke diameter of 9 mm. The gas production rate was 723 m³/h equivalent to GOR of 428 m³/m³ and very small water production rate was measured evaluated at 14 l/h.

Table III.15: The Production Data after Treatment well N°2.

Measurement day	Choke diameter (mm)	Separator unit	Rate (m ³ /h)		GOR	Pressure (kg/cm ²)			Temp. Oil (°C)	K Psi	Water rate (l/h)		Observations
			Oil	Gaz		WHP	Pipe	Separation			Recuperated	Injected	
28/07/2023	9.53	1440	3.02	1201.15	397	48.8	9	8.43	15	.9342	0		
25/10/2023	9	1440	1.69	723.22	428	20.56	15.67	15.89	20	.628	14		

The table below shows a summary of oil production gain after carrying out the matrix acidizing jobs on the wells N°1 and 2.

Table III.16: The Gain of Production after Operation.

Oil rate	Well N°1 (m ³ /h)	Well N°2 (m ³ /h)
Before matrix acidizing	1.38	0
After matrix acidizing	6.09	1.69
Gain	4.71	1.69

- **Comments and comparison**

- ❖ **Well N°1 (The High Performer):** This well was already active but highly restricted. The acidizing job was incredibly successful here, yielding a massive absolute gain of +4.71 m³/h. This 4.4-fold increase indicates that severe "skin damage" (wellbore clogging) was successfully dissolved, opening up highly permeable pathways to the reservoir.
- ❖ **Well N°2 (The Revival):** While the absolute gain (+1.69 m³/h) is lower than Well N°1, the treatment achieved a critical qualitative milestone: it brought a dead well back to life. A pre-treatment rate of 0 m³/h usually means the near-wellbore area was completely blocked or the formation pressure couldn't overcome the damage.

Why the Results Differ The difference in post-acidizing flow rates between the two wells (6.09 vs 1.69 m³/h) can typically be attributed to two main reservoir characteristics:

- ✓ Reservoir Quality (Permeability & Pressure): Well N°1 likely sits in a zone with better natural permeability or higher reservoir energy. Once the acid cleaned up the damage, the reservoir's natural capacity easily pushed out a higher volume of oil.
- ✓ Damage Type and Depth: Well N°2 might have suffered from deeper formation damage that the matrix acid injection didn't fully penetrate, or it simply drains a tighter, less productive section of the reservoir.

III.8. Economical Evaluation [20]

This section dedicated to economical evaluation of the matrix acidizing operations performed on the two studied wells N°1 and 2. The purpose of this evaluation is to calculate the payout time which is the time required to amortize the matrix acidizing investment relative to the production gain obtained after the operation.

The payout time which is sometimes called payback period is an economic indicator used to evaluate whether a stimulation treatment is financially worthwhile. The payout time estimates how long (time) it takes for the production gain generated by the stimulation treatment to recover the stimulation treatment cost.

The payout time helps petroleum engineers and operators to get answer about: will the increased production from the matrix acidizing job recover the treatment cost fast enough to justify the treatment job?. It is commonly helpful and effective during candidate well selection, economic screening, post-job evaluation and budget planning as well as for approval decision.

▪ The Payout time calculation rule

The payout of an operation is equal to the number of days of production from a well treatment day required to cover the cost invested in the treatment operation by the net profit realized from the treatment:

$$\text{Payout time (day)} = \frac{\text{Matrix Acidizing cost (\$)}}{\text{Equivalent gain (\$/Day)}} \dots \dots \dots \text{(III. 1)}$$

Equivalent gain (\$/Day): Dollars income per day of the production gain generated by the matrix acidizing treatment with reference to the actual oil (or gas) price.

• Well N°1 and 2 matrix acidizing costs

The details of the matrix acidizing job costs performed on the studied wells N°1 and 2 are shown in the table below:

Table III.17: The job costs of the wells.

Type of operation	Well N°1	Well N°2
First day	9563.38 \$	7974.85 \$
Main Treatment	12351.30 \$	10558.73 \$
Total job cost	21914.68 \$	18533.58 \$

- **Well N°1 and 2 production gain generated from matrix acidizing treatment**

The oil rate gain obtained after the matrix acidizing performed on the wells N°1 and 2 successively on dates January 01, 2021 and October 18, 2023,

Table III.18: The Production Data of wells after Operation.

Well	Oil Production Rate Gain (m ³ /h)
N°1	4.71
N°2	1.69

- **Well N°1 and 2 payout time with reference to the performed matrix acidizing treatments**

To calculate the payout time regarding to the matrix acidizing jobs performed on the wells N°1 and 2, we proceed as follows:

- Calculate the oil production volume per day with reference to oil production gain by m³/Day.
- Convert the oil production volume per day from m³ to bbl/Day,
- Calculate the equivalent gain (\$/Day) with reference to actual oil price.
- Calculate the payout time (days)

NB: The actual oil price was calculated with reference to the minored oil price obtained from internet:

- During the late of the year 2020 and the year 2021 for the well N°1,
- During the year 2023 for the well N°2.

Internet links:

✓ **Well N°1**

- Oil Volume Gain/Day = $4.71 \times 24 = 113.04 \text{ m}^3/\text{Day}$.
- Oil Volume Gain/Day = $113.04 \times 6.289 = 710.91 \text{ bbl/Day}$.
- Equivalent Gain (\$/Day) = $710.91 \times 40 = 28436.40 \text{ \$/Day}$.

✓ **Well N°2**

- Oil Volume Gain/Day = $1.69 \times 24 = 40.56 \text{ m}^3/\text{Day}$.
- Oil Volume Gain/Day = $40.56 \times 6.289 = 255.08 \text{ bbl/Day}$.
- Equivalent Gain (\$/Day) = $255.08 \times 70 = 17855.60 \text{ \$/Day}$.

NB:

- 1 m³ = 6.289 bbl
- Minored 1bbl Oil Price:
 - ✓ Well N°1 (2020-2021): 40 \$/bbl.
 - ✓ Well N°2 (2023): 70 \$/bbl.

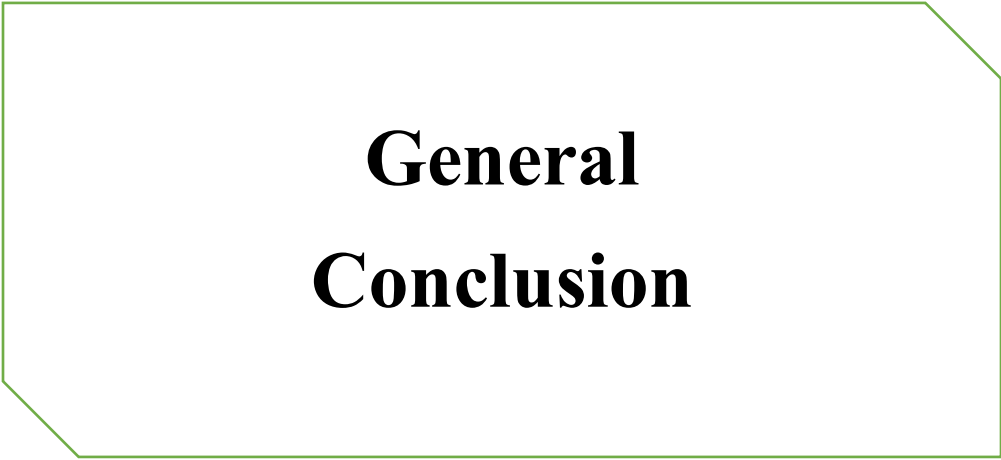
The estimated payout time of the performed matrix acidizing jobs on the wells N°1 and 2 is presented in the table below:

Table III.19: The payout of Operation wells.

Well	Operating Cost (\$)	Equivalent gain (\$/Day)	Payout time (Day)
N°1	21914.68	28436.40	0.77
N°2	18533.58	17855.60	1.04

After an economic analysis of the two transactions, we conclude that:

- The cost of the matrix acidizing treatment performed on the well N°1 by using the Organic acid could be recovered under the evaluated oil rate in less than 1 day production time.
- The cost of the matrix acidizing treatment performed on the well N°2 by using the Mud Acid (6:1.5) could be recovered under the evaluated oil rate in 1 day production time.
- Referring to the results obtained, Matrix Acidizing Treatment remains one of the most effective reservoir stimulation methods in oil and gas industry.



General Conclusion

The productivity of oil and gas wells is strongly dependent on the condition of the near-wellbore region, where even a slight alteration in permeability can significantly impact the reservoir hydrocarbon flow capacity. In sandstone and shaly sandstone reservoirs, this region is particularly sensitive to various damage mechanisms induced during drilling, completion, and production operations. These mechanisms often result in reduced permeability and impaired well performance, making formation damage one of the major challenges in reservoir exploitation.

This study investigates the characteristics and most common types of damage in the formations of the Hassi Messaoud and Bir Berkine oil fields, as well as the treatment techniques employed, the most commonly used acids, and their additives.

This work contributed effectively to diagnosing the causes of damage in the Hassi Messaoud field, identifying the basic requirements for the success of acidization operations, in addition to accurately distinguishing between the different stages of matrix acid treatment of the rock.

Furthermore, the study analyzes the treatment results, evaluates the effectiveness of acid treatment by comparing production rates and productivity indicators before and after treatment, and enhances understanding of the economic efficiency and feasibility of acid treatment processes.

On the basis of the case studies performed in this thesis, the following conclusions could be summarized:

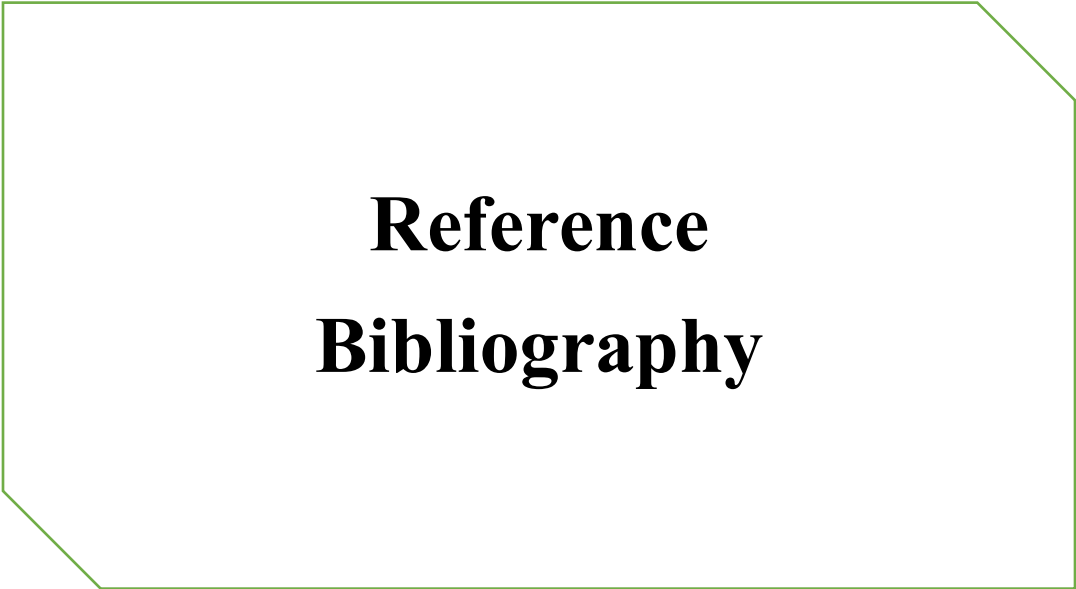
- The Null oil production rate after drilling or the production loss could be heavily related to the formation damage.
- The formation damage type must be meticulously investigated using the whole available data such as, well test, production, drilling and well intervention, geology, petrophysics, laboratory and offset wells.
- When the formation damage is related to mineral deposits, a matrix acidizing treatment is heavily recommended to improve well productivity.
- The matrix acidizing treatment should be carefully associated to the acid type selection which in turn is linked to acid-rock and acid-reservoir fluids contacts. These latter are deeply related to acid type, rock type, mineralogy contents and complexity, acid damaging effect and reservoir fluids compatibility.
- To access the acid-rock and acid-reservoir fluids contacts, special laboratory tests are heavily recommended to assess the aggressiveness of acid on the rock and its compatibility with reservoir fluids.
- Prior acid job, a compatibility test must be carried out with actual produced oil.

- Selecting the right acid type requires a right operational methodology and procedure to place safely, carefully and in the right way the acid in the formation.
- The investigation, the acid type selection and the acid placement procedures presented for the two studied wells N°1 and 2 are well conducted and strengthen by experience.
- The matrix acidizing campaign was highly effective for both wells, though it served different purposes. For Well N°1, it acted as a massive production booster, while for Well N°2, it served as a successful reactivation tool, Consequently, the flow rate in both wells increased, leading to a corresponding rise in Productivity Index (PI).
- The production gain obtained from the matrix acidizing performed on the wells N°1 and 2 had a good economic impact in terms of payout time. Regarding the actual oil price, the payout time obtained for the two studied cases are around 1 day.
- The technical and economical results obtained from the studied cases confirm that the matrix acidizing treatment remains an essential stimulation method for oil and gas industry.

Recommendations

Acidizing is a key technique for enhancing and restoring well productivity in the Hassi Messaoud region. Its successful implementation requires careful design and substantial investment. Based on the conducted study and the obtained results, the following recommendations are proposed:

- From time to time, well tests should be performed on wells to provide a precious data for investigations in the context of formation damage.
- To access the acid-rock and acid-reservoir fluids contacts, special laboratory tests are heavily recommended to assess the aggressiveness of acid on the rock and its compatibility with reservoir fluids.
- In the case of water production (well producing water), the Acid-Water compatibility test should be performed in addition to Acid-Oil compatibility test.
- The experience gained from the two matrix acidizing jobs conducted on the two studied wells should be taken into account for the future planned matrix acidizing jobs in the studied areas.
- Each acid must be tested before any use in oil reservoir rocks.

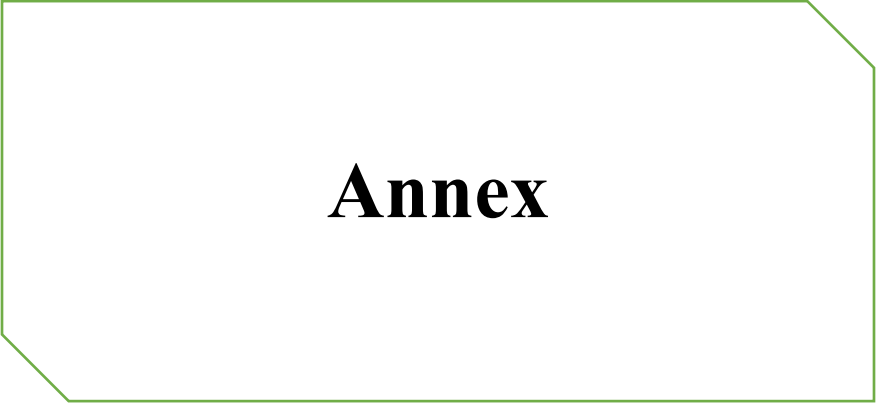


Reference Bibliography

- [1] Amira BOUSSEDJRA & Naima BELAHJI, Tretaiment par Acidification, Champ Hassi Guettar West, Master's thesis, KMOU ,2020.
- [2] Sonatrach Document. and quot;nature of formation damage and quot.
- [3] BOY, X. and quot ; Manuel d'endommagement des réservoirs & quot;. Technip Edition, 1983.
- [4] BENABED Hiba, ELANSARI Nada, BENBRAHIM Sofiane, EVALUATION OF THE EFFECIENCY OF MATRIX ACIDIZING OPERATION ON WELL ODZ-1BIS, Memory of master 2023 (Option: production), Kasdi Merbah Ouargla University.
- [5] BOURDAROT G., Interprétation des essais de puits, june 1990.
- [6] BARKAT Mohamed El Fares and BOUKHOUTTA Salem, OPTIMISATION D'UN DESIGN DE STIMULATION PAR ACIDIFICATION D'UN RESERVOIR DU GISEMENT DE HASSI MESSAOUD, Memory of master 2023 (Option : production), Kasdi Merbah Ouargla University.
- [7] Formulaire du producteur & quot;. Technip Edition, IFP. 1970.
- [8] Editions Technip, Manuel of reservoir acidizing, Paris 1983.
- [9] Endommagement de la liaison couche troue. Denis Perrin. ENSPM Formation Industrie IFP Training 2006.
- [10] Cour les essais du puits et les interprétations des resultat-realisee par Mr. Atlili Elhadi –IFP Training.
- [11] AL-shwssari Akram, Mohammed Husam, Alwerafi Mohammed Ahmed Ali, Le rôle des méthodes de l'acidification pour évaluer la production dans le champ Haoud Berkaoui, Master's thesis, (Option : production), Kasdi Merbah Ouargla University, 2016.
- [12] Website <https://www.google.com/url?sa=t&source=web&rct=j&url=http%3A%2F%2Fviscosity-hydrochloric-acid.blogspot.com%2F2016%2F01%2F4-acid-treatments.html&opi=89978449>.
- [13] Dominique Veillon, La liaison couche trou (Tome 1 et 2)" Editions Technip, 2001, IFP.
- [14] Manuel d'acidification des réservoirs. Edition Technip. 1983.
- [15] Programmes d'acidification des puits et Rapports journaliers des opérations, Sonatrach 2010.
- [16] La liaison couche trou (Tome 1 et 2)" par Dominique Veillon. Editions Technip, 2001, IFP.

Reference Bibliography

- [17] Data Bank; Division Production; SONATRACH ; (EP/département techniques puits ,techniques nouvelles), HMD".
- [18] Data "SH/DP/EP, geological department, "HMD".
- [19] Program of well acidizing Daily Operations Reports, EP director, "HMD".
- [20] Data "SH/DP/EP, Operation department, "HMD".



Annex

Annex 1

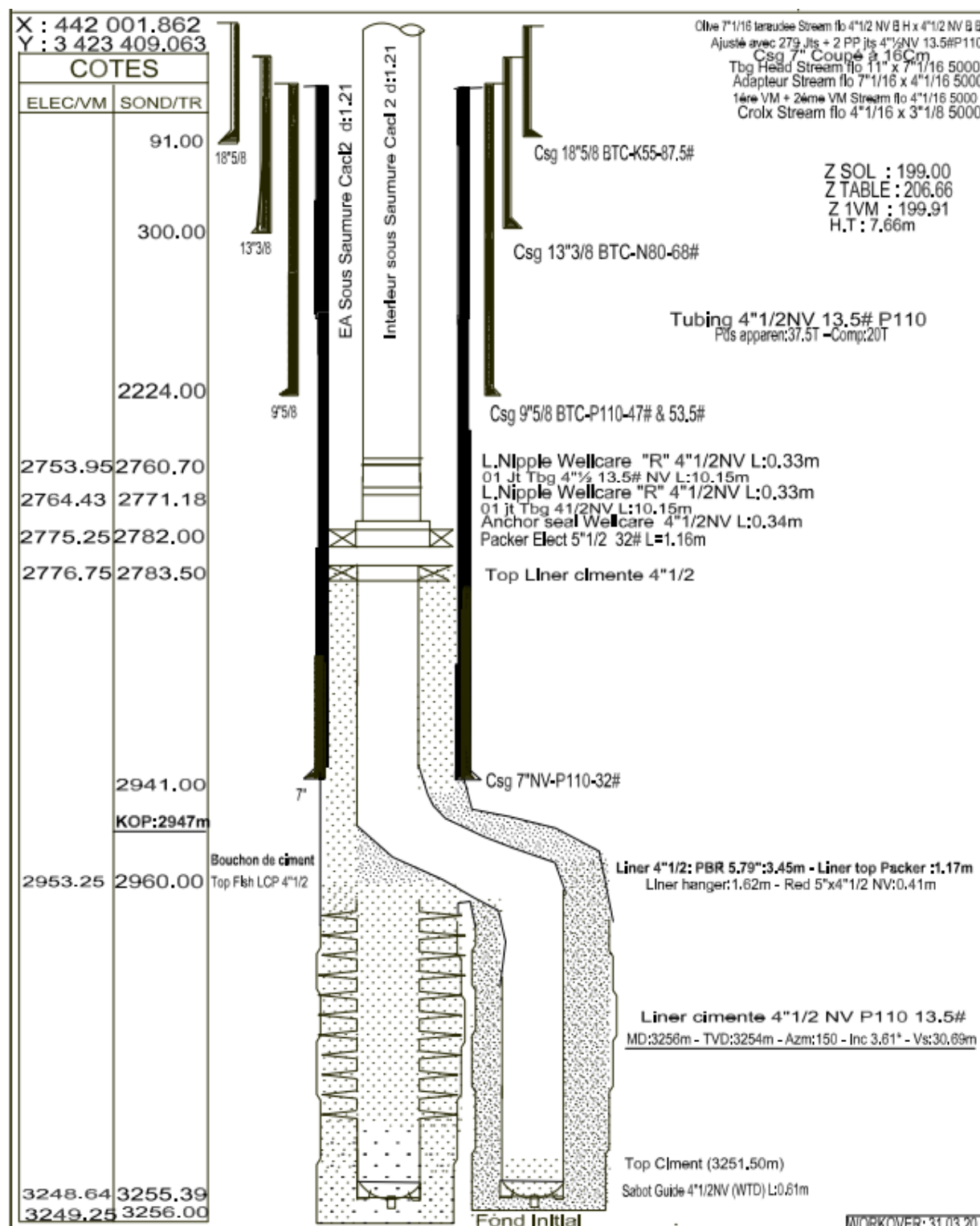


Figure A.1: Well n°1 completion

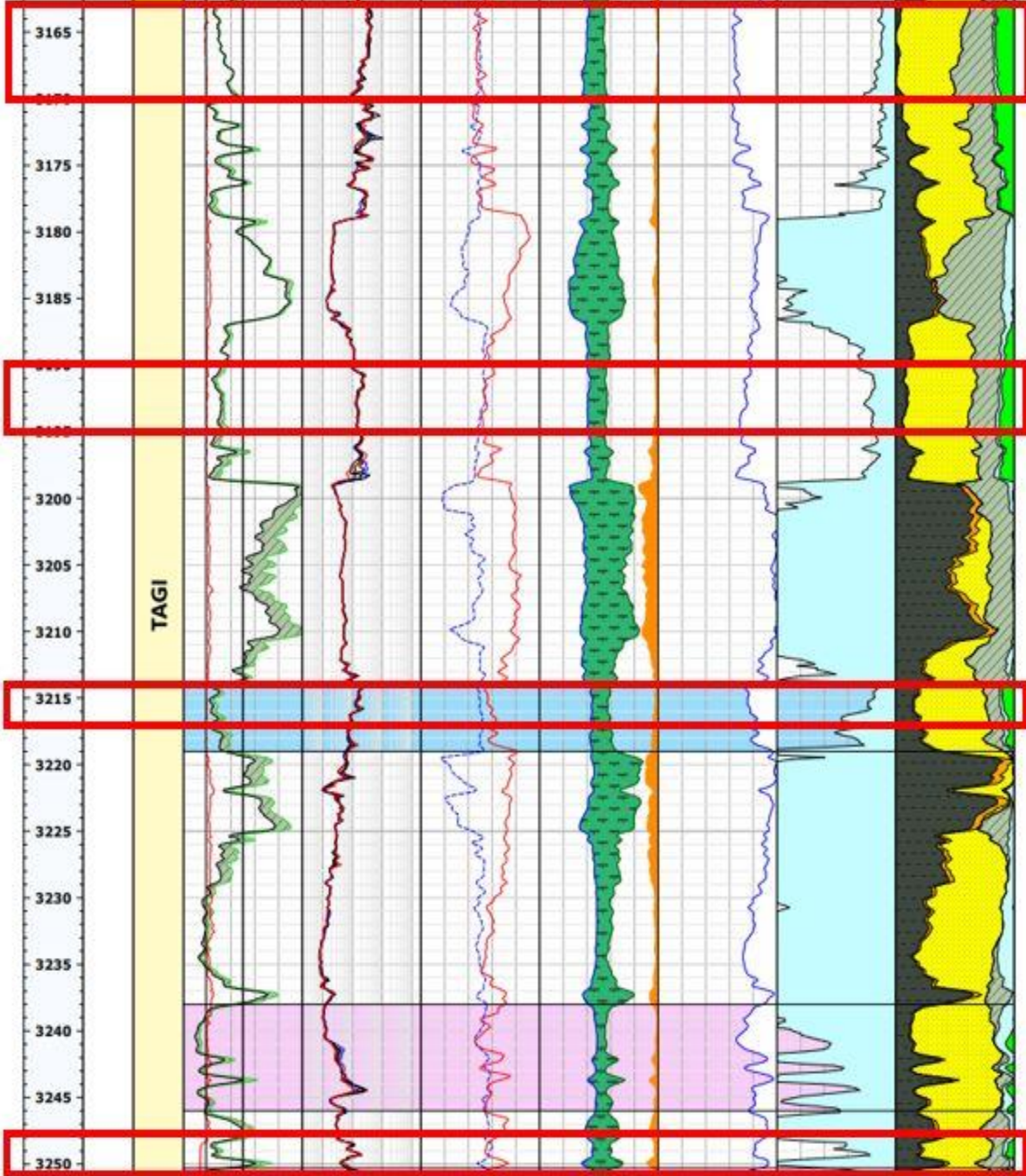


Figure A.2: ELAN data for the well n°1

Annex 2

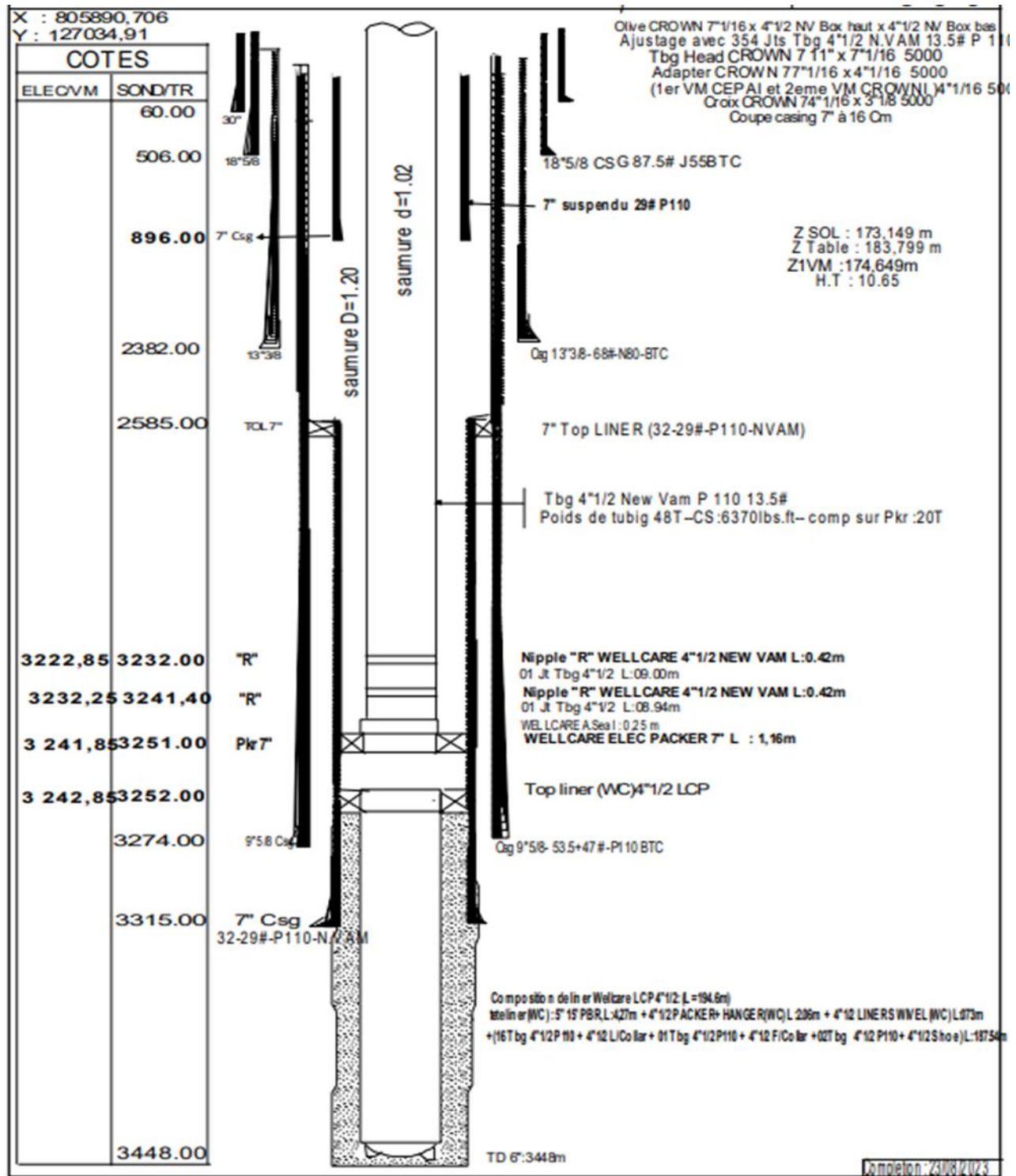


Figure A.1: Well n°2 completion

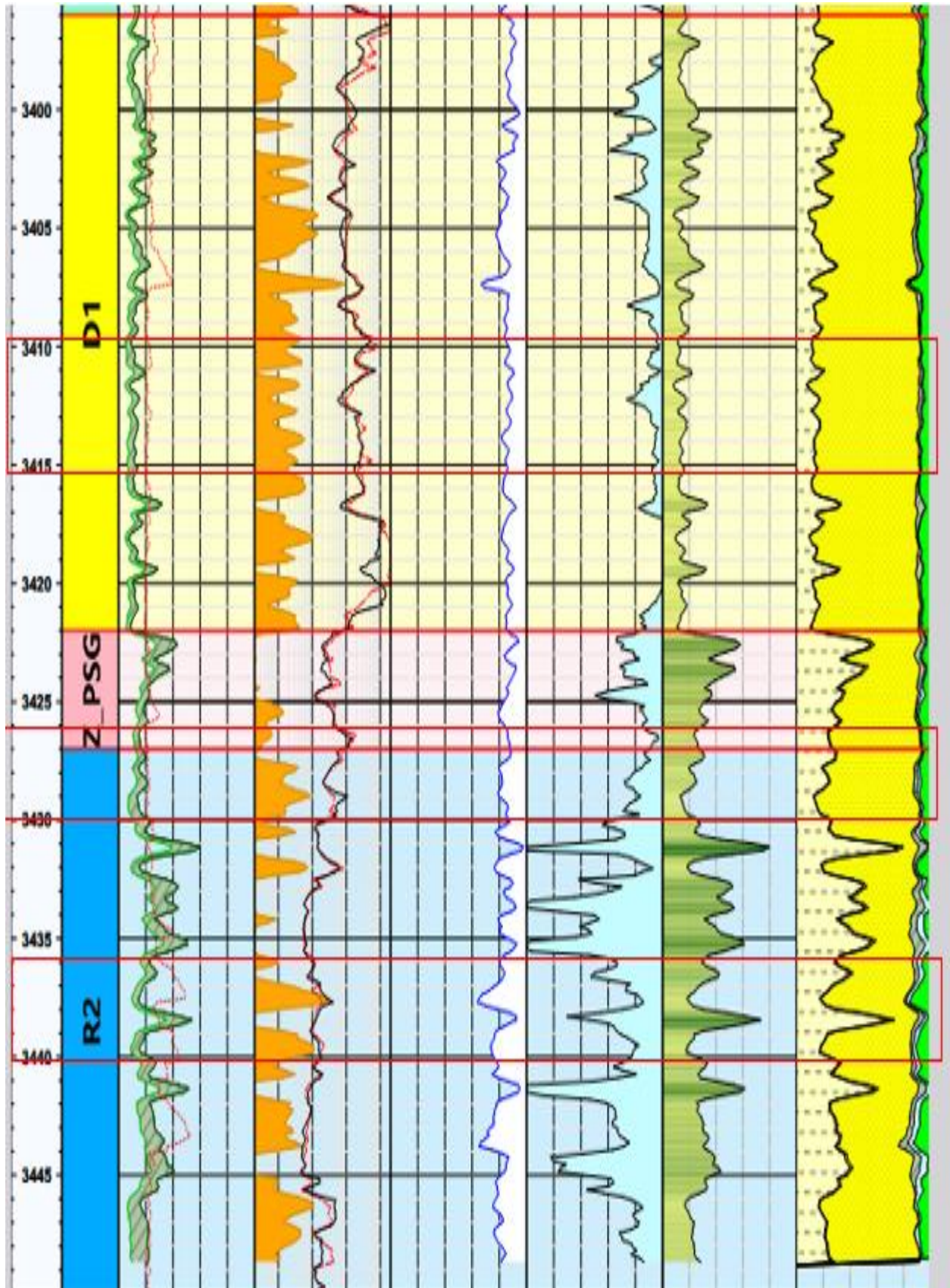


Figure A.2: ELAN data for the well n°2

Annex 3

Related Coiled Tubing Best Practices

- **Pressure test:** Pressure test is an operational standard requirement recommended before opening the well, it's performed for purpose to test the integrity of the training lines of coiled tubing and the surface well equipment. Once the coiled tubing equipment installed, perform the pressure test at low pressure and high pressure for 15 min. Perform also Pressure Test of DFCV (Double Flapper Check Valve) at 2000 Psi for 10 min.
- ✓ Low pressure: the low pressure value used during Pressure Test is generally oscillated between 250 Psi and 500 Psi.
- ✓ High Pressure: the high-pressure value depends on the calculated Maximum Allowable Operating Wellhead Pressure (MAOWP) which is mainly related to three points, Fracturation Pressure, MWWP (Maximum Wellhead Working Pressure) and maximum working pressure of the Coiled Tubing Pressure Control Equipment and tools used (supposed very high-pressure resistance).
 - If the calculated MAOWP is bigger than MWWP (Maximum Wellhead Working Pressure): the High-Pressure value will be the MWWP and the used MAOWP should be slightly less than MWWP (usually 10% less than MWWP).
 - If the calculated MAOWP is smaller than MWWP (Maximum Wellhead Working Pressure): the High-Pressure value will be slightly less the calculated MAOWP (in all cases the high pressure value should be minimum 20% less than MWWP) and the used MAOWP should be slightly less than the High Pressure value (usually 10% less).
 - The calculated MAOWP is calculated based on Reservoir Fracture Gradient, Reservoir Depth, Filling Fluid-Tubing Friction Pressure Loss and Filling Fluid Hydrostatic Pressure.
 - This MAOWP is heavily taken into account when the Coiled Tubing operation is about treatment (squeeze) and not about well cleaning.
- **During RIH phase:**
 - ✓ If any friction is encountered, switch fluids, increase the rate or perform any other recommended CT operational practice, after that continue RIH.
 - ✓ Adjust the pumping rate if necessary (within the limitation of the tool and CT) and re-adjust the CT speed accordingly.
 - ✓ Adjust Nitrogen rate if necessary to ensure return whenever it's required (observe return).

- ✓ Perform Pull Test as recommended in standard.
- ✓ Slow down before downhole elements (Nipples), Top of LCP and before tag TD.

- **Annulus Integrity Test:** This test is standardized and best practices requirements performed to check if there is any existing communication **between tubing and the different annulus**.
 - Pressure up Annulus A and keep Tubing and Annulus B opened to atmospheric pressure,
 - Pressure up Annulus B and keep Annulus A and Tubing opened to atmospheric pressure.
 - Record and observe live pressures then confirm that there is no annulus communication.
 - Bleed off slowly and respectively the two annuluses to atmospheric pressure.

- **Injectivity test:** the purpose of this test is to check the reservoir suitability of fluid injection. It's performed when the Coiled Tubing operation is about treatment (squeeze) not CleanOut. The principle is to start injecting fluid by increasing the rate until pressure stabilizes with rate. This test helps engineers to take decision about continuing or abandoning the treatment as well as changing treatment job strategy or method.