REPUBLIQUE ALGERIENNE DEMOCRATIQUE ET POPULAIRE
Ministère de l'Enseignement Supérieur et de la Recherche Scientifique

N° Série : ………/2024

Université Kasdi Merbah Ouargla

Faculty of Hydrocarbons Renewable Energies and Earth and Universe Science

Hydrocarbon Production Department

MEMORY

To obtain the Master's degree

Option: Professional production

Presented By:

Hamidi Ahmed Mohtadi Bouchami Sifeddine

-TOPIC-

Well optimization by matrix treatment with acidification in the Hassi Messaoud field

Submitted on: 06/06/2024 before the examination committee

Jury :

Président :SID ROUHOU HADJ MOUHAMED **Univ. Ouargla**

Examinateur :OUAZAZI MOUHAMED **Univ. Ouargla**

Acknowledgement

Praise be to Allah, who has given me the courage, strength and made it easy to me to achieve my goals.

First of all, I would like to express my deepest gratitude to my supervisor, **Mr. Touahri Abdul-Jabbar**, for his guidance, his seriousness and his sound advice.

I would also like to thank the chairman, and the jury examiner, for agreeing to examine my work.

My warmest thanks for the IRARA Base team, especially **Mr.Atlili** for his help, encouragement and invaluable advice throughout the internship period.

I would also like to mention the support and encouragement of my dear

parents and **friends**.

Finally, I would like to thank everyone who has contributed, directly or indirectly, to the success of this work, for which I have devoted so much of my time and heart.

merci

DEDICACE

I dedicate this work to :

To the woman who gave me a taste of life and a sense of responsibility The woman who fought for me...

Thank you, Mom.

To the one who has always been my source of inspiration and courage ....

Thank you dad.

To my brother Reza and all my sisters **Bayan, Maria, Serene and little Zainab.**

To all my extended family

To my friends: **Ahmed, Khaled, Khaldoun, Zainuddin, Osama, Oussama K, Youssef b ,K Bahaa,Toto Massoudi, Khaldoun Ibrahim, Molz, Raouf**

To all my friends and colleagues without exception. Especially for the class of 2019

Sif eddine Bouchami

DEDICACE

I dedicate this modest work above all to the light of my life, the source of my happiness and the guide of my path to: my very Dear Parents

whom I can never thank enough for their sacrifices and for their presence throughout my studies and simply in my life.

To my Brothers **ABDELMADJID AWAB, MOUNIB**

To my Sister **Naira**

To all my Family

AND COUSINS

To my close friends WHO ican call them brothers

SIF, YAHIA, MOUIZ, OUSSAMA, RAOUF, WASSIM, LAMINE BOUJBOUJ, FOUAD, YOUCEF K, IBRAHIM

To all the people I have had the pleasure of knowing. To all my classmates

H.AHMED MOUHTADI

Abstract

the objective of acid treatment is to mitigate well-side damage and reinstate the original permeability of the formation. However, it would be erroneous to assume that injecting acid into a sedimentary layer invariably enhances production. At present, a comprehensive acid performance assessment is underway for WELL MDZ657, considering diverse mineralogical compositions, to address wellbore obstruction issues. A test on this well is devised to comprehend the phenomenon and forecast production outcomes accurately. The ensuing recommendations encompass well-specific strategies, subsequent acid stimulation procedures, and broader implications for the HMD field.

Key aspects acidizing, solvent application, damage assessment, and skin Factor, matrix stimulation.

Résumé

L’objectif du traitement à l'acide est d'atténuer les dommages causés au puits et de rétablir la perméabilité initiale de la formation. Cependant, il serait erroné de penser que l'injection d'acide dans une couche sédimentaire améliore invariablement la production. Actuellement, une évaluation complète de la performance de l'acide est en cours pour le puits MDZ657, en tenant compte de diverses compositions minéralogiques, afin de résoudre les problèmes d'obstruction du puits. Un test sur ce puits est conçu pour comprendre le phénomène et prévoir avec précision les résultats de la production. Les recommandations qui en découlent englobent des stratégies spécifiques au puits, des procédures de stimulation acide ultérieures et des implications plus larges pour le champ HMD.

Les mots clés l'acidification, l'application de solvants, l'évaluation des dommages et le facteur cutané, la stimulation matricielle.

الملخص

الهدف من المعالجة بالحمض هو تخفيف الضرر على جانب البئر وإعادة النفاذية الأصلية للتكوين. ومع ذلك، سيكون من الخطأ افتراض أن حقن الحمض في طبقة رسوبية يعزز الإنتاج بشكل ثابت. في الوقت الحاضر، يجري حاليًا تقييم شامل لأداء الحمض في بئرWELL MDZ657 ، مع الأخذ في الاعتبار التركيبات المعدنية المتنوعة، لمعالجة مشاكل انسداد حفرة البئر. تم وضع اختبار على هذا البئر لفهم الظاهرة والتنبؤ بنتائج الإنتاج بدقة. وتشمل التوصيات الناتجة عن ذلك استراتيجيات خاصة بالبئر، وإجراءات التحفيز الحمضي اللاحقة، والآثار الأوسع نطاقا لحقل HMD.

تشمل الجوانب الرئيسية التحميض واستخدام المذيبات وتقييم التلف وتحفيز مصفوفة.

Table of Contents

List of tables

TABLE OF FIGURES

LIST OF ABBREVIATION

HMD: :HASSI MESSAOUAD

Kd: damage permeability

IP: productivity index

SBU: short build up

DST: drille system toole

DCCE : diameter of the coiled tube (inch).

Ptbg: pressure losses in the tubing

Qg: gas flow

WC: water contacte

GOR: gradient oil ration

CT: coiled tubing

PT. Fond : the treatment pressure at the bottom of the well

API: American Petrolum Institut.

LBU: Long Build Up

N2: Azote

OH: Open Hole

PBR: Polish Bore Receptacle

PLT: Production logging

SNB: Snubbing

SBU: Short Build Up

TVD: Total Vertical Depth

TD: Total Depth

TW: Treated Water

WO: Work Over

WC: Water Cut

WHP: Well Head Pressure

IPr: actual productivity in (m^3 /h/ bar).

IPth: theoretical productivity of the same dimension.

$4H_2SiF_6$: *Flu silicic acid*

DFCV: Downhole Flow Control Valve

POOH: Pulling Out of Hole

BHA: The Bottom Hole Assembly

EGMBE: ethylene glycol monobutyl ether.

RIH: Running in hole

Introduction

Algeria's hydrocarbon sector plays a pivotal role in driving economic growth and development, serving as the backbone of the nation's economy. The exploration and production of oil and gas contribute significantly to government revenue, foreign investment, and employment opportunities. Moreover, Algeria's strategic location along the Mediterranean coast facilitates the export of hydrocarbons to international markets, further enhancing its economic importance. The hydrocarbon industry not only supports various sectors within the country but also positions Algeria as a key player in the global energy market. This dual impact underscores the critical nature of effective management and innovation within the sector to maintain and enhance its contributions to the national economy. Extracting hydrocarbons from oil or gas fields involves complex processes of bringing them from the reservoir to the surface. These processes include drilling, casing, and various methods of lifting the hydrocarbons. However, during the lifespan of a reservoir, well productivity typically diminishes after a certain period of production. This decline can be attributed to either natural depletion or potential damage to the reservoir rock, which can be assessed through well tests. Natural depletion occurs as the reservoir pressure drops with the extraction of hydrocarbons, while damage to the reservoir rock can result from various factors, including the invasion of drilling fluids and the deposition of solids within the pore spaces. Stimulation refers to the artificial creation of a zone near the well, facilitating fluid flow by either increasing the permeability of the formation or reducing the viscosity of the fluids. Acid injection, a stimulation technique employed for over fifty years, is frequently used to enhance the productivity or injectivity of wells. The acid works by dissolving the minerals that clog the pore spaces, thereby improving the flow paths for hydrocarbons. This method is particularly effective in carbonate formations, where the acid can react with the rock to create larger channels for fluid movement. The primary objective of acid treatment is to eliminate clogging around wells and restore permeability. However, it's important to note that injecting acid into a sedimentary formation doesn't always guarantee improved production. The effectiveness of acid treatment can be influenced by factors such as the type of formation, the nature of the damage, and the specific conditions within the well. Therefore, a comprehensive approach is necessary to optimize the results of such treatments. Before acid treatment, a comprehensive study should be conducted to identify the damage, including its position, type, and origin. Additionally, a thorough analysis should be carried out to better select the most appropriate treatment method. This involves evaluating the mineralogical composition of the formation, the properties of the fluids present, and the overall condition of the well. By understanding these factors, engineers can design a treatment plan that maximizes the chances of success while minimizing potential risks. For this purpose, this work is subdivided into four parts, each addressing a critical aspect of the topic:

Chapter 1 Hassi Messaoud Field generalities – This chapter provides an overview of one of Algeria's most significant oil fields, discussing its geological characteristics, production history, and economic impact.

Chapter 2 Origin and Mechanism of Damage and the Concept of Skin – This chapter delves into the various causes of formation damage, the mechanisms through which it occurs, and the concept of skin, which refers to the additional pressure drop caused by near-wellbore damage.

Chapter 3 Matrix acidizing theory – This chapter explores the theoretical underpinnings of matrix acidizing, including the chemical reactions involved, the design of acid treatments, and the factors that influence their effectiveness.

Chapter 4 Case study of well MDZ657

– This chapter presents a detailed case study of a specific well, analyzing the problems encountered, the acid treatment applied, and the results obtained. Finally, the conclusion summarizes the findings and provides recommendations for future practices in well stimulation and hydrocarbon extraction.

Chapter 1: HASSI MESSAOUAD FIELD GENERALITIES

1.1 Historical Background of the Hassi Messaoud Field

The Hassi Messaoud oil field, discovered in 1956 by CFPA and SN.Répal, saw significant development following CFPA's discovery of oil-bearing sandstone in 1957. Nationalization in 1971 led to increased drilling activity, reaching an average of 34 wells per year by 1977. Development initially focused on vertical drilling, transitioning to unconventional methods from 1997 to exploit structurally complex zones. Challenges such as salt deposits and gas breakthroughs accompanied production. The field is divided into 25 production zones, but geological complexities sometimes obscure communication between wells within the same zone.

1.2 Hassi messaoud location

Hassi Messaoud, situated 700 km southeast of Algiers, 350 km from the Tunisian border, and 80 km east of Ouargla, covers an expansive 2000 km² area and rises to an elevation of 142 meters. Characterized by a desert climate, temperatures fluctuate between 0°C and 47°C on average. The region is often buffeted by sandstorms, with winds gusting up to 100 km/h, primarily from the NNE direction during autumn and spring. Renowned as the largest oil field within Algeria's Triassic province, Hassi Messaoud boasts vast reserves and expansive coverage, spanning multiple square kilometers. (figure.1)

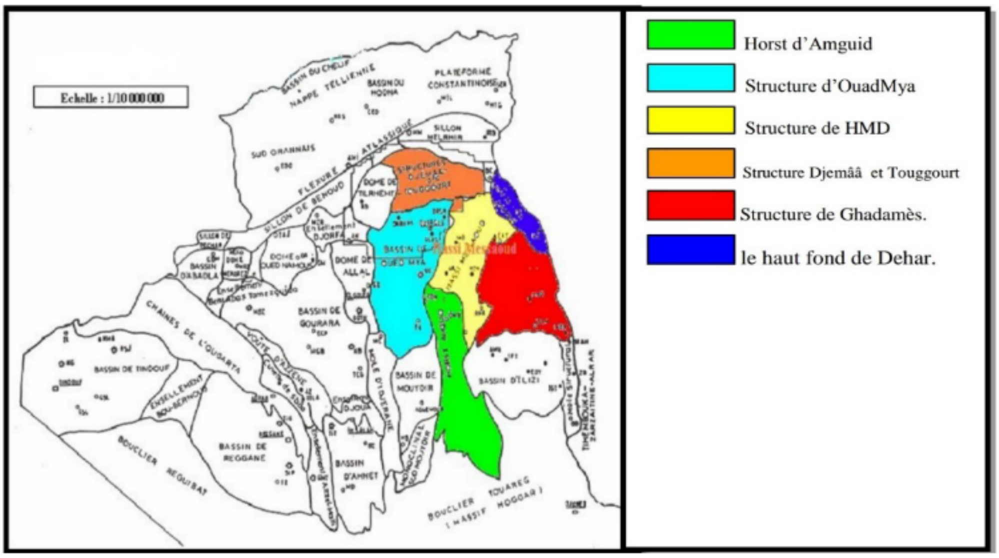


FIGURE 1 GEOGRAPHIC LOCATION OF HMD ([1])

1.3 Geological Framework

The HMD field area occupies a central position within the Triassic province, constituting Algeria's largest oil field both in terms of area and reserves, covering approximately 2200 km². It is bordered by significant features: to the northwest are the Ouargla fields, including Gellala, Ben Kahla, and Haoud Berkaoui, while the El Gassi, Zotti, and El Agreb formations lie to the southwest. In the southeast, one finds the Rhourde El Baguel and Mesdar fields. Geologically, its boundaries are defined by the Oued M'ya depression to the west, the Amguid El Biod ridge to the south, and the Djammâa-Touggourt structure to the north. To the east, it is flanked by the highlands of Dahar, Rhourde El Baguel, and the Ghadames Depression (figure.2). (Horst de leau) water ridge

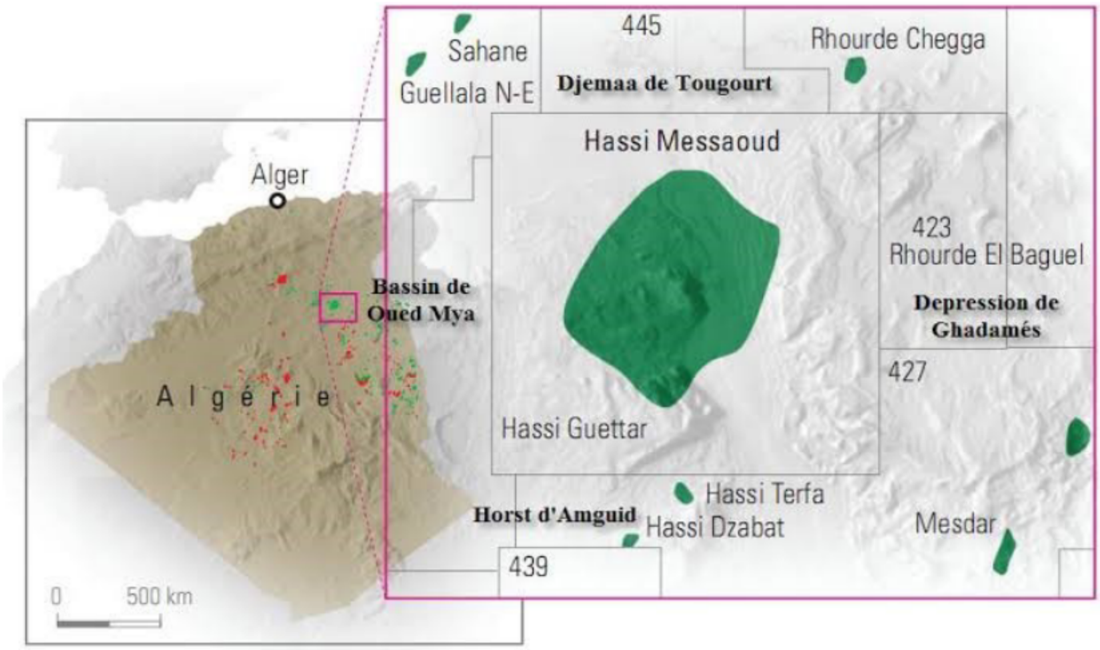


FIGURE 2 GEOGRAPHIC LOCATION OF HMD [1]

1.4 Zonation and Spatial subdivision of the Hassi Messaoud field

The zonation and spatial subdivision of the Hassi Messaoud field involve intricate delineations to optimize oil production. The field is subdivided into numerous production zones, each characterized by distinct geological and reservoir properties. These zones are delimited by non-productive areas, facilitating efficient management and development strategies. However, communication between wells within the same zone can be obscured by reservoir heterogeneity or structural compartmentalization induced by fault blocks. Geologically, these zones often correspond to separate structural blocks separated by tectonic faults, with boundaries continually revised based on new data obtained from the installation of new wells. This zonation framework enables comprehensive reservoir management, enhancing the field's overall productivity and longevity. The zonation and spatial subdivision of the Hassi Messaoud field employ a unique alphanumeric system for precise identification. This system combines geographical numbering with chronological numbering, as illustrated). For instance, a designation like "Omn43" follows this pattern:

- "O": Represents the uppercase letter denoting the Ouargla permit.
- "m": Signifies the lowercase letter representing the 1600 km² block.
- "n": Denotes another lowercase letter indicating the 100 km² square.

- "4" and "3": Correspond to the abscissa and ordinate, respectively, pinpointing the specific location within the designated square. This alphanumeric system allows for systematic organization and efficient management of the field's extensive spatial layout, facilitating clear identification and communication across various operational aspects(Figure 3).

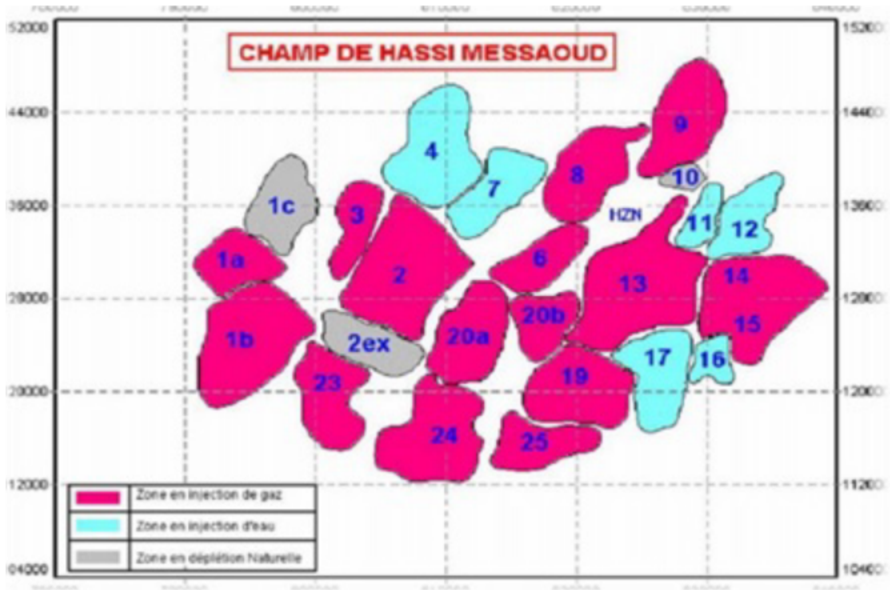


FIGURE 3 HASSI MESSAOUD FIELD ZONES([1])

1.5 Petroleum system

1.5.1 Source rock

• **Silurian:** The parent rock of the entire Saharan platform is composed of Silurian clays. The very rich, black, carbonated, and radioactive clays represent this source material, which is organic and ranges from 20 to 70 meters in thickness. The organic material is amorphous. The presence of Tasmanaceae confirms the marine origin of this substance, and its petroleum contribution is evident. Currently, it can be stated that after the migration of hydrocarbons generated in the Paleozoic era, there was a second phase of more significant generation, which ceased by the end of the Cretaceous due to decreased subsidence. The Silurian is preserved to the north of the Hassi Messaoud field and to the west (in the Oued Mya basin). [2]

1.5.2 Cap rock

The coverage of the Ordovician reservoirs is provided respectively by the outpouring of eruptive rocks as well as by the thick series of evaporites from the Triassic or Jurassic ages.

I.5.3 Traps

Traps refer to areas most favorable for the presence of hydrocarbon accumulations, characterized by lower pressure and temperature than that of source rocks, and by a barrier that forces hydrocarbons to accumulate. [3]

There are three types of traps:

• Structural traps

These traps result from tectonic movements such as anticlines or fault traps.

• Stratigraphic traps

This involves the combination of two different environments corresponding to the transition from a permeable medium to an impermeable one, such as sandy lenses, beveled surfaces, etc...

• Mixed traps: These traps exhibit characteristics of both structural and stratigraphic origins, such as the HMD structure (anticlinal truncated by the Hercynian unconformity). In the Oued Mya basin and the northeast of Hassi Messaoud, the recognized traps so far are of mixed type, combining both stratigraphic and structural features.[1]

1.5.4 Reservoir Description

The reservoir is subdivided into three zones based on grain size criteria:

- Lower coarse zone (Lower Ra)
- Middle fine zone (Middle Ra)
- Upper coarse zone (Upper Ra)

The base of Ra is delineated as a lower coarse zone where three drains develop, distinguished by their grain size parameters.[1] This division can also be validated by the following characteristics:

- D1 : Coarse sandstones with dominant arcuate oblique stratifications, well-defined and often micro-conglomerate-based, with absence of tigillites.
- ID: Thinner levels and higher frequency of silty levels, with local presence of tigillites. It marks a very gradual transition between D1 and D2.
- D2 : Coarse but well-sorted sandstones with dominant tabular oblique stratifications forming mega-ridges, with some intercalations of silty levels with fine bioturbations.
- For this lower part of Ra containing the best reservoir levels, it is noteworthy the progressive extension of erosion zones towards the central field area.
- D3 : Corresponds to the middle fine zone (lower grain size). The main characteristic

of this drain is the abundance of silty interbeds and fine sandstones with very strong bioturbations (especially tigillites).

The marine character of this drain is well-marked. It could correspond to an infra-littoral platform environment, composed of bioturbated clay-silt levels where tidal or storm-influenced marine bars develop. In such an environment, the existence of kilometer-scale permeability barriers is highly probable. [4]

- D4 : Corresponds to the upper coarse zone. These are sandstones with frequent tabular oblique stratifications forming mega-ridges ranging from one to over two meters in thickness. [2]

To recognize and track the reservoirs in any location within the field, it has been subdivided into packages or slices using the various sedimentological parameters mentioned earlier, as well as their wireline log and petrophysical properties.

1.5.5. Characteristics of the Reservoir:

- According to their classification, degree of quartzification, and clay content, the characteristics of the reservoir rock vary considerably. [4] Some points to note are:
- Significant vertical diversity exists.
- Porosity ranges between 5 and 10%.
- Permeability averages between 0.1 to 200 millidarcies.
- Due to its lightness, the oil has an average surface density of 0.8 (45 °API), enhancing recovery rates by reintegrating gases.
- Viscosity stands at approximately 0.2 centipoises at saturation.
- The bottom volume coefficient Bo is 1.7 m3/stdm3.
- The average total compressibility of the oil (oil+water+rock) is 3.63 x 10^4 (kg/cm2) -1.
- Initial oil content ranges from 80% to a maximum of 90%.

Chapter 2: Origin and Mechanism of Damage and the Concept of Skin.

2.1 INTRODUCTION

The identification of damage becomes apparent through the observation of a decline in well flow rate, typically manifested by a reduction in productivity index and the presence of positive skin (damage coefficient). The objective of this chapter is to provide guidance to technicians engaged in well operations, aiding them in making informed decisions regarding the selection of chemical products necessary for the development of well intervention strategies.

All deposits, whether mineral or organic in nature, have the potential to disrupt the natural permeability of a reservoir by migrating within it or by obstructing the wellbore perforations. This impairment can manifest in different segments along the flow path of the effluent, ranging from the reservoir itself to the surface facilities.

2.2 Localization of Damage

2.2.1 At the bottom of the well

As a general rule, deposits typically consist of various types of sediments (particles from the formation, corrosion products from equipment) or precipitates (salts, paraffin, asphaltenes).

2.2.2 At the wall of the well

- **(Cake externe (zone 1))**

The external cake is composed of solid mineral or organic particles that move along the borehole wall during drilling, consolidating the wellbore walls and limiting mud infiltration into the formation.

2.2.3 At the vicinity of the wells

- **cake interne (zone 2)**

The internal cake is composed of fine solid particles from mud, cement, and completion fluids, forming a very thin layer near the wellbore, which impedes the permeability of the formation.

- **The invaded zone (zone 3)**

The zone invaded by mud and cement filtrates is located beyond the internal cake, which will alter the natural environment of the porous medium.

2.3 Particle accumulations

Different types of organic particles can cause reservoir plugging due to changes in thermodynamic conditions associated with production. (figure.4).

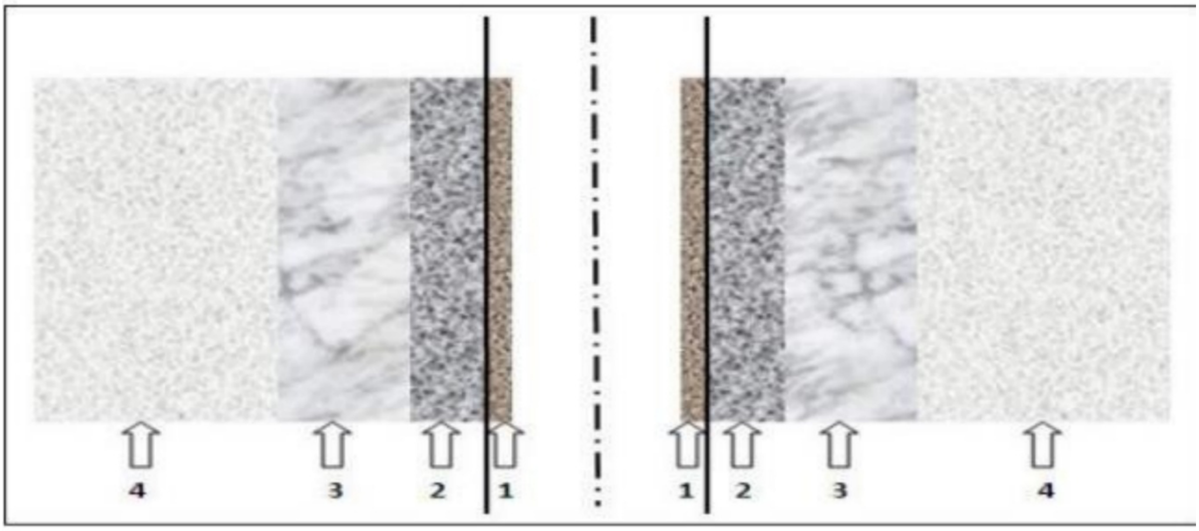


FIGURE 4: LOCALIZATION OF DAMAGES. [5]

2.4 Damage mechanisms:

see the table below

TABLE 1:REPRéSENTATION DES MéCANISMES DE L'ENDOMMAGEMENT. [5]

Type of process	Physical reduction in pore size	Relative permeability decrease
fluid-rock interaction	• Migration des fines. • Gonflement des argiles. • Invasion de solides. • Absorption/précipitation de grosses molecules (polymers).	• Modification of wettability due to the absorption of surfactants.
fluid-fluid interaction	• deposit • Emulsion • Sludge	• Modification of fluid saturation. • Fluid blocking (water blocking, gas blocking)
pressure-temperature interaction	• Deposits	• Gas breakthrough • Condensate deposits • Water coning
mechanical process (induced by stress)	• Decrease in permeability • Plugging of perforations	

2.4.1 Drilling Damage:

a) Mud cake

The mud cake provides a physical barrier to prevent the penetration and loss of drilling fluid, as well as subsequent fluid losses, into a permeable formation.\

b) Cementation:

- Washout plugs & spacers
- Destructive to the mud cake.
- Dispersant additives, surfactants.
- Invasion of filtrate... a few inches.
- Slag
- High pH.
- Precipitation of $CaCO_3$.
- Free H_2O...... water block.
- Squeeze
- Formation damage, potentially fracturing (Limited invasion due to volumes and fluid composition).

2.4.2 Actual Damages (Formation damage)

It is a term that describes any reduction in natural permeability in the vicinity of the well (the critical zone). This reduction is caused by:

- Any contact between the formation and an external fluid (drilling fluid, completion fluid, stimulation fluid, etc.).

- The reservoir fluid itself, because this fluid has a certain thermodynamic equilibrium (P, T), but during production, there will be a change in its parameters, which can result in solid precipitation. [5]

2.4.2.1 Damage due to fluids used during operations

For adherence to safety standards, drilling, work-over, and sometimes snubbing operations involve well killing. Damages resulting from operational fluids include:

- Perforation Plugging

- Wettability Change

Solvents and surfactants, particularly present in the filtrate of inverse emulsion muds (utilized for preventing sludge or emulsion formation).

- Water Block:

This issue is prevalent in gas and low-pressure reservoirs. Indications include:

• Lack of return during stimulation operations.

• Emergence of water production.

• Production decline post-use of water-based muds.

The remedy involves employing a surfactant, acting as an emulsifier to enhance oil mobility.

- Emulsion Formation

Characterized by high viscosity, emulsions can significantly diminish well productivity, inversely related to viscosity. They can be dispersed by injecting surfactants to reduce interfacial tension and break them apart.

- **Formation of Sludges (Emulsion (Sludges))**

It generally forms due to the incompatibility between heavy oil and mineral acid during a matrix treatment operation.

2.4.2.2 Damage due to production:

- **Mineral Deposits (Scale Deposits):**

Changes in temperature and pressure associated with production result in the precipitation of salt from fluids, sulfate deposition, carbonate deposition, and iron deposition.

- **OrgÉnic Deposits (asphaltenes and paraffin):**

The precipitation of kinds of paraffin occurs when there is a decrease in pressure and temperature during production(figure.5)

FIGURE 5 : ORGANICS DéPOSITS (PARAFFINES) [5]

2.4.2.3 **Damage due to the presence of clays in the reservoir:**

- **Fines Migration:**

High-rate production from a well creates turbulence in the flow, causing the migration of fine particles (clays, sands...).

- **Swelling Clays:**

There is a type of clay in the form of sheets (Smectite), which swells when it absorbs water (it can swell up to six times its initial volume).

2.4.3 Pseudo damages (Pseudo damage):

2.4.3.1 **Damage due to wellbore geometry:**

In this damage, two situations are found:

- Partial Penetration:

Partial perforation creates convergence between flow lines as they approach the well, reducing flow rate.

- Well Deviation:

When the well is deviated at a certain angle, it increases the contact surface area between the well and the reservoir, thus aiding production.

2.4.3.2 Damage due to completion

In this part, three elements affect this damage:

- Perforation:

Flow lines begin to converge to enter the perforations, causing a positive skin effect, which is significant when vertical permeability is low. Parameters of perforations that can influence this skin effect include:

- Perforation density.
- Phase difference between perforations.
- Gravel pack.
- Crushed zone.

2.4.3.3 Damage due to turbulence during production:

Generally, turbulence occurs when a well is put into production at a high rate or may also be caused by various pseudo damages as well as plugging at the perforation level, thus modifying the flow regime from a Darcy regime (laminar) to a non-Darcy regime.

2.4.4 Damage due to perforations

Most perforation operations are performed in an overbalanced condition, leading to the formation of a cake filtrate in the perforation tunnels, causing skin and pressure drop around the wellbore.

2.4.4.1 Filtrate invasion during cementing

During liner cementing, cement filtrate can invade the matrix, causing damage.

2.4.5 Stimulation damage.

In the case of acidizing, damage is caused by secondary reactions if the acid used is not suitable. After hydraulic fracturing, the propped fracture can be partially plugged by the fluid carrying the proppants (frac gel).

2.4.6 Damage due to water injection.

- Water saturation around the wellbore if the injection rate is not properly controlled (water block).
- Blocking by sulfate deposits (scale) due to the incompatibility of injected water and formation water.

Non-filtration of injected water.

- Bacteria action: Anaerobic bacteria can develop in injection wells in the absence of oxygen, leading to...

2.5 Damage detection

A number of widely-used methods are available, including the following:

- Sampling and laboratory analysis.
- Complete well history.
- Well testing.
- Production system analysis.
- Production logging (PLT ...). [6]

2.5.1 Sampling and laboratory analysis

Sampling and analysis of reservoir fluids and even injected fluids to know the components and concentration of each component (minerals), all of which will help determine the solubility index (Ks) and at what concentration precipitation will begin.

2.5.2 Well tests

Well tests with good pressure buildup are a privileged means of gathering information to assess whether reservoir production is declining. We however, that the total skin **"S"** includes parasitic factors (pseudo skins) which must be to determine whether real clogging exists. Well testing also provides other information of vital importance: changes in static layer pressure permeability in downhole conditions, which may differ significantly from surface measurements surface measurements, productivity index and flow efficiency**.** [6]

2.5.3 Complete well history

The well history is a very interesting source, as it contains all the information on the various phases of drilling, completion and also all that concerns production profiles the various operations (Snubbing, Workover, Stimulation...etc.) that have already been carried out on the well. The history can be used to detect any cause of damage.

2.5.4 Production logs (PLT, ...)

Production logs play a very important role in damage detection. damage. The PLT, example, shows the contribution of each perforated bank to the well's total production. perforated banks to the well's total production, and thus provides a good indication of the location of damage.

2.5.5 Analyse du système de production

Lorsqu'on remarque une baisse dans le débit de production d'un puits, on va faire une analyse sur le système de production, on utilise pour cala la méthode de l'analyse nodal (Nodal Analysis), donc on commence du réservoir vers le fond du puits (In flow), elle est représentée par la courbe IPR (PWF=F(Q)) ,puis on passe vers la deuxième partie du système, le fond du puits jusqu' au surface (Out flow), elle est aussi représentée par la courbe VLP (PWF=F(Q)), ce qui nous permet de définir l'endroit du l'endommagement. [6]

2.6 Notion of skin (damage coefficient)

Skin is defined by a dimensionless factor determined by well tests.

It represents the total degree of damage to a well, without differentiating between matrix damage (for which acidification may be a solution) from secondary damage secondary damage caused by the well configuration: the Pseudo-Skin (figure.6).

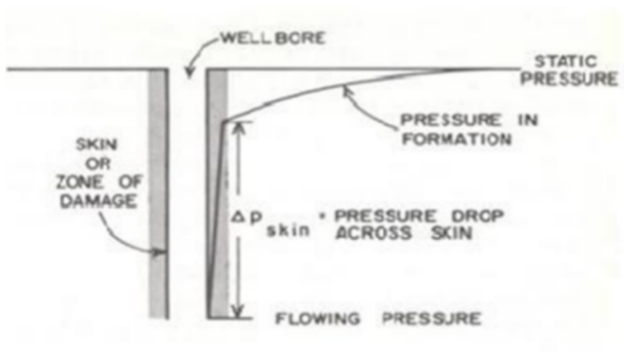


FIGURE 6 PRESSURE PROFILE IN THE NEAR WELLBORE FOR A WELL WITH FORMATION DAMAGE [7]

2.6.1 Skin origin

2.6.1.1 Perforations:

The ideal well model assumes that its contact with the formation extends over 360º, but with perforations, it is quite conceivable that production is forced through the openings alone. This results in a loss of head expressed by the skin Sp, called the parietal effect coefficient which is a function of the number of perforations, their distribution and penetration power.

2.6.1.2 Partial penetration:

Perforation of only part of the well's height restricts the flow lines flow lines around the well. This contributes to the existence of a positive skin (pseudo skin Sc) which varies with formation thickness, well diameter and perforated height.

2.6.1.3 Well inclination

Well inclination improves flow around the well, and contributes to negative skin negative skin.

2.6.1.4 Hydraulic fracturing Hydraulic

fracturing considerably improves flow around the well, it leads to a negative skin.

2.6.1.5 Horizontal wells

Under certain conditions, a horizontal well can be treated in the same way as a vertical well. a negative skin due to the improved flow.

2.6.1.6 Gas wells deviation from Darcy's law

In a gas well, the fluid velocity in the vicinity of the well is often high, and the flow no longer follows Darcy's law. Darcy's law near the well.

A positive skin as a function of flow rate reflects the additional head losses due to this deviation from Darcy's law Darcy's law.

2.6.1.7 Overall damage:

In all cases, additional head losses localized near the well (matrix), can be treated as

skin. The skin measured during a test is therefore the resultant of of all these skins.

$$S = S_e + S_p + S_c \quad \text{......................(Eq II-1)}$$

- **Se**: actual damage in the vicinity of the well (matrix);
- **Sp**: head loss due to perforations;
- **Sc**: flow constriction due to partial penetration.

2.6.2 Consequences of a change in permeability around the well on

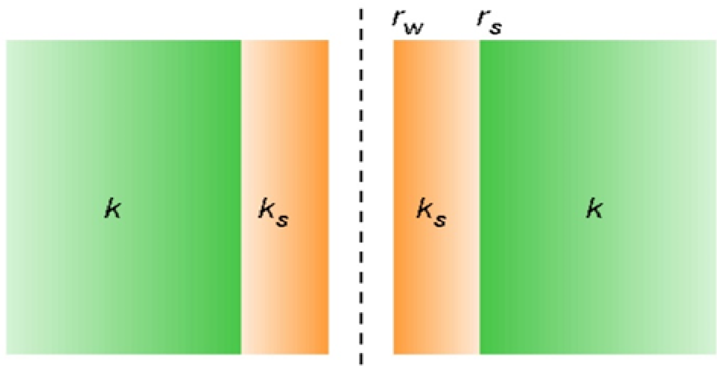


Figure 7: Effect of skin on Permeability [8]

The re radius and Ke permeability of the damaged area (figure.7) are related to the Skin by Hawkins' expression

Hawkins:

$$S = \left(\frac{ki}{Ke} - 1\right)\ln\left(\frac{re}{rw}\right) \ldots\ldots\ldots\ldots\ldots\ldots \quad \text{(Eq II.2)}$$

Ki: reservoir permeability.

Ke: permeability of the damaged zone.re: radius of damaged zone.

rw: well radius.

We can see that if :

- **S>0:** the permeability of the zone adjacent to the well is lower than that of the rest of the formation (case of damage);
- **S<0**: Corresponds to an improvement;
- **S=0:** Ke= K (no damage).

2.7 **Effect of skin on productivity**:

1- Productivity index:

The productivity (or injectivity) index of a well is defined as the flow rate associated with a depression between the bottom of the well and the reservoir, it is a well potential and is expressed for a case of a liquid in a circular radial flow, steady state:

$$IP = \frac{Q}{Pg\text{-}Pf} \quad \text{.........................(Eq II-3)}$$

- The IP of a well in production decreases during its production, this is explained by:
- Turbulence at high flow rates;
- Existence of free gas;
- High viscosity (not the case with HMD);
- Compressibility of the rock reduces **K** permeability.

There are two types of IP:

$$IPth = \frac{Q}{(PG - Pf - \Delta Ps)} \quad \text{.........................(Eq II-4)}$$

- **Q** : débit d'huile en (m^3/h).
- **IPr:** actual productivity in (m^3 /h/ bar).
- **IPth:** theoretical productivity of the same dimension.
- **PG:** reservoir pressure in (bar).

- **ΔPs**: Additional pressure drop due to skin in (bar).
- **Pf**: down hole pressure in (bar).

Note that well productivity **(IP)** is a function of permeability and conductivity **(KH).** In fact, a decrease or increase in **K** will directly lead to a decrease or increase in **PI.**

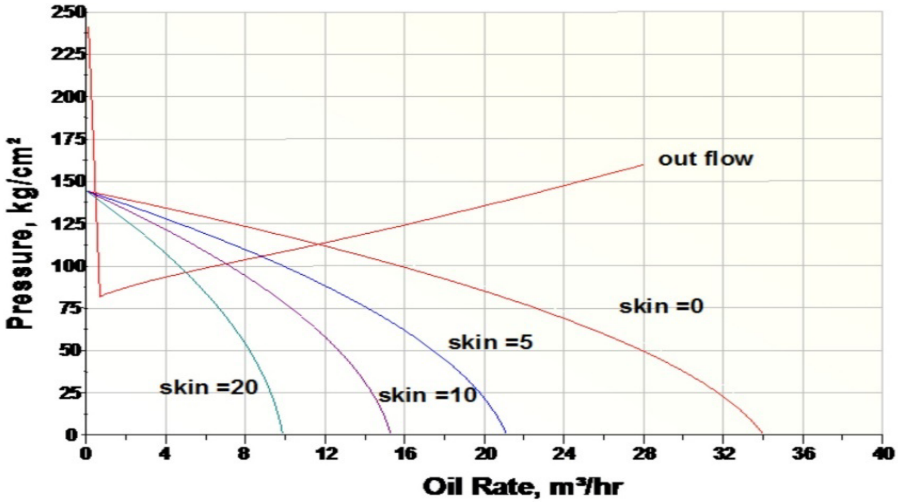
According to relationship (4), a decrease in **ΔPs** leads to an improvement in permeability. Well productivity is a function of **KH,** and is therefore reduced when a reservoir has a low useful or low permeability; hence the idea of reservoir stimulation to improve productivity.

If a reservoir has: **S > 0** Then **ΔPs** is high, **K** low, **IP** low, resulting in a drop-in production rate. In this case, the well must be restored by stimulation.

Knowledge of IPR and the Hawkins equation is essential for understanding the effect of formation damage on well productivity. (figure.8)

For an oil well, the IPR equation:

Q



$$= \frac{kh(PG-Pwf)}{141.2\ B\mu \ln(\frac{re}{rw})} \quad \text{......................} \quad \textbf{(Eq II-5)}$$

FIGURE 8: RPI VARIATIONS FOR DIFFERENT [5]

With:

- **S**: total skin.
- **Q:** oil flow rate under bottom conditions (bbl/d).
- **K:** permeability (md).
- **h:** tank height (ft).
- **Bo:** volumetric factor (m3/stm3)
- **μ:** oil viscosity (cp).
- **PG:** reservoir pressure (psi).
- **Pwf:** dynamic bottom pressure (psi).
- **Re:** drainage radius (ft).
- **rw**: well radius (ft).

2- HORNER's method

the concepts used are:

Pwf (t): Flow pressure; time is counted from the start of Production. **Pws** (**Δt**): Pressure in up-dip; time is counted from time tp of well closure

Pws (Δt= 0) = **Pwf (tp).**

The principle of flow superposition is used to interpret pressure rise, the equation becomes:

Pi - Pws (Δt) = (Eq II-6)

Pws = f (log)………………. (Eq II-7) [5]

Interpretation:

The previous equation shows that bottom pressure varies linearly as a function of log

(tp + Δt / Δt) On a graph Pwf = f (log (tp+Δt /Δt)) once the effect of a straight line with slope m:

Extrapolated pressure:

For Δt---> 8 either (tp +Δt /Δt) = 1 this pressure value is called the extrapolated pressure. It is

Noted (p*)

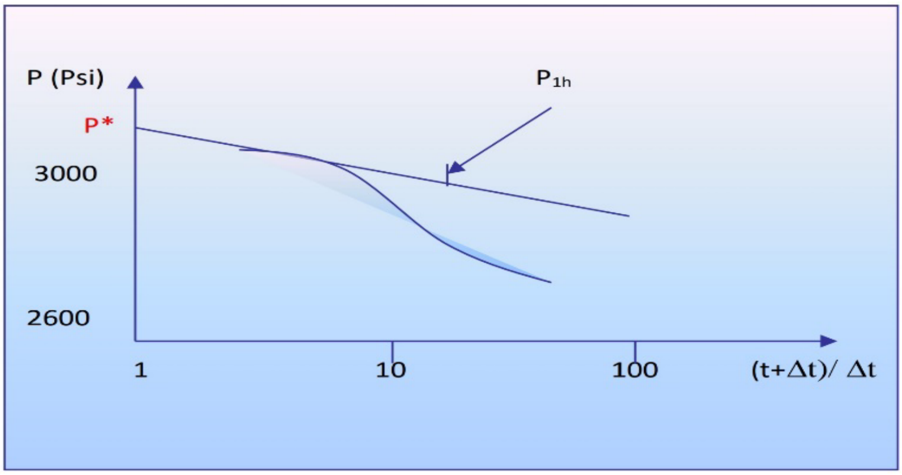


FIGURE 9 PRESSURE RISE CURVE

Chapter 3. MATRIX ACIDIZING THEORY

INTRODUCTION

Matrix acidizing is a widely employed stimulation technique in the oil industry to enhance productivity in formations with wellbore damage. It involves injecting acid into the reservoir below fracturing pressure, leading to chemical reactions that remove the impairment and restore or improve permeability. Planning acidizing jobs for homogeneous reservoirs with small pay is relatively straightforward, but challenges arise when dealing with multilayered reservoirs and long producing intervals due to difficulties in achieving uniform acid distribution throughout the pay zone. If any damage remains in the perforated interval, optimal well productivity cannot be achieved. Various methods are used to ensure proper fluid distribution, including straddle packers, perforation wash tools, squeeze packers with retrievable bridge plugs, ball sealers, and diverting agents. Straddle packers and perforation wash tools are considered more effective in theory as they enable selective injection, but these mechanical methods have limitations as they require a good cement bond and a working string, making them unsuitable for through tubing operations in completed wells. Ball sealers also require a good cement bond and are not recommended for long perforated pay zones with high shot density or low rate treatments, as well as gravel packed wells. Matrix acidizing with diverting agents, such as solid particulates, acid emulsions, viscous liquids, oil soluble resins, or foams, is a preferred method for treating multilayered reservoirs or long producing intervals. However, there is currently no established methodology for tailoring and controlling these treatments. The proposed method aims to optimize acid volumes without the use of diverting agents for both single and multilayered reservoirs, providing better control over the injection process and allowing for estimation of stimulation levels in each layer during treatment. [9]

3.2 Acid Solutions

all chemical compounds which increase the concentration of hydronium ions (H_3O^+) in a water solution below a pH of 7 can be considered acids. The pH is a measurement of the concentration of hydronium (H_3O^+) and hence a measure for the acidity of a solution. There are only of few kinds of acids that are commonly used in acidizing. [10]

3.2.1 Most common types of acids in acid stimulations

We distinguish between inorganic (mineral) and organic acids. Among inorganic acids, *hydrochloric acid, HCl*, is the most popular. It is very strong and the basis of almost every acidizing treatment, no matter what kind of formation. “Strong” means that it is totally dissociated into hydrogen and chloride ions when in solution.

Carbonic acid, H_2C0_3, is an example for a weak mineral acid.

Hydrofluoric acid, HF, which is not strong although inorganic, is used in sandstone formations. The objective of most HF acidizing treatments is to eliminate damage around the wellbore due to particle invasion from the mud solids after the drilling process and swelling, dispersion, movement or flocculation of formation clays.

In the presence of hydrochloric acid, hydrofluoric acid is poorly dissociated and behaves like a weak acid. This becomes important when doing sandstone acidizing in order to handle precipitations which we will see in the next chapter.

For operability purposes hydrofluoric acid (liquid) is handled and added in form of ammonium bifluoride, $(NH_4)\ HF_2$ (solid).

The only two organic acids that are frequently used are *acetic acid, CH_3COOH*, and *formic acid, HCOOH*, which in terms of strength is between hydrochloric and acetic acid. They are both used for dissolving carbonate formations. Since organic acids are weak, they do not totally dissociate and hence react incompletely with the reservoir rock. Taking acetic acid, CH_3COOH, as an example, it will partially dissociate by the reaction:

$$CH_3COOH \leftrightarrow H^+ + CH_3COO^- \quad [11]$$

Whenever the chemical activity, the driving force for a change, of the reaction products balances the activity of the reactants, the acid reaches equilibrium. At this point the dissolution of the formation material stops, even though acetic acid molecules may still be in solution.

The equilibrium of the acetic acid dissociation is described by the equilibrium constant:

$$Kp=\frac{[H^+][COOH^-]}{[CH_3COOH]} \quad ....(Eq\ III\text{-}1)$$

In this case the equilibrium constant is also referred to as the *dissociation constant.* As can be seen in Eq. [3.6] K_D is small for weak acids as for acetic acid. At 150°F acetic acid has a K_D of $1.488x10^{-5}$ and formic acid of $1.486x10^{-4}$. In general, the higher the concentration of organic acids, the lower the dissociation. Therefore, organic acids are frequently used in retarded acidizing jobs.

3.3 Petrography of reservoir formations and acid selection [12]

Matrix acidizing is performed in two main types of formations:

- **carbonates and sandstones.**

Acidizing of both groups face different general requirements. Each formation composition within the two groups theoretically requires individual treatment and recipe in terms of acid type, acid concentration, injection rate, injection pressure (since we do not want to frac the formation) and additives. In order to find the adequate treatment for each formation, we first need to understand the rock.

The decisive factor in the effectiveness of a reaction between the rock and the acid is determined by the components of the rock which naturally cannot be changed. Hence the composition of the rock in the near wellbore region can be regarded as a given parameter for each well. The acid-rock combination, the mineral distribution and the morphology will result in different reaction rates and reaction products. We will see that when doing matrix acidizing the acid has not the same effect on the carbonate rock as on the sandstone rock. The mode of action in each case is a very different one.

3.3.1 Carbonates

When doing carbonate acidizing, we mostly use hydrochloric acid, HCl. The ideal chemical reaction can be described as follows:

$$CaCO_3 + 2HCl \rightarrow CaCl_2 + H_2O + CO_2 \qquad [11]$$

The surface reaction rate of limestone with hydrochloric acid is very high which can cause wormholes even up to 10 feet long in the near wellbore region connected to the flow channels. Wormholes are caused by non-uniform dissolution of limestone, which basically means that larger pores grow faster than the smaller ones. The limiting factor in most of the cases is the mass transfer. If initially a well has no skin at all or the wormhole length after the acid treatment is larger than the skin radius, then the pressure drop across the wormholes is negligible which eventually means infinite permeability across this region. Taking a look now at Hawkins formula, Eq. [2.5]:

$$s=\{{}^{k}/_{k_s-1}\}*\{\ln {}^{rs}/_{rw}\} \quad \text{…………(Eq III-2)}$$

we can see that assuming an infinite permeability (**k_s =∞)** and a wormhole radius which equals the skin radius (***r_{wh}*** = ***r_s***) the skin factor results in:

$$s = -\ln(\frac{rw_h}{rw}) \quad \text{……….(Eq III-3)}$$ [11]

We know that a negative skin factor effectively means that the apparent radius of the well is being enlarged.

Acetic and formic acid reacts on limestone as follows:

Formic acid with limestone

$$CaCO_3 + 2CHOOH \rightarrow Ca(CHOO)_2 + H_2O + CO_2$$ [11]

acetic acid with limestone→

$$CaCO_3 + 2CH_3COOH \rightarrow Ca(CH_3COO)_2 + H_2O + CO_2$$

We can assume that at pressures above 70 bar carbon dioxide stays in solution after the reaction. In the reaction of dolomite with hydrochloric acid it must be considered that the ratio of calcium to magnesium is not constant. An idealized chemical reaction is shown below:

$$CaMg(CO_3)_2 + 4HCl \rightarrow CaCl_2 + MgCl_2 + 2H_2O + 2CO_2$$ [11]

3.3.2 Sandstones and clays

Most sandstone formations are composed of quartz particles, $Si0_2$, which are bonded together by various kinds of cementing materials, mainly carbonates, silica and clays. This diversity of materials in the composition makes it a lot more difficult to predict the outcome of a reaction. Hydrochloric acid alone in most of cases will not be enough to dissolve the rock. An idealized primary reaction of hydrofluoric acid on sand (silicon dioxide) and clay could look as follows: [9]

reaction of hydrofluoric acid on silicon dioxide

$$SiO_2 + 6HF \rightarrow H_2SiF_6 + 2H_2O$$ [13]

reaction of hydrofluoric acid on clay

$$Al_2Si_4O_{10}(OH)_2 + 36HF \rightarrow 4H_2SiF_6 + 12H_2O + 2H_3AlF_6$$ [11]

A big concern in terms of clays reacting with hydrofluoric and hydrochloric acid solutions is damage due to secondary reactions. The primary reaction results in complete dissolution of the aluminosilicate and is the only reaction leading to the removal of clay damage. Fluorides act to dissolve silicon and an excess of acid is required to dissolve non-silicon cations and keep them in solution.

The dominant silicon fluoride species among the silicon reaction products can best be described as $HSiF_5$. Experiments showed that when H_2SiF_6 is added to HCl, immediate decomposition to $HSiF_5$ and free HF occurs.

The secondary reaction of HF with aluminosilicate, in essence, is the reaction of flu silicic acid with aluminosil0.icate. Now other cations are dissolved from the aluminosilicate which is connected with further acid consumption. The reaction, however, does not dissolve the silicon in the aluminosilicate. Rather, all portions of clay are removed except the silicon which eventually leads to an amorphous and chemically complex silica-gel residue or film. Furthermore, silicon originally present as $HSiF_5$ is completely precipitated as a silica-gel film on the surfaces of the reacting aluminosilicates. This film contains a large amount of water which either comes from the reaction products or from the solution itself. The secondary reaction benefits the formation of sodium and potassium fluosilicate precipitates (Na_2SiF_6, K_2SiF_6) to a high extent. These insoluble fluoride precipitates are gelatinous type materials which occupy a large volume of pore space in the sand around the wellbore and are responsible for treatment failures especially in high permeable feldspar formations [14].

Therefore, in crucial cases (high number of sensitive clays or high temperatures which accelerate reactions), a good advice is to reduce the concentration of hydrofluoric acid in order to limit the potential for detrimental secondary reactions.

We also have to consider that hydrofluoric acid is able to dissolve quartz and clay particles but will cause problems when reacting with calcium carbonate [3]:

$$Ca^{++} + 2F^{-} \rightarrow CaF_2 \quad [11]$$

Whenever free fluoride and calcium are present, they will precipitate. Hydrofluoric acid should therefore among other reasons always be used together with a surplus of hydrochloric acid. The surplus of hydrogen ions will bond the free fluorides in order to bar them from reacting on calcium. Furthermore, a combination of hydrochloric, HCl and hydrofluoric acid, HF, should be used due to the manifold composition of sandstone rocks. A preflush of hydrochloric acid is almost standard in order to remove the calcium and magnesium but this will be the focus of a later chapter. A rule of thumb states that a formation with about 15-20% HCl solubility should be treated by HCl alone.

3.3.3 Differences in the mode of action

When acidizing either limestones or dolomites, acid enters the formation through pores in the matrix of the rock or through naturally induced fractures. The intensity of the reaction depends due to mass transfer limitation on the injection rate, the contact area and the number and size of the fractures if present.

The reaction rates vary depending on the formation and the acid. Hydrochloric acid, for instance, reacts faster with limestone than with dolomites, and only very little with sandstone.

The fast reaction rate of carbonates and the potentially resulting wormholes might have a penetration into the formation of 10 ft whereas in sandstone formations it might probably only be 1 ft. The structures of wormholes depend on the flow geometry, the injection rate and the mass transfer rates. The wormholes propagate due to the unevenly progressing etching pattern of hydrochloric acid with carbonates. Naturally the acid will have more impact in flow channels with the largest exposed area, like a natural or induced fracture or an already etched wormhole, than in a very narrow path. Now it is also understood why acid fracturing treatments in sandstone formations are not applicable – the reaction rate of hydrochloric acid as well as of hydrofluoric acid on sandstones is too slow to create unevenly etched channels in terms of enlarging fractures or even creating wormholes

The big difference we have to consider in sandstones compared to carbonate acidizing is that we do not create any wormholes in order to get a connection to various flow channels but we basically remove the damage around the wellbore. Additionally, when using hydrofluoric acid in sandstones we usually dissolve clay particles or fines resulting either from the drilling or production process.

3.4 Procedure design

In planning the stimulation treatment, the sequence of the fluid patches and the exact timing is crucial. Each well has experienced a different kind of damage, therefore theoretically requires a unique treatment. The stages which a sequence normally consists of apart from the treatment itself are preflush and postflush [8].

First of all, we want to know in what kind of formation the acid treatment is to be performed. In case of carbonate reservoirs, the selection of the acid type becomes easier. Furthermore, in most of the cases no preflush is required. In sandstone acidizing a core analysis would give information on the amount of cement, clays, other pore filling minerals and the type and distribution of the components. However, in most of the cases cores of the desired formation are not available which turns the whole process into some kind of guess work which is very much dependent on experience with the particular petrography of the reservoir formation. A mixture of hydrochloric and hydrofluoric acid is commonly used as a main treatment.

The physical placement must be determined and consequently we can decide whether diverting or retarding agents should be added to the acid system.

3.4.1 Preflush

In many acid stimulation treatments, preflushes are used ahead of an acid treating solution to prepare or condition the formation which is going to be stimulated so the formation will accept the acid in the most favorable sections.

The main purpose of the preflush is to displace the brine from the wellbore to avoid contact between the hydrofluoric acid and the formation brine containing potassium, sodium and calcium which leads to precipitations. In sandstone acidizing a hydrochloric acid preflush is required to dissolve carbonates in the formation so the hydrofluoric acid will not spend on those but rather remain active to dissolve the clays and silicates.

Aromatic Solvents, either with or without hydrochloric acid, can be used to remove paraffine and asphaltene components. Mutual solvents, such as ethylene glycol monobutyl ether (EGMBE), are also used in preflush (and also in postflush) fluids because of their ability to dissolve away the oil coating.

A kerosene or diesel oil preflush can be used in order to allow the formation to react with the acid in the oil-producing interval while restricting the invasion of acid into the water-producing strata. [11]

3.4.2 Main treatment

The purpose of this stage is the removal of the damage of the well. The injection rate influences the placement of the live acid and thus the success of the treatment to a large extent. The type of acidizing job matrix acidizing or acid fracturing - determines the ideal injection rate. The acid system, depending on the formation, is injected with a rate which in terms of matrix acidizing must not correspond to pressures exceeding fracture pressure. In general, low injection rates that produce pressures below the breakdown pressure are recommended to repair skin or shallow formation damage as sometimes in sandstone wells. Low pump rates are also recommended when acidizing in proximity to high water saturation zones.

With injection rate kept constant the pressure at the pump can be observed. Whenever the pressure decreases the formation starts to take notice of the injected acid. A fast decline means a fast reaction of the acid with the formation. In carbonates wormhole velocities increase with injection rate which means for rapid wormhole propagation a high injection rate should be applied. On multizone treatments where different zones accept the acid solution at different pressures, a more complete acid coverage can be obtained also by applying high pumping rates. If the formation is able to sustain higher forces, the maximum allowable pressure for the tubing, the surface equipment and the pump, together with the maximum achievable pump rate, must be kept in mind since in such a case those parameters will define the pressure limit and not the reservoir rock parameters. [11]

3.4.3 Postflush

The overflush is used to displace the main acid flush at least 4 feet away from the wellbore. The precipitation products are pushed as far away as possible from the critical region, the near wellbore.

Postflushes can also be used as an over-displacing medium. Retarded acids might help to obtain greater penetrations of the acid since the reaction time of the retarded acid on the formation is longer than its injection time.

Since a flow of the acid system back to the well immediately after the treatment is not beneficial for avoiding corrosion, water or brine could be an overflush which would help to minimize the contact time of the live acid on the tubing and the casing. Naturally, we try to avoid additional precipitation products. In acidizing sandstone formations with hydrofluoric acid a ammonium chloride, NH_4Cl, postflush is recommended instead of postflush consisting of potassium chloride, KCl. [11]

3.4.4 Success evaluation, possible damage and general recommendations

Generally, success can be measured in terms of Productivity Index (PI) improvement or skin reduction. An acid stimulation treatment can also cause further damage instead of damage removal. Precipitation products coming from the reaction itself or loose solids generated during the acidizing job might cause further plugging of flow channels. Dirt from the tank or tubular, release of fines from carbonate rocks, precipitation of iron reaction products, plugging by colloidal sludge and chemical incompatibility of the acid system itself or with the formation might cause further problems. Some crude oils and strong inorganic acids can produce sludges such as organic deposits which cannot be dissolved.

State of the art nowadays is the *real-time monitoring* of an acidizing job. The skin factor correlated, for instance, with Paccaloni's model from the measured pressure changes is plotted versus the injected volume of acid solution during the acidizing job to determine the optimum point when to stop the injection. Continuation of the treatment would probably lead to an increasing skin factor again as can be seen in the graph.

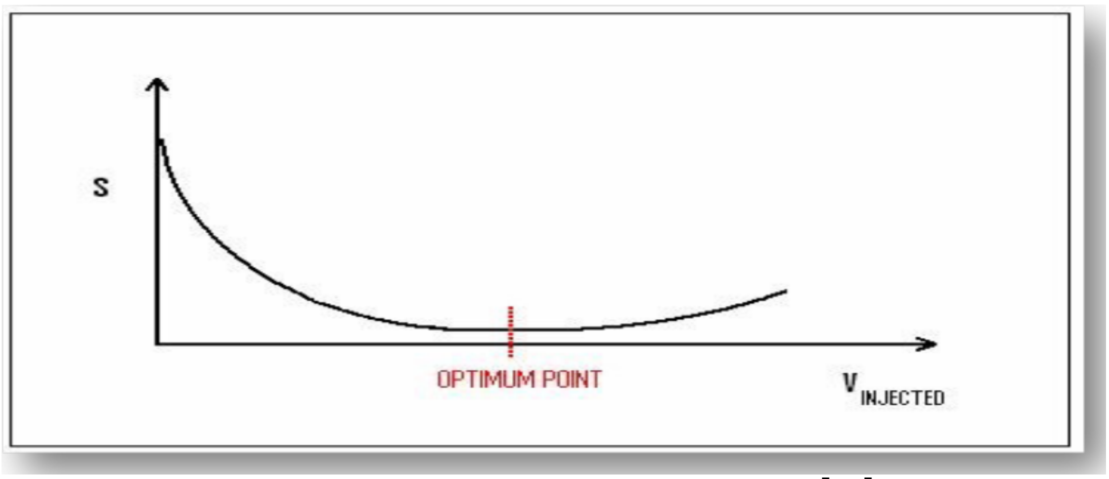


FIGURE 10: THE PRINCIPLE OF REAL-TIME MONITORING [12]

Below, we can find a summary, in order to shortly review on some general operation recommendations before and after the treatment

- During the preparation of the acid solution minimize open air time while mixing the fluid batches.
- Make sure the tanks and flowlines are clean.
- A corrosion inhibition measure is to not produce the spent acid into the flowline after the acidizing job, but in tank. We can never be sure that 100% of the live acid totally reacted on the formation rock.
- Oxide layers which may develop on the surface metallic components should be removed by pickling in order to avoid precipitations downhole.
- Depending on the acid solution pumped, be aware that damage can also occur during shut-in time and not only during pumping and the primary reaction.

3.5 CONCLUSION

In conclusion, matrix acidizing is a valuable technique in reservoir stimulation, providing a means to enhance oil and gas production by improving the permeability of the formation. Its success depends on careful planning, understanding of reservoir properties, and effective management of operational and environmental challenges.

Chapter 4. CASE OF STUDY

4.1 Generalities of well MDZ657

The well MDZ657 [15] was drilled and completed on 05/04/13 as a horizontal open hole. Despite a DST result indicating oil production at a rate of Q=6.13m3/h, the well failed to produce. Consequently, it was decided to implement an intelligent completion to facilitate multi-stage frac operations(Figure.11).

The completion features several production sleeves, frac ports, and a straddle packer. Although some hydrocarbons were encountered after the frac operations, with 40% of oil after the 2nd frac stage and 30% after the 3rd stage, subsequent workover activities from 09/03/2019 to 14/06/2019 aimed primarily at retrieving a stuck snubbing 2 "3/8 yielded no hydrocarbon indicators, even after multiple cleanouts. It was only during the last matrix treatment with Mud Acid that traces of hydrocarbons were detected in the return. The near-wellbore reservoir formation may have incurred damage due to mud invasion. The well is situated in zone 23-Complexe, as depicted in the accompanying detailed map of the well location and relevant offset wells.).

FIGURE 11: MDZ657 WELL LOCATION MAP [15]

4.2 Treatment objective

The main purpose of that intervention is to use a combined treatment "Reformat-

HCI 15%" to remove the mud damage and attempt to restore the hydrocarbon pathway into production.

- Current Well Situation: [15]

il faut aussi parler du logiciel ou programme que avez utilisé

il faut bien commenter ces figure en parlant de leurs références

FIGURE 12. MDZ657 WELL PRODUCTION PARAMETER THE WELL IS CURRENTLY SHUT-IN

FIGURE 13. MDZ657 WELL PRODUCTION PARAMETER [15]

4.3 WELL DATA [15]

Table 2Well data MDZ65

Well name	**MDz-657**
Well Type	Oil producer
Rock Type	Sandstone
Casing size	7", 32 #/ft 3450m TR
Completion	4 /2" [1]13.5#/ft Pli0, 4316 m
BHP	PFS (25/04/2014) PG=364.36kg/cm2
Total depth	4316m TR (WD: 3461.5m)
Current TD	4305m TR (Copperhead plug depth)
KOP	3135m TR
Restriction	ID 3.75" Open hole packer 1 at 3473.19 m ID 3.75" Open hole packer 2 at 3572.35m ID 3.75" Open hole packer 3 at 3658.30m ID 3.75" open hole packer 4 at 3953.73m ID 3.75" open hole packer 5 at 4254.67m
Frac Ports depth	stage 1: 4113.47 - 4145.38m Frac Port @ 4116.17m stage 2: 3797.61 - 3829.52m Frac Port @ 3,800.31m stage 3: 3527.48 - 3559.39m Frac Port @ 3,530.18m

4.4 Well Test MDZ657 [15]:

The pressure test measurement history of the well summarized in the following table:

TABLE 3 MDZ657 WELL TEST [15]

type of Test	Date	Pression kg/cm			Debit m^3/h		Index Prod.Inj.	Hk			Skin	Duse	remarque
		Gisement	Fond dyn	Tete				proche	Lointain	(Hw*Kyz			
DST	26/03/2013	431.46	274.41	46.4	Huile	0.13	0.044	0	0	24	-2.7	9.53	Realise dans le 04. vs 1000 m. Azi NIIO. Incl 89.30, realise a TD 3461 m. PFD@-2935 m.
PFS	24/07/2013	0	0	0	0	0	0	0	0	0	0	0	Puits n' a s atteint la stabilité. PG non representative.
PFS	25/04/2014	364.36	0	138.37	0		0	0	0	0	0	0	PFS
PFS	30/04/2021	385.48	0	153.63	0	0	0	0	0	0	0	0	La colonne remplie de l'huile
BUILD up	11/10/2021	364.28	0	46	0	0	0	0	0	0	0	9.53	Mesure BU considérée comme PFS, Kick off négatif (puits non eruptive)
PFS	11/12/2022	376	0	152	0	0	0	0	0	0	0	0	column fill of Oil

- Production Characteristics:

Table 4 Production well testing [15]

Date de	Diam	unite	debit	GOR	PRESSION	Temp	K	DEBIT EAU (l/h)	OBSERVA

measure	Duse mm	separ	HUILE	GAZ		TETE	PIPE	SEPAR	HUILE	PSI	RECUPEREE	INJECTEE	
• PUITS													
23/03/2013	9.53	1440	153	6.13	153	46.4	10	04.49	29	0.4377	0		....

4.5 Geological Characteristics

4.5.1 PLAN

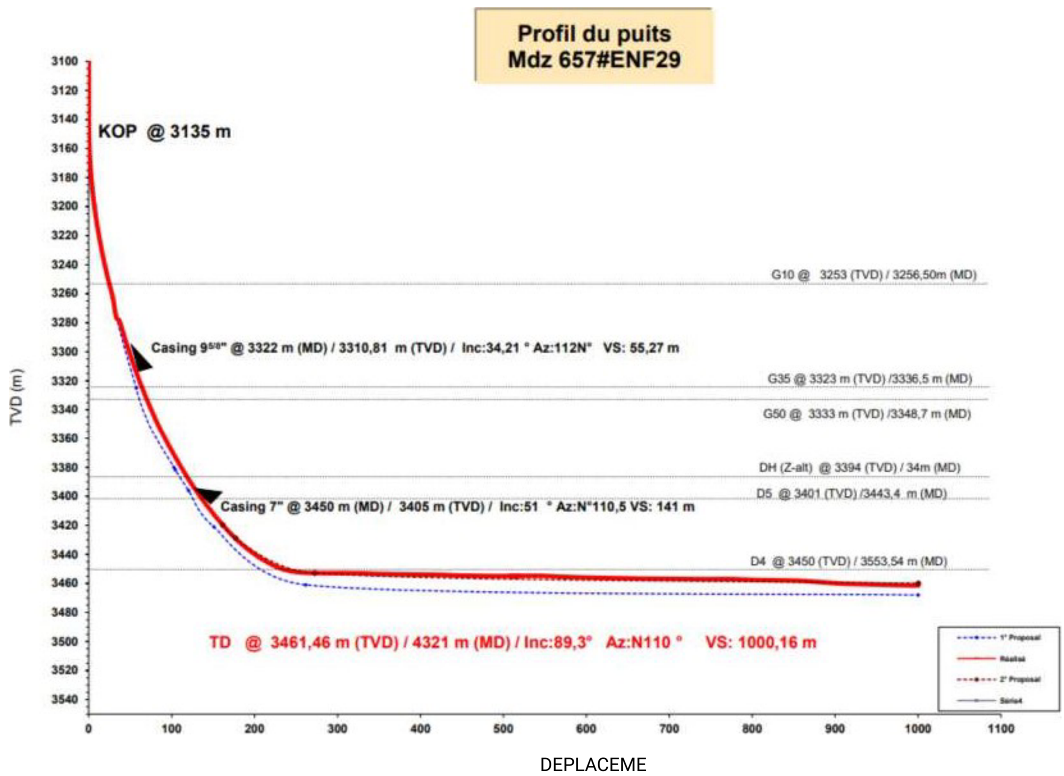


FIGURE 14: MDZ657 PROFILE [15]

4.5.2 Short Radius Azimuth

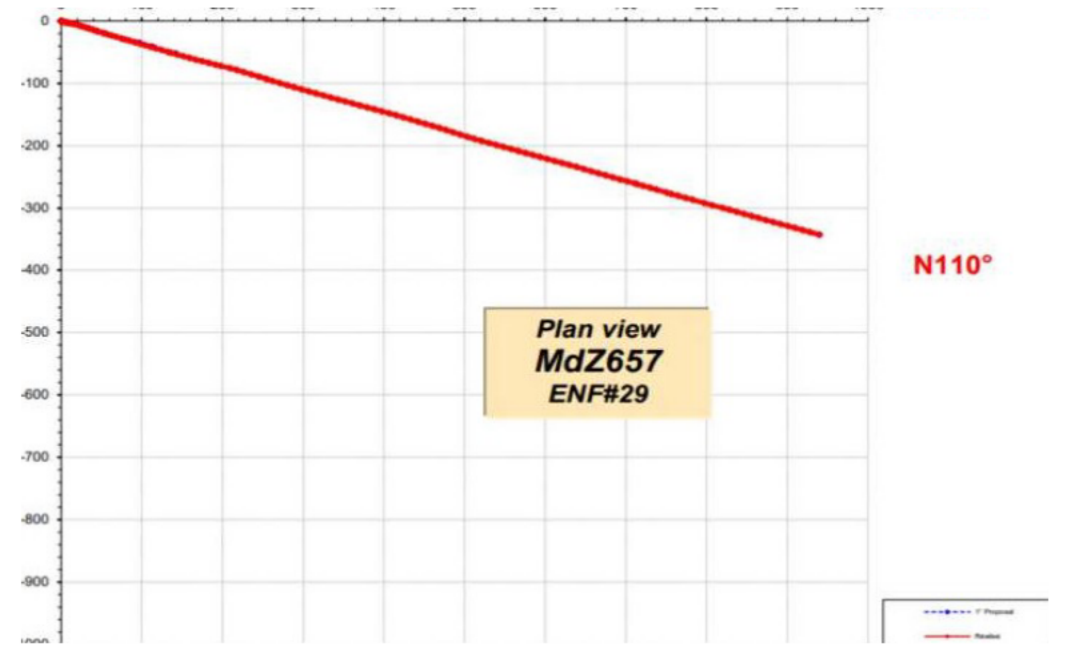


FIGURE 15: MDZ657 SHON RADIUS AZIMUTH [15]

Formations & Petro-physical Characteristics.

CARACTERISTIQUES PETROPHYSIQUES DU RESERVOIR														
DECOUPAGE			RESULTATS-CAROTTE						INTERPRETATION-ELAN					
DRAIN		TOIT___MUR (metres)	EPAIS. (m)	EPAIS.EFF (m)	PERMEA. (md)	PHIE. (%)	So (%)	Sw (%)	SILT. (m)	INTER.INTER	PERMEA (md)	PHIE (%)	Sw (%)	VCL (%)
D5	MD	3442 --- 3551	109	RESERVOIR COMPLETEMENT FORE							NON REALISE			
	TVD	3401 --- 3449	48											
D4	MD	3551 --- 4321	770											
	TVD	3449 --- 3457	08											

FIGURE 16 MDZ 657 FORMATIONS & PETRO-PHYSICAL CHARACTERISTICS. [15]

4.6 WELL Intervention History:

TABLE 5 MDZ657 LAST WELL INTERVENTIONS [15]

Nb	Date Fin	Operations	Sous/operation
01/01/2024	01/01/2024	OPERATIONSPECIALE	OPERATION SPECIALE
01/01/2024	01/01/2024	OPERATION SPECIALE	kick off
21/12/2023	21/12/2023	OPERATION SPECIALE	Matrix Acidizing Day2: Squeeze
20/12/2023	20/12/2023	OPERATION SPECIALE	Matrix Acidizing ,Day1: TC With Jet Blas
11/12/2022	11/12/2022	WIRELINE	Mesure de pression PFS
09/12/2022	09/12/2022	WIRELINE	Mesure de pression PFS
11/10/2021	11/10/2021	WIRELINE	Mesure de pression LBU
07/10/2021	07/10/2021	OPERATION SPECIALE	Kick off+Jaujeage
06/10/2021	06/10/2021	WIRELINE	Measure de pression LBU
30/04/2021	30/04/2021	WIRELINE	Measure de pression PFS

01/10/2019	01/10/2019	OPERATION SPECIALE	CLEAN OUT
28/07/2019	28/07/2019	OPERATION SPECIALE	OPERATION SPECIALE
28/07/2019	28/07/2019	OPERATION SPECIALE	Clean out + KO après WO 2eme tentative
20/07/2019	20/07/2019	OPERATION SPECIALE	Clean out + Kick Off 2eme tentative
13/07/2019	13/07/2019	OPERATION SPECIALE	Mise en production après WO
15/06/2019	15/06/2019	WIRELINE	Controle
14/06/2019	14/06/2019	WIRELINE	Controle
12/06/2019	12/06/2019	WIRELINE	Instrumentation

4.7 The well MDZ657:ZONE HASSI MESSAOUD

The well has been drilled and completed on 05/04/13 as horizontal open hole, the well did not produce even though the DST gave a result of Q=6.13m3/h of oil. It has been decided to run an intelligent completion to allow multi-stages frac operations. The completion is equipped with several prod sleeves and frac ports, straddle packer. Although we had some hydrocarbons after the frac operation, [40% of oil after the 2 nd frac stage, and 30% of oil after the 3 rd frac stage]. [15]

However, after the last workover [09/03/2019 to 14/06/2019] aimed mainly to fish the stuck snubbing 2 "3/^{8} there were no indicators for hydrocarbons even after several clean out, till the last matrix treatment with Mud Acid where there were some traces of hydrocarbons in return. The near wellbore reservoir formation might have been damaged by the mud invasion.

As a last attempt to restore the well productivity before going for other expensive operations (perforation & frac or drilling another short radius), we recommend that stimulation design that aims to:

- Wash intensively of the Port sleeves intervals of Liner with combination of Reformat, Treated Water and HCl 7.5% by using a High-Pressure Jetting Tool (Pulsonix/ Power Wave).
- Ensure that there is no communication between tubing and annulus by performing an annulus pressure tests of both Al =4"1/2x9"5/8 and A2=9"5/8 x 13"3/8 during the first day before going for the matrix treatment.
- Unload all the spent acid and other treating fluids by continuous pumping of nitrogen.
- Treating the formation by a preflush of aromatic solvents (Reformat) and leaving it soaking overnight; which would ensure a good flow back later by decreasing the viscosity of the treating fluids and mud filtrate if it might exist. Aromatic solvents would as well liberate the surface contact of the mud cake from any viscous film that might exist which could prevent the HCl 15% from reacting efficiently with the Mud cake CaC03 particles.
- Perform a stimulation with high concentration of HCl 15% as a main treatment.
- However, as the spent treating fluids' viscosity might increase after reaction of HCl 15%, an overfush of reformat will be followed in order to decrease the viscosity of spent treating fluids, which would ensure a good flowback.
- The overflush reformat would ensure as well deep penetration of the highly corrosive HCl 15% into the near well formation and pushing it away from the completion.
- Ensure continuous kick off at the end of the treatment until all dissolved materials and spent acid are disgorged from the wellbore.
- Put the well back into production and evaluate it with "Jaugeage" once all well flow parameters are stabilized.

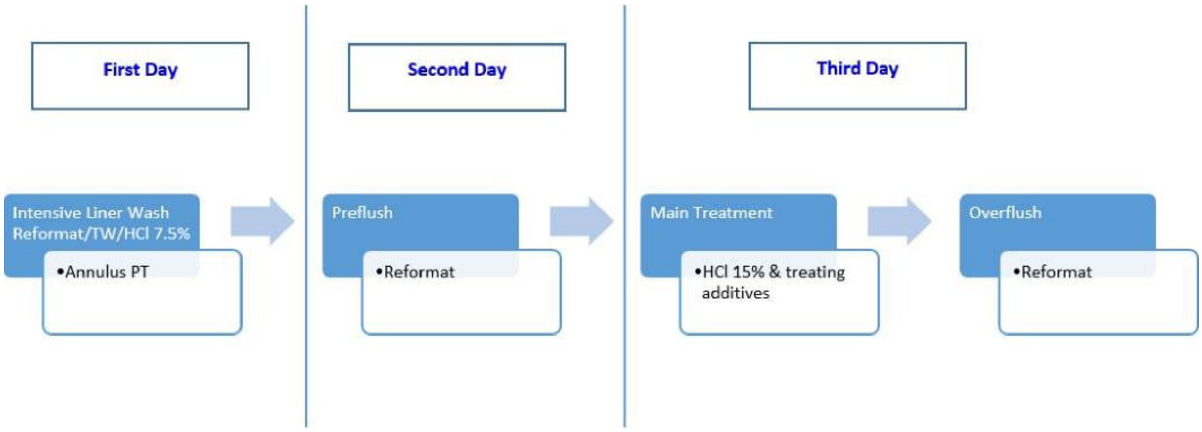


FIGURE 17 THE PROCEDURE THAT WE DONE IN THE WELL MDZ657 [15]

- First day: Reformat/ TW/ HCI 7,5% intensive Liner wash with HPJT and annulus pressures test.
- Second day: Filling the well with the Dead Oil then squeezing 40m3 Reformat into formation and leaving the well shut-in and treatment soaking overnight.
- Third day: Treating the formation with the HC115% followed by an over-flush of reformat, then kicking off the well and observing the fluids on return.

Equipment and Product:

4.7.1 Equipment

- One Coiled Tubing Unit (1 "3/^{4} size for is recommended for two first days).
- One (01) High-pressure pumping unit
- One (01) High-pressure N2 convertor
- Three (03) tanks for transporting and mixing products
- Jetting nozzle on the 1 st day. Full-bore nozzle for the squeeze on 2 nd and 3rd day.

4.7.2 Products

- 27 m^3 Treated Water 2% NH4Cl.
- 14 m^3 Reformat for the Liner wash. [1 st day].
- 12 m^3 HC17.5% for the Liner wash. [1 st day].
- 34 m^3 Dead Oil for filling the well. [2 nd day]

- 40 m^3 Reformat for the squeeze. [2 nd day]
- 24 m^3 HC115% with treating additives. [3rd day]
- 08 m^3 Treated water 3% NH4Cl. [3rd day] •
- 21 m^3 Reformat for: RIH & Squeeze. [3rd day] .
- 21 m^3 Liquid Nitrogen for 1st day and 3rd day.

4.7.3 Job Procedure for the Stimulation Treatment

4.7.3.1 Day 01

The procedure for cleaning out the liner with Reformat, TW, and HCI 7.5% in the annulus largely follows a familiar sequence, emphasizing safety and thorough equipment preparation. It begins with a meticulous visual inspection to detect any surface leaks, followed by the installation of an adjustable choke for control. Equipment setup is then initiated, including the positioning of coiled tubing, high-pressure pumping units, N2 units, and chemical mixing tanks. Treating lines are meticulously prepared, ensuring they are filled with treated water and free from obstructions. Rigging up the coiled tubing injector precedes a series of pressure tests, starting with low-pressure assessments at 300 psi for 5 minutes, escalating to high-pressure tests at 5000 psi for 10 minutes. Notably, a separate pressure test of the Downhole Flow Control Valve (DFCV) against 1500-2000 psi is conducted, ensuring comprehensive integrity across the system. This detailed protocol underscores the commitment to operational safety and efficiency in the cleaning-out process.

the process begins cautiously, with the well opened to the flare line. Initially, the coiled tubing is inserted at a slow pace of 5 meters per minute, while circulating treated water (TW) at a minimal rate. Subsequently, the speed of the coiled tubing is gradually increased within allowable limits. Throughout the operation, the nitrogen rate is adjusted as necessary to facilitate returns, particularly in the event of encountering hard tags or friction. Should the coiled tubing encounter difficulties, such as hard tagging or increased friction, the TW rate is elevated accordingly. Once the coiled tubing reaches the depth of 3000 meters, the TW rate is further increased to 0.8-1 barrels per minute (bpm), and the fluid is switched to Reformat. Adjustments are made to both the coiled tubing speed and Reformat rate to ensure a consistent flow of Reformat at the nozzle. At the depth of 3526 meters, high-pressure jetting along the liner commences, spanning from 3526 to 4304 meters. Throughout this process, the well is choked to 300 psi for optimal control, after that, Start POOH to kick off point while lifting with N2 and ensure that all treating fluids are disgorged from the wellbore.

Upon completing the operation of Pulling Out of Hole (POOH) with the coiled tubing to surface, the nitrogen supply is halted. The coiled tubing is brought to the surface, where the swab valve is closed, and all pressure is gradually bled off. Following this, the rig is lowered down to prepare the coiled tubing injector for the next day's operation. The Bottom Hole Assembly (BHA) is readied with a full-bore nozzle in anticipation of the upcoming operations. This meticulous process ensures the safe and efficient conclusion of the coiled tubing operation while preparing for subsequent activities with due diligence. [15]

TABLE 5 CT OPERATION [15]

From(m)	To (m)	Interval length (m)	System	CT Speed m/min	Q(bbl/min)	Time (min)	Volume
3526m	4304m	778	Nitrified Reformat	15	1 6	52	14
4304m	3526m	778	Nitrified TW	15	1 2	52	10
3526m	4146m	620	Nitrified HCI 7.5%	13	1 5	48	12

4146	3526m	620	Nitrified TW	15	12	42	8

4.7.3.2 Day 2

The process begins by assembling the Bottom Hole Assembly (BHA) with a full-bore nozzle, ensuring its integrity by pumping fluid through it and confirming there are no partial blockages. Subsequently, the coiled tubing injector is rigged up, and pressure testing ensues. All treating lines are pressurized with 2% treated water (TW), first at a low pressure of 300 psi for 5 minutes, then at a high pressure of 5000 psi for 10 minutes. Additionally, the Downhole Flow Control Valve (DFCV) undergoes a pressure test against 1500-2000 psi

Upon reaching a depth of 3000 meters, the TW rate is augmented to 0.8 barrels per minute (bpm). At Total Depth (TD), the well is choked, and the fluid is switched to Dead Oil. The coiled tubing is then parked 2 meters above TD, and the well is filled until confirmation of fluid return is obtained.

Following this, the annulus pressure is gradually increased to 30 bar, with A2 maintained at 15 bar. Subsequently, a 40m3 volume of Reformat is introduced, and the well is closed once the Reformat reaches the nozzle. The remaining Reformat is then squeezed into the reservoir formation at the maximum allowable rate. This meticulous procedure ensures the systematic and efficient execution of coiled tubing operations while prioritizing safety and integrity throughout. The operation transitions to Pulling Out of Hole (POOH) with the coiled tubing to the surface. The coiled tubing is then displaced with Dead Oil. Upon reaching the surface, the coiled tubing is positioned, the swab valve is closed, and the treatment is left to soak overnight. Subsequently, all trapped pressures are bled off, and the rig is lowered down from the coiled tubing injector head

4.7.3.3 Day 03

The operation begins by assembling the Bottom Hole Assembly (BHA) with a full bore nozzle, followed by pumping fluid through the BHA to ensure the nozzle is not partially plugged. Subsequently, the coiled tubing injector is rigged up, and pressure testing is conducted using fresh water. All treating lines and the master valve undergo a pressure test at low pressure (300 psi) for 5 minutes, followed by a high-pressure test (5000 psi) for 10 minutes. The Downhole Flow Control Valve (DFCV) is also pressure tested against 1500-2000 psi. After testing, the fresh water is flushed to the flare line, and the system is displaced with reformat. Next, the master valves are opened while the production wing valve remains closed, and the pressure is recorded. Coiled tubing operations commence by Running in Hole (RIH) through the Christmas tree at a slow speed of 5 meters per minute (m/min), gradually increasing to the allowable limit. Circulation is established with reformat at a minimal rate.

Upon reaching Total Depth (TD) at 4304 meters, the annulus pressure is gradually increased to 30 bar, with A2 maintained at 15 bar. Squeezing operations then commence as follows: [Insert details of squeezing operations here]. This comprehensive procedure ensures the systematic execution of coiled tubing operations while maintaining safety and integrity throughout. [15]

- 08 m^3 Treating acid (15% HCL)   1st stage @ 4116m TR
- 04 m^3 Overflush Reformat

- 0.5 m^3 Spacer Treated Water 3% NH4Cl
- 1m^3 Foam (2,000 scf/bbl)
- 0.5 m^3 Spacer Treated Water 3% NH4Cl

- 08 m^3 Treating acid (15% HCl)   2nd stage @ 3800m TR
- 04 m^3 Overflush Reformat

- 0.5 m^3 Spacer Treated Water 3% NH_4Cl
- 01m^3 Foam (2,000 scf/bbl.)

- 0.5 m^3 Spacer Treated Water 3% NH_4Cl

- 08 m^3 Treating acid (15% HCl) 3rd stage @ 3530m TR
- 04 m^3 Overflush Reformat
- CT string volume of TW 3% NH4Cl for displacement.

Following the completion of squeezing all treating fluids into the formation, the production wing valves are opened. Subsequently, A2 and Al are slowly and respectively bled to atmospheric pressure. This step ensures controlled pressure release from the annulus. To ensure continuous kick-off and disgorge all treating fluids from the wellbore, adjustments to kick-off depth and nitrogen rate may be necessary based on the return observed at the flare line. After ensuring a successful kick-off and discharging of treating fluids, the operation proceeds with Pulling Out of Hole (POOH) of the coiled tubing to the surface, with nitrogen supply stopped. Once the coiled tubing reaches the surface, all pressure is bled off, and the rig is started down from the coiled tubing injector head. Subsequently, all equipment is demobilized in a systematic manner. This meticulous procedure ensures the safe conclusion of coiled tubing operations while preparing for equipment retrieval and demobilization. [15]

NOTES

Ensure that all Pressure Control Equipment are installed including an adequate lubricator.

To ensure that CT string can be pulled out safely, monitor the weight indicator continuously and make Pull Test(s) and check the weight regularly, at least every 600m in the vertical section and repeat it whenever any abnormal weight change observed.

Before passing through any restriction or if any CT weight loss is noticed, adjust the CT to low speed and increase liquid pumping rate, ifthefrictions still exist, pick up the CT and start pumping nitrified water with high rate all while trying to RIH again and passing that section successfully.

Make sure to have a good return otherwise stop the CT and wait for return. N2 rate could be adjusted if it is required.

The pumping rate and CT speed could be readjusted all that without exceeding the working limitations.

Make sure to bleed-offof all pressure, before starting the rig down

Appendix 1 well schematic

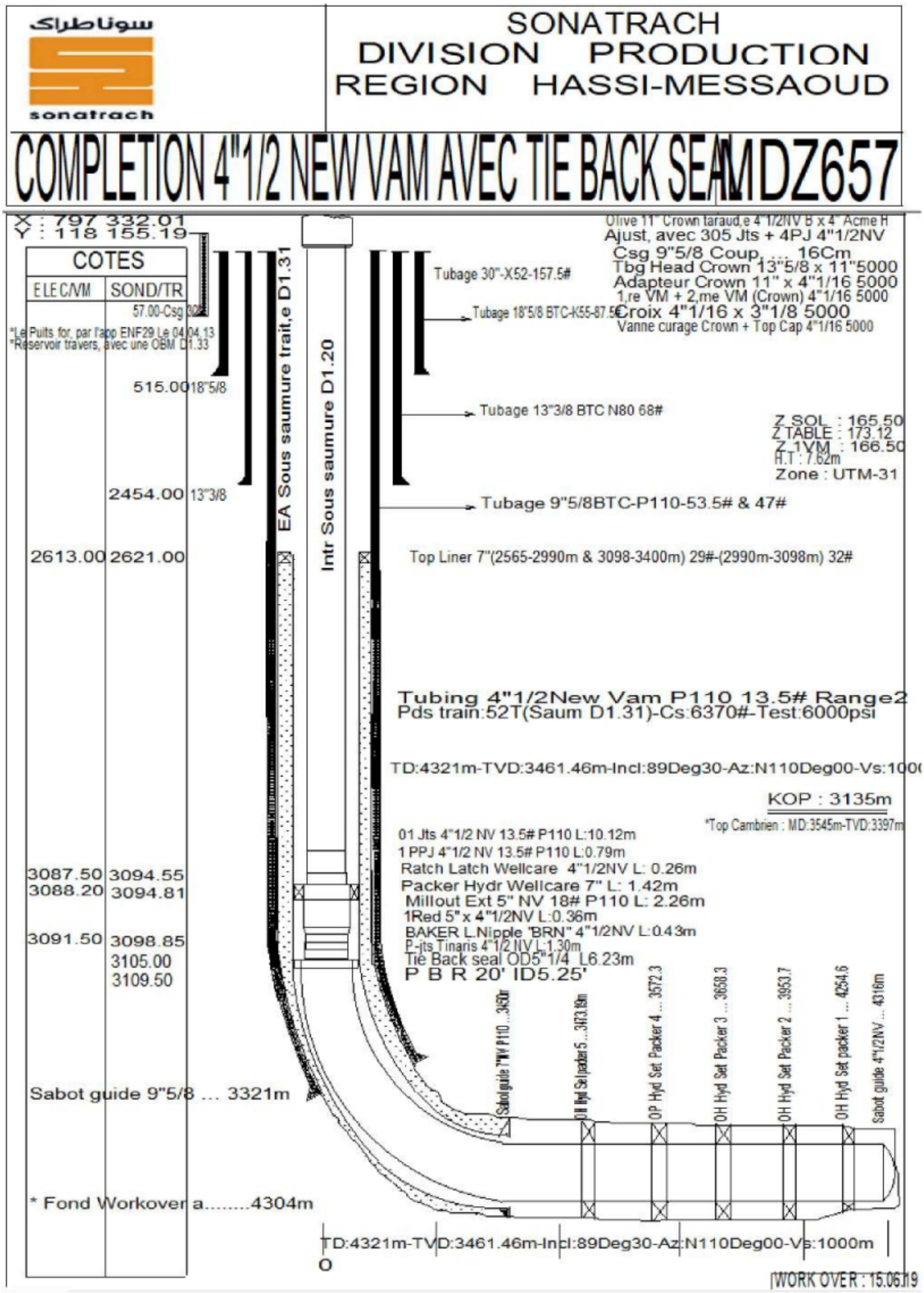
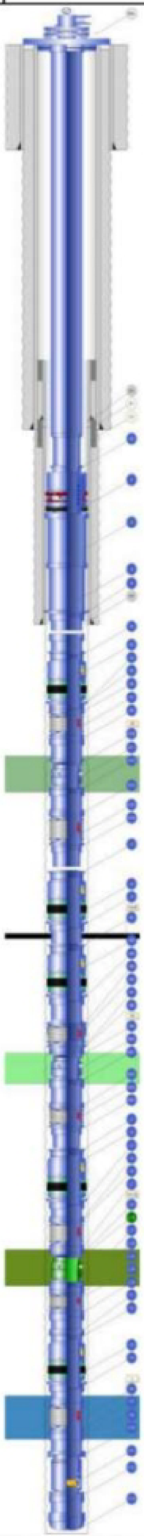


FIGURE 18WELL TECHNICAL DATA SHEET [15]



Item Nos	Depth To Top	Length (Meters)	Nos Joints	Description of Item Including Part Nos & Serial Nos Where Applicable	OD (Inches)	ID (Inches)
		7.000		ENF-31 Elevation		
	7.150	0.150		Tubing Hanger below HOP		
	8.650	1.500		Pup jnt 4"1/2 13.5# P110 NV		
	8.650	0.000		4"1/2 13.5# P110 N V Pup Jt (Space out)		
	8.650	0.000		XXX mT Compression		
	3386.650	3378.000	364	4"1/2 13.5# P110 N V TBG Jts		
	3387.350	0.700		X-Over 4"1/2 13.5# P110 NV x 4"1/2 T Blue		
	3393.450	6.100		Tie Back Seal		
	3399.550	6.100		20' TBR		
	3401.050	1.500		Liner Top Packer		
	3403.210	2.160		HPS Liner Hanger		
	3404.140	0.930		X-Over 5" NV x 4"1/2 NV		
	3470.140	66.000		4"1/2 13.5# P110 N V TBG Jts		
	3470.420	0.280		X-Over 4"1/2 13.5# P110 NV x 4"1/2 LTC		
	3472.270	1.850		Pup Jt 4"1/2 13.5# P110 LTC		
OHP.1	3473.510	1.240		OH Hydrailic set Packer		
	3474.460	0.950		Pup Jt 4"1/2 13.5# P110 LTC		
	3474.720	0.260		X-Over 4"1/2 13.5# P110 LTC x 4"1/2 NV		
	3494.220	19.500		4"1/2 13.5# P110 N V TBG Jts		
	3495.400	1.180		Pup Jt 4"1/2 13.5# P110 NV		
	3499.080	3.680		Production Sleeve		
	3499.480	0.400		X-Over 4"1/2 13.5# P110 VT x 4"1/2 NV		
	3527.480	28.000	3	4"1/2 13.5# P110 N V TBG Jts		
	3527.760	0.280		X-Over 4"1/2 13.5# P110 NV x 4"1/2 LTC		
	3529.600	1.840		Pup Jt 4"1/2 13.5# P110 LTC		
D5	3530.180	0.580		Frac Ports		
	3531.130	0.950		Pup Jt 4"1/2 13.5# P110 LTC		
	3531.390	0.260		X-Over 4"1/2 13.5# P110 LTC x 4"1/2 NV		
	3559.390	28.000	3	4"1/2 13.5# P110 N V TBG Jts		
	3560.540	1.150		Pup Jt 4"1/2 13.5# P110 NV		
	3564.220	3.680		Production Sleeve		
	3564.650	0.430		X-Over 4"1/2 13.5# P110 VT x 4"1/2 NV		
	3569.150	4.500		4"1/2 13.5# P110 N V TBG Jts		
	3569.430	0.280		X-Over 4"1/2 13.5# P110 NV x 4"1/2 LTC		
	3571.290	1.860		Pup Jt 4"1/2 13.5# P110 LTC		
OHP.2	3572.530	1.240		OH Hydrailic set Packer		
	3573.480	0.950		Pup Jt 4"1/2 13.5# P110 LTC		
	3573.740	0.260		X-Over 4"1/2 13.5# P110 LTC x 4"1/2 NV		
	3655.140	81.400		4"1/2 13.5# P110 N V TBG Jts		
	3655.420	0.280		X-Over 4"1/2 13.5# P110 NV x 4"1/2 LTC		
	3657.260	1.840		Pup Jt 4"1/2 13.5# P110 LTC		
OHP.3	3658.500	1.240		OH Hydrailic set Packer		
	3659.440	0.940		Pup Jt 4"1/2 13.5# P110 LTC		
	3659.700	0.260		X-Over 4"1/2 13.5# P110 LTC x 4"1/2 NV		
	3764.300	104.600	3	4"1/2 13.5# P110 N V TBG Jts		
	3765.450	1.150		Pup Jt 4"1/2 13.5# P110 NV		
	3769.130	3.680		Production Sleeve		
	3769.610	0.480		X-Over 4"1/2 13.5# P110 VT x 4"1/2 NV		
	3797.610	28.000	3	4"1/2 13.5# P110 N V TBG Jts		
	3797.890	0.280		X-Over 4"1/2 13.5# P110 NV x 4"1/2 LTC		
	3799.730	1.840		Pup Jt 4"1/2 13.5# P110 LTC		
D4	3800.310	0.580		Frac Ports		
	3801.260	0.950		Pup Jt 4"1/2 13.5# P110 LTC		
	3801.520	0.260		X-Over 4"1/2 13.5# P110 LTC x 4"1/2 NV		
	3829.520	28.000	3	4"1/2 13.5# P110 N V TBG Jts		
	3830.590	1.070		Pup Jt 4"1/2 13.5# P110 NV		
	3834.270	3.680		Production Sleeve		
	3836.140	1.870		X-Over 4"1/2 13.5# P110 VT x 4"1/2 NV		
	3948.640	112.500		4"1/2 13.5# P110 N V TBG Jts		
	3948.920	0.280		X-Over 4"1/2 13.5# P110 NV x 4"1/2 LTC		
	3950.780	1.860		Pup Jt 4"1/2 13.5# P110 LTC		
OHP.4	3952.020	1.240		OH Hydrailic set Packer		
	3952.970	0.950		Pup Jt 4"1/2 13.5# P110 LTC		
	3953.230	0.260		X-Over 4"1/2 13.5# P110 LTC x 4"1/2 NV		
	4079.730	126.500		4"1/2 13.5# P110 N V TBG Jts		
	4080.840	1.110		Pup Jt 4"1/2 13.5# P110 NV		
	4084.520	3.680		Production Sleeve		
	4085.470	0.950		X-Over 4"1/2 13.5# P110 VT x 4"1/2 NV		
	4113.470	28.000		4"1/2 13.5# P110 N V TBG Jts		
	4113.750	0.280		X-Over 4"1/2 13.5# P110 NV x 4"1/2 LTC		
	4115.590	1.840		Pup Jt 4"1/2 13.5# P110 LTC		
D4 (2)	4116.170	0.580		Frac Ports		
	4117.120	0.950		Pup Jt 4"1/2 13.5# P110 LTC		
	4117.380	0.260		X-Over 4"1/2 13.5# P110 LTC x 4"1/2 NV		
	4145.380	28.000		4"1/2 13.5# P110 N V TBG Jts		
	4146.510	1.130		Pup Jt 4"1/2 13.5# P110 NV		
	4150.190	3.680		Production Sleeve		
	4151.150	0.960		X-Over 4"1/2 13.5# P110 VT x 4"1/2 NV		
	4251.350	100.200		4"1/2 13.5# P110 N V TBG Jts		
	4251.630	0.280		X-Over 4"1/2 13.5# P110 NV x 4"1/2 LTC		
	4253.460	1.830		Pup Jt 4"1/2 13.5# P110 LTC		
OHP.5	4254.700	1.240		OH Hydrailic set Packer		
	4255.650	0.950		Pup Jt 4"1/2 13.5# P110 LTC		
	4255.910	0.260		X-Over 4"1/2 13.5# P110 LTC x 4"1/2 NV		
	4272.710	16.800		4"1/2 13.5# P110 N V TBG Jts		
	4273.850	1.140		Pup Jt 4"1/2 13.5# P110 NV		
L	4277.530	3.680		Production Sleeve		
	4279.400	1.870		X-Over 4"1/2 13.5# P110 VT x 4"1/2 NV		
	4302.400	23.000		4"1/2 13.5# P110 N V TBG Jts		
	4304.100	1.700		X-Over 4"1/2 13.5# P110 NV x 4"1/2 LTC		
	4304.880	0.780		Flow Thru Circulating Valve		
	4305.710	0.830		X-Over 4"1/2 13.5# P110 LTC x 4"1/2 NV		
	4315.010	9.300	1	4"1/2 13.5# P110 N V TBG Jts		
	4315.280	0.270		Guide Shoe		

FIGURE 19WELL TECHNICAL DATA SHEET [15]

Conclusion

Before proceeding with Any type of treatment in the wells of Hassi Messaoud, a comprehensive Study is essential. This study includes the well history, production and/or injection parameters, as well as the analysis of the recovered deposits. It helps to understand and determine the nature of the damage, its location, the means to treat it, and the appropriate acid formulation for each type of treatment. Additionally, it aids in analyzing and interpreting the results of the treatments to improve their efficiency and reduce investment costs.

The analysis of the results from acid treatments carried out in wells MDZ657

- **Identifying the Type of Damage:** Accurately determining the type of damage is crucial for selecting the appropriate treatment method. Proper identification allows for the most effective treatment and acid formulation.
- **Effectiveness of Acidification:** Wells damaged by mechanical interventions (such as snubbing or workover) show more significant gains from acidification compared to those damaged by natural processes (like fines migration). Mechanical damages are more readily corrected by acid treatments.
- **Impact of Damage Skins:** Larger damage skins correlate with better operational outcomes post-treatment.Wells with high skin values tend to show substantial improvements after acidification.
- **Operational Challenges:** Even when damage is reduced, the expected increase in flow rate can be obscured by other operational issues. A comprehensive approach addressing all production challenges is necessary.
- **Penetration of Mud Acid**: Despite its strong dissolution capabilities, Mud acid has limited penetration into the formation, which can diminish its effectiveness.
- **Acid Volume Limitations:** The limited volumes of injected acid impact treatment results. Insufficient acid amounts may not reach all the damaged zones effectively.
- **Outdated Well Tests:** Some well tests (Build Up) are outdated, potentially leading to inaccurate skin estimations. Updated and accurate testing is essential for reliable data.
- **Low Permeability Issues:** Low permeability formations do not allow for good penetration of treatment acids, limiting the effectiveness of acidification operations.

Finally To optimize well treatments in Hassi Messaoud, it is crucial to conduct a thorough preliminary study.This study should include the well history, analysis of production parameters and recovered deposits, and a precise assessment of the damage and its location. The results show that treatments must be adapted based on the type and severity of the damage, and other operational problems must also be addressed to maximize production gains. Managing the volumes of injected acids and updating well tests are also essential for improving treatment efficiency and reducing costs.

Referencess

Referencess

[1] G. D. S. S. Sonatrach DP-HMD rapport interne 2020 .

[2] S. D. E. 2020.

[3] P. Alain, A. PERRODON, 1985..

[4] 1. Beicip / franlad.

[5] f. civan, "]-Faruk civan, réservoir formation damage, Fundamentals, Mödling, assessment and megration. univ-of Oklahoma.2000".

[6] d. veillon, "]"La liaison couche trou (Tome 1 et 2)" par Dominique Veillon. Editions Technip, IFP2001".

[7] c.l.ezenweichu.[Online].Available: https://www.vurup.sk/wp-content/uploads/dlm_uploads/2017/07/pc_2_2015_ezenweichu_323_rev.pdf.

[8] T. O. a. R. Allen, 3rd printing, p.137-13.

[9] B.Hall.[Online].Available:https://onepetro.org/JPT/article-abstract/30/09/1220/167950/A-New-Technique-for-Generating-In-Situ?redirectedFrom=PDF.

[10] O. G.Chacon, 11 January 2022. [Online]. Available: https://www.mdpi.com/2227-9717/10/1/174#table_of_contents.

[11] m. hawkins, "Economides, M. J. and Nolte, K. G. 1989. Reservoir Stimulation. New Jersey, 2nd Edition,".

[12] m.l.chavez.[Online].Available: https://www.semanticscholar.org/paper/Evaluation-and-Optimisation-of-Matrix-Acidizing-in-Chavez/b2f375762b400a78ed9faa293ca6d49a2f8c4b32.

[13] p.dwi,2020. [Online]. Available: Prasetya_Dwi_Aurianto_2022_IOP_Conf._Ser.-_Earth_Environ._Sci._1014_012015.

[14] R. D. a. S. Gdanski, February 1996, pp. , p. 145-149. .

[15] D. S. DP-HMD, "Document: Sonatrach DP-HMD, production Department, Study Service".