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Presented by Mr.

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The choice of an acid system for treatment by matrix acidizing, application in the region of Haoud Berkaoui

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ملخص

في قطاع النفط والغاز، تمثل الرواسب العضوية والمعدنية المختلطة التي تعيق الثقوب في المناطق المجاورة لمنطقة الآبار مشكلة خطيرة. في منطقة حوض بركاوي، يستخدم تحمض المصفوفة بشكل متكرر لتخفيف هذا الضرر، باستخدام ثلاثة أنظمة حمضية مميزة تقدمها الشركة للمساعدة في استعادة الخصائص الأولية. الهدف من هذا العمل هو فهم وتحليل الماضي من أجل النظر في النظام الحمضي الفعال الذي تم تصميمه وفقًا لخزان بعض الآبار المرشحة. يتم جمع وفحص أنواع مختلفة من البيانات. ومع ذلك، تم إجراء تجارب في المختبر لتأكيد وظيفة كل حمض. تكشف مقارنة تحليل البيانات الميدانية والصور المجهرية والنتائج المختبرية بتفسير الاستجابة منحنيات الحمضية (ARC)أن نظامًا واحدًا فقط من حمض الطين

(6 % HCl-1.5 % HF) يستخدم بشكل مناسب في المجال من أصل ثلاثة لتقليل Skin factor بالإضافة إلى ذلك ،

فإنه يؤدي إلى زيادة معدل التدفق لمعظم الآبار التي تم استخدامها، بالإضافة إلى زيادة النفاذية النسبية في منطقة الآبار.

(7 لبئرN1 و 3.7 لبئر N2) تحل هذه الدراسة المشكلات المتعلقة بإنتاج الآبار وتقلل من تكاليف التشغيل من خلال تحديد الاختيار الأمثل للحمض والإضافات المناسبة لتحسين استعادة البترول من الآبار.

الكلمات المفتاحية : تحمض المصفوفة، حمض الطين، استعادة البترول، النفاذية، skin factor

Abstract

In the oil and gas sector, mixed organic and mineral deposits obstructing perforations in the vicinity of the wellbore area are a serious issue. In the Haoud Berkaoui region, matrix acidizing is frequently used to relieve this damage, utilizing three distinct acid systems that the company offers to help restore the initial properties. The objective of this work is to comprehend and analyze the past in order to look into the effective acid system that has been tailored to the reservoir of some candidate wells. Various types of data are gathered and examined. Nonetheless, experiments in the laboratory were carried out to confirm each acid's functionality. A comparison of the field data analysis with the interpretation of Acid Response Curves (ARC), micro-scopic photos, and laboratory results reveals that only one mud acid system (6 % HCl-1.5 % HF) out of the three is used adequately in the field to reduce the skin factor. Additionally, it results in a flow rate gain of the majority of wells where is was used, as well as an increase in relative permeability in the wellbore region (7 for well N1 and 3.7 for well N2). This study solves well production-related issues and lowers operation costs by identifying the optimal acid choice and appropriate additives for optimizing oil recovery from wells.

Keywords : matrix acidizing, mu acid system, oil recovery, permeability, skin factor

Résumé

Dans le secteur du pétrole et du gaz, les dépôts organiques et minéraux mixtes qui obstruent les perforations à proximité de la zone de forage sont un problème grave. Dans la région de Haoud Berkaoui, l'acidification matricielle est fréquemment utilisée pour éliminer ces endommagements, en utilisant trois systèmes acides distincts que la société propose pour aider à restaurer les propriétés initiales. L'objectif de ce travail est de comprendre et d'analyser l'historique afin d'examiner le système acide efficace qui a été adapté au réservoir de certains puits candidats. Divers types de données sont recueillis et examinés, mais des expériences en laboratoire ont été menées pour confirmer la fonctionnalité de chaque acide. Une comparaison de l'analyse des données de terrain avec l'interprétation des courbes de réponse acide (ARC), des photos microscopiques et des résultats de laboratoire révèle qu'un seul système d'acide de boue (6 % HCl-1,5 % HF) sur les trois est utilisé adéquatement sur le terrain pour réduire le skin factor. De plus, il en résulte un gain de débit de la majorité des puits utilisés, ainsi qu'une augmentation de la perméabilité relative dans la région des puits (7 pour le puits N1 et 3,7 pour le puits N2). Cette étude résout les problèmes liés à la production de puits et réduit les coûts d'opération en identifiant le choix d'acide optimal et les additifs appropriés pour optimiser la récupération du pétrole des puits.

Mots clés : acidification matricielle, système acide de boue, récupération de pétrole, perméabilité, skin factor

Table of contents

Chapter I :Theory of sandstone matrix acidizing

Chapter II : Presentation of the studied region

Chapter III : ***Matrix acidizing technique and laboratory tests***

Chapter IV : Acidizing operation evaluation, laboratory results and discussion

List of figures

List of tables

General introduction

Well stimulation techniques are used to improve the flow of oil or gas from the reservoir by breaking up the rock or creating new channels around the well. Recently, these techniques become one of the most important focuses to increase profit and reduce cost in oil and gas wells. The most commonly used stimulation techniques are matrix acidification and hydraulic fracturing. Oil production can be enhanced by using chemical reagents to eliminate scales and asphaltene (Azizollah 2018, 2021a, 2021b). Matrix acidizing is a developed stimulation technique used to improve it by removing or minimizing formation damage and changing the petrophysical properties of the reservoir rock which are the porosity and the permeability near the vicinity of the wellbore (Crowe et al. 1992). This damage is the result of the natural depletion and major during pre-operations and productions such as drilling, completion, water/gas injection, and improved oil recovery (IOR). The treatment involves pumping acids below the formation fracturing pressure and it is applied in both sandstone and carbonate formations (Shafiq MU et al. 2014). The acid system differs but the same practice is done. In carbonate reservoirs, the acid job design is based on the use of hydrochloric acid (HCl) to dissolve carbonate minerals and create wormholes that allow fluids (oil, gas, and water) to flow more freely into the well (Mohamed 2000). In sandstone reservoirs, mud acid is more common, which is a mixture of hydrochloric acid and hydrofluoric acid (HCl/HF), used to dissolve sand (quartz), feldspar, carbonate minerals, and clay particles and achieve permeability increase by less or more radial penetration of acid deeply into the formation (Leong and Hisham 2019).

A variety of mud acid systems have been used based on the aspects of their feasibility, reaction mechanism as well as cost, health, safety, and environmental impact (Al-Harthy et al. 2009; Gomaa et al. 2013; Wang et al. 2013; Abdelmoneim and Nasr-El-Din 2015). Retarded and organic acids were also applied to solve some problems associated with reservoir parameters, increase oil production and minimize damage (Al-Harbi et al. 2011,2012; Andotra 2014; Shafiq and Shuker 2013; Shafiq and Ben Mahmud 2016).

In sandstone matrix acidizing, many acids are sometimes less efficient and may create problems leading to treatment failure and bad economic returns if they are not carefully selected and not well adapted to the formation. The choice of an appropriate acid system is now a preoccupation in many fields of Algeria Sahara due to the decrease of oil production, especially in the Haoud Berkaoui region where three different acids are utilized randomly and they are sometimes not compatible with damaged formation so the absence of the restauration of the initial porosity and permeability of the well. The mineralogy study of the whole region is not taken in consideration to determine the different parameters to avoid several problems of oil wells production later and bad economic consequences.

The objective of this work is to identify the causes of formation damage of many selected wells that lead to well stimulation using matrix acidizing technique. It also presents this technique and describes the combination of laboratory results of several tests especially the well mineralogy, acid response curves, and some microscopic photos to find out the efficient acid system for better reservoir permeability improvement. The precision and the rapidity of measurements leading to best treatment of the reservoir rock should not be restricted only for some wells' samples to understand chemical reactions with different minerals or organic deposits.

This thesis consists of two parts:

The theoretical part contains two chapters:

The first presents the background of the sandstone matrix acidizing technique, different previous researches findings using many types of acid systems, the criteria of treatment fluid selection, stimulation fluid additives and methods to avoid and treat different types of formation damage.

In the second one, the studied region is presented by taking in consideration the following aspects: regional and local geology, the reservoirs fluids composition and propreties and the most frequent damage in Haoud Berkaoui fields.

The experimental part consists also of two chapters:

The third chapter contains the typical operation procedure using Coiled Tubing, history of acidized wells, different laboratory tests and qualitative and quantitative deposition analysis of the deposited scales.

In the fourth chapter, acidizing operations evaluation of many wells and laboratory tests results are discussed in order to choose the optimal acid system concentrations with best additives and to minimize the damage and reducing operation cost in the future.

Chapter I

Theory of sandstone matrix acidizing

Introduction

Acidizing is one of the most widely used techniques among all the stimulation techniques applied in the oil and gas industry (Ituen, 2017). Sandstone acidizing is used to dissolve the damage around the wellbore or the fine particles which can block the pore throats and pore spaces while carbonate acidizing creates wormholes with massive permeability in carbonates. It is always being a serious attention to choose a suitable type of acid, its concentration, and volume needed to inject in the damaged zone. The change of temperature and mineralogical composition of the reservoir region require the addition of special additives with acid system. This damage is caused by the assorted and complex nature of the sandstone formation. Different factors have an effect on matrix acidizing, including the rock properties reaction rate of acid with rock, injection rate of acid, porosity, permeability, mineralogy, pore structure and mineral distribution (Maheshwari and Balakotaiah, 2013).

I. Formation damage

The efficiency of a matrix stimulation treatment depends primarily on the removal of the damage that restricts the well productivity. Each damage type has different mechanisms by which they can be removed. Dilution, dissolution, complexation, solubilization and dispersion are some of these mechanisms and they should be matched appropriately for efficient treatments. A sharper than expected decline in production is indicative of formation damage. Formation damage can also occur during drilling or completion of the well. The extent of the damage is calculated from the analysis of pressure buildup or drawdown tests. The tests provide valuble information for optimizing the treatment and for evaluating its results. Once damage has been characterized in a well, its origin must be determined to help select the correct treatment design. Various types of damage can exist in the same well because almost every operation performed on the well (drilling, completion, workover, production and stimulation) is a potential source of damage. The physical characteristics of the damage are essential parameters because they determine the desired characteristics of the treating fluid. Laboratory testing is an integral part of the damage identification and remedial fluid selection process. Candidate Identification and Damage Characterization provides additional information regarding types of damage and laboratory studies.

I.1. Meaning of damage

Damage is defined as an obstacle preventing the flow of fluids from the reservoir to the well. It represents all the incrustations whether mineral or organic that can alter the natural permeability by their deposition inside the reservoir by sealing the perforations see even the production tubing and surface installation.

I.2. Mechanisms of formation damage

Formation Damage can be classified into four types based on their damage mechanism (Mahesh et al 2016) :

*Chemical

*Thermal

*Mechanical

*Biological

I.3. Location of damage

Figure 01 below illustrates the areas of location of the damage taking into account the well configuration.

a. At the bottom of the well:

Generally, deposits are formed by sediments of various origin (particles from formation, corrosion products of equipment) or precipitates (salts, paraffins, asphaltenes).

b. Around the well:

***External cake (zone 1):** The external cake is made up of solid mineral or organic particles deposited during drilling on the hole wall (to consolidate the well walls and reduce mud infiltration into the formation). It is removed mechanically by scraping or chemically by washing with solvents or acids.

***The internal cake (zone 2):** The internal cake consists of fine solid particles from the mud, cement and filling fluids, is located in a very thin crown in the immediate vicinity of the well and blocks the pores, making the medium little permeable.

***The invaded area (zone 3):** Beyond the internal cake is the area invaded by the slurry and cement filtrates, which will modify the natural environment of the porous medium. One can observe:

*Change in wettability;

*Formation of emulsions;

*Swelling and/or disintegration of clays;

*Various precipitation (mineral and sometimes organic) in case of incompatibility of a filtrate with the fluids in place.

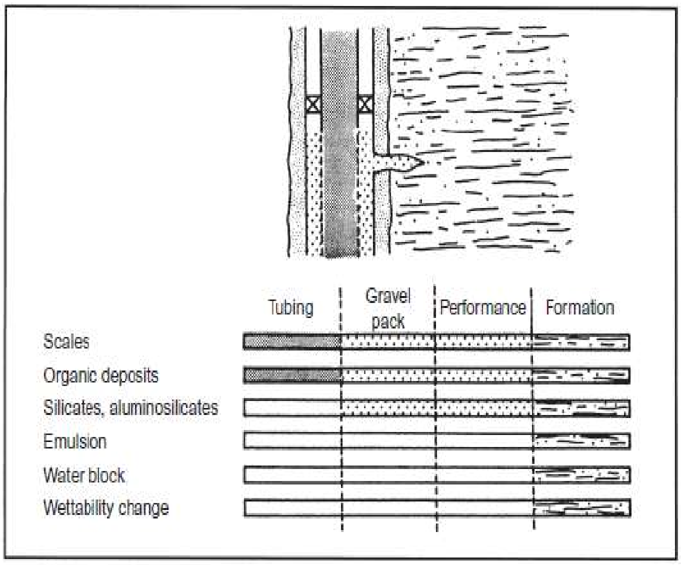


Figure 01 : Location of various types of permeability damage near the wellbore (Economides and Michael 1987).

I.4. Cause and mechanisms of damage

I.4.1. During the drilling phase

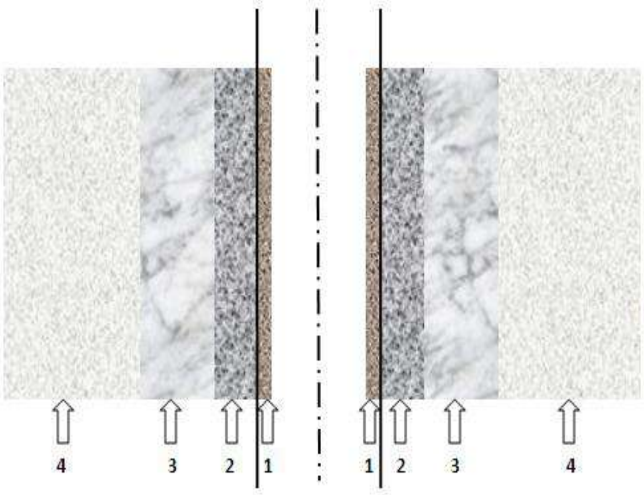
A. Crushing of rock reservoir

This purely mechanical action is likely to block certain reservoirs. Indeed, the spraying of many particles allows them to clog the pores while the compaction effect is added to achieve blocking.

It is mainly in carbonated or soft formations that the phenomenon occurs. It can then reach significant proportions to the point of preventing practically any subsequent flow. Nevertheless, this source of damage is not very dangerous. First, it does not occur systematically over the entire carbonate reservoir. Then, it is very easily resorbable which is law of principal.

B. Solid contained in drilling fluid

The flooding of the formation can be represented schematically by several areas away from the well axis as shown in the Figure 02.



Zone 1: external cake lining the well walls **Zone 2:** internal cake: solids having penetrated the porous medium

Zone 3: zone invaded by the slurry filtrate **Zone 4:** virgin zone where permeability is not affected

Figure 02 : Schematic representation of the flooding of a reservoir by the drilling fluid during its crossing (Sonatrach/ EP HBK, 2020).

Zone 1 of very low thickness (maximum a few millimeters), does not really concern us from the point of view of damage. We know in principle how to eliminate the cake in a simple way when the time comes (cementing).

The invasion of the formation by the solid particles of the mud is represented by zone 2. This zone generally has a relatively moderate depth, of the order of a few tens of centimeters. These solids, driven by the filtrate, penetrate the pores according to several factors:

*Overpressure on the reservoir.

*The permeability of the layer.

*The fineness of the solid particles facilitates their invasion especially when it is homogeneous.

As an order of magnitude, removal of 10 to 15 bar is often desirable in field development for layer damage. Moreover, clogging can vary widely with the morphology of the ground: radius of pores, tortuosity.

C. Drilling fluid filtrate

Its depth, variable, can reach several meters in the case of deep invasion.

The penetration of the filtrate, and to some extent the resulting solids, is a function of several cumulative factors. These are:

*The overpressure exerted on the reservoir,

*The permeability of the formation,

*The intrinsic value of the slurry static filtrate, measured in the filter press namely: the number of cm^3 collected in 30 min under 100 psi (7 Kg/cm^2) of pressure, *The flow of mud,

*The time of contact mud-ground during drilling.

D. Cementing reservoirs and their restoration

Accidental fracturing of the ground: It usually follows a density and a height of cement too high compared to the layer, a too brutal manoeuvre of the column during its descent, or an excessive dodge pressure especially at the time of the blocking. Such an incident can have consequences on the quality of the cementing, see undesired cracking of the reservoir. A "normal" operation, correct and without excess (speed, pressure), is the only attitude to adopt except to risk costly and random recoveries.

Action of the cement slag filtrate: The aqueous cement slag filtrate is likely to cause the same damage as that of the drilling fluid and must therefore, like it, be closely controlled both in quantity.

I.4.2. During the completion phase

A. Damage due to punctures

Most of the perforation operations are over-balanced which leads to the formation of a cake filtrate in the perforation tunnels causing a skin and a drop in pressure near the wells.

B. Invasion of the cement filtrate

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

C. Damage due to stimulation

In the case of acidification, damage is caused by secondary reactions if the acid used is not discharged in time (very quickly).

After hydraulic fracturing, the sustained fracture may be partially blocked by the fluid carrying the support agents (frac gel).

I.4.3. During the operation phase:

A. Damage due to water injection

Water saturation around the well if the injection flow is not well controlled (water-block),

Blockage by sulphate deposits (scale) due to incompatibility of injection water and formation,

No filtration of injected water,

Action of bacteria: Anaerobic bacteria can develop in injection wells in the absence of oxygen up to a temperature of around 70 °C.

These bacteria are sulphate-reducing, that is, they chemically reduce sulphates to H_2S. Eventually, you will have acid-resistant organic matter, equipment damage, and iron in various forms. These products cause injection wells to be plugged. Their elimination requires careful sampling and analysis.

B. Production well

Increase of S_W: The excessive production of water is able to increase Sw in the vicinity of wells and thus to decrease the relative permeability of hydrocarbons.

***Organic deposits:** this type of deposit can first occur in the formation during a treatment by pumping a fluid «cold» compared to the heavy elements of the crude.

More generally, organic deposits occur throughout the well, including tubing and perforations, but can also occur in the collection network. We will have:

- Paraffins and waxes, heavy fractions of paraffinic hydrocarbons,
- Naphthenic and aromatic hydrocarbon asphaltenes and resins.

***Mineral deposits:** Mineral deposits (scales) are found throughout the well from collection to formation, such as organic deposits. The main ones are:

- Calcium carbonates: **$CaCO_3$,**
- Sulphates: **$BaSO_4$ (H_2O), $BaSO_4$, $SrSO_4$,**
- Sodium chloride: **NaCl,**
- Iron corrosion products: **FeS, Fe_2O_3, $FeCO_3$.**

I.5. Detection of damage

Several methods of very classic use are available which we will remember:

*Sampling and laboratory analyses,

*Well testing,

*Complete history of wells,

*Analysis of the production system.

I.6. Skin effect on permeability (Figure 03)

The Hawkins Expression (1) established in 1956 connects radius and Ke permeability of the damaged area to the Skin:

$$S = \left(\frac{K}{K_s} - 1\right) ln \frac{r_s}{r_w} \tag{1}$$

S : skin;

K : reservoir permeability (non zone damaged);

Ks : permeability of the damaged area;

r_s : radius of damaged area;

r_w : well radius.

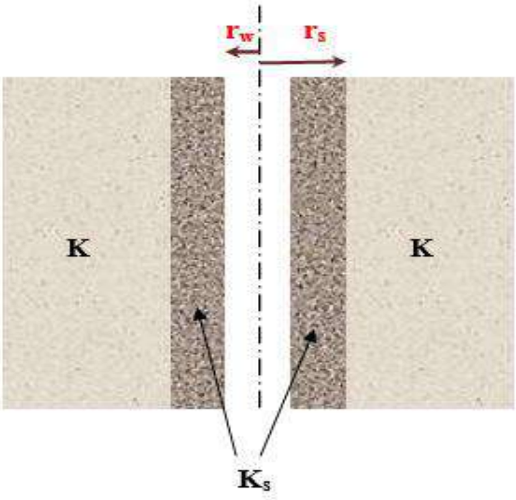


Figure 03 : Influence of skin on permeability (Sonatrach/ EP HBK, 2020).

We see that if:

S > 0: The permeability of the area adjacent to the well is less than that of the rest of the formation (in case of damage);

S < 0: The permeability of the area adjacent to the well is greater than that of the rest of the formation (case of stimulation improvement);

S = 0: K = Ks (no damage).

I.7. Skin effect on productivity

I.7.1. Concept of the productivity index

The productivity index (PI) of a well is defined as the flow associated with a depression between the bottom of the well and the deposit, it is a potential of the well and is expressed for a case of a liquid in a circular radial flow, steady state by the Equation 2:

$$IP = \frac{Q}{P_G - P_f} \tag{2}$$

There are two types of IP:

- **IPr :** actual productivity in (m^3/h)/ (Kg/cm²);
- **IP$_o$:** theoretical productivity of the same size.

The theoretical productivity index (**IP$_o$**) is given by the Equation 3:

$$IP_o = \alpha \frac{hk}{\mu\beta ln\frac{re}{rw}} \quad (3)$$

Where:

α: coefficient depends on the units used.

h: the height of the producing layer

k: permeability

μ: the viscosity of the fluid

β: background volumetric factor

r_e: the drainage radius

r_w: the well radius

Regarding the actual well, all disturbances around the well are grouped as "S" (skin factor) as follows (Equation 4)

$$IP_o = \alpha \frac{hk}{\mu\beta\left(ln\frac{re}{rw}+S\right)} \quad (4)$$

The flow rate (Re) is defined as the ratio between the actual flow obtained and the theoretical flow (Equation 5) that the ideal well would give under the same bottom conditions:

$$Re = \frac{Q}{Q_o} = \frac{IP}{IP_o} = \frac{ln\frac{re}{rw}}{ln\frac{re}{rw}+S} \quad (5)$$

In practice, Ln (re/rw) is often between 7 and 9, hence the simplified form (Equation 6):

$$Re = \frac{IP}{IP_o} = \frac{7}{7+S} \text{ à } \frac{9}{9+S} \quad (6)$$

Note: A skin of 7 to 9 corresponds to a flow capacity reduced by half. Conversely, a skin from –3.5 to – 4.5 (following stimulation for example) corresponds to a flow capacity multiplied by two.

I.7.2. Skin effect on productivity

Knowledge of the Inflow Performance Relationship (IPR) and the Hawkins equation are essential to understand the damage effect (SKIN) of formation on well productivity.

For an oil well the IPR Equation (7) reads:

$$q = \frac{kh(P_G - P_{wf})}{141{,}2\mu\beta\left(ln\frac{re}{rw}+S\right)} \quad (7)$$

Where:

q **:** oil flow conditions (bbl/day); **r_e** : drainage radius (ft);**K** **:** permeability (md) **;** **rw:** well radius (ft);

h **:** reservoir height (ft) ; **S** **:** total skin (dimensionless);

μ **:** oil viscosity (cp) **;** **β** **:** background volumetric factor (bbl/STB).

P_G: reservoir pressure (psi);**P_{wf}:** dynamic background pressure (psi);

I.8. Types of skin factor

In contrast to how it has typically been incorrectly expressed as a simple linear sum of all the relevant skin factors—Yildiz (2006) observed that skin factor should be expressed as a suitable function of the individual skin factors.

According to Yildiz (2006), the interaction between the total skin factor and each of its constituent parts is mostly non-linear, necessitating the use of a precise mathematical model to break down the total skin factor into its constituent parts.

Skin can be divided into following types

a. The mechanical or formation skin factors (Sd)

b. Completion pseudo skin factor (Sp)

c. Partial penetration skin factor (Spp)

d. Geometrical pseudo-skin factor (Sg)

e. Multiphase pseudo-skin factor (Sm)

f. Non-Darcy flow or Rate-dependent high velocity or turbulent flow pseudo-skin factor(Sturb)

II. Acidizing technique

Acidizing is one of the most stimulation method used to remove damage in oil and gas wells. Different operations such as drilling, completion, workover production and other long-time operations can cause formation damage. It is described as the change in pressure and the flow rate in the wellbore from the original flow rate (Achnivu et al., 2008). The acidizing operation can be performed using various acids in order to minimise that damage and maintain the productivity of the reservoir by allowing faster circulation of the hydrocarbons. This acid plays an essential role to increase the porosity and permeability of a reservoir (Kalfayan 2008). There are two categories in which acidizing is divided which are fracture acidizing and matrix acidizing (Figure 04).

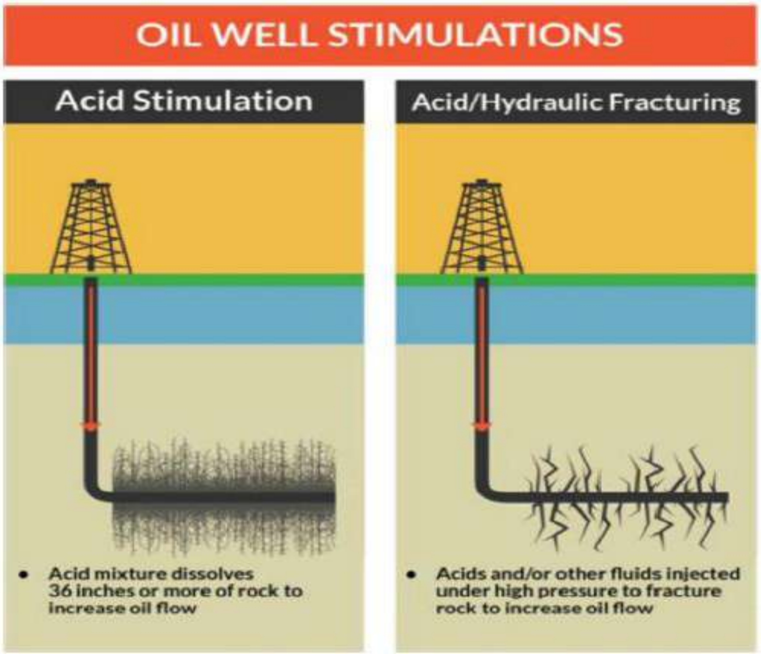


Figure 04 : Oil flow stimulation illustration (Leong Van Hong et Hisham Ben Mahmoud.2018).

II.1. Fracturing Acidizing

Acid fracturing is a stimulation technique in which a hydraulic fracture is created by injecting a fluid above the breakdown pressure of the formation, so that the rock cracks, and then an acid is injected flows through those permeable channels; can dissolve minerals and remove fine particles for the hydrocarbons to flow more rapidly to create permeable channels. This technique can only be used in carbonate reservoirs, due to the high dissolution rate of carbonate minerals in acids. Figure 05 shows a picture of an acid fracture obtained in a laboratory experiment, evidencing the non-uniform dissolution that leaves a path partially open after the pressure is relieved.

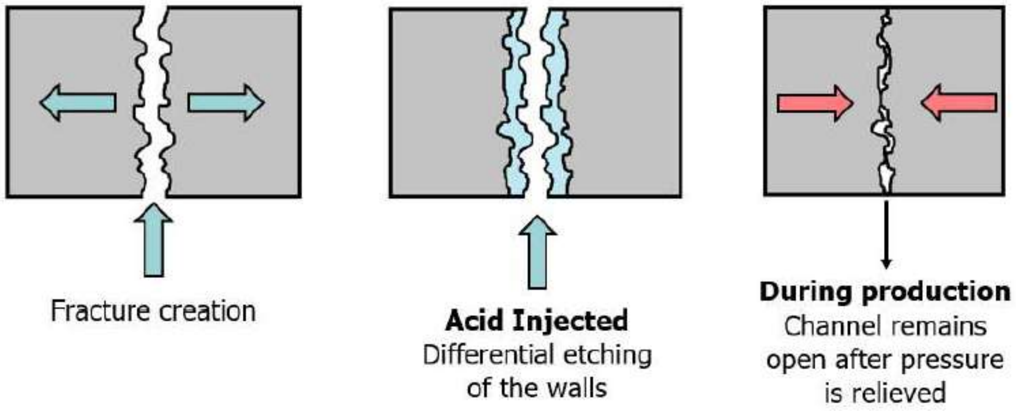


Figure 05 : Illustration of the acid fracturing operation (Schwalbert 2019).

In recent years, well productivity has been improved by the application fracturing treatments applied in reservoirs with diverse geological settings. However, the formation of a complex fracture has been revealed due to heterogeneity and local properties of the rock (Adachi et al., 2007).

II.2. Matrix Acidizing

The process of matrix acidizing is when reactive fluids such as acids are injected at a pressure less than the fracture pressure of the formation; In sandstone acidizing, the main goal is to eliminate or dissolve the fine particles and the damage that is bridging or clogging the pore spaces. In carbonate deposits, which are largely acid-soluble, the acidic process creates conductive pathways known as wormholes, which are highly permeable and conductive flow paths for hydrocarbons (Ghommem et al; 2015, Wilson, 2016). Conversely, when acidifying sandstone, the acid can only dissolve a small portion of the rock. Therefore, remediation of formation damage and restoration of rock permeability is the focus of matrix acidification (Cruz-Maya et al; 2011, Zhou and Nasr-El-Din, 2016). This can be achieved by targeting the area near the borehole (8-24 inches) and improving its permeability (King 1986; Zerhboub et al., 1994). This area is mainly damaged by clay swelling, migration of fine particles and deposition of scale during production as explained in (Al-Harthy, 2008; 2009). Experimental studies showed the influence of several factors on matrix acidification, including acid injection rate, rock properties, reaction rate of acid with rock, permeability, porosity, mineralogy, pore structure, and mineral distribution (Qiu et al. 2011 ; Maheshwari and Balakotaiah, 2013). In the last decades, various formations, in particular low-temperature reservoirs (<100 °C), clean sandstones (<10 % dolomite) and clean dolomites, have been extensively treated with matrix acidification (Morgenthaler, 2013). However, few fields or deposits with these characteristics exist and now deep, hotter and heterogeneous deposits with complex mineralogy are in need of acid treatment. New technologies need to be developed to increase the efficiency of sandstone or carbonate acidification and mitigate the adverse effects of precipitation.

II.3. Why is Acidizing in Carbonates different than in Sandstones?

The primary objective of acidizing stimulation is to remove or bypass formation damage around the wellbore. However, both chemical and physical aspects of carbonate acidizing are very different from sandstone acidizing. The rock content causes the reaction rate to be much faster in carbonates. Hydrofluoric (HF) acid is widely used in sandstones, while Hydrochloric acid (HCl) is utilized in carbonates. The different nature of porosity and permeability (intergranular porosity in sandstones vs. vuggy, fractured porosity in carbonates) (ELMABRUK ELSAFIH Norman, 2021). In addition to the faster rate of reaction, in carbonates the acid follows preferential flow paths called vortex, thus bypassing damage rather than dissolving it (Economides et al., 1994). The difference in the dissolution path between carbonates and sandstones is showing in Figure 06.

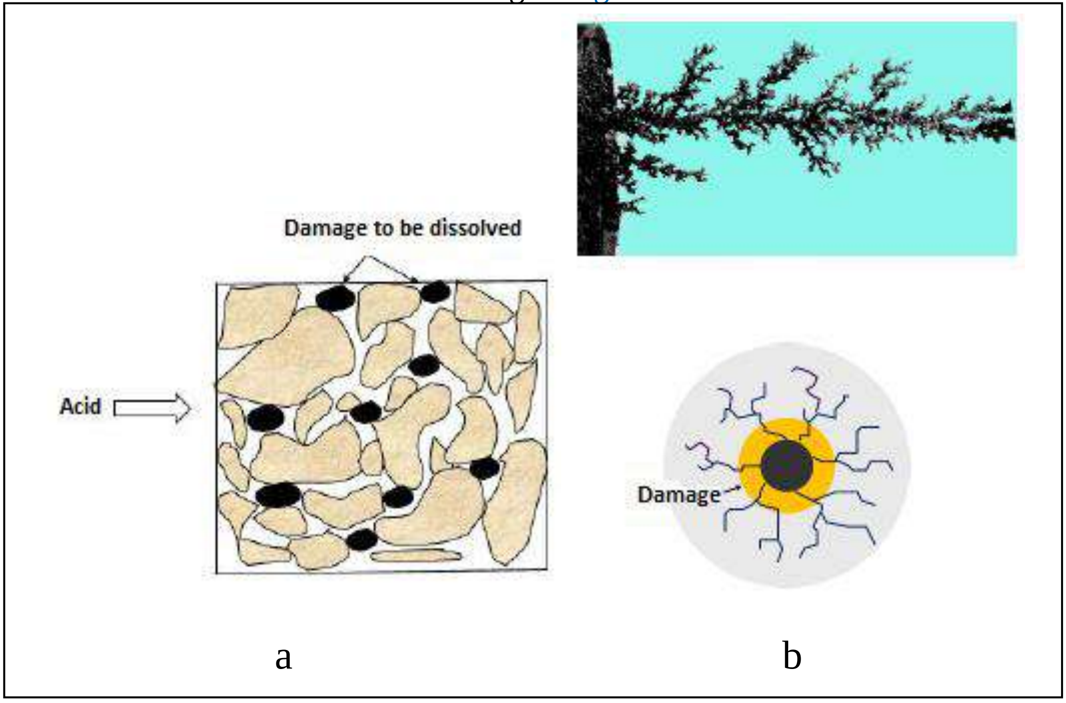
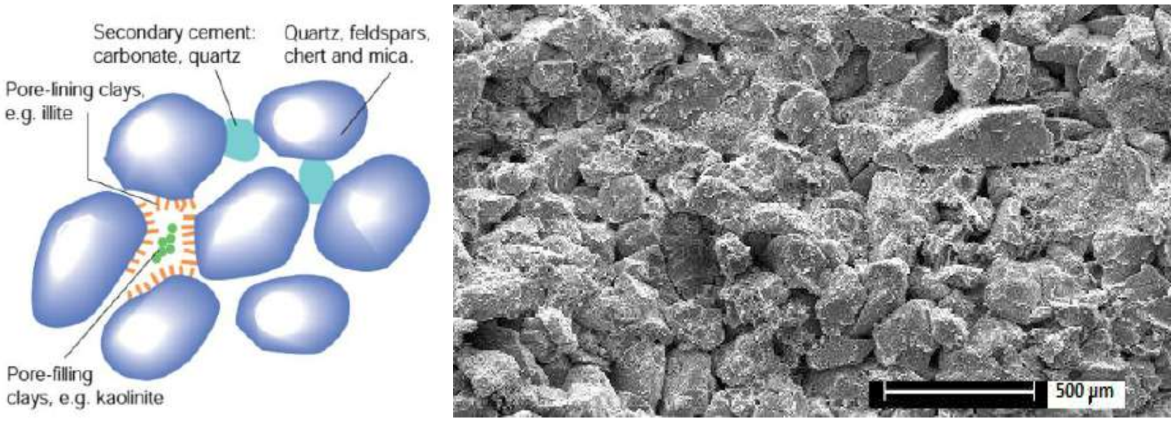


Figure 06 : a. HF acid injection in Sandstones **b.** HCl acid injection in Carbonates (Modified after Buijse 2000).

II.4. Sandstone Acidizing

II.4.1. Sandstone formation

The knowledge of the formation composition is very important in matrix acidizing of any sandstone or carbonate reservoir. The sandstone formation is often composed of silica and silicate minerals. It also includes quartz, feldspars, clays, and zeolites (Muecke, 1982). Sandstone is a clastic sedimentary rock where Quartz (also known as silica), is the most common grain found in the sandstone formation, but it also contains other minerals such as feldspar and clay which are usually cemented by silica, calcite or iron oxides (Shafiq & Ben Mahmud, 2017). The reservoir sandstone framework is often consisting of quartz grains which are cemented by an overgrowth of dolomites, quartz, and feldspar. Kaolinite and pore-lining clays such as illite usually reduce porosity and permeability. Figure 07 represents the structure of minerals present in the sandstone rock. Table 01 shows the concentration of different minerals present in a typical Berea sandstone core sample utilized in for core flooding test.



a **b**

Figure 07 : a. Constituents of sandstone, all of whichare soluble in HCl–HF mud acid system as described by Crowe et al. (1992) **b.** MEB photo of sandstone formation.

Mineral	Concentration(wt%)	Chemical formulae
Quartz	75	SiO_2
Feldspar	5	$K_{0.5}Na_{0.5}AlSi_3O_8$
Dolomite	5	$CaMg(CO_3)_2$
Siderite	5	$FeCO_3$
Chlorite	5	$Mg_6Si_4O_{10}(OH)_8$
Mica/Illite	5	$KAl_3Si_3O_{10}(OH)_2$

Table 01 : Mineralogy of a typical Berea sandstone (Al-Shaalan and Nasr-El-Din 2000).

II.4.2. Sandstone Acidizing technique

Sandstone acidizing is applied in to stimulate well inflow performance in sandstone reservoirs. The most important target of sandstone matrix acidizing is to remove any precipitate products resulted from the contact with the mud acid (HF/HCl) that restrict the flow of hydrocarbons and minimize permeability around the wellbore. Secondary and tertiary reactions are the responsible of the formation of these products. HF acid contains Fluoride ion (F-) that has the possibility to react with sandstone minerals such as sand grains, feldspar, and clays but hydrochloric, sulfur and nitric acids do not react with the sandstone formation effectively (Smith and Hendrickson, 1965). The use of a mixture of HCl acid with HF acid is discovered in 1940 by Dowel to decrease the formation of reaction products (Smith, 1965). The combination is named mud acid and in sandstone acidizing, the common application is to inject the mud acid with a concentration of 3 % HF and 12 % HCl (Smith and Hendrickson 1965; Abdelmoneim and Nasr-El-Din, 2015). The multiple phases of fluids and their interactions with the formations particles makes sandstone acidizing a very difficult and challenging task. Mud acid reactions with the formation can dissolve different minerals; the most necessary understandings are the reactions of carbonates with HCl and HF and the reactions of HF with silicates, feldspar and quartz (Equations 8 and 9)

$$\mathbf{4HF + SiO_2 \rightarrow SiF_4 + 2H_2O} \tag{8}$$

$$\mathbf{6\,HF + SiO_2 \rightarrow H_2SiF_6 + 2\,H_2O} \tag{9}$$

Soluble gas silicon tetra fluoride (SiF_4) resulted conduct like CO_2 and can subject supplementary reactions. The high pressure keeps it in the solution. Stimulating carbonate formation includes a reaction between an acid and minerals like calcite ($CaCO_3$) or dolomite $CaMg(CO_3)_2$. The first reaction of carbonate with acid is showed in Equation 10 (Hill et al. 1994).

$$\mathbf{2HCl + CaCO_3 \rightarrow CaCl_2 + CO_2 + H_2O} \tag{10}$$

II.4.3. Acidizing Mechanism

The dissolution of minerals begins immediately when hydrofluoric acid arrives to the sandstone reservoir. The speed of dissolution and reaction of particles is related to their reaction rate with acid and the exposed surface area (Shafiq & Ben Mahmud, 2017). Quartz tends to react at a slower rate whereas feldspars and clays tend to act at a faster rate. Figure 08 represents the reactions taken place when sandstone formation is reacted with mud acid.

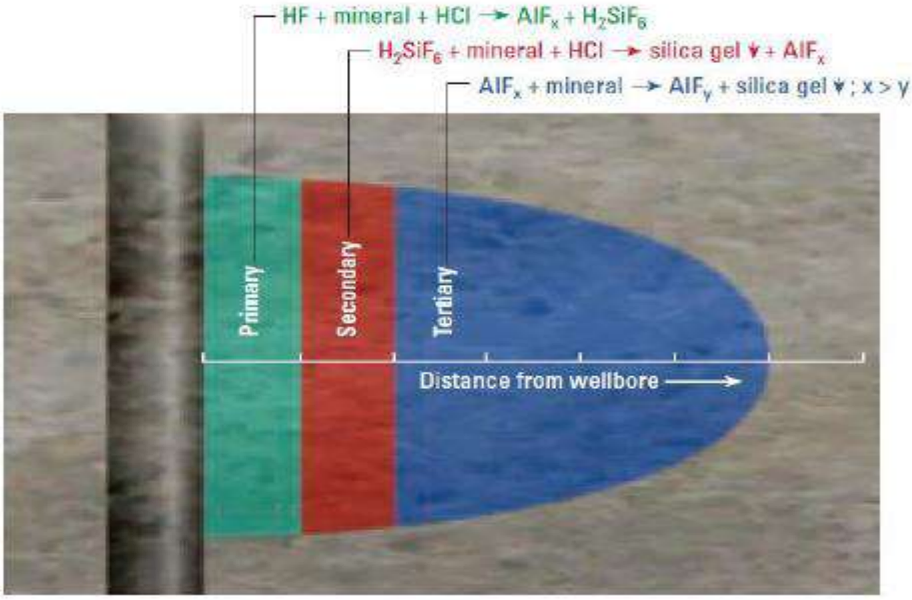


Figure 08 : Sandstone Acidizing reactions (Al-Harthy, 2009).

In 2009, Al-Harthy explains that when mud acid is applied with sandstone formation there are generally three reactions occurred. The first one takes place near the wellbore with the formation of aluminium and silica fluorides. Minerals are often dissolved quickly in these reactions and without any precipitation. The second reaction which is slow occurs later with the first molecules that form silica gel (a precipitate). The third reactions take place far from the wellbore region with the formation of a supplementary precipitate which is a silica gel. the quick kinetics of the secondary and tertiary reactions at higher temperature can cause the failure of the operation. HF is the main acid used to act with minerals but the addition of HCl has the target of minimising the exhaustion de HF and the maintenance of an acidic surroundings (Shafiq & Ben Mahmud, 2017).

Therefore, a suitable acid should be chosen to eliminate the damage or fines which reducing pores for fluids to move faster. The secondary and tertiary reactions during sandstone acidizing mentioned before can create another damage due to the formation of insoluble products.

Silicates are formed by the reaction of sodium and potassium ions with fluorosilicic acid (H_2SiF_6), the primary reaction product, as shown in Equation 9. Fluorosilicic acid is water soluble, but upon reaction with sodium and potassium ions (Equations 11 and 12, respectively) it can form insoluble sodium fluorosilicate and potassium fluorosilicate precipitates (Ying-Hsiao et al., 1998).

$$SiF_6^{2-} + 2Na^+ \rightarrow Na_2SiF_6 \qquad (11)$$

$$SiF_6^{2-} + 2K^+ \rightarrow K_2SiF_6 \qquad (12)$$

Fluoride precipitates are formed by the reaction between calcium and fluoride ions, i. H. CaF_2 (Figure 09). The solubility of this product is very low and a precipitate may form, but this can be removed if a sufficient HCl pre-flush is performed (Shafiq et al., 2018). The reaction is shown in Equation 13 (Ying-Hsiao et al., 1998).

$$CaCO_3+2HF \rightarrow CaF_2\downarrow+ H_2O+ CO_2 \qquad (13)$$

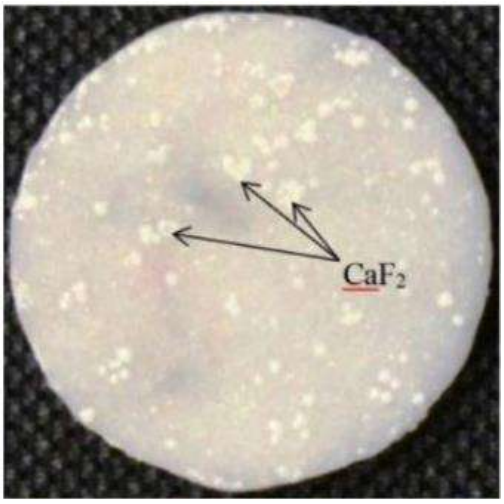


Figure 09 : CaF_2 precipitated on marble ($CaCO_3$) after reacting with 10 % HCl/1.5 % HF/ 0.5 % citric acid (Podoprigora, 2017).

Colloidal silica precipitate is formed by the reaction of hydrofluoric acid (HF) with sandstone formation, which is very complex due to multiple interactions. First, HF acid reacts with silica to form silica tetrafluoride (SiF4), which produces fluorosilicic acid (H_2SiF_6) due to the further reaction between HF acid (Shafiq et al., 2018).

As explained by (Shaughnessy and Kunze, 1981), as soon as the concentration of reacting HF becomes very low, silica precipitates. The reaction (Equation 14) dissociating with the high concentration of HF dissolves silicate minerals.

$$6HF + SiO_2 \longrightarrow H_2SiF_6+2H_2O \qquad (14)$$

The reaction (equation 15) reverses at a low concentration to regenerate HF acid and precipitate silicic acid (Al-Harbi et al. 2011):

$$H_2SiF_6+4H_2O \longrightarrow Si\,(OH)_4+6HF \qquad (15)$$

These precipitation reactions may be averted by releasing three phases of acidizing presented by different researchers (Gidley, 1971; Kalfayan and Metcalf, 2000 and Shafiq et al., 2018).

II.4.4. Treatment Design Optimization

All too often an acid formulation, be it mud acid or one of the HF based fluids, is pumped into a formation without design considerations. It may appear to have succeeded when in fact it has failed. The basic mechanisms of acidification are known, but coupling these phenomena to conditions such as reservoir heterogeneity, naturally occurring impure minerals, and the distribution of minerals in the reservoir is extremely complicated. This explains why matrix acidification has been considered more of an art than a science, and why simple recipes that work well in one area can fail utterly in another. The selection of the treatment liquid is an important step in the design of a matrix treatment. The process of choosing a fluid is complex because there are many parameters involved and each parameter can vary widely. There may be several fluids that are appropriate for a particular problem, but some may have advantages over others. This section of the handbook provides a comprehensive discussion to help designers select the optimal fluid to solve a specific problem. Although all parameters relevant to fluid selection are discussed, emphasis is placed on the mineralogy of the formation, particularly in the case of sandstone deposits. The decision-making processes are based on experience and the combination of specialist knowledge in the fields of chemistry, geochemistry and geology. This selection process is based on matching the liquid not only to the damage, but also to the conditions that caused the damage. After choosing the right treatment...

III. Treatment Fluid Selection

III.1. Basic Concepts

Matrix treatment is about removing damage that is affecting well productivity. Therefore, it is important to know the extent and type of damage, the location and the cause. Damage is characterized by two important parameters: (1) composition and (2) location. These parameters determine the properties of the treatment liquid and the technique used to reach and eliminate the damage. The location of the damage is important because the treatment fluid contacts several other substrates (e.g., tubing rust or carbonate cementitious material in the formation) before reaching the damage. It must still be effective when it reaches the damaged area. In addition, rerouting techniques must be used. Hydrofluoric acid is used in sandstone formations to dissolve silicates. Non-acidic systems are sometimes used to disperse fines and allow their production with the treatment liquid. Figure 10 and Figure 11 show decision trees for designing a treatment for a sandstone reservoir damaged by silt and clay. The criteria for selecting the treatment fluid are mineralogy, mechanisms of formation damage and their remediation, petrophysics, and downhole conditions. The compatibility of the treatment fluid with the rock is an important factor. Compatibility means that the permeability does not decrease when the formation comes in contact with the fluid. This compatibility concept applies in particular to sandstone, where numerous harmful reactions can occur.

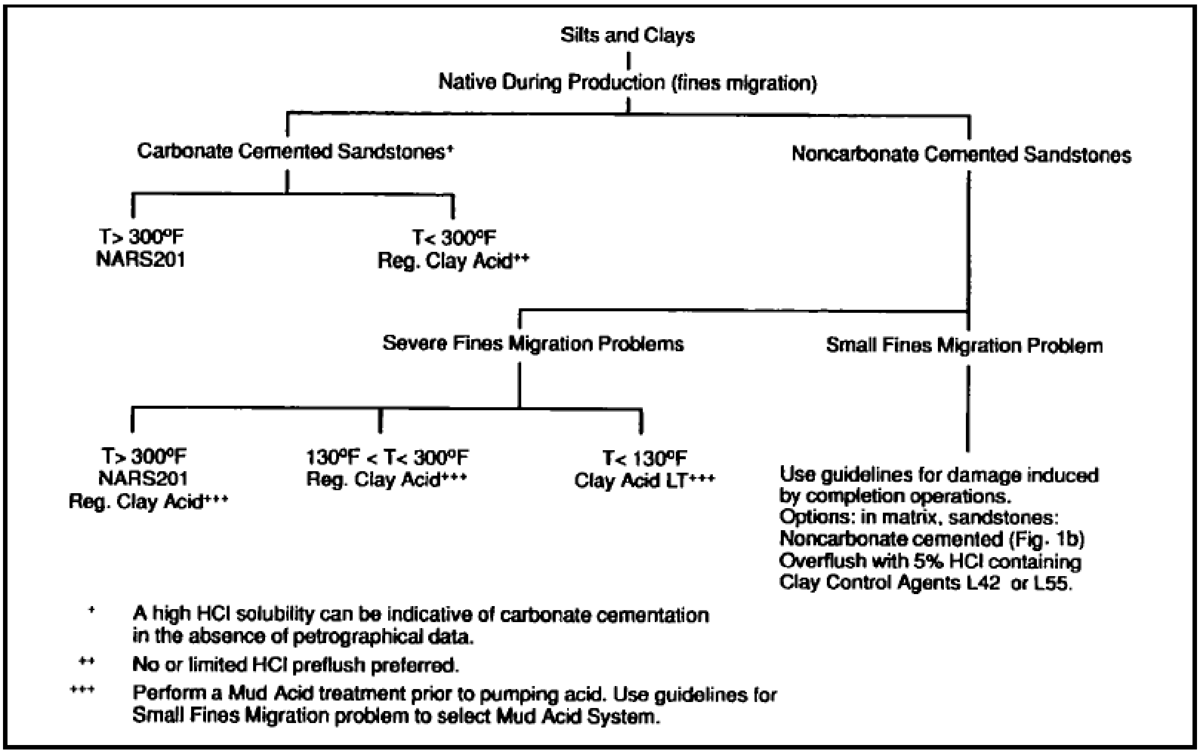


Figure 10 : Treatment fluid selection in sandstone acidizing: silt and clay damage native during production (fines migration) (Schlumberger, 1998).

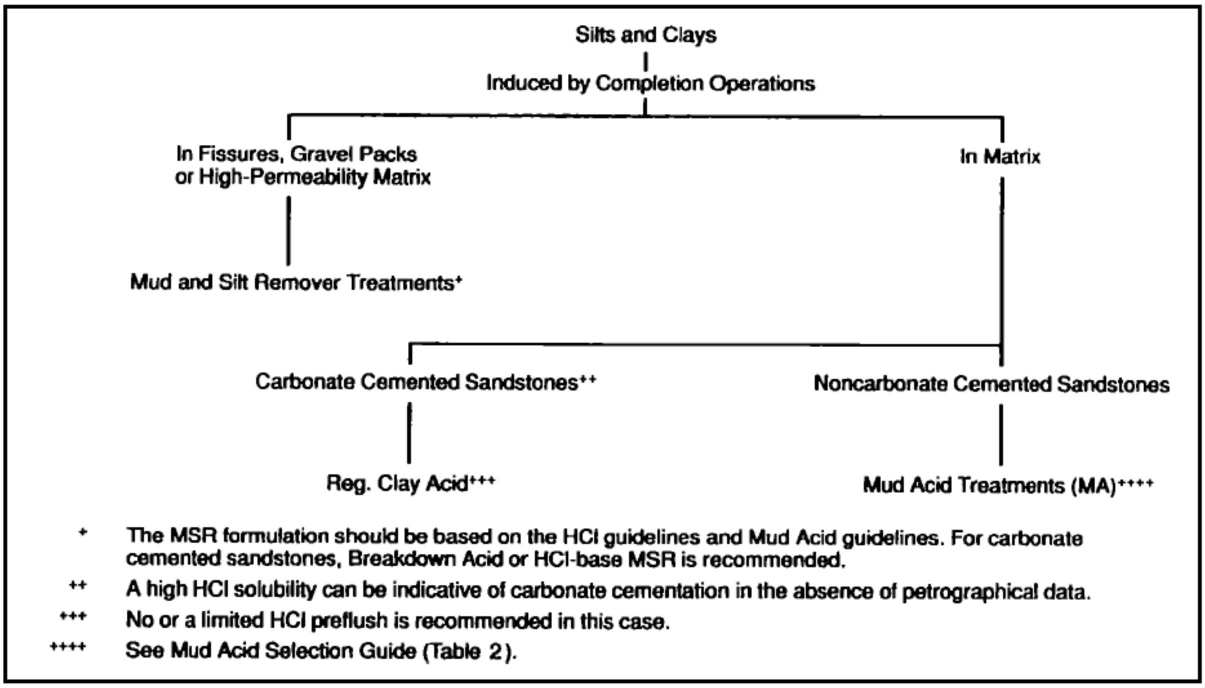


Figure 11 : Treatment fluid selection in sandstone acidizing: silt and clay damage induced by completion operations (Schlumberger, 1998).

III.2. Mineralogy Criteria

III.2.1. The Concept of Sensitivity

A successful matrix treatment depends on the favorable response of the formation to the treatment fluid. Thus, the treating fluid must remove damage and be completely compatible with the formation rock and fluids. The sensitivity of a formation to a given fluid includes all the detrimental reactions that can take place when this fluid contacts the rock: the deconsolidation and collapse of the matrix, the release of fines or the formation of precipitates. A formation is “sensitive” if the reaction between the rock minerals and a given fluid induces damage to the formation. This concept is represented in Figure 12. Acid penetration is described as the movement of chromatographic waves. Damaging reactions can occur both in the damaged zone and in the undamaged formation. The precipitation of some damaging compounds cannot be avoided. Sufficient volumes of treating and overflush fluids push potential precipitates deep enough into the reservoir that their effects are minimized because of the logarithmic relationships between pressure drop and distance from the wellbore. The sensitivity of a sandstone is affected by hydrofluoric acid damage, and other factors. Silicon, aluminium, potassium, sodium, magnesium, and calcium ions can form precipitates at a given temperature, once their product solubility is exceeded, and damage the formation. Thus, sensitivity depends on the overall reactivity of the formation minerals with the acid. Reactivity also depends on the structure of the rock and the distribution of minerals within the rock; that is, the probability of the acid reaching the soluble minerals.

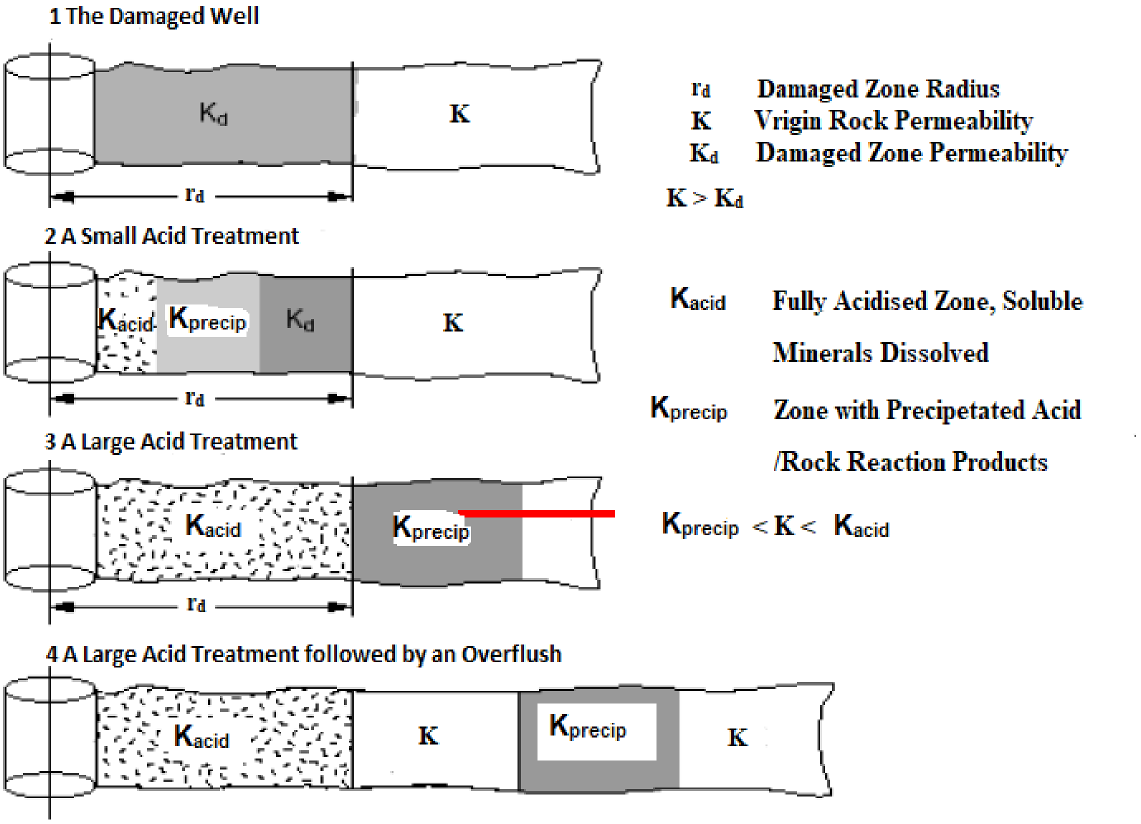


Figure 12 : Permeability changes when acidizing a damaged well (Schlumberger, 1998).

From a mineralogical view, two factors affect the reactivity of a given mineral, (1) chemical composition and (2) surface area (Table 02). The composition and constitution (petrography) of the rock are important factors used to determine potential sensitivity. Typically, sandstone reservoirs are made of a framework of silicate grains, quartz, feldspars, chert, and mica. This framework is the originally deposited sand. Secondary minerals, precipitated in the original pore spaces, are the cementing materials for the grains (most frequently secondary quartz overgrowth or carbonates) and the authigenic clays. This means that the clays were precipitated in the pore space long after the initial formation of the rock. These newly formed clays appear either as pore lining (attached to grain surfaces) or as pore filling.

Minerals	Surface Area	Solubility	
		HCl	HCl-HF
Quartz	Low	No	Very Low
Chert	Moderate to high	No	Low
Feldspars	Low to moderate	Very Low	Low to moderate
Micas	Moderate	Low	Moderate
Kaolinite	High	Low	High
Illite	High	Low	High
Smectite	High	Low	High
Chlorite	High	Low to moderate	High
Calcite	Low to moderate	High	High,butCaF_2 precipitation
Dolomite	Low to moderate	High	
Ankerite	Low to moderate	High	
Siderite	Low to moderate	High	

Table 02 : Surface Area and Solubility of Sandstone Minerals (Schlumberger, 1998).

III.2.2. Rock Structure

The actual solubility of minerals in a sandstone reservoir strongly depends on their position within the rock structure.Thus, a petrographic study is helpful in understanding the response of a rock to a treatment during a flow test. It is important to note the following:

III.2.3. HCl Solubility

The solubility of the rock in hydrochloric acid is generally considered to represent the carbonate content of the sandstone. This assumption must be verified during a petrographic study because other minerals, such as oxides, sulfides, and chlorite clays, are also partially soluble in HCl. A sandstone with an HCl solubility greater than 20 % should not be treated with a straight HF acid. HF reacts with calcium carbonate to form a calcium fluoride precipitate. When the solubility is less than 20 %, an HCl preflush helps prevent contact between HF and the carbonate rock.When the solubility is higher than 20 %, an HCl-base treatment fluid can be used; however, to avoid additional deconsolidation problems, a straight fluoboric acid (Clay Acid) treatment is often preferred.

III.2.4. Clay Content

It is important to know the amounts of each type of clay with the formation; however,it is much more important to know the position and distribution of the clays in the reservoir they determine the rock response to the treatment.

IV. Methodology of Fluid Selection

Fluid selection is based on a simple principle: the fluid must efficiently remove the damage and increase permeability. The damage that could result from precipitates must also be considered.There is some controversy regarding the degree of damage caused by precipitates. For instance, Shaughnessy and Kunze(1981) have emphasized the damaging potential of $Si(OH)_4$, whereas Crowe(1985) has shown that such precipitation may not cause a serious problem. The complex mineralogy of many sandstones encourages the formation of several potentially damaging precipitates. The potential damage of precipitates depends on several factors:

*** Chemical Factor**

Solubility of the precipitates in the after-flush fluid and the native reservoir fluids.

*** Crystallographic Factor**

Whether the precipitates are amorphous or crystalline

*** Morphological Factor**

Relating to the extraction of grains that can migrate (precipitation out of solution in the pore space), and whether they cover undissolved particles (precipitation on the surface of existing grains).

***Concentration Factor**

Whether the concentration is high enough to cause plugging of the pore system.

*** Reservoir Factor**

The damage is also related to rock properties such as permeability, pore size and pore configuration. The possibility of precipitation and its effects on the formation permeability can be determined by flow tests, and that information can be used to develop the optimum treating fluid. Flow tests under realistic conditions are the only laboratory tests that can detect the effect so fin compatibility between injected fluid and formation minerals. Not only is a potential damage or permeability reduction quantitatively assessed, but the nature of the damaging process can also be identified by a combination of effluent analysis and core analysis after treatment (SEM, X-ray, thin section).

V. Other Criteria for Fluid Selection

V.1. Permeability

The permeability of the formation influences the selection of the treating fluid in two ways. First, permeability affects the type and extent of damage. A highly permeable formation can easily be penetrated by foreign solid particles or fluids,and the depth of the damage can be large. A low-permeability sandstone will merely be damaged by invasion of foreign particles; however, this type formation can be more sensitive to the invasion of foreign fluids because the small pores often contain a large quantity of clays that have a high reactivity toward fluids. The permeability also influences the amount of damage caused by precipitates. A low-permeability formation is more severely damaged by precipitates than a high-permeability formation. The same is true for damage resulting from water block.

V.2. Produced Fluids

In some cases, the type of produced fluids precludes the use of some stimulation fluids. This applies to gas wells, where it is preferable to minimize the use of purely water-base fluids. Materials that lower surface tension (surfactants, alcohols) and/or gases (foams) are recommended. In other cases, adverse reactions between acids and formation oils or formation waters dictate the use of only specific acid formulations.

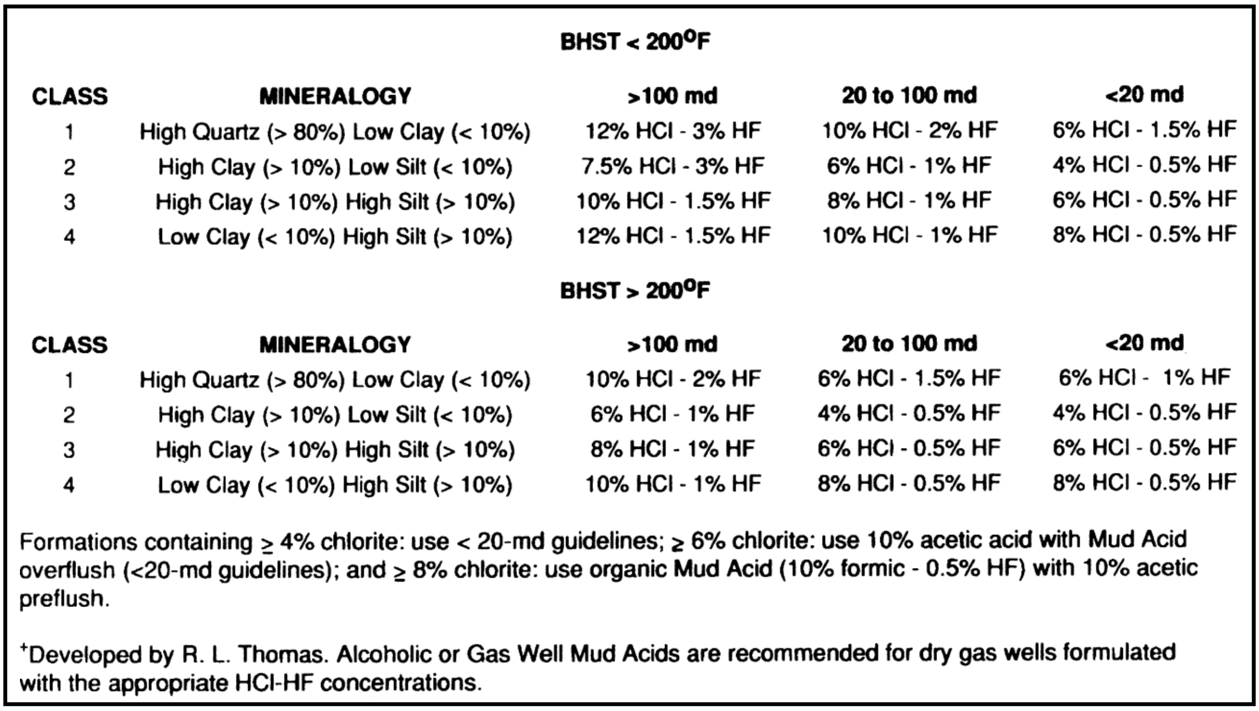
V.3. Physical Conditions of the Well

The formation temperature is an important factor because it influences the efficiency of corrosion inhibitors and there action rates. Several treating fluids decrease reaction rates at high temperatures and provide deeper live-acid penetration. Reservoir pressure influences the flowback of spent fluids. In order for a fluid to flowback, the pressure differential must exceed the capillary pressure. Surface-active materials are used to lower capillary pressure and facilitate cleanup. Energized fluids can also be used for this purpose.

VI. Acids Used to Avoid Damaging Precipitates

VI.1. Mud acid

Using available data on HF acids/sandstone interactions and field experience (Hekim and Fogler, 1977), McLeod (1984) proposed a guideline for using acids in sandstone matrix treatments. This guideline, designed to recommend acid formulations to avoid or retard precipitation, was modified by Thomas (Table 03) to include a wider range of permeability and formation mineralogy. Additionally, the Thomas guidelines include the effect of temperature. Lowering the HF/HCl ratio is a way to retard precipitation; HCl acid increases the dissolving power of the HF acid and a lower HF content reduces the precipitation of amorphous silica and other compounds as well. This explains the successful use of low-HF acid formulations such as 13.5 % HCl-1.5 % HF and 6.5 % HCl-1 % HF formulas.



BHST < 200°F

CLASS	MINERALOGY	>100 md	20 to 100 md	<20 md
1	High Quartz (> 80%) Low Clay (< 10%)	12% HCl - 3% HF	10% HCl - 2% HF	6% HCl - 1.5% HF
2	High Clay (> 10%) Low Silt (< 10%)	7.5% HCl - 3% HF	6% HCl - 1% HF	4% HCl - 0.5% HF
3	High Clay (> 10%) High Silt (> 10%)	10% HCl - 1.5% HF	8% HCl - 1% HF	6% HCl - 0.5% HF
4	Low Clay (< 10%) High Silt (> 10%)	12% HCl - 1.5% HF	10% HCl - 1% HF	8% HCl - 0.5% HF

BHST > 200°F

CLASS	MINERALOGY	>100 md	20 to 100 md	<20 md
1	High Quartz (> 80%) Low Clay (< 10%)	10% HCl - 2% HF	6% HCl - 1.5% HF	6% HCl - 1% HF
2	High Clay (> 10%) Low Silt (< 10%)	6% HCl - 1% HF	4% HCl - 0.5% HF	4% HCl - 0.5% HF
3	High Clay (> 10%) High Silt (> 10%)	8% HCl - 1% HF	6% HCl - 0.5% HF	6% HCl - 0.5% HF
4	Low Clay (< 10%) High Silt (> 10%)	10% HCl - 1% HF	8% HCl - 0.5% HF	8% HCl - 0.5% HF

Formations containing ≥ 4% chlorite: use < 20-md guidelines; ≥ 6% chlorite: use 10% acetic acid with Mud Acid overflush (<20-md guidelines); and ≥ 8% chlorite: use organic Mud Acid (10% formic - 0.5% HF) with 10% acetic preflush.

[+]Developed by R. L. Thomas. Alcoholic or Gas Well Mud Acids are recommended for dry gas wells formulated with the appropriate HCl-HF concentrations.

Table 03 : Mud Acid Selection Guide (Schlumberger, 1998).

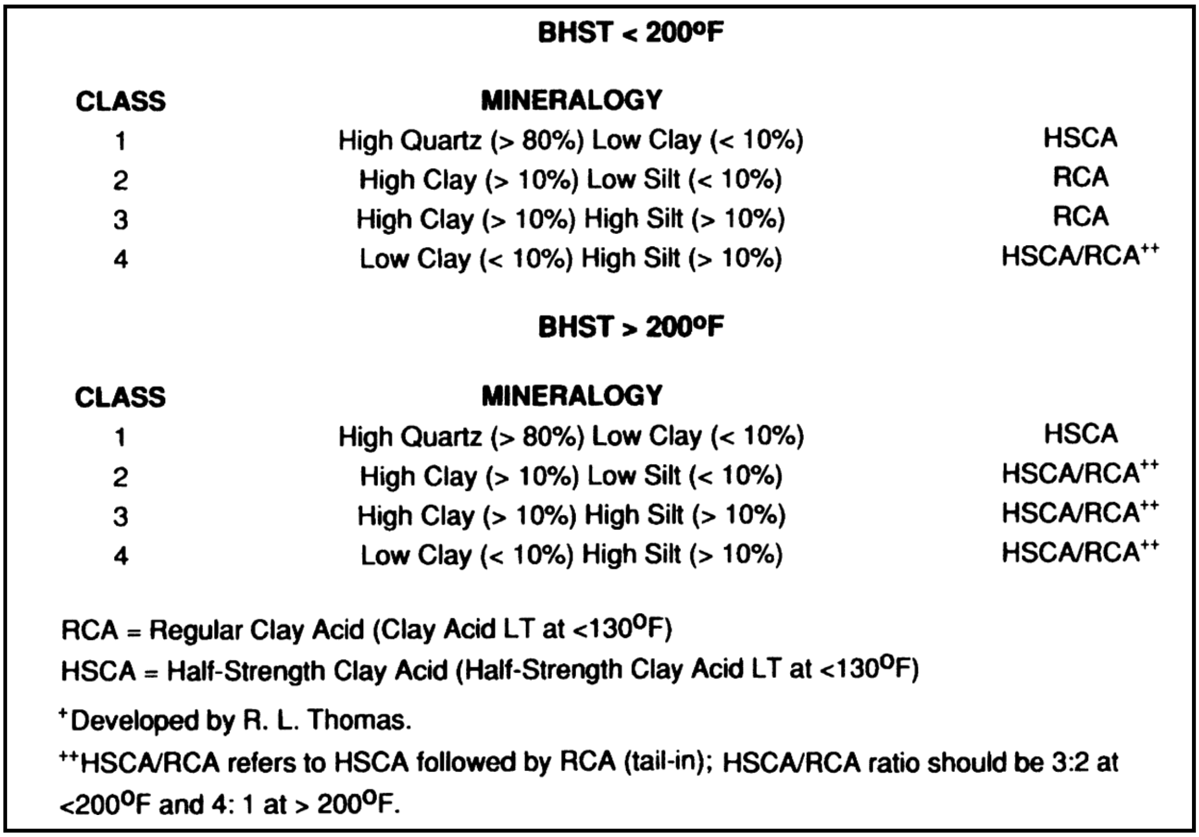
VI.2. Clay Acid

Clay Acid is a matrix acidizing fluid for sandstone reservoirs using fluoboric acid (HBF4). HF is produced through the hydrolysis of HBF4 according to the following reaction 16:

$$HBF_4 + H_20 \longrightarrow HBF_3OH + HF \tag{16}$$

At any given time there is only a limited amount of hydrofluoric acid available. Thus, Clay Acid demonstrates the ability to avoid damaging reactions/precipitates. The HF is consumed by reaction on formation fines followed by hydrolysis of fluoboric acid to produce more HF. Therefore, Clay Acid is a “retarded acid.” At higher temperatures (150 F [65 °C]), the kinetics of the hydrolysis is rapid. However, equilibrium conditions dictate that there is only a limited amount of HF present at any given time in solution. For example, at 212 F (100 °C) only 0.15 % HF is present. Thus, the system reaction rate is similar to a very dilute Mud Acid solution.

Clay Acid offers many advantages over straight HF (Mud Acid) formulations because there is only a very limited amount of HF available at any given point and time. Therefore, the probability of forming precipitates of fluosilicates or silica is decreased tremendously. A Clay Acid selection guide is provided in Table 04.



BHST < 200ºF

CLASS	MINERALOGY	
1	High Quartz (> 80%) Low Clay (< 10%)	HSCA
2	High Clay (> 10%) Low Silt (< 10%)	RCA
3	High Clay (> 10%) High Silt (> 10%)	RCA
4	Low Clay (< 10%) High Silt (> 10%)	HSCA/RCA++

BHST > 200ºF

CLASS	MINERALOGY	
1	High Quartz (> 80%) Low Clay (< 10%)	HSCA
2	High Clay (> 10%) Low Silt (< 10%)	HSCA/RCA++
3	High Clay (> 10%) High Silt (> 10%)	HSCA/RCA++
4	Low Clay (< 10%) High Silt (> 10%)	HSCA/RCA++

RCA = Regular Clay Acid (Clay Acid LT at <130ºF)
HSCA = Half-Strength Clay Acid (Half-Strength Clay Acid LT at <130ºF)

+Developed by R. L. Thomas.

++HSCA/RCA refers to HSCA followed by RCA (tail-in); HSCA/RCA ratio should be 3:2 at <200ºF and 4: 1 at > 200ºF.

Table 04 : Clay Acid Selection Guide (Schlumberger, 1998).

A major advantage of Clay Acid is its ability to inhibit the migration of fines present in the sandstone. Depending on the fines attacked, partial dissolution takes place (some aluminum and silicon) and boron is included in the lattice of the crystal. A new surface with different properties is formed as a result of this topochemical reaction. The sand grains are not affected. The reaction by-products (borosilicates) appear as a coating on the initial surfaces. They will not plug the pores. In addition, the coating desensitizes the minerals and welds them together and to the sand grains.

When Regular Mud Acid (12 % HCl-3 % HF) is used to treat cores containing illite, cubic grains of K_2SiF_6 are observed. They plug the tubing at the outlet of the core cell and appear in the pore system as individual grains which can migrate and plug the porosity. Their effect on permeability has been shown to be extremely negative. When Clay Acid is used to treat cores with illite, this K_2SiF_6 precipitate is not formed.

This shows the positive effect of using fluoboric acid (Clay Acid) for treating sensitive sandstones that contain potassic feldspar or illite clay. The same kind of observation is made with sandstones containing large amounts of clays. Borosilicates blanket migrating fines after the dissolution of the damaging particles. Therefore, Clay Acid is a good treatment fluid in many of the cases cited in the guidelines of McLeod (1984). It has two advantages over the

HCl-HF formulations with a low HF content.

*The dissolving potential of this treatment fluid is still very high (8 % HBF_4 is ultimately equivalent to approximately 2 % HF).

*The borosilicate coating permanently stabilizes fines, that is, eliminates swelling and migration.

VII. Preflush and Overflush Fluids

The fluid selection path in Figure 09 and Figure 10 indicates the main treating fluid. However, preflush and overflush fluids must be used for maximum efficiency of the treating fluid. The preflush and overflush should be applied using the following guidelines.

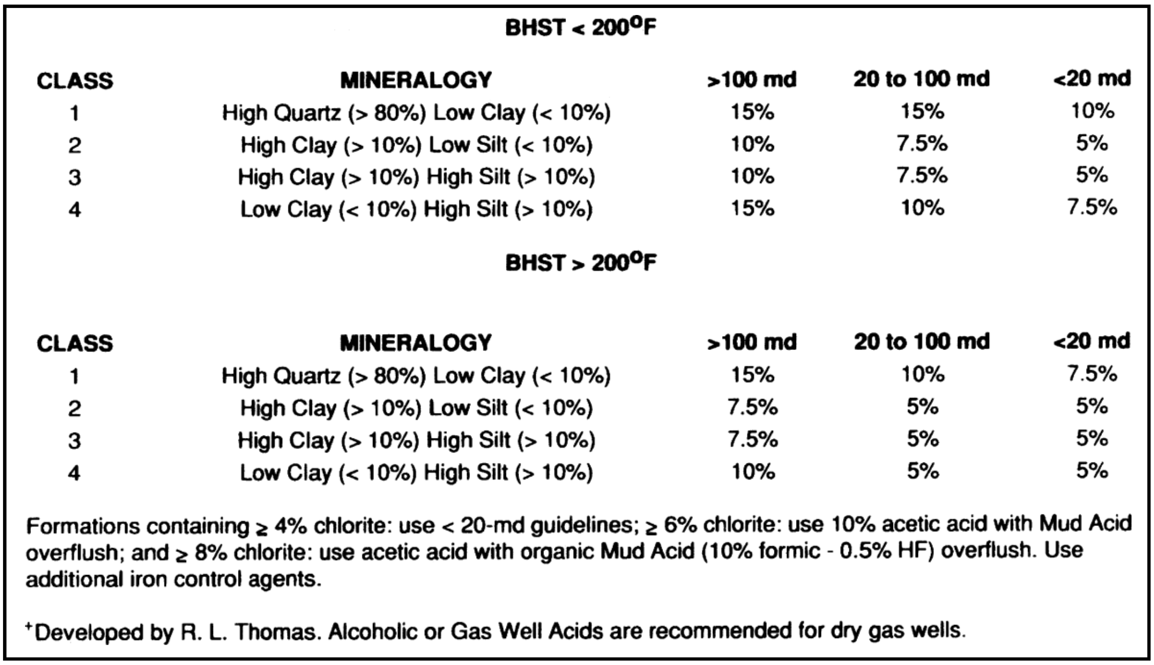
VII.1. Preflush

Typically, HCl is used as a preflush in sandstone acidizing to accomplish the following.

Displace brine from the wellbore when an ammonium chloride spacer is not used, to avoid contact between HF and any formation brine containing K^+,Na^+or Ca^{2+}.

Dissolve a maximum amount of carbonate to minimize CaF_2 precipitation. Acetic acid can replace HCl to dissolve carbonates in high-temperature wells (above 400 F [204 ^{0}C]).

The HCl Concentration Selection Guide is shown in Table 05. Similar to the Mud Acid Selection Guide, the HCl concentration is a function of the mineralogy, permeability and temperature of the formation. In general, the recommended HCl concentration decreases with increased fines content or temperature, whereas it increases with permeability. The quantity of preflush per foot is designed to dissolve all HCl-soluble minerals two feet radially from the wellbore (Table 5). Field experience indicates that lower volumes of HCl are adequate. Walsh et al.(1982) reported that 12 % HCl-3 % HF can be used in a formation with 6 % calcite without creating damage due to CaF_2 or AlF_3 precipitation. However, spent HCl-HF can react with calcite to form calcium hexafluosilicate.Thus; the quantity recommended in Table 05 will assure precipitation problems are not encountered. When sandstones containing no carbonates are treated, a small HCl preflush is nevertheless recommended to exchange clay cations before pumping the HCl-HF treating fluid, to prevent precipitations. Xylene, with or without HCl, can be used to remove paraffin and asphaltene components. Mutual solvents can be used provided they have been thoroughly tested for their compatibility with the crude oil in place. They are normally used in combination with HCl or ammonium chloride. Other additives such as surfactants, clay stabilizers and complexing agents can be formulated as necessary.



BHST < 200°F

CLASS	MINERALOGY	>100 md	20 to 100 md	<20 md
1	High Quartz (> 80%) Low Clay (< 10%)	15%	15%	10%
2	High Clay (> 10%) Low Silt (< 10%)	10%	7.5%	5%
3	High Clay (> 10%) High Silt (> 10%)	10%	7.5%	5%
4	Low Clay (< 10%) High Silt (> 10%)	15%	10%	7.5%

BHST > 200°F

CLASS	MINERALOGY	>100 md	20 to 100 md	<20 md
1	High Quartz (> 80%) Low Clay (< 10%)	15%	10%	7.5%
2	High Clay (> 10%) Low Silt (< 10%)	7.5%	5%	5%
3	High Clay (> 10%) High Silt (> 10%)	7.5%	5%	5%
4	Low Clay (< 10%) High Silt (> 10%)	10%	5%	5%

Formations containing ≥ 4% chlorite: use < 20-md guidelines; ≥ 6% chlorite: use 10% acetic acid with Mud Acid overflush; and ≥ 8% chlorite: use acetic acid with organic Mud Acid (10% formic - 0.5% HF) overflush. Use additional iron control agents.

+Developed by R. L. Thomas. Alcoholic or Gas Well Acids are recommended for dry gas wells.

Table 05 : HCl Concentration Selection Guide+ (Schlumberger, 1998).

VII.2. Overflush

The role of the overflush is to displace the main acid flush greater than four feet from the wellbore. If precipitation of reaction products occurs, it will result in a small decrease in production. However, the main treatment fluid still has to be carefully selected to minimize the formations of precipitates during the flowback. Recommended overflush fluids include the following.

- ammonium chloride brine, 5 to 7.5 % HCl or diesel for oil wells.
- ammonium chloride brine, 5 to 7.5 % HCl or nitrogen for gas wells.

In all cases, a surfactant and/or a mutual solvent is recommended to leave the formation water-wet and facilitate the flowback of spent acids. Nitrogen or energized (with nitrogen) fluids are recommended in low-pressure wells to facilitate the unloading of fluids.

VIII. Stimulation Fluid Additives

Although proper fluid selection is critical to the success of a matrix treatment, the treatment may be a failure if the proper additives are not used. The main treating fluid is designed to effectively remove or bypass the damage, whereas additives are used to prevent excessive corrosion, prevent sludging and/or emulsions, provide uniform fluid distribution, improve cleanup, and prevent precipitation of reaction products. Additionally, additives are used in preflushes and/or overflushes to stabilize clays, disperse paraffin/asphaltenes and inhibit scale/organic deposition.

There are certain additives that are used in almost all acid formulations. These include corrosion inhibitors, surfactants, mutual solvents, and iron control agents. The main problems addressed by these additives are corrosion, emulsions, and sludging. Other problems that are handled by additives include clay control, friction reduction, and scale inhibition. Specialty additives are also available for problems that occur on a less frequent basis.

To solve some of the common problems that exist in oil and gas wells a list of acid additives have been utilized during matrix acidizing (Bybee 2003). Table 6 shows the summary of additives used in matrix acidizing and their functions.

Acid additives	**Functions**
Corrosion inhibitors	*To reduce or retard the rate of corrosion of steel by acid *To create an inhibitory film on the metal surface *To protect the acid pumping and handling equipment *To protect the equipment and tool such as casing, pump and valve
Clay stabilizers	*To keep clay and fines in suspension *To prevent migration and swelling of clays
Diverting agents	*To place the reactive fluid evenly *To bracket the interval exposed to the acidizing fluid
Iron control agents	*To dissolve the corrosion products in the casing or tubing *To dissolve the iron minerals in the well
Surfactants	*To lower the surface and interfacial tensions *To change or maintain the wettability of the wells to break and weaken the emulsions

Table 06 : Summary of the additives used in matrix acidizing and their functions (Leong V.H and Hisahm B.M 2018).

IX. Methods to avoid different types of formation damage

IX.1. Emulsions: they are stabilized by surface-active materials (surfactants) and by foreign or native fines. Generally, mutual solvents with or without de-emulsifiers, are used for treating emulsion problems. De-emulsifiers, which may work very well in a laboratory or in a separator or reservoir because of a large number of droplets in contact per unit volume, may not work by themselves in a porous medium because of mass transport phenomena in getting the product where it should work. Another reason they may not work alone is the mechanism involved in breaking emulsions, which should provoke the coalescence of droplets and then phase separation. Because the fluids are viscous, there is usually fines migration associated with it and a Mud Acid treatment should be considered.

Treatment of Water-Outside-Phase Emulsions can include:

- A water-base carrier fluid which may contain mutual solvent: U66 or U100 non emusifiers: W27, W35, W39, W53, or W54.
- alcohol-base CLEAN SWEEP* fluid.

A typical treatment design for a water-outside-phase emulsion is:

1. Pump ammonium chloride brine containing a mutual solvent or pump alcohol base CLEAN SWEEP fluid.
2. Pump a diverter stage; foam or ball sealers.
3. Repeat step 1 and step 2 based on zone thickness.
4. Flush to top perforation with 3 % ammonium chloride brine, nitrogen, crude oil or diesel.

Tubeclean fluid is not necessary unless the tubing is suspected of being contaminated with materials such as rust or paraffin. Nitrogen is always recommended in low-pressure wells to aid cleanup.

Treatment of Oil-Outside-Phase Emulsions can include:

- An oil-base carrier fluid which may contain mutual solvent: U66 or U100 non emusifiers: W27, W35, W39, W53, or W54
- Mudclean OB
- xylene-base or toluene-base CLEAN SWEEP fluid.

A typical treatment design for an oil-outside-phase emulsion is:

1. Pump Tubeclean fluid.
2. Pump xylene-base or toluene-base CLEAN SWEEP fluid.
3. Pump a diverter stage; foamed or gelled hydrocarbon or ball sealers.
4. Repeat step 2 and step 3 based on zone thickness.
5. Flush to top perforation with 3 % ammonium chloride brine, nitrogen, crude oil or diesel.
6. Pump HCl or Mud Acid (optional).

The tubulars should be cleaned to remove materials such as rust and scales prior to pumping CLEAN SWEEP fluids. The L400 should not be active until it contacts water.

Nitrogen is recommended in low-pressure wells; foam diversion techniques should be used. If nitrogen is not available, three to four barrels of a gelled hydrocarbon (for example, YF* “GO” fluid) is recommended for each diverter stage. Matched-density ball sealers, buoyant ball sealers or a straddle packer can be used for diversion. The well should be flowed back immediately after treatment execution.

IX.2. Wettability Change

This damage is removed by injecting (mutual) solvents to remove the oil-wetting hydrocarbon phase and then injecting strongly water-wetting surfactants. A surfactant by itself will not work. The oil phase, which is often precipitated asphaltenes or paraffins and is responsible for this oil-wetting, must be removed first with a solvent. The same applies to an adsorbed oleophilic (oil-liking) surfactant. Then, a strongly water-wetting surfactant can be injected and adsorbed onto the rock minerals. This reduces the tendency for new hydrocarbon precipitates to stick to the mineral surfaces and oil-wet them again. The treatment life is tremendously increased.

- A water- or oil-base carrier fluid (depending on conditions) that may contain mutual solvent: U66 or U100 surfactant: F40, F52.1, F75N, F78
- Mudclean OB
- Xylene-base or toluene-base CLEAN SWEEP fluid (oil wells only)
- Alcohol-base CLEAN SWEEP fluid (oil and gas wells).

Mutual solvent systems are economical and perform well in most cases. Mudclean OB fluid is specifically designed to remove oil-base muds and also to water-wet the formation. CLEAN SWEEP fluids are typically required when a severe problem exists.

If the wettability change is due to native reservoir properties and is not induced by extraneous fluids, a follow-up treatment using a strongly water-wetting surfactant (F40, F52.1, F75N, F78) is advised.

IX.3. Water Block

A water block is usually treated by reducing the surface tension between water and oil or gas using surfactants or alcohols. Alcoholic systems are particularly suitable in gas wells because they also promote the vaporization of water in the produced gas.

Water blocks in gas wells can be effectively removed using:

- Alcohol-base CLEAN SWEEP fluid
- Gas Well Acid
- Alcoholic Acid
- A water-base carrier fluid which may contain: mutual solvent: U66 or U100.surfactant: F40, F75N, or F78.alcohol: F3 or K46.

Water blocks in oil wells can be effectively treated using:

- xylene-base or toluene-base CLEAN SWEEP fluid
- No aqueous Acetic Acid

· a water- or oil-base carrier fluid (depending on conditions) which may contain mutual solvent: U66 or U100 surfactant: F40, F75N, or F78.

IX.4. Scales

Various solvents dissolve scales, depending on their mineralogy. Contact time is a very important factor in the design of a scale-removal treatment. The major problem when treating scale deposits is allowing sufficient time for the solvent to reach and effectively dissolve the bulk of the scale material. The treating fluid must dissolve most of the scale for the treatment to be successful. A treatment strategy for damage caused by scales is to first dissolve the scale, then encourage inhibition.

IX.4.1. Scale Removal Treatment Design

To properly design a scale removal treatment, an analysis of the scale and associated water is recommended. An x-ray diffraction analysis can be performed to determine the scale composition. Laboratory solubility tests to determine the type and volumes of removal agent and the contact time for scale removal can then be performed. The following guidelines should be applied when collecting scale samples.

1. Obtain scale samples with the underlying surface intact if possible.
2. If the scale must be removed, get as large a sample as possible.
3. Provide the most complete information possible on the source and condition of the sample and any limits on removal techniques.
4. Well data such as bottomhole temperature and pressure, production figures, calliper logs and well history are helpful.

IX.4.2.Treatment Design for Removal of Carbonate Scales ($CaCO_3$ (Figure 13), $FeCO_3$, $SrCO_3$, $BaCO_3$)

HCl and organic acids are used to remove carbonate scales. Ninety-five gal of 15% HCl dissolves approximately one ft 3 of calcium carbonate. HCl concentrations should be carefully selected. Deep, hot wells may require organic acids to avoid corrosion of metal goods due to long acid exposure times.

HCl can rapidly wormhole through carbonate. If placement techniques are not correct, the acid can be lost into the formation and little scale will be dissolved. Sufficient contact time between the acid and the scale is necessary. Washing the acid back and forth across the perforations will achieve the best results.

A surfactant (for example, F75N at 2 gal/1000 gal) in the fluid improves penetration. A chelating agent (for example, L41 at 250 lbm/1000 gal) prevents reprecipitation.

Figure 13 : An example of deposited calcite (Sonatrach/ EP HBK, 2020).

IV.4.3.Treatment Design (Conversion Treatment) for Removal of Calcium Sulfate Scale

A typical conversion treatment design for sulfate scale removal is:

1. Pump P121.
2. Pump HCl plus U42 for iron scale.
3. Pump GYPBAN fluid; contact time 12 to 72 hr.
4. Pump HCl (removes calcium carbonate).
5. Repeat step 3 and step 4 as required.

Washing action improves removal.

***Treatment Design (Chelating Treatment) for Removal of Calcium Sulphate (Figure 14) Scale**

A typical chelating treatment design for sulphate scale removal is:

1. Pump P121.
2. Pump an aqueous solution containing U42 and F75N at 2 gal/1000 gal (GYPBAN R1 fluid).
3. Circulate 3 % (wt/wt) ammonium chloride brine.
4. Pump HCl to remove residuals.

One gal of U42 dissolves 1.5 lbm $CaSO_4$ (anhydrite) or 1.9 lbm $CaSO_4 \times 2H_2O$ (gypsum). Maximum temperature is 400 F (204 °C). Soak for 24 to 36 hr. Washing action improves removal.

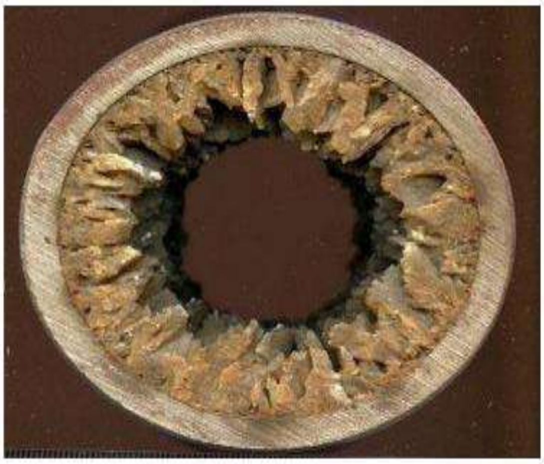


Figure 14 : An example of $CaSO_4$ deposition in an oil pipe (Sonatrach/ EP HBK, 2020).

IX.4.4. Treatment Design (Chelating Treatment) for Removal of Barium Sulphate and Strontium Sulphate Scales

Barium sulphate and strontium sulphate scales can be removed using the procedure described to remove calcium sulphate scale (chelating treatment). An aqueous solution containing 20 % (vol/vol) U42 dissolves 0.9 lbm/ft^2/day barium sulfate at 150 F (66 °C). Soaking periods up to 12 days are required.

IX.4.5. Treatment Design for Iron Scales - FeS, FeO, FeCO3

Acid treatments (HCl) dissolve iron scales (Figure 15). Maintain oxygen-free systems by using oxygen scavengers (for example, J353). Use iron chelating agents (L41, L58, L62,or U42).

Figure 15 : Sandstone core face after acidizing (a) without iron (permeability improved) and (b) with iron (permeability damaged) (Rady and Nasr-El-Din, 2015).

Chlorides - NaCl, KCl are soluble in:

· low-salinity water solutions or 1 to 15 % HCl which may contain a surfactant (F40, F75N, or F78).

Hydroxides - Ca(OH)2, Mg(OH)2 are treated with:

- 3 to 15 % HCl containing a surfactant (F40, F75N, or F78).

Silica Scales can be dissolved using: Mud Acid.

IX.4.6. Scale Prevention

Scale prevention involves the use of chemical inhibitors to affect the nucleation growth or adherence of scale crystals. There are three mechanisms of scale inhibition.

- chelating scaling ions
- “poisoning” crystals
- dispersing crystals.

Dowell does not market a product designed to disperse scale crystals. Polyacrylic acids are usually used for this purpose. Typically, the inhibitor is continuously added to production or injection fluids or

displaced into the formation during squeeze treatments. There, it adsorbs onto the rock or precipitates as widely dispersed, low-solubility particles in the pore spaces. The inhibitor is then slowly solubilized at a few parts per million by the produced or injected fluid. This small concentration is usually required to inhibit scale development by the threshold effect. The term “threshold effect” refers to the mechanism when a scale crystal is formed. The inhibitor adsorbs onto the surface of the crystal and prevents further growth.

*Chelating Agents

Chelating agents bond to one cation; therefore, large quantities may be required. Other ions can affect the process. Scale Removal Agent L56 (Na_2H_2 EDTA) can be used to dissolve scale and chelate the dissolved metal ions.

*Treatment Design for Squeeze Treatment with Chemical Inhibitors

Mix inhibitor with water or light brine (1 part inhibitor to 19 parts aqueous fluid). The brine can be potassium chloride or ammonium chloride brine. Use 2 gal of inhibitor per foot of interval. Design for five to seven feet of penetration. Use L59 inhibitor aid to improve efficiency.

1. Pump inhibitor solution.
2. Overflush three to four feet with nitrogen or brine.
3. Shut-in for 4 to 48 hr.

Monitor production. Treatment is required again when the inhibitor concentration falls below 5 ppm

IX.4.7. Organic Deposits (Figure 16)

The most common methods of removing organic deposits are mechanical, thermal, and chemical. Figure 17 shows the deposition sites of this type of scale.

Figure 16 : a. Some Asphalten samples **b.** Deposited Praffins (Sonatrach/ EP HBK, 2020).

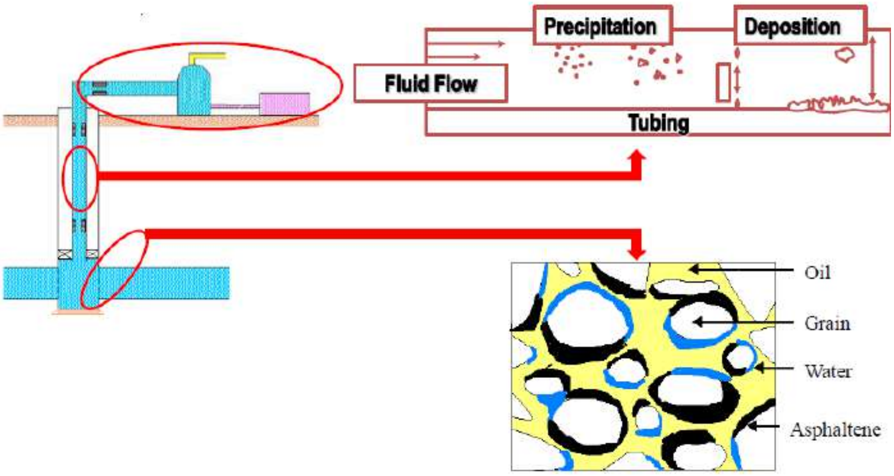


Figure 17 : Asphaltene deposition sites.

IX.4.7.1. Mechanical Methods

Scrapers and cutters are commonly used to remove organic build up from tubing and surface flow lines. In surface flow lines, they can be economical to use because the cuttings can be flushed from the lines. In tubing, perforation plugging may occur if the cuttings need to be circulated from the well. Fluid loss to the perforations can also damage the formation. Frequent mechanical cleanup can become more costly

as lost production is added to the cost of the treatments. Wireline scrapers or scrapers attached to sucker rods are used to clean up organic deposits and to minimize downtime and costs. Surface flow lines are mechanically cleaned with slowly-soluble wax or naphthalene plugs pumped through the line. Plastic or rubber spheres are also used.

IX.4.7.2. Thermal Treatments

Hot oiling is a very popular method for paraffin deposit removal. The paraffin is melted and dissolved by the hot oil that is circulated down the well and through the surface lines. Typically, the heated oil (lease crude or other oil) is circulated down the casing and up the tubing. Heating is generally great enough to raise the temperature of the oil higher than that of the formation. There is some evidence that hot oiling can damage the permeability, particularly in wells with low bottomhole pressures and temperatures (less than 160 F [71 °C]). The melted paraffin can precipitate and deposit in the matrix. Continued heating and injection only moves the precipitation (cooling) distance deeper into the critical near-wellbore area. Because the organic deposits frequently contain mineral scales or formation fines (or both), these can contribute to damaging the permeability if forced into the formation.

IX.4.7.3. Chemical Treatments

There are several types of chemicals available; solvents, dispersants, detergents and synergistic blends. Solvents, dispersants and detergents are used primarily for removal. Dispersants are also used as inhibitors. Organic deposits (paraffins and asphaltenes) are usually resolubilized by solvents. Blends of solvents can be tailored to a particular problem, but an aromatic solvent is an efficient, general purpose
fluid. Adding a small amount of alcohol is often beneficial when dissolving asphaltenes.

IX.4.7.3.1. Solvents

Solvents are highly-aromatic materials that dissolve a specific weight of deposit.

Solvents for Paraffin Removal

* A26 (xylene) and P121 (toluene) are used as a solvents for paraffin and asphaltenes. They are used full strength or diluted with diesel or clean lease oil.

U66 is used if there is brine present in the deposit. The U66 helps the solvent to more directly contact and penetrate the solvent.

* Dowell Acid Dispersion (DAD) is a solvent-in-acid emulsion containing a dispersant. DAD can be a very effective solvent if there is an HCl-soluble scale present in the organic deposit. DAD can also be used to clean up oil wells that are being converted to water injectors and for treatments to maintain injectivity.

* Toluene-base CLEAN SWEEP fluid plus emulsion remover (not a dispersant).

Solvents for Asphaltene Removal: A26 and P121 are used as a solvents for paraffin and asphaltenes. They are used full strength or diluted with diesel or clean lease oil.

IX.4.7.3.2. Dispersants

Dispersants inhibit or break up (or both) existing deposits into smaller sizes. They can diffuse several times their own weight in material. Dispersants are less widely used than solvents but are more cost effective.

Dispersants for Paraffin Removal

- Paraffin Dispersant U82 - use at 1 to 10 % (vol/vol) in 3 % ammonium chloride brine.
- PARAN II fluid (1 part Dispersing Agent U74 and 9 parts P121), use at 5 to 10 % (vol/vol) in 3 % ammonium chloride brine.
- PARAN III fluid (1 part Emulsifying Agent U80 and 9 parts P121), use at 5 to 10% (vol/vol) in 3 % ammonium chloride brine containing 10 % (vol/vol) L400 or L401. Aqueous solutions of U82, PARAN II and PARAN III fluids can penetrate and loosen organic deposits enough that the washing action of the fluid disperses and removes the deposit. Dispersant concentration depends on the type, hardness, adhesion and temperature of the deposit. For matrix, wellbore and tubing cleanup treatments, a soaking period of several hours, followed by a washing action is recommended before returning the well to production. In some cases, dispersed-phase systems have been found to remove more paraffin than conventional aromatic solvent systems.

Dispersants for Asphaltene Removal

- Asphaltene Dispersant U101 is a blend of dispersants, surfactants and solvents used at 1 to 10 % (vol/vol) in P121.
- PARAN II fluid (1 part U74 and 9 parts P121), use at 5 to 10 % (vol/vol) in water or acid.
- PARAN III fluid (1 part U80 and 9 parts P121), use at 5 to 10 % (vol/vol) in water containing 10% (vol/vol) L400 or L401.

IX.4.7.3.3. Detergents

Detergents are surfactants that work in the presence of water to water-wet paraffin and asphaltene particles, formation, tubing and flow lines. Detergents breakup deposits and prevent reagglomeration.

IX.4.7.3.4. Synergistic Blends

Synergistic blends are mixtures of solvents, dispersants and detergents.

IX.4.8. Paraffin/Asphaltene Prevention

There are many methods for preventing or reducing organic deposits. Included in these are the use of plastic-coated tubing and flowlines, downhole heaters to maintain temperatures above the cloud point and production techniques to increase flow rates and to minimize deposit build-up. Surfactants and crystal modifiers may be effective in controlling or inhibiting organic deposition. P124 can be used as inhibitors when squeezed into the formation. U101 was specifically developed for asphaltenes. Typically, 1/3 of the inhibitor will be produced back following the treatment, 1/3 will be permanently adsorbed in the formation and 1/3 will be produced back at 50 to 100 ppm. The use of U82 to remove organic deposits also has been reported to have a preventive capability following a cleanup treatment. The mechanism for inhibition is not understood.

IX.4.8.1. Placement Strategy

Inhibitors can be placed by tubing displacement, squeeze, continuous injection via the annulus, and continuous injection via macaroni string. Dowell provides tubing displacement and squeeze services.

Tubing Displacement

The tubing displacement technique simply removes the organic deposit from the tubing and wellbore. The fluid system is displaced down the tubing, allowed to soak for four to six hours and flowed back. Advantages of the tubing displacement method are:

* suitable for all completion types

* lower treatment costs (versus squeeze method)

* no formation contact.

Disadvantages of the tubing displacement method are:

* effective life of two to four weeks

* production loss during the treatment.

IX.4.8.2. Squeeze Method

If organic deposition is occurring in the reservoir, then an inhibitor (P124 or U101) squeeze treatment is required. This can be performed in one of two ways.

* Full Strength Squeeze ¾ The inhibitor is squeezed into the formation at a volume of 10 to 20 gal/ft, allowed to soak for 6 to 12 hr and the well is returned to production.

* Misted Nitrogen Squeeze ¾ The inhibitor is atomized with nitrogen and squeezed into the formation. This method improves the life of the inhibitor treatment up to four times the normal life of a common inhibitor squeeze. By atomizing the inhibitor and displacing it into the formation with nitrogen, the inhibitor is more evenly dispersed throughout the formation, thus taking a longer time period for the inhibitor to be produced from the well. This technique treats a much larger portion of the reservoir and has been found to make much more effective use of the inhibitor.

Advantages of the squeeze method are:

* three - to six-month effective life

* treats the reservoir

* suitable for all completion types.

Disadvantages of the squeeze method are:

* treatment basis can be high

* production loss during the treatment.

Typically, a squeeze treatment preceded by a tubing displacement is recommended. Diversion techniques must be used. The following steps are recommended.

1. Pump Tubeclean fluid to remove iron/organics from the tubing.
2. Pump the solvent/dispersant system (see guidelines in Table 7) to remove near wellbore damage (25 to 50 gal/ft). Shut-in for three to four hours.
3. Stimulate the formation with appropriate acid systems (optional).
4. Pump inhibitor (misted with nitrogen if possible) plus F75N or U100. See inhibitor selection guidelines in Table 8).
5. Overflush with nitrogen, P121, A26 or crude to yield 10 ft penetration.
6. Return the well to production and monitor returns for inhibitor. Determine the critical inhibitor level by monitoring the inhibitor level in the produced crude and the production rate.

Problem	**Choice of Solvent/Dispersant**
Paraffin	U82 in 3 % ammonium chloride brine PARAN II or III fluid
Severe Paraffin	CLEAN SWEEP I or II, P121
Asphaltene	PARAN II or III fluid
Severe Asphaltene	P121, P121 plus 1 to 2 % U101
Paraffin/Asphaltene	PARAN II or III fluid
Severe Paraffin/Asphaltene	P121 plus 1 to 2 % U101

Table 07 : Solvent/Dispersant Selection Guide (Schlumberger, 1998).

Problem	**Choice of an Inhibitor**
Paraffin	10 % P124 or U82 in 3 % ammonium chloride brine at 100 to 150 gal/ft
Severe Paraffin	10 % P124 in 3 % ammonium chloride brine at 200 to 300 gal/ft
Asphaltene	30 % U101 in P121 at 100 to 150 gal/ft
Severe Asphaltene	30 % U101 in P121 or A26 at 200 to 300 gal/ft
Paraffin/Asphaltene	P124 plus U101 in P121 or A26 (100 to 150 gal/ft)
Severe Paraffin/Asphaltene	P124 plus U101 in P121 or A26 (200 to 300 gal/ft)

Table 08 : Inhibitor Selection Guide (Schlumberger, 1998).

IX.4.9. Mixed Deposits

Mixed (organic/inorganic) deposits often require a dual-solvent system, such as a dispersion of a hydrocarbon (often aromatic) solvent into an acid.

Removal of mixed deposits is typically accomplished using:

* Dowell Acid Dispersion (DAD)

* xylene-base or toluene-base CLEAN SWEEP fluid

* 3 to 15 % HCl which may also contain

surfactants: F40, F75N, or F78

mutual solvents: U66 or U100

iron control additives: L41, L58, L62, or U42

Laboratory testing should be performed to determine the most efficient acid/solvent type and ratio; for example, deposits composed primarily of scale may require a 90:10 system (Table 9). The DAD fluid should be tested with a crude oil sample to evaluate the potential for emulsions or sludges. DAD fluid is designed to remove acid-soluble scale, not sulfate scales. The DAD fluid can be used in a stage treatment with paraffin/asphaltene solvents/dispersants and inhibitors. DAD fluid can also be used as the sole treatment fluid where inhibition is not considered important. The treatment should be designed for three to four feet radial penetration. Diversion techniques should be used.

% Organic Deposits+ Acid	Solvent Ratio
10	90:10
20	80:20
30	80:20
40	70:30
50	70:30
60	60:40
70	60:40
80	50:50
90	50:50
+The weight % of the sample that is soluble in P121 or A26, that is, the organic component.	

Table 09 : DAD Fluid Selection Guide (Schlumberger, 1998).

IX.5. Silts and Clays

Damage from silts and clays located in the near-wellbore is within a 3 to 5 ft radius. Damage may also occur in a gravel pack. In sandstones, the damage is removed using acid containing HF (Mud Acid of various strengths or in combination with organic acids) or Clay Acid and its similar variations. Silt and clay removal is often a complex process, generally requiring dilute HCl (5 to 15 %) and different formulations/strengths of HF acids which may contain surfactants, iron stabilizers, surfactants, mutual solvents, blends of aromatic solvents and a host of other additives which may be necessary to dissolve and prevent the reprecipitation of iron, silica, aluminum, and asphaltic compounds that may be associated with clay and silt.

The treatment strategy for damage caused by mud or completion fluid is:

1. disperse and suspend the solids
2. dissolve the solids
3. use solvents to help with the wettability
4. stabilize the clays.

The treatment strategy for damage caused by clays is:

1. stabilize the clays
2. dissolve or fuse (or both) the clays.

IX.6. Bacteria

Bacteria and their slimy deposits multiply quickly under a broad range of conditions and can cause plugging in injection, disposal or geothermal wells. Sulfate-reducing bacteria also lead to hydrogen sulfide corrosion. Hypochlorous acid attacks bacteria (and polymers). M91 is five percent sodium hypochlorite.

The treatment strategy for damage caused by bacteria is:

1. Pump M91 (50 to 75 gal/ft).
2. Pump 3 % ammonium chloride spacer (25 gal/ft).
3. Pump an HCl overflush.
4. Pump Mud Acid (optional).
5. Overflush.

Diversion techniques must be used. The M91 should be pumped in 5 stages with a 15 min shutdown period between stages. The HCl should not directly contact the M91; chlorine gas will be released if this occurs. The HCl overflush is pumped to increase the activity of M91 downhole; that is, to generate hypochlorous acid. Mud Acid or Clay Acid can be used to remove silt and clay damage followed by an overflush.

Conclusion

Acidizing of sandstone reservoirs is an essential step to ensure high production by removal of damage or by introducing new pathways. There are a limited number of reasons why sandstone acidizing treatments do not succeed. Its success is very important to take in consideration by following these steps:

*Identify the presence of acid-removal skin damage;

*Select appropriate fluids, acid types, concentrations and treatment volumes;

*Choose a proper treatment additive program;

* Determine a treatment placement method;

*Ensure a proper treatment execution and quality control;

* Evaluate the treatment.

Chapter II

Presentation of the studied region

Introduction

The Oued Mya basin offers an area where a good number of hydrocarbon deposits are developing. The Haoud Berkaoui deposit is among them considered as complex by its heterogeneity of facies and the fault network that affects it.

The region of Haoud Berkaoui represents a main hydrocarbon producing area of the Algerian Sahara, it is composed essentially of several fields: Haoud Berkaoui, Benkahla and Guellala field and the periphery, and with three reservoirs Trias Argilo-Partially exploited sandstone, Triassic clay-sandstone impregnated with oil and the lower series which is the main reservoir of the region. And the majority of its producing wells suffer from damage by the various operations carried out at the level of the latter which makes oil recovery increasingly difficult.

I. Regional geology of Oued Mya basin

I.1. Geographical situation of the Oued Mya basin

The Oued Mya Basin is located north of the Saharan Shelf (Figure 18). The boundaries of the basin are:

*In the North: The Djemaa-Touggourt high structural;
*South: Mouydir Basin;
*To the East: The structural top of Amguid-Hassi Messaoud;
*To the West: The vault of Allal.

The geographical boundaries of the Oued Mya basin are the best reference points: Parallels 31 15’ and 33 00’ limit to the South and the North respectively, and Meridians 6 15’ and 3 30’ limit to the East and the West.

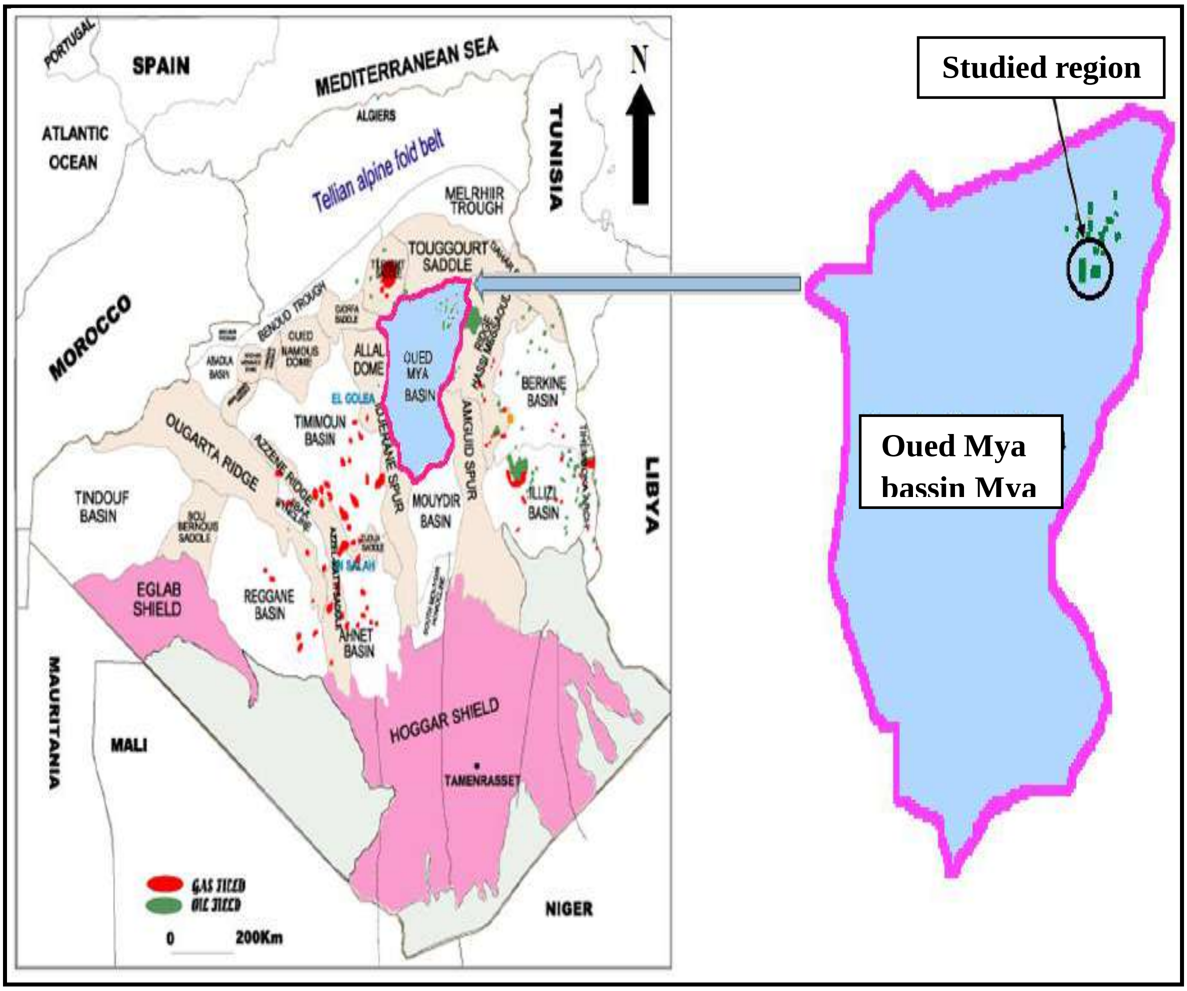


Figure 18 : Geographic location of the Oued Mya Basin in the Saharan Platform sedimentary basins (Sonatrach/PED, 2020).

I.2. Geology of the Oued Mya basin

The Oued Mya basin is an intracratonic basin in which the standard series of the triasic province are developed; A thin Mio-pliocene section and a thick Mesozoic series thickness towards the North-East of the basin and rests in angular discordance on Paleozoic formations strongly affected by hercynian erosion. The evolution of the Oued Mya basin since the Cambrian has two major stages:

1) The sedimentation of the Paleozoic, practically restricted to the lower Paleozoic and its pre-hercynian structuring;

2) The creation of a basin in the Triassic and its evolution during the Mesozoic and Tertiary periods.

I.3. Oil interest in the Oued Mya basin

The Oued Mya basin is one of the richest basins in Algeria and contains several oil and gas fields in the Triassic sandstones, which are the main oil objective.

The giant field of Hassi R'mel contains condensate gas with an oil ring, and the fields of Haoud Berkaoui, Benkahla and Guellala contain oil. Several other oil discoveries have been made in the basin, mainly in the Triassic sandstones, but also in quartzitic sandstones of the Ordovician and Lower Devonian sandstones.

The major oil interest of the basin is related to the presence of the Triassic reservoirs, however, the understanding of the oil results obtained to date and the guides for exploitation must be sought in the Paleozoic evolution of this basin.

I.3.1. Source rocks

Radioactive Silurian graptolite clays are the main source rock of the basin. This excellent bedrock has been in the oil phase since the Late Cretaceous. It reaches the gas phase in some highly buried areas.

The El Gassi clays and the Azzel clays of the Ordovician form secondary mother rocks.

I.3.2. Reservoir rocks

The main reservoirs in the Oued Mya basin are the Triassic fluvial sandstones, which include:

*Lower Series reservoir in the center of the basin "much of the 438 block": Haoud Berkaoui, Benkahla, Guellala, Garet Echouf and in the south of Hassi R'mel. The total thickness of the Lower Series is on average 50-70 m. The average porosity of the Lower Series is 9-12 % and the permeability can exceed the values of 100 mD.

*T1 reservoir in the north of the central part of the basin: Haoud Berkaoui and Guellala and in Hassi R'mel (members B and C).

*T2 reservoir in the Hassi R'mel region (member A).

The total thickness of the two sets T1 and T2 is on average in the order of 100 m and increasing northward, where it can exceed 200 m. The average porosity of the T1 and T2 reservoirs is 15-20% and the average permeability is greater than 200 mD.

The quartzite sandstones of the quartzite unit of Hamra considered as the main objective since the recent oil discovery in the structure of Haoud Berkaoui (case of BKP wells).

The secondary reservoirs are:

The sandstones of the Lower Devonian, the quartzitic sandstones of the Ordovician (slab of M'Kratta, The sandstones: of Oued Saret, Ouargla, El Atchane) and the sandstones of the Cambrian; The sandstones and carbonates of the Moscovian in the northwest of the basin and the carbonates of the Jurassic in the northeast (WEC Algérie, 2007).

I.3.3. Cover rock

Regional coverage is provided by the thick evaporative series of the Triassic salifers S4 and levels S3 to S1 of the Lias. The clays intercalated between the triasic reservoirs can provide local coverage.

Eruptive rocks, when thick enough and not fractured, are a good local cover for the Lower Series reservoir. For Paleozoic reservoirs, the cover is provided by the intercalated clay series.

I.4. Traps

Trapping in the Oued Mya basin is of the following type:

1) Structural: characterized by a low amplitude;
2) Stratigraphic: bevel and bar point of the lower series and T1 reservoirs;
3) Mixed: Benkahla field.

I.5. Migration

The hydrocarbons generated, especially in the North-East part of the Wadi Mya basin, have migrated to the high areas where the trapping took place, the migration took place from the West to Hassi Messaoud, and from the North to the South in the fields of Haoud Berkaoui, Benkahla, Guellala and even Hassi Messaoud.

The reservoirs are fed vertically by means of faults, laterally along the drains formed by the reservoir levels.

The timing between the introduction of the late Triassic, early Jurassic salt cover and the beginning of hydrocarbon generation in the Middle Cretaceous implies that all the amount of hydrocarbons generated is accumulated and trapped in the same basin in the absence of leaks (WEC Algeria, 2007).

II. Presentation of the studied region

II.1. Geograhic situation

The Haoud Berkaoui region is located north of the Oued-Mya depression (Block 438) (Figure 19). This structure is located in the most subsidence oriented North-East/South-West, the latter separated from Erg Djouad by a furrow whose amplitude varies from 200 to 400 Km, its width varies from 25 to 30 Km to the south-west and from 08 to 10 Km to the north-east.

The Haoud Berkaoui fields are located in the north-east of the Algerian Sahara, approximately 590 km southeast of Algiers, 23 km southwest of Ouargla, and 100 km west of Hassi Messaoud.

These fields are located in the basin of Oued Mya which corresponds to an intracratoinque basin forming part of the triasic province.

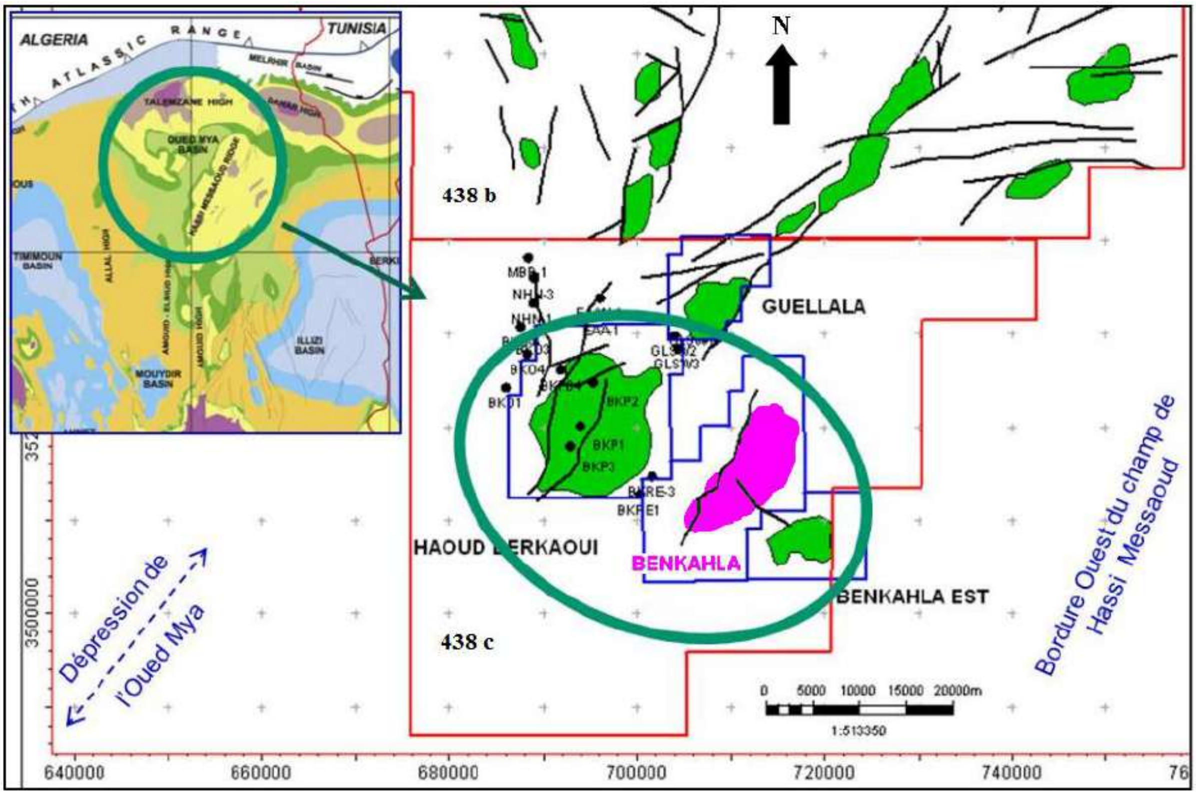


Figure 19 : Geographical location of the operating perimeters of Haoud Berkaoui, Benkahla, Guellala, and Benkahla-Est (BEICIP-FRANLAB, 2012).

II.2. Local Geology

The structure of Haoud Berkaoui is located in the north-east of the depression of Oued Mya, in the most subsidence oriented North-east/South-west, separated from the ridge of Erg Djouad by a furrow whose amplitude varies from 200 to 400 Km, its width varies from 25 to 30 Km in the south-West and 8 to 10 km to the Northwest.

The deposit of Haoud Berkaoui has the structural form of a vast anticlinal brachy (anticlinal whose section by a horizontal plane is not much longer than wide), lying in the direction North-South, it is located in the permit of El M'zaid, at the level of the block 438, this permit corresponds to the eastern half of the paleo-syncline paleozoic and hydrocarbon system of Oued Mya, oriented globally SSW- NNE.

The deposit is limited to the west by the Idjérane-M'zab ridge, composed by the Allal and Tilrhemt moles, to the north by the Djemââ-Touggourt system to the east by the Agreb-Messaoud structural zone, and opens to the south on the Mouydir depression.

In the southern part, the vast structure of Haoud Berkaoui has two (2) main structural directions: NNE and NE, two (2) submeridian faults define a central horst, their rejection can reach 150 m at the top of the structure, The latter is engraved on both sides to finally reach only twenty meters.

The structure of Haoud Berkaoui is widened respectively on its south-east flank forming a secondary structure corresponding to the tops of the wells: OKN 451 and OKN 441. The south and north periclines are affected by faults oriented N 60°, presenting the characters of a slight game in a stall.

The Haoud Berkaoui deposit, which is heavily structured, with a 300 m vertical closure and a 175 km^2 closed area, is the largest structure in the Oued Mya basin.

The main clay-sandstone reservoir, the lower series consists of alternating sandstone benches, clay, and past silty. In this context, the heterogeneity, whether in litho facies or in particle size in the reservoir is extremely marked in this sector, causing difficulties in zoning and correlations even at the scale from one well to another.

II.2.1. Structural geology of Haoud Berkaoui

The structure of Haoud Berkaoui is a vast anticline, which is spread in structural directions (NNE-SSW). The anticline is approximately 22 km long and 15 km wide with a total vertical relief of about 300 meters above the oil water contact. The field has gone under intensive subsurface structural deformation resulting in the creation of massive fault system in the area.

The two principal normal fault systems have been recognized and well understood. Faults F1 and F2 have the same directions and define a central horst fault system. The principal fault F1 varies in throw and can reach 200 m. F1 is sealing fault, which leads to divide the field into 2 flanks.

- East flank: It is the main flank of Haoud Barkaoui (OKN zone). Reservoir pressure is maintained by water injection with average pressure of 250 kg/cm^2 . It has good petro-physical characteristics.

- West flank: It is OKJ zone where reservoir pressure is completely depleted about 150 kg/cm^2. It has poor petro-physical characteristics.

The second principal fault F2 crosses the west flank. The throw along this fault ranges from zero at each end to a maximum of 120 m just north of its intersection with another normal fault.

II.3. The seismic aspect

Since the beginning of seismic prospecting in block 438, the Haoud Berkaoui field has always been a real obstacle to the progress of the work, responding with difficulty to applied seismic.

This is due to the presence of a limestone slab on the surface, the latter absorbs and attenuates the high frequencies of the signals emitted. In addition to the limestone slab, other factors all the more harmful that cause many sources of noise, such as: pipes lines, the life base, drilling in progress, motors… etc. Therefore, the seismic response obtained was of poor quality, as well as insignificant and the results of interpretation were in the majority of cases erroneous.

A seismic acquisition was performed by the National Geophysical Enterprise (ENAGEO), whose acquisition parameters used during this campaign are:

-Coverage: 12,000 %, with the use of 240 geophones, 120 of which on both sides, 150 m apart.

-Inter trace: distance between geophones: 30 m.

-Sweep/vibrated point: 4

-Sweep length: 12 seconds.

-Out-Out filter: slope: 3 db/oct, to eliminate stray and very low frequency signals.

-Vibroseis interval: the distance between two Vibroseis in series: 12.5 m.

Based on the above parameters, adequate treatment was performed by Western Geophysics in London.

II..31. The geophysical interpretation of the results obtained

After the interpretation of the seismic lines, a single horizon was recognized, identified and calibrated thanks to a seismic coring of the well OKN02, it is the roof of the lower series.

On medium-quality seismic recordings, the recognition of the lower series was reliable and quite easy, while on poor-quality lines, the monitoring of this series was more difficult and more subjective. The lower series is not a good reflector on most of the region, this is due to the low contrast of acoustic impedance between the Tripas and Paleozoic formations.Very small differences at crossings were observed; their effect is negligible. Several new faults are highlighted thanks to this recent seismic acquisition. The F1 fault already existing on the old interpretation made by BEICIP FRANLAB. Many SW-NE steering faults are highlighted in the same direction as the F1 fault. Another fault, oriented East-West, is of direction perpendicular to the direction of the other faults which are connected to it, thus explaining the shift in depths at the level of the existing wells in this zone.

After having realized the map in isobaths on the roof of the lower series, this one whose degree of reliability is quite satisfactory, made it possible to determine the oil/water contact, which equals to –

3324 m, consequently, the structure of Haoud Berkaoui widens to the structure of Ben Kahla having the same oil-water contact. As a result, the surface impregnated with hydrocarbons is much wider than that defined by the old interpretations. Another flaw and weak closure structure is still detected immediately north of well OKN42, in which oil drilling planning was proposed.

The different formations and faults of the Haoud Berkaoui field are represented in the first seismic profile through the BKP1 well (Figure 20).

II.3.2. Calculation of the release of the two major faults

The two faults are represented in the second seismic profile (Figure 21) We have the average wave speed V = 3400 m/ms.

For fault 1: double time: 2T= 74 ms, so T= 37 ms.

The discharge Z1=V.T= 3400.37= 125.8 m.

For fault 2: double time: 2T= 90 ms, so T= 45 ms.

The discharge Z2=V.T= 3400.45= 153 m.

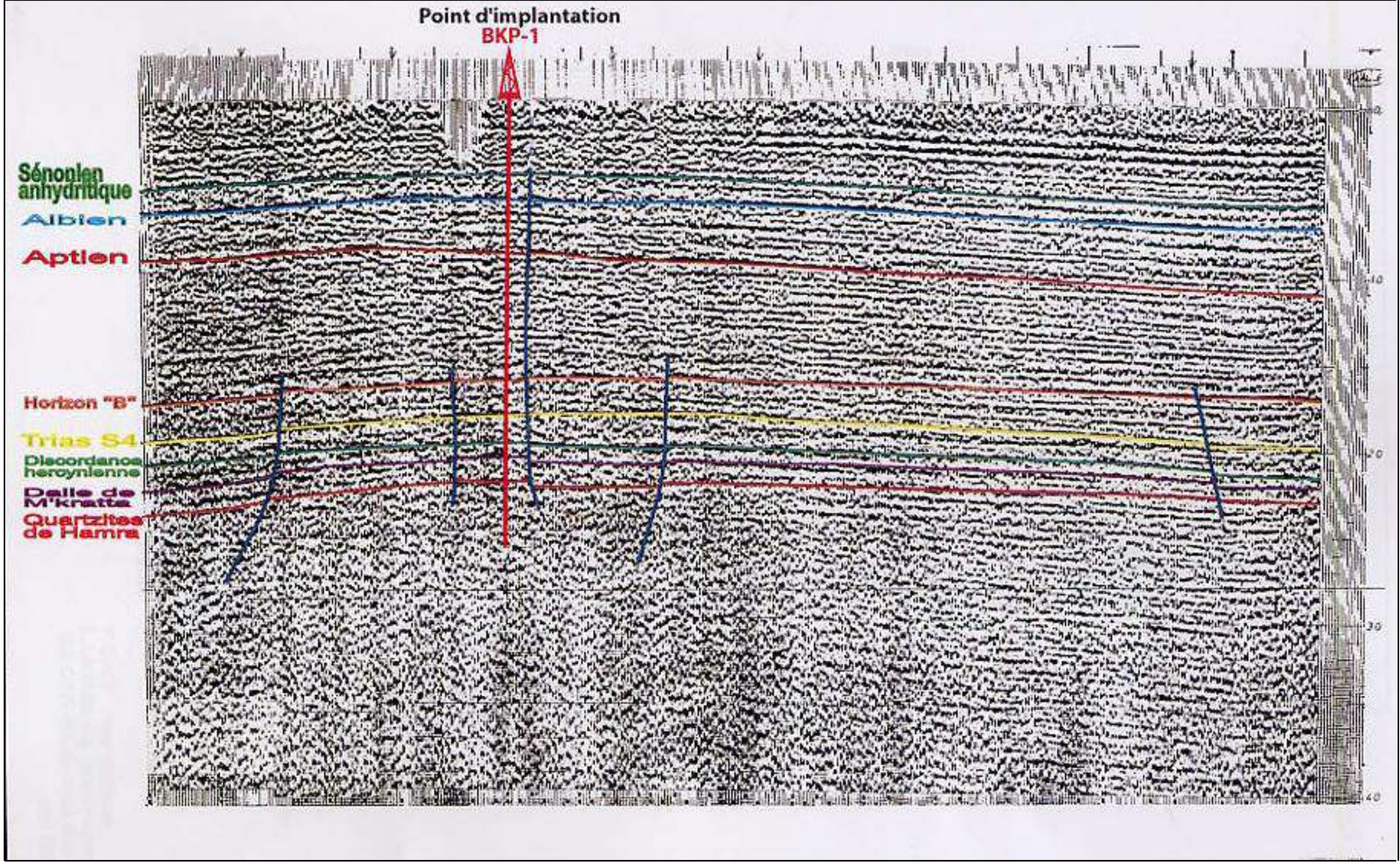


Figure 20 : Seismic profile showing the different formations and faults through the BKP1 well (Haoud Berkaoui field) (Sonatrach/ PED, 2020).

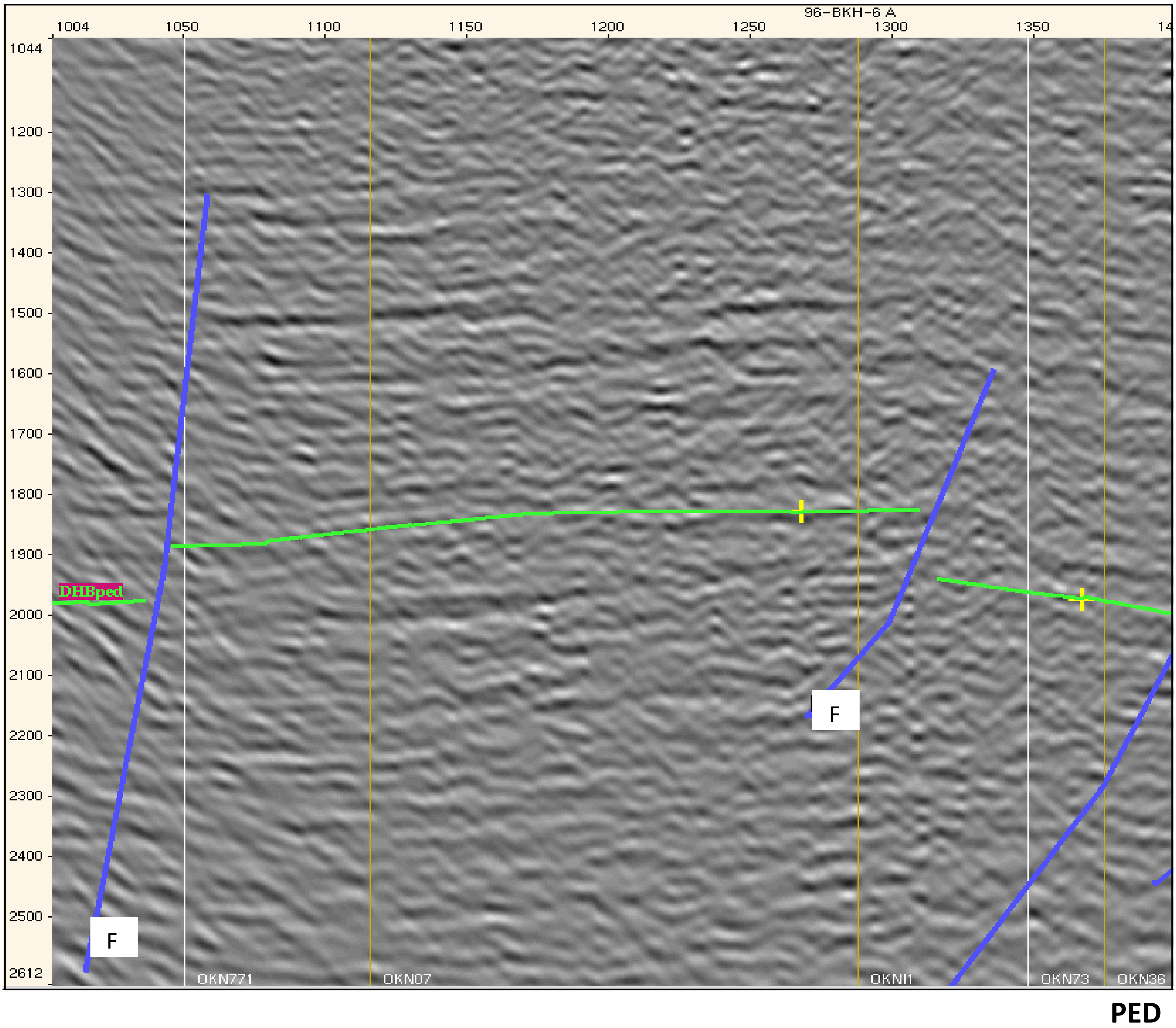


Figure 21 : Seismic profile showing the two major faults (Sonatrach /PED, 2020).

By interpreting the seismic campaign, several new results are highlighted, these results answer the questions already asked, and clarify certain ambiguities.

The most interesting and famous conclusion from this companion is the fact that the structures of Berkaoui and Ben Kahla are connected, since the oil/water contact is the same for both structures, it is therefore very likely that the two structures would be connected.

The surface impregnated with hydrocarbons increases, on the one hand because the oil/ water contact of the two structures already mentioned is the same, and on the other hand because the eastern region of the study, separating the two structures, and which was considered flat and without petroleum interest, is actually a structure with the existence of positive closures.

The differences between the actual depths at the wells, and the values of the curves passing through them, are of the order of 0 to 4 m, which are from a seismic point of view negligible, therefore, the map in isobaths realized is of a very satisfactory degree of reliability. The old faults are confirmed and the new ones are highlighted.

II.4. Drilling and completion architecture

The typical Berkaoui drilling program is divided into five distinct phases (Figure 22):

A- Phase 26"

Drilling in 26" until penetration of about thirty meters in the Sénonien Lagunaire. The fluid, used during the passage of this horizon, is a bentonite mud characterized by a density of 1 to 1.05, a viscosity of 70 to 100 cp and a natural filtrate. An 18"5/8 casing is laid on the bottom and cemented to the surface.

B- Phase 16"

Drilling in 16" until penetration of the Cenomanian of about fifty meters. The fluid, used during the passage of this horizon, is a reverse emulsion mud characterized by a density of 1.2 to 1.25, a viscosity of 45 to 55 cp, a HP HT 6–8 filtrate and a 70/30 H/E. Casing 13"3/8 is laid on the bottom and cemented to the surface.

C- Phase 12"1/4

Drilling in 12"1/4 until penetration of about thirty meters of the Anhydritic Lias.

The fluid, used during the passage of this horizon, is a reverse emulsion slurry characterized by a density of 1.25 to 1.30, a viscosity of 45 to 55 cp, a filter HP HT 6–8 and an H/E of 70/30.

The 9"5/8 casing is laid on the bottom and cemented to the surface.

D- Phase 8"1/2

Drilling in 8"1/2 to the base of the lower clays. The fluid used is a reverse emulsion slurry characterized by a density of 2.02 to 2.05, a viscosity of 45 to 60 cp, a filtrate HP HT 6–8 and an H/E of 90/10. A 7" casing is laid at the base of the lower clays.

E- Phase 6’’

Coring in 6" until the final dimension (about fifty meters in the Siluro-Devonian). The fluid, used during the passage of these two reservoirs, is a reverse emulsion slurry density of 1.30 to 1.48, a viscosity of 45 cp, a filtrate HP HT 6–8 and an H/E of 96/04.Liner 4’1’/2 will be installed at the bottom, anchored in the 7’’ casing and fully cemented. The oil produced is transported to the surface through production tubings of different diameters 3’1/2 or 4’1/2. The choice of tubing depends on the productivity of the well.

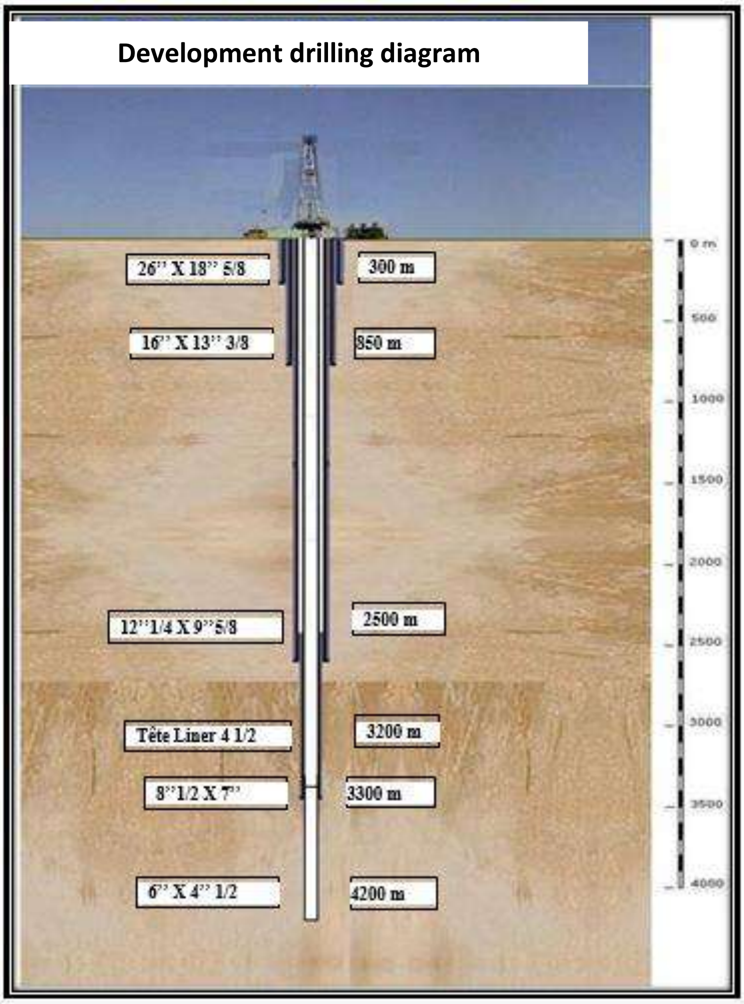


Figure 22 : A diagram of drilling phases of Berkaoui fields (Sonatrach/ EP HBK, 2020).

II.5. Lithostratigraphic appearance

A. Cenozoic

Miopliocène: 0 - 50 m: Formed of alternating red and beige sandstone to abundant, calcareous cement and sandstone limestone with white sand and lightly consolidated sandstone.

B. Mesozoic

Cretaceous: 50 to 1960 m

•**Upper carbonates:** 50 to 210 m: Affected by tertiary erosion, this series of upper carbonates is limited at the top by the Miopliocene discordance. It is mainly composed of white limestones, fine, vacuolar and fossiliferous, with intercalations of yellow limestone, compact, sometimes dolomitic and vacuolar, and beige clay limestone up to 196 m and dolomitic marl at the base.

- **Terminal anhydrite:** 210 to 259 m: Solid white anhydrite with intercalations and gray Dolomitic marl runs.
- **Rolling debris series:** 259-452 m: Alternating white anhydrite, grey dolomitic marl, beige Dolomitic limestone, predominantly green grey dolomitic marl to red brown at the base.

- **Salt Series:** 452-652 m: There are two sets:

452 to 598 m: White to beige solid salt with intercalations of white anhydrite and passed from grey clay to red brown.

598 to 652 m: White to rare massive anhydrite of clay.

- **Turonian:** 652-726 m: Represented by a set of white chalky limestone with brown grey clay limestone.
- **Nomanian:** 726-800 m

726 to 775 m: Composed of alternating white anhydrite and dolomitic grey marl with salt.

775 to 800 m: Intercalations and passes of grey clay and beige dolomite limestone with the presence of salt

- **Albian:** 800-1374 m: Alternating white to beige sandstone, fine to medium, friable to clayey cement, grey green to silto-sandy red brown clay, soft to plastic, slightly dolomitic, with passes of yellow sand, fine to very coarse, subangular to subarrondi poorly classified.
- **Aptian:** 1374-1405 m: Hard beige crystalline dolomite past white, soft dolomite limestone and grey marl.
- **Barrémien:** 1405-1793 m: Alternating yellow sand, fine to coarse, subanguleux to subarrondi poorly classified, from fine red brown grey to coarse argilo carbonate with red brown clay, light grey and soft green to silto-sandy plastic.
- **Neocomian:** 1793 to 1960 m: Red brown clay, green grey, soft to indurated, silto-sandy slightly dolomitic; Past dolomite beige hard crystalline, fine to medium clay sandstone, soft white clay dolomitic limestone and powdery white anhydrite, sometimes hard crystalline. Presence of lignite and gypsum at the base.

Jurassic: 1960 at 2802 m

- **Malm:** 1960 to 2138 m: Green grey and soft red to plastic clay, sometimes sandy, past hard crystalline beige dolomite, fine to medium white sandstone, friable to argilo-carbonate cement. Intercalations of soft to dolomitic grey marl with passes of powdery white anhydrite.
- **Sandstone Dogger:** 2138 to 2343 m: Green and brown grey clay, soft to plastic, sometimes silty, from white to beige limestone, soft to medium hard clayey, grey marl with soft dolomitic green sandstone and hard grey dolomite, traces of powdery white anhydrite.
- **Dogger Lagoon:** 2343-2451 m: Marl and grey clay with green sandstone, soft to indurée dolomitic with intercalations of white anhydrite, crystalline beige dolomite and soft grey white chalky limestone.

- **Anhydritic lias:** 2451-2718 m: Powdery soft white anhydrite, sometimes hard crystalline, intercalations of grey to grey green and soft red to plastic clay, slightly dolomitic of grey dolomite, microcrystalline beige.
- **Salt Binder:** 2718-2779 m: Colourless solid salt, with pasty red brown clay.
- **Lias horizon (B):** 2779-2802 m: Grey to light grey marl with red brown clay trim.

Triassic: 2802 to 3525 m

- **Triassic S1 + S2:** 2802 to 3047 m: Alternating white to grey anhydrite, soft powdery colourless solid salt, sometimes pink and brown clay pasty red saliferous.
- **Triassic S3**: 3047-3,288 m: Colourless, sometimes pink solid salt with fine saliferous grey clay.
- **Upper clays:** 3288-3352 m: Red brown clay, tender to more or less saliferous with fine drifts of colourless solid salt.
- **Triassic S4:** 3352-3,395 m: Red brown clay to pasty grey green, sometimes indurated, saliferous at the base with intercalations of colourless to pink salt.
- **Lower clays:** 3395-3406 m: Red brown clay, sometimes grey-green indurated.
- **Sandstone Triassic T2:** 3406 to 3431 m: Fine sandstone, red brown, compact, hard and micaceous. Also very fine sandstone, light grey with argilo-carbonate cement. Conglomerate with clay elements at the base.
- **Sandstone trials T1:** 3431 to 3460 m: Consisting of:

Red to grey brown clay, dolomitic and silty in places.

Fine grey to red brown sandstone, with ferruginous and carbonated clay cement.

Slightly dolomitic red brown clay.

- **Andesiates:** 3460-3470 m: The Andesiatic series is anisopaque. Dark green andesiate sometimes altered, with many calcite-filled cracks.
- **The lower series :** 3470 to 3519 m, is composed of alternating fine and medium clay, grey and green grey at conglomerate level and red and green brown clay, sometimes dolomitic with intercalations of dolomitic zones with a modified appearance.

C. Paleozoic

- **Gothlandian:** The Gothlandian was the first and only Paleozoic horizon recognized entirely under the Triassic discordance.It is mainly represented by the indurated and silty clay, grey to black, sometimes plastic, with intercalations of fine white sandstone to grey beige.

The radioactive carbonate zone appears from 3653 m. A powerful evaporative series represented by about 1000 m of salt and anhydrite, ranging from Triassic S4 to Lias anhydritic.

In the south of the region, this cover is directly transgressive on the paleozoic substratum, thus ensuring the coverage of the bevels of the different reservoirs of the Triassic.

II.6. The perimeters of Haoud Berkaoui in Ouargla

The Regional Management currently consists of seven perimeters on the territory of the Wilaya of Ouargla (Figure 23):

Haoud-Berkaoui: Trias -T1 and Lower Series reservoirs covering an area of 303 km^2 (J.O of 13 July 2005).

Benkahla: Trias «Lower Series» reservoirs covering an area of 268.56 km^2 (J.O of 13 July 2005).

Guellala: Trias -T1 and Lower Series reservoirs covering an area of 99.06 km^2 (J.O of 13 July 2005).

Benkahla East: Trias «Lower Series» reservoirs covering an area of 102 km^2 (J.O of 13 July 2005).

South Berkaoui: “Lower Series” Triassic Reservoirs covering an area of 23.36 km^2 (N°711/ALNAFT/DEH/2016).

Erg el Arma Nord – Guellala Ouest: "Lower Series" Triassic reservoirs covering an area of 43.70 km^2 (N°712/ALNAFT/DEH/2016).

Berkaoui West – Nechou – Medjbeb: “Lower Series” Triassic Reservoirs covering an area of 110.74 km^2 (N°713/ALNAFT/DEH/2016).

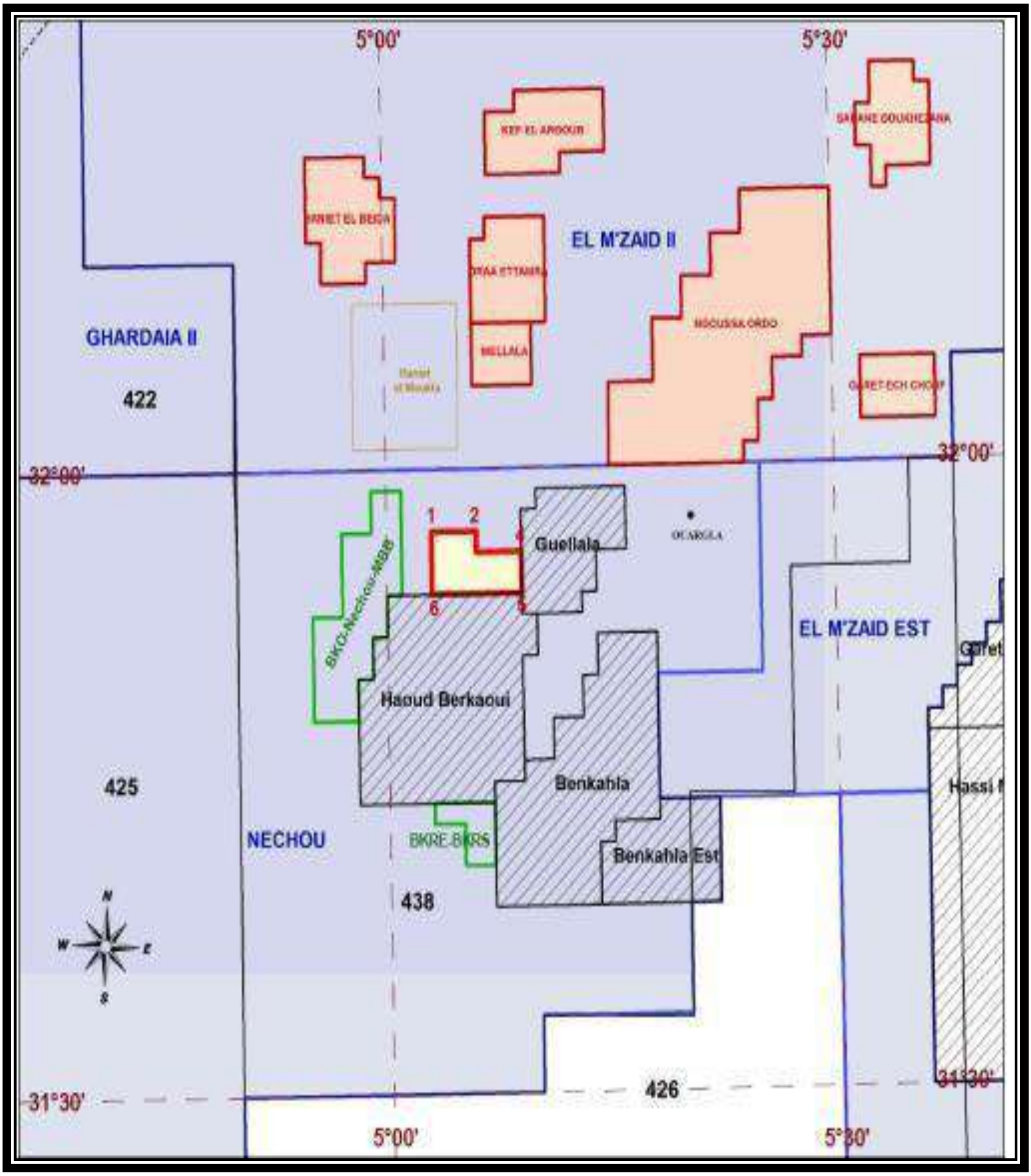


Figure 23: The limits of the surface area of the Haoud Berkaoui region (Sonatrach/ EP HBK, 2020).

II.7. Block 438

Block 438 located in the western part of the Oued Mya basin, and representing the most explored area in this basin. This area lies between the two giant deposits of Hassi R'mel in the Northwest and Hassi Messaoud in the Southeast (Figure 24).

In the Triassic, the primary objective is the Lower Series, while the T1 and T2 reservoirs are a secondary target on a large part of the block.

The Paleozoic objectives are located at a considerable depth, the Lower Devonian is present only in the axis of the Oued Mya furrow and the Ordovician objectives are practically marginal and of little interest.

The exploited fields are listed in the following Table 10:

		Reservoir				
Bloc	**Field**	**T2**	**T1**	**SI**	**QH**	**D**
438 c	Haoud Berkaoui		✓	✓	✓	
	Benkahla			✓		
	Guellala		✓	✓		
	Benkahla-Est	✓		✓		
	Erg El Arma-Nord, Guellala-Ouest, Medjbeb, Nechou-Nord, HBK-Ouest et HBK-Sud		✓	✓		
438 b	Mokhag El Kebach, Haniet El Mokta			✓		
	Kaf El Argoub, Draa Etamra, Garet Echchouf		✓	✓		
	Mellala, Zidane Lakhdar, Bab El Hattabt			✓		
	Haniet El Beida		✓			
	Guellala Nord-Est			✓		✓
	N'goussa		✓	✓		✓
	Sahane-Boukhazana					✓

Table 10 : Representative table of fields exploited in block 438 (Sonatrach/ EP HBK, 2020).

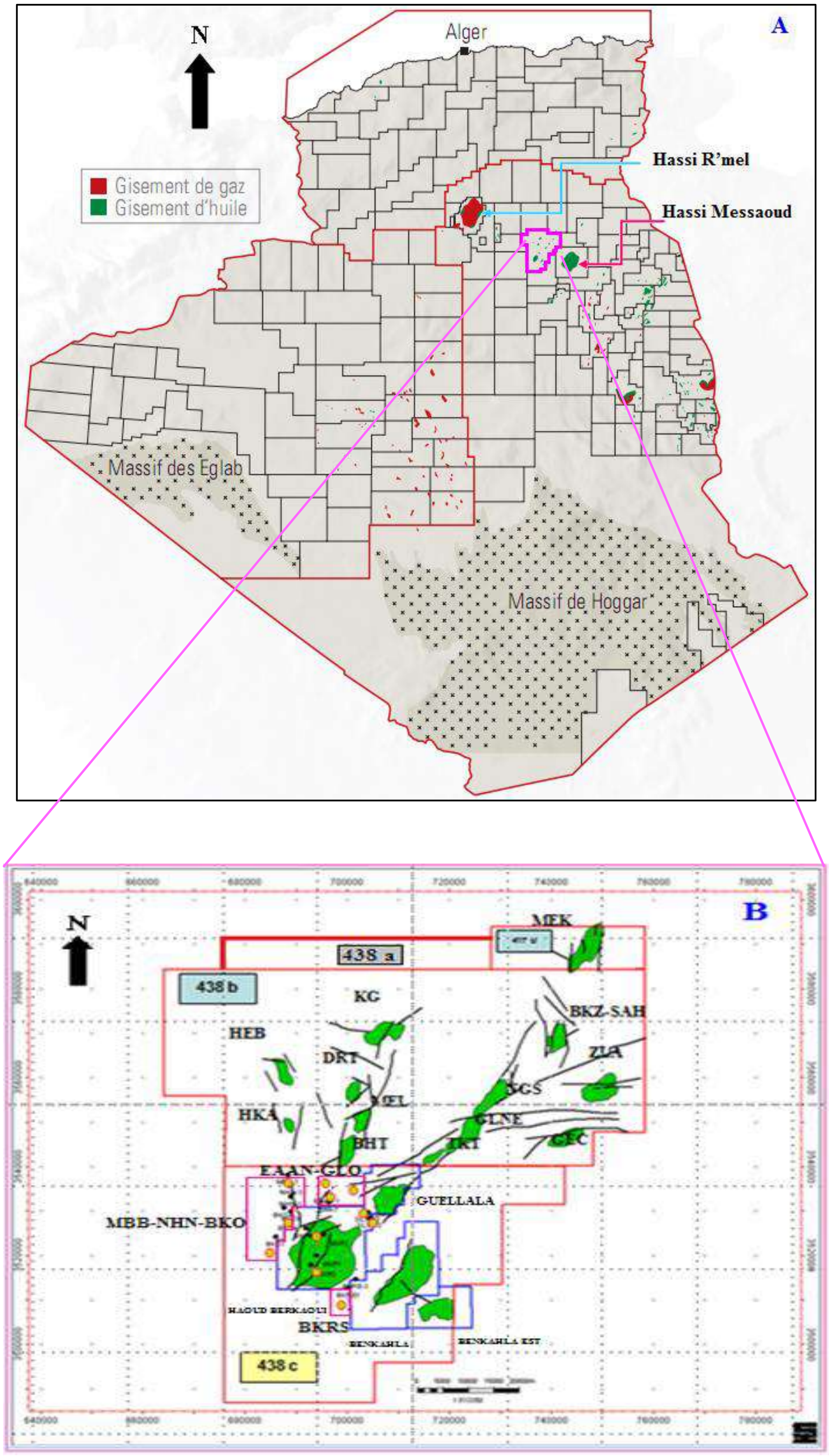


Figure 24 : A. Situation of Block 438 in South-East Algeria ; **B.** Main and peripheral fields in Block 438 (Sonatrach/ EP HBK, 2020).

III. Fields presentation

The region consists mainly of three main fields (Berkaoui, Benkahla, Guellala) and small structures on the periphery. The fields of Haoud-Berkaoui are spread over an area of 6300 km^2, the main ones being:

III.1. Haoud Berkaoui field (HBK)

The Haoud-Berkaoui deposit covers an area of 175 km² with an elevation of 220 m above the mother's level. The field was discovered in 1965 by the "CFPA", by the OK101 survey, over an area of 175 km^2; it was put into production in January 1967, with an average depth of 3350 m.The Tables 11 and 12 show the Berkaoui reservoir initial conditions (TAG) and its petrophysical charactiristics.

The names of the wells for the HBK field are: OKN, OKM, OKJ (HBK).

Currently oil extraction is done naturally (natural depletion) and artificially (gas lift), while citing that the reservoir pressure is maintained by water injection (in some areas).

Haoud-Berkaoui is one of the four main structures in the region of the same name. It is also home to:

1. A production centre.
2. Production and maintenance workshops.
3. Stores and equipment storage areas.
4. An administrative base, headquarters and office.
5. A living base.

Formation	T1/Lower Series
Pi (kgf/cm^3)	518
Pb (kgf/cm^3)	190
Density (^{o}API)	43
GOR (m^3/m^3)	165
Reference depth (m)	-3100
T(^{o}C)	100
WOC (m ss)	-3324

Table 11 : Berkaoui reservoir initial conditions (TAG) (Sonatrach/ EP HBK, 2020).

Formation	T1	Lower Series
H(m)	**24**	**80**
H_u(m)	7.5	25
Φ(%)	8.3	8.8
S_w(%)	25.5	32.7
K(mD)	20.4	56.2

Table 12: Petrophysical charactiristics of Berkoui reservoir (Sonatrach/ EP HBK, 2020).

III.1.1. Stratigraphy subdivision of the reservoir

The depth Triasic sandstone reservoir of Haoud Berkaoui is approximately 3550 m. Different sedimentary accumulation superpose from secondary to quaternaries age. The reservoir is divided into 4 parts subdivision represented on Figure 25.

From the bottom to the top:

- The lower serie (serie inferiors): It is alternative of shall and sandstone formation cemented with dolomite. Formation reservoir thickness is about 50 m.
- The eruptive serie. It is composed with green andesitic volcanic rock. It is almost eroded which create fissure filled with calcite. Formation thickness is about 75 m.
- The Trias "T1": It is composed with tiny sand, brown, hard and cemented with dolomite
- The Trias "T2": It is composed with tiny sand, brown, hard and cemented with dolomite.

These two main stages of regional history lead us to consider two sedimentary megacycles, Paleozoic and Mesozoic, traditionally separated by Hercynian discordance, with the continuity throughout the Paleozoic period of the high zones structuring the Oued Mya basin (WEC Algeria, 2007).

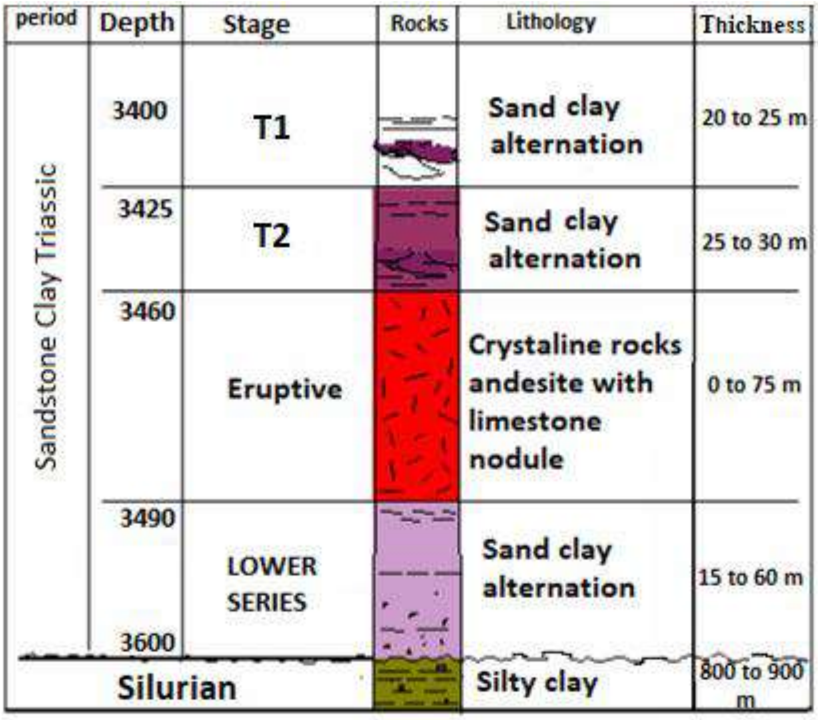


Figure 25 : Reservoirs subdivision of Haoud Berkaoui field (Sonatrach/ EP HBK, 2020).

III.1.2. Reservoir fluid properties

The following Table 13 shows the initial characteristics of Haoud Berkaoui reservoir fluids.

Properties		**Oil**	**Gas**	**Reservoir Water**
B_O initial reservoir pressure (m^3/m^3)		1.46	0.00347	1.04
B_O bubble pressure (m^3/m^3)		1.59	0.00581	-
µ at initial reservoir pressure (cp)		0.337	0.0419	0.76
µ has bubble pressure (cp)		0.245	0.022	-
Compressibility (kg/cm^2)		2.8 e-4	-	0.2494
Residual oil saturation (%)		25%	-	
Density at initial reservoir pressure		0.81	0.81	1.22
The dissolution GOR Rsi/GWR (stm^3/m^3)		165	-	GWR 0.4
PH		-	-	3.2
Saturation pressure		-	-	148
At atmospheric pressure	**Density**	-	-	1.26
	Viscosity	-	-	0.37

Table 13 : Reservoir fluid properties (Sonatrach/ EP HBK, 2020).

III.2. SOUTH BERKAOUI

The South Berkaoui field belongs to the Oued Mya depression, it is located in Bloc438c. Seismic interpretation shows that the South Berkaoui field belongs to the same western trend as Berkaoui and Benkahla.

The structure of South Berkaoui was highlighted in 2011 following the drilling of the South-1 Berkaoui well (BKRS- 1) and the Table 14 shows its petrophysical characteristics. The well was drilled in the southeastern part of the Benkahla mining area, approximately 1.7 Km southeast of the BKRE-2 well and 3.7 Km east of the OKRN-1 well in Block 438C.

III.2.1. Reservoirs

The Lower Series: main objective: Sandstone ensemble with clay siliceous cements at the base and carbonated siliceous clay at the top.

The Intermediate Series: andesitic rocks intra deposition of the Lower Series. Affected by pedogenetic phenomena, its thickness is maximum north of the structure.

The T1: secondary objective: This formation consists of sandstone clay facies, varying in thickness from 20 to 30 m.

The T2: compact reservoir.

Well	Reservoir	Hu(m)	PHI(%)	Sw (%)	VCL(%)
BKRS-1	T1	4,5	6,2	7	7.5
	SI	8.23	9.6	24.7	9

Table 14 : Petrophysical charactistics of the south Berkaoui reservoir (Sonatrach/ EP HBK, 2020).

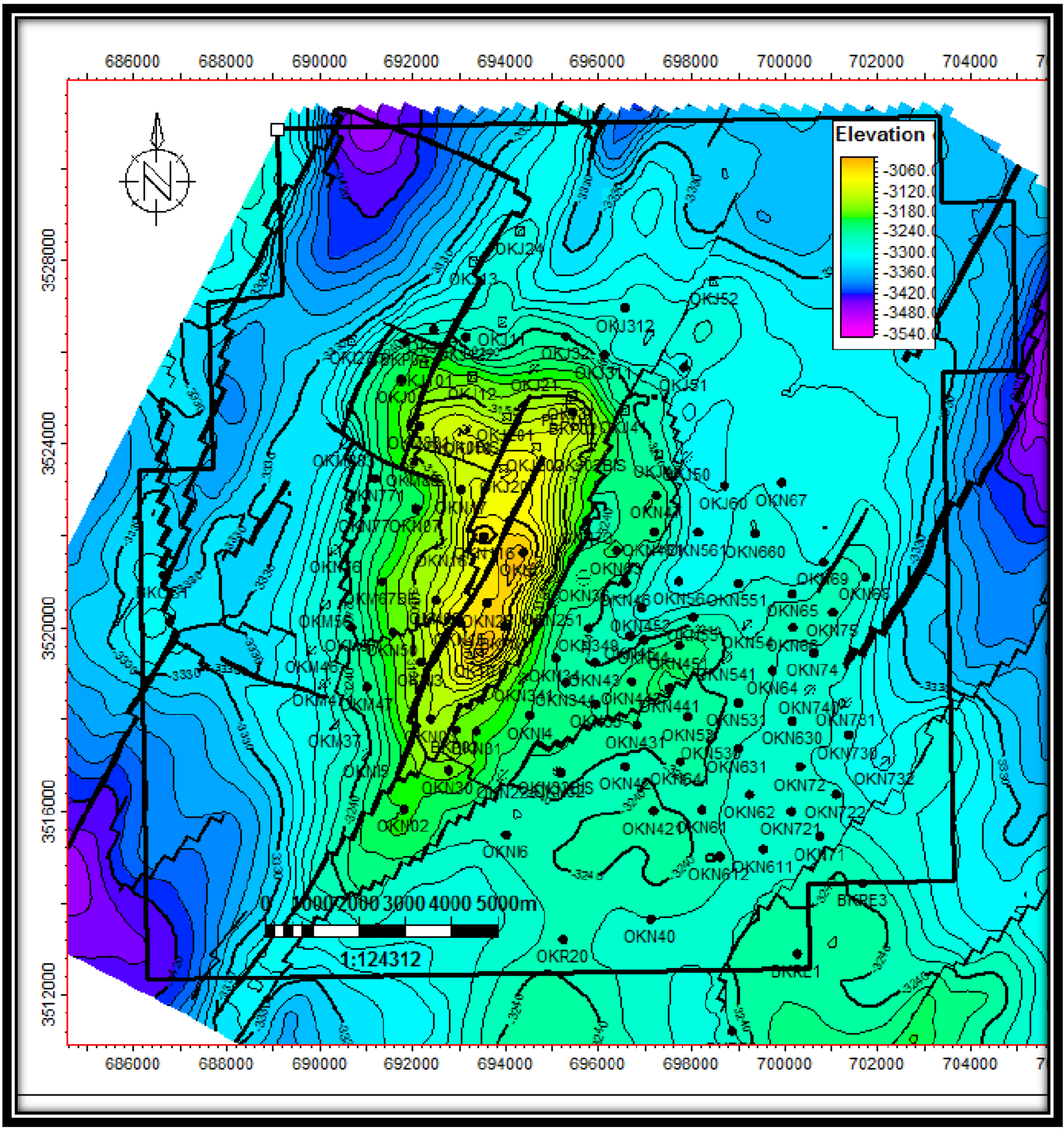


Figure 26 : Isobathe on the roof of Haoud Berkaoui’s Lower Field Series (Sonatrach/ EP HBK, 2020).

III.3. Benkahla field (BKH)

The Benkahla field is located in the southern half of block 438, about 100 Km west of Hassi Messaoud and 30 km southwest of Ouargla.Located in the heart of the Oued Mya depression, this structure has developed in connection with the recent release of old regional accidents oriented Northeast Southwest.The field was discovered in 1967, by drilling the OKP24 well which revealed the existence of oil at the level of the Lower Triassic Series rigs and the Tables 15 and 16 shows its petrophysical characteristics. Benkahla was put into production in May 2, 1967 with reserves of about 86.8 million stm³ of oil. The average depth is 3550 m. It produces by its own reservoir energy helped by pressure maintenance and gas lift.

Benkahla is one of four major structures in the region. It houses:

- A production centre.
- The Benkahla structure was put into production in 1967.
- Water injection began in 1984.
- The start-up of the gas lift began in 1993 from the Guellala UTG.

III.3.1. The reservoirs of Benkahla field:

The Benkahla Clay Sandstone Triassic is divided into four reservoir and non reservoir zones:

***The lower series** (main reservoir): Set sandstone clay, with siliceous cements clay at the base and siliceous clay carbonated at the top.

***The eruptive** (non reservoir): Andesitic rocks intra deposition it of the Lower Series. Affected by pedogenetic phenomena, its thickness is maximum north of the structure.

***The T1** (T1 is absent on this structure, except for OKP1, OKP24, OkS55 and OKT06)

***The T2** (non reservoir): Compact reservoir.

Formation	T1/Lower Series
Pi (kgf/cm^3)	532
Pb (kgf/cm3)	190
Density (°API)	43
GOR (m^3/m^3)	165
Reference depth (m)	-3300
T(°C)	104
WOC (m ss)	-3324

Table 15: Initial conditions of Benkahla reservoir (Sonatrach/ EP HBK, 2020).

H(m)	40
H_u(m)	23
Φ(%)	9
S_w(%)	32
K(mD)	70

Table 16: Petrophysical Charactiristics of Benkahla reservoir (Sonatrach/ EP HBK, 2020).

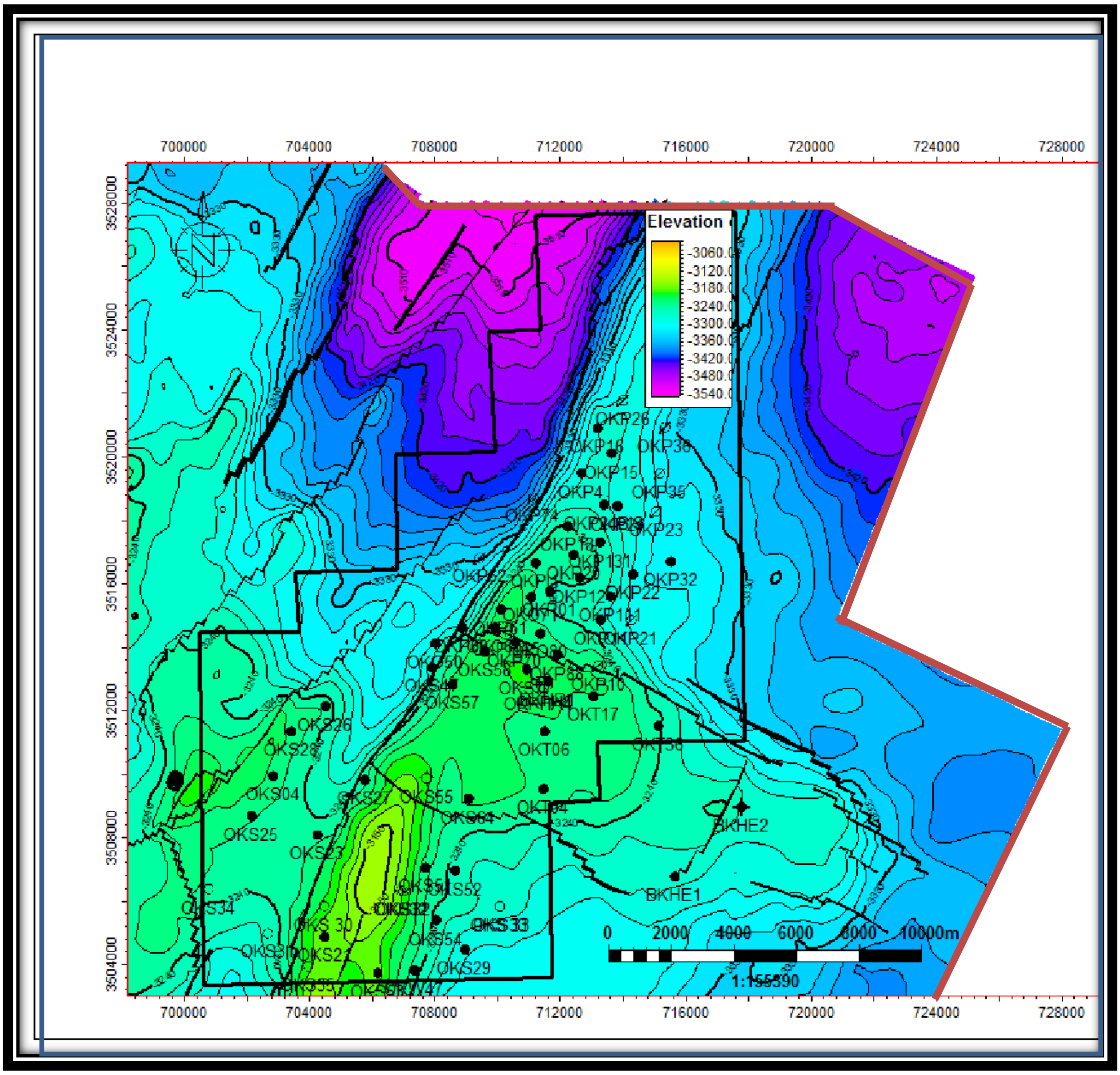


Figure 27 : Isobathe on the roof of the Lower Benkahla Field Series (Sonatrach/ EP HBK, 2020).

III.4. Field of Guellala (GLA)

The Guellala deposit has a surface area of 35 Km² and the oil accumulation of this field was discovered on 28 October 1969 by the drilling of well GLA02 by the company SOPEFAL in Block 438 and the Tables 17 and 18 shows its petrophysical characteristics. The structure of Guellala is a domed anticline, comprising 2 small structures at its center. This anticline is about 9 km long and 7 km wide, an area of 63 km², with a structural closure of 75 m.It was put into production in February 1973, with reserves of 99 million tonnes of oil. The average depth is 3500 m. Its production is assured like Berkaoui and Benkahla.

Water injection began in 1982.

The start-up of the gas lift began in 1993 from the UTG of Guellala.

Guellala is one of the four main structures in the region. It houses:

- A production centre.
- A gas processing plant.
- A fire station.

III.4.1. Reservoirs

The reservoir of the field of Guellala is of Triassic age, it is constituted from bottom to top:

The Lower Series: Main Objective, Sandstone ensemble with clay siliceous cements at the base and carbonated siliceous clay at the top.

The Intermediate Series: Andesitic rocks intra deposition of the Lower Series. It is affected by pedogenetic phenomena, its thickness is maximum at Guellala.

The T1 : Secondary obejective, This formation consists of sandstone clay facies, varying in thickness from 6 m to 15 m.

The T2: Compact reservoir.

Formation	T1	Lower Series
Pi (kgf/cm^3)	533	
Pb (kgf/cm3)	177	185
Density (°API)	43	
GOR (m^3/m^3)	186	197
Reference depth (m)	-3100	
T(°C)	104	
WOC (m ss)	-3370	

Table 17: Initial conditions of Guellala reservoir (Sonatrach/ EP HBK, 2020).

Formation	**T1**	**Lower Series**
H(m)	**15**	**50**
H_u(m)	7	25
Φ(%)	8	9
S_w(%)	25	32
K(mD)	16	230

Table 18: Petrophysical Charactiristics of Guellala reservoir (Sonatrach/ EP HBK, 2020).

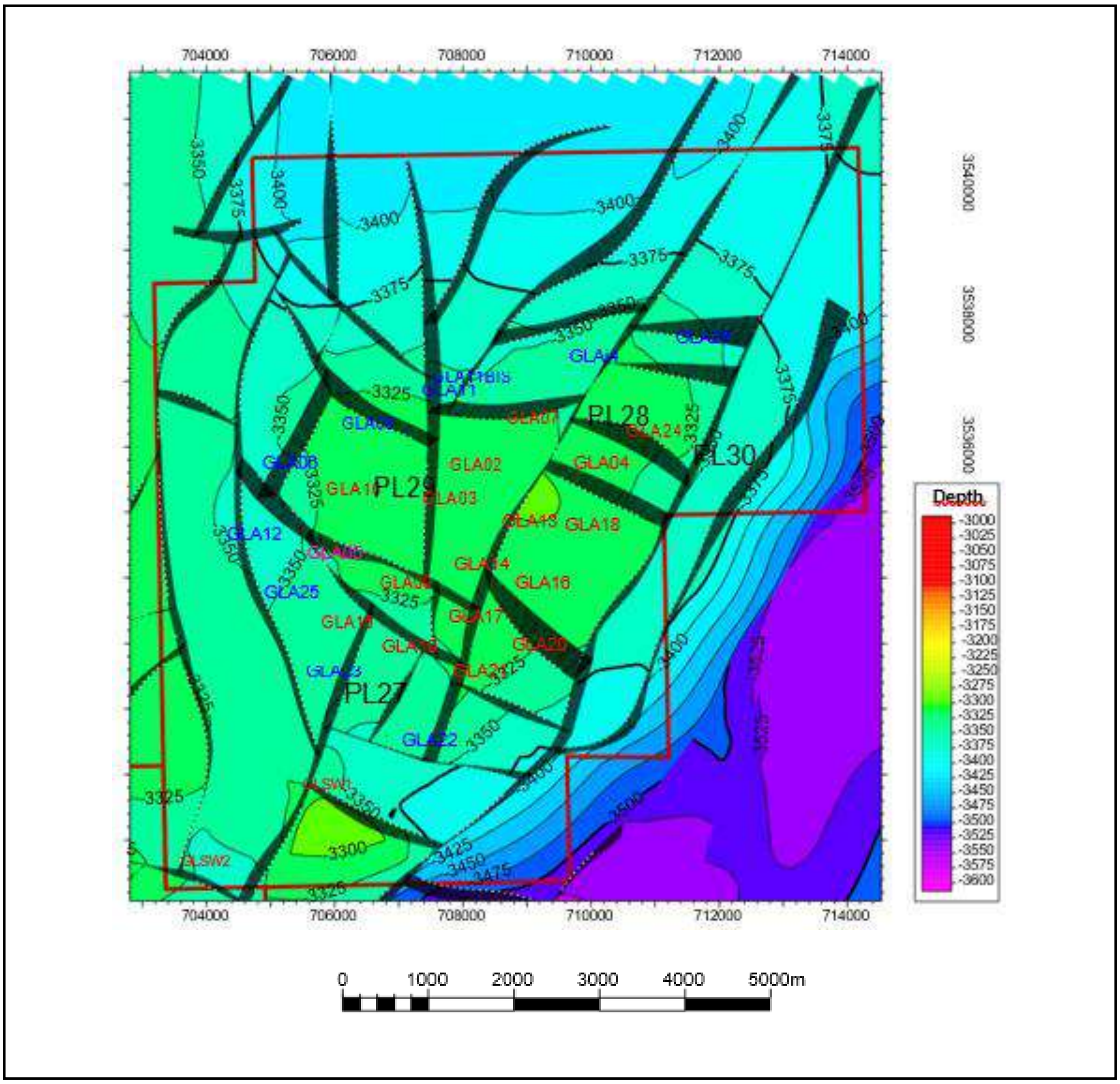


Figure 28 : Isobathe on the roof of the Lower Series of the Guellala field (Sonatrach/ EP HBK, 2020).

III.5. Peripheries

It is composed of more than 10 potatoes. Some wells are produced by natural depletion and others are activated by the gas lift.

Among these small fields we have : N'goussa(N'GS) / Drâa Tamra (DRT)/ Guellala Nord-Est (GLANE)/ Haniet El Beida (HEB)/ Mokh El Kabech(MEK) / Boukhazana (BKZ) / MELLALA (MEL) /BAB EL HATTABET (BHT) / HANIET EL MOKHTA (HKA) …

6-ERG EL ARMA NORD-GUELLALA OUEST.

The field of Guellala West and Erg El Arma belongs to the depression of Oued Mya, it is located in block 438c. The seismic interpretation shows that the EAAN & GLO field belongs to the same western trend as Berkaoui and Guellala.

The "Erg El Arma Nord" structure was discovered in 2007 following the drilling of the Erg El Arma Nord 1 (EAAN1) well for the exploration of the culmination located on the northern part of the Berkaoui/ Erg El Arma Nord trend which is separated from the Berkaoui field by an enselement. The location of the well EAAN1 on the structural axis of Berkaoui/ Erg El Arma is located in blockade 438c. It is located 1.8 km north of the "EAA-1" well borehole. With a total depth of 4280 m, the main reservoirs crossed are the Hamra Quartzite (QH), Lower Series (SI) and Trias (T1) namely that:

- DST #1 (Trias T1, Lower Series), Productive Engineering Test Passed: The test interval between 3544 m and 3559 m of the "SI" reservoir gave the following results on a Duse of 32/64 : Oil flow = 20 m^3/h; GOR = 124 m^3/m^3; Head pressure = 2210 psi; Oil density = 0.81.
- DST #2 (QH), test technically passed non-productive
- DST #3 (SI), technically passed productive test

The drilling of the EAAN2 well in 2010 in the «Erg El Arma Nord» structure passed through the main reservoirs of the Trias (T1), Lower Series (SI) and Quartzite de Hamra (QH) until reaching the total depth of 4325 m TVD. The results of the tests carried out on these reservoirs show that:

- DSTn°1 Trias (T1), technically passed test, productive oil and gas well with an average oil flow of 4.15 m^3/h and an average gas flow of 718.06 m^3/h.
- DSTn°2 Ordovician "Hamra Quartzites" Technically unsuccessful test (BHA DST leak).
- DSTn°3 Trias Lower Series Technically Passed Test, Oil Production Well, Non-Explosive

The «Guellala Ouest» structure was discovered in 2010 following the drilling of the Guellala Ouest 1 (GLO 1) well in the northern part of the Haoud Berkaoui mining area. With a total depth of 4320 m, the main reservoirs Hamra Quartzites (QH), Lower Series (SI) and Trias (T1) were crossed.

The QH reservoir was compact, while the SI reservoir is hydrocarbon. The oil-water contact is at 3585 m.

The test interval between 3562 m and 3585 m of the «SI» reservoir gave the following results on a Duse of 32/64 : Oil flow = 7.2 m^3/h; GOR = 109 m^3/m^3; Head pressure = 419 psi; Oil density = 0.882. The Table 19 shows petrophysical characteristics of some wells.

Well	Reservoir	Hu(m)	PHI(%)	S_W (%)	VCL(%)
EAAN-1	**QH**	Tight			
EAAN-2	**T1**	12.34	9.5	24	15
	SI	1.37	8.7	43	13.2
GLO-1	**SI**	5.89	10.3	27	9.4

Table 19 : Petrophysical characteristics of the erg EL ARMA reservoir North-Guellala West (Sonatrach/ EP HBK, 2020).

III.6. Berkaoui West – Nechou - Medjbeb

The West Berkaoui field belongs to the Oued Mya depression, it is located in block 438c. Seismic interpretation shows that the West Berkaoui fields belong to the same western trend as Berkaoui and Guellala.

- The Berkaoui West structure was discovered by the first drilling of well BKO1 in 2001 which was put into production on 22/07/2003, it crossed the Triassic reservoir «T1» on the interval 3504.00 m @ 3511.50 m and 3514 m @ 3524 m, for a total thickness of 17.5 m. The test gave 3.35 m^3/h of oil and 747 m^3/h of gas. The Triassic of the lower series was recognized aquifer, it was encountered lower than the water body -3324 m. Currently the well is closed due to head pressure equalization with line pressure.
- A second BKO2bis well was drilled in 2004, 5.5 km from BKO1. The well encountered a total loss problem, it was abandoned on 23-12-2004 at dimension 427 m and showed that the structure is high, which justified the drilling of several delineation wells BKO3-NHN1-BKO4-BKO5-BKO6-NHN2-NHN3-BKOS1-NHN4 on this high axis. The BKO3 well was drilled in 2005 with the aim of exploring the Triassic reservoirs on the high axis Berkaoui – Nechou. Located west of the Berkaoui field, this well began production in January 2009. At its first DST in the Lower Series reservoir the initial flow was Qi = 23.6 m^3/h. Next, the drilling of the NHN1 well located northwest of block 438c of the El M'zaid permit, and west of the Berkaoui field. The purpose of this drilling is to explore the high axis Berkaoui West Nachou. This well is located at approximately the same structural level in the "T1" as well BKO3. The NHN1 well gave a flow of 6.38 m^3/h in the Ordovician (QH/GA).

• Well BKO4 was drilled in 2007 and is currently closed to explore deep reservoirs.

• Then comes the drilling of well BKO5 for the delineation of the oil accumulation encountered in the Trias «T1» and Lower Series.

• Well BKO6 is located 1.66 km northwest of BKO3 and 1.57 km southwest of BKO5. It is approximately 5 km south of well NH1. The prospect of this well falls within the framework of delineation of the western part of the Berkaoui field. It aims to explore the Triassic and Ordovician reservoirs.

• The NHN2 well was drilled in 2008, is located about 5 km northwest of the NHN1 well and 7 km north of BKO3. The purpose of this drilling is to confirm the hydrocarbon potential of the West Berkaoui structure. Test results show that the Ordovician reservoir is non-productive and that the Lower Series is aquifer.

• The NHN3 well drilled in 2008, located 2.5 km north of the NHN1 well, and 1 km west of the NHN2 well, was designed to confirm the proven reserves after the NHN1 well was drilled by a northward delineation. The test on a 32/64' Duse in the Lower Series between the interval 3534 m and 3557 m gave 14.48 m^3/h of oil and a GOR of 190 m^3/m^3. This well was put into production in 2013.

•The purpose of drilling the BKOS1 well in 2008 was to explore the Triassic and Ordovician reservoirs on the western flank of the Berkaoui deposit and south of BKO1. Test results show that the Ordovician reservoir and Lower Series are aquifer.

•The MBB1 hole drilled in 2008, aimed at the delineation of the Triassic reservoirs (T1, Lower Series) and Hamra Quartzites. The DST gave an oil flow of 2.21 m^3/h and head pressure 9 kg/cm^2 in the T1. Currently, this well is closed due to its low head pressure.

•The BKOS2 well drilled in 2011, located in a favourable oil environment, is located west of the Berkaoui field (block 438c), about 5Km south of the BKOS1 well. It aims to delineate the Triassic reservoir (T1), and to explore the Ordovician reservoirs however both reservoirs have been tested in water.

*The last well in the structure is the Nechou North 4 (NHN4) well drilled in 2011, in the western part of the Haoud Berkaoui region, it is part of the delineation of the western flank of the northern zone and the Hamra Quartzites. With a total depth of 4268 m, the T1 was tested with hydrocarbons in the range 3488 m and 3506 m on a Duse of 32/64 " with an oil flow of 17.3 m^3/h and a GOR of 246 m^3/m^3. The Table 20 shows petrophysical characteristics of some wells.

Well	Reservoir	Hu(m)	PHI(%)	S_W (%)
NHN-4	T1	16	8	30
NHN-3	T1	10	6	16
	SI	7	10	17
BKO-3	SI	9.6	9	24

Table 20 : Petrophysical characteristics of the Berkaoui reservoir West- Nechou-Medjbeb (Sonatrach/ EP HBK, 2020).

IV. Most frequent damage in Haoud- Berkaoui

Among the most common damages in Haoud-Berkaoui are:

IV.1. Salt deposits: salt has been one of the main exploitation problems since the beginning of the Haoud-Berkaoui field. The change in pressure and temperature during production causes the salts to precipitate. These salts are essentially sodium chlorides (NaCl) with a distribution of 2/3 NaCl and 1/3 other salts. Despite the continuous injection of water by concentrics and frequent scratching by the Wire-Line, the salts continue to precipitate causing the total closure of the wells.

IV.2. Organic deposits: Small quantities of asphalt have been found in wells since production. These deposits are deposited in the tubing and even in the porous medium.

IV.3. Migration of fines: during production, when the chosen flow rate is large and the flow is turbulent, the migration of fine particles occurs (clay, sand, etc.) from the formation towards the well approaches causing a clogging of the perforations hence the decrease of the productivity.

IV.4. Drop in reservoir pressure: the reservoir pressure of the Haoud- Berkaoui field keeps falling. Despite attempts to maintain pressure that was not felt on all wells. This pressure drop favours deposits of salt, paraffins and asphalt. As a result, the majority of the wells are made of gas-lift.

IV.5. Sealing due to drilling: the presence of certain products in the drilling mud can cause the formation of emulsions. Due to the hydrostatic pressure, the sludge filtrate tends to enter the reservoir and the solid particles settle on the well wall as cake.

IV.6. Water inlets: premature inflows of injection or formation water are observed in some wells, which has led to the clogging of some perforations. This increased the skin due to partial penetration.

IV.7. Work-Over and snubbing fluids: generally, there is always formation of an emulsion, change of wettability and clogging of the perforations as a result of the invasion of the formation by the fluids of Work- Over and snubbing.

IV.8. Clogging after stimulation: more damage to the formation may occur as a result of poor choice of acid type and additives. This clogging results in the products of secondary reactions.

V. Causes of damage in Haoud Berkaoui fields

The history of the well is essential for the diagnosis of damage. The well can be damaged during:

V.1. During Drilling

The main cause of well plugging in the Haoud Berkaoui fields is the drilling itself. During well drilling, two cases are present:

- Cases where casing 7 is laid in andesite: in this case the T1 is devoid of petroleum interest. Phase 8 1/2 is drilled with a high density sludge (1.95 to 2) due to the high pressure of the horizon B. However, it happens that the brittle T1 sandstones do not support the pressure exerted, which causes losses of sludge, hence the need to install the casing 7 in the clay part of T2.
- Drilling of the two T1 and SI reservoirs at the same time: despite the significant pressure difference

between the two T1 and SI reservoirs, they were often drilled at the same time. To avoid problems during drilling, the SI must be drilled with a low-density sludge (0.90 to 1) that is adapted to its pressure. The T1, andesite and intercalary clays of the ID cause friction or entrapment, hence the solution taken each time is the increase in density, which unfortunately leads to clogging of the main reservoir.

At the end of the phase the well is received with a serious problem due to the damage caused by the drilling mud.

- **Drill fluid solids invasion**

Particulate materials (clays, cuttings, heaving agents, and circulation loss additives) contained in the drilling fluid are potentially damaging.

Embedded in the pay zone, they fill the formation pores, causing a reduction in permeability. This process is limited to a few inches around the well walls .

- **Borehole filtrate invasion**

The liquid phase of the sludge contains variable types of positive and negative ions and surfactants. They are forced into porous areas by differential pressure, moving or mixing with some of the blank reservoir fluids.

This can create clogging due to one or more mechanisms that can reduce the absolute permeability of the porous medium, or reduce the flow due to relative permeability or viscosity effect.

The increase in water saturation causes waterblocking or else reduces the relative permeability of the hydrocarbon by causing a viscous emulsion.

Particle migration effects include hydration or dehydration of clays, dispersion or flocculation of clays that are strongly or slightly inflatable.

V.2. During cementation

The aqueous slag filtrate + cement solid particles are likely to cause the same damage as that of the drilling fluid.

Ensuring a high pH value of cement slag is harmful to clay minerals. Also in contact with brines it can cause precipitation of calcium carbonate. Finally a water blockage can be caused when there is an excessive amount of open water.

V.3. During Perforation

Perforations can be plugged with debris and solids of the completion fluid;

The formation around the perforation is crushed and compacted by the process. This zone has an average thickness of 0.5 in, its permeability can be reduced to 80 % .

V.4. Well Neutralization Damage

Typical damage variants caused during Completion, snubbing and Work-over induce:

a weakening of the permeability of perforation formation and productivity by suspension of solids, bacteria and polymer residues.

Common problems resulting from filtrate invasion (swelling, dispersion, water block, emulsion and mineral deposits).

V.5. Damage in the gravel pack

The major sources of this type of damage included: the wrong location of the gravel pack, its pollution, its inadequate dimensions.

V.6. Damage During Initiation of Production

It can be:

*Caused by the incompatibility of completion fluid with formation fluid. Brines used for density may precipitate in contact with the forming brine;

*Due to cleaning of the high flow well which can cause severe blockages in the formation by free particles;

V.7. Bridging due to stimulation and fluid injection

In the case of acidification, the damage is caused by the secondary reactions of the chosen acid and its additives as a result of their poor choice or incomplete or delayed evacuation.

The injection of fluids incompatible with formation fluids such as desalination water caused little various precipitated mineral, organic.

Conclusion

Haoud Berkaoui in Oued Mya basin is one of the important productive regions of oil in Algeria but the repetetive damage around the wellbore area due to many operations in different wells needs to look for more comprehensive study of its origin, its location and the through the history of wells and diverse laboratory tests to understand more all the chemical reactions to find out the best way to treat and eliminate this damage using the best acid system with the suitable additives to avoid mineral and organic deposits.

Chapter III

Matrix acidizing technique and laboratory tests

Introduction

In order to increase the flow rate of oil and gas wells and eliminate the damage around the wellbore region. Matrix acidizing is one of the most common stimulation techniques used for that reason using Coiled Tubing (CT) which is considered as one of the most adaptable and flexible technology. The speed and convenience of Coiled Tubing has been used to provide benefit to well productivity in different applications. Some common applications of CT are the fracturing, well testing, unloading of the well, acidizing, scale milling and other intervention activities.

Martix acidizing technique is not sufficient to ensure the oil productivity enhancement. Different laboratory tests are also important in order to: know the detailed composition of the reservoir , evaluate the skin factor, check the performance each acid system, choose the best one for maximum oil recovery, avoid bad economic results and to increase the percentage of success of this operation in the future.

I. Haoud Berkaoui main reservoir damage analysis

The liquid phase of the sludge contains damaging components. And since the filtrate can reach more than 5 m (15 ft) depth, the damage caused by the filtrate is probably the most important cause of the production drop.

**** Drilling program applied to HBK**

Since the Lias needs to be drilled with a sludge density of 2.0 up to 2.05 to prevent problems during drilling:

*Of swelling of clays;

*Calcium chlorinated waters from Horizon B.

Two types of well architecture were followed.

Case 1: Installing 7’ on the roof of the eruptive rocks (andesite) (Old program)

There the zones T1 and T2 are drilled with the same density of mud of the inflating clays and the Horizon B (d = 2.02-2.05), this equivalent density causes a fracturing of these formations, followed by a total loss at the level of T1, because this sequence has a set of cracks. This will cause a drop in the hydrostatic level which will cause a huge economic loss.

Case 2: Install 7’ to T2 roof (new program)

In order to achieve the loss damage, the T1 and T2 are drilled in the same phase with the lower series and the eruptive, and the fact that the pressure of T1 sometimes exceeding 500 kgf/cm² (up to 530 kgf/cm²) we are therefore obliged to drill with a mud of density equal to 1.47-1.48, in order to achieve the risk of uncontrollable arrival.

However, this density of mud will cause damage to the lower series which represents only 200 to 230 kgf/cm^2 of pore pressure. The damage to the reservoir is caused by the filtration of the sludge due to the difference in pressure between the bottom and the reservoir.

The Table 21 below summarises the differential pressures on the lower series layer for some wells drilled:

Well	**d_b**	**P_h (kg/cm^2)**	**P_p (kg/cm^2)**	**P (kg/cm^2)**
OKN 611	1,47	419,59	271,94	147,65
BKRE 1	1,52	517,02	338,74	178,28
OKJ 312	1,49	515,21	313,19	202,02
OKN 68	1,48	535,89	306,04	229,85
OKN 75	1,48	506,87	250,00	256,87
OKJ 311	1,48	530,64	258,35	272,30
OKN 722	1,48	510,32	210,00	300,32
OKN 61	1,49	520,38	175,16	345,22

Table 21: The differential pressures on the Lower Series layer (Sonatrach/ EP HBK, 2020).

II. Evaluation of the skin factor by the method of pressure build-up

There are several techniques for evaluating the skin factor with the use of well testing because the impact of damage on the well's properties might be significant. When selecting a technique for stimulation and contaminant removal in the bottom zone, it is crucial to comprehend the effects of skin component (Mahesh CP, 2016).

An analysis of the well's characteristic inflows can be done using a steady flow rate and pressure build up during the closure time. Data on pressure build up that is a function of time can be displayed on the graph. Dr. Horner (Figure 29) created a method to determine the skin factor of data recovery pressure of the oil well in the early 1950s.

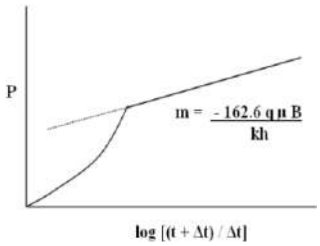


Figure 29 : Horner Plot (Patel and Singh 2016).

From the diagram of pressure as a function of log [(t + Δt) / Δt], the slope **m** (equation 18)is a function of the steady flow rate **q**, the viscosity of reservoir fluid, volume factor **B** and capacity reservoir **kh**. By determining the constant angle, the total skin factor **S** can be calculated using the Equation 17 and 18 of Van Everdingen and Hurst

$$S_{total} = \frac{P_{1hr} - P_{wf}}{m} - \log\frac{K}{\varphi\mu\, c\, r_w^2} + 3.23 \qquad (17)$$

Where:

$P_{1\,hr}$: extrapolated value of the pressure for t =1 hour from the chart Horner

P_{wf}: bottomhole pressure during the test

m: slope of the curve in the diagram Horner

k: the effective permeability, calculated from from the slope

c: compressibility of the liquid

r_w:well radius

φ: Porosity

μ: the viscosity of reservoir fluid

$$m = -\frac{162.6\, q\, \mu\, B}{Kh} \qquad (18)$$

where:

q: flow rate steady viscosity of the liquid

B: volume factor

kh: capacity of the reservoir

k : effective permeability

h: height of the productive interval

μ : viscosity of the liquid

III. Design Methodology of matrix acidizing

Candidate selection, damage characterization, treating fluid/additive selection, treating fluid volume determination, determining the maximum injection rate/surface pressure, and placement strategy are some of the steps that make up the matrix treatment design methodology (Thomas RL 1998).

III.1. Advantages of Coiled Tubing

Fast running into and pulling out of holes saves both time and money. It has the ability to pump fluid as well as transport downhole tools. These are its main advantages. Additionally, compared to other fluid injecting equipment, it is a small unit with a short rig up and rig down time (Khan et Mian.T, 2015).

Benefits of employment in CT include:

1. Safe and effective interventions for well-being (live)
2. Site preparation is required less effectively
3. Simple to rig up and move around
4. Circulation can continue during RIH/POOH
5. Production downtime is decreased as a result of shorter travel distances
6. Reduced risks and negative environmental effects compared to traditional methods.
7. Less crew or personnel are required for the work
8. Decreased prices.

III.2. Why Acidizing through Coiled Tubing ?

*Performing the treatment through CT avoids exposing the wellhead or completion tubulars to direct contact with corrosive treatment fluids.

*CT movement provides the ability to accurately place small volumes of acid. Spotting the treatment fluid with CT will help to ensure complete coverage of the interval.

*The CT pressure control equipment configuration allows the treatment to be performed on a live well. The potential formation damage associated with well killing operation and the corresponding

loss of production time are thereby avoided.

*Jetting effect is something that can be effective in smaller casings and provided that a proper purpose built nozzle is used. This cannot be achieved with conventional techniques.

*It is imperative, in many matrix treatments, to perform the well flow back as soon as possible after the acid job.

*Spotting the treatment fluid also avoids the need to bullhead wellbore fluids into the formation ahead of the treatment.

*Long intervals can be more effectively treated using techniques and tools that have been developed for use with CT, This is particularly important in horizontal wellbores.

III.3. Equipments of Coiled Tubing for matrix acidizing (Mian Tauseef Raza 2015)

A coiled tubing unit's main parts include the control cabin, power pack, injector head, coiled tubing reel, and pressure control equipment (Figure 30). The energy source for all machinery and operations is the power pack. In order for the CT unit to operate and function, it supplies hydraulic energy. Additionally, it has diesel engines that power hydraulic pumps that supply each component with the necessary pressure energy and flow rate. A CT unit's control cabin serves as its command center. It includes the clutches, gears, and other equipment needed to monitor and manage job performance. The coiled tubing reel is spooled with CT string. It greatly simplifies the storage and transportation of CT string. The injector head supplies energy when the CT is injected into the well, and the same is true when the CT is being retrieved. A tension in the string is required for the proper spooling onto the reel and the smooth feeding of CT. A pair of opposingly driven endless chains makes up an injector head. Chains are mounted with gripper blocks, tubing outer diameter size series of grippers, for better grip. Between the opposingly pressed chains, tubing is held in place. This system is in charge of supporting the entire weight of the CT string inside the wellbore. Hydraulic motors are used to drive the chains in order to run or retrieve the tubing. Pressure control equipment (Figure 31) includes the BOP stack and stripper. During run in, the stripper ensures a pressure seal in a dynamic string environment.

Figure 30 : Coiled Tubing unit of Schlumberger Company.

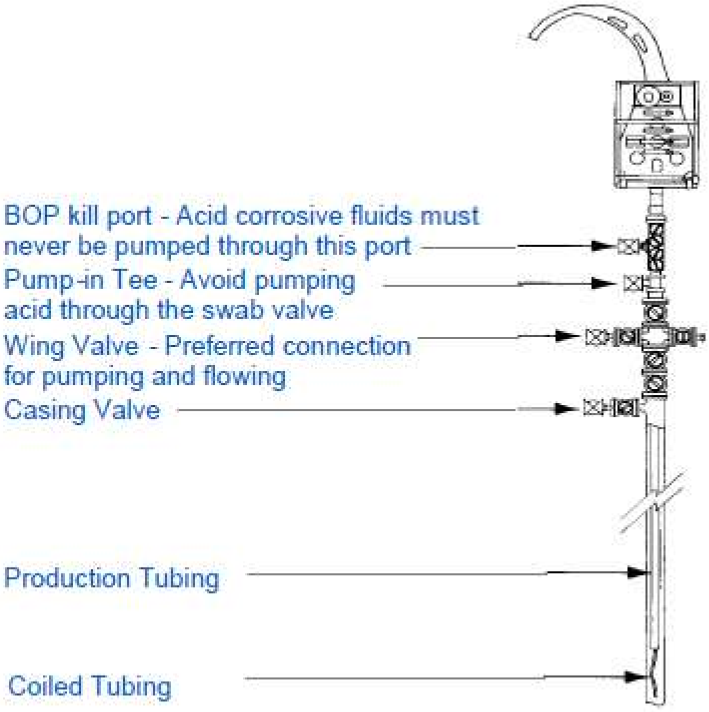


Figure 31 : Pressure Control Equipment Configuration (Pratap 2005).

III.4. Candidate wells selection

The engineering exercise of the decision process for well stimulation requires considerable knowledge of many diverse processes. The process of candidate selection consists of identifying wells delivery. To have an idea about well production, it is important to follow candidate selection advisor (Figure 32):

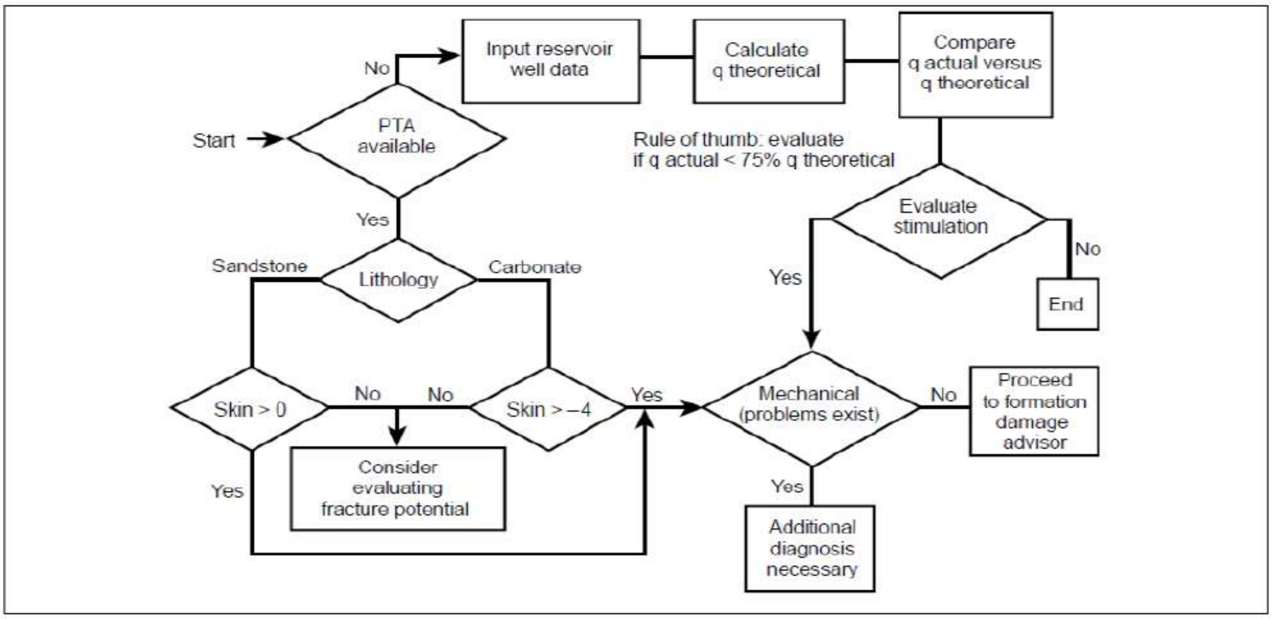


Figure 32 : Candidate selection advisors (CSA) (Sonatrach/ EP HBK, 2020).

Build up test required to quantify several parameters such us permeability, skin and current reservoir pressure…, “but sometimes well test data are not available”. When build up test is done, systems analysis can be performed with perform software to:

- Match current production or bottomhole flowing pressure;

- Calibrate the reservoir net pay, permeability, average reservoir pressure, skin effect.

- The key is to calibrate the system to forecast production on the basis of various stimulation scenarios (perform software).

• Skin is the most important parameter to make decision about near well bore damage if:

- Skin is negative: there is not near wellbore damage;

- Skin is positive: we can assume that near wellbore is damaged, but we have to assess mechanical skin caused by tubing size and other restriction.

• When we have huge pressure drop between reservoir pressure and well flowing pressure.

• Production logging tool to identify participation of each interval (at perforation level).with this new technology we can estimate and locate position of damaging zones.

III.5. Typical operation procedure

The operation is done in two successive days tube clan and matrix acidizing:

A. Tube clean (First day)

In first day treatment, they performed tube clean treatment or wellbore cleanup which is commonly used to remove scale, paraffin or other materials from the perforation and liner by using jetting nozzle. These treatments normally use acid or solvent systems that are placed in the wellbore. The operation is done as follow:

- Verifying connection types for wellhead in advance of the job.
- Establish equipment on site and rig up treating lines.
- It is obliged to hold pre-job safety meeting ensure all personnel are present;
- Make up standard jetting tool to the coiled tubing and connector.
- Rig up adapter flange and CT injector on well head.
- Flush coil with treated water and leave filled for pressure testing and RIH.
- Pressure test equipment and lines to 5000 psi for 10 minutes with treated water and wellhead valves then pressure up the annulus as follows: 7" x 3-1/2" to 1200 psi and 9”5/8x7” to 500 psi (recording the pressure).
- With well rigged up, open well to permit returns to flare line
- Run in hole coil tubing to Top Sediment with pumping treated water at 0.3 bbl/min and nitrogen at 500 scf/min

- Perform a regular weight checks while running each 500 m.
- Run slowly coil tubing while reach restriction.
- Increase the rate of treated water, when passing through the restriction.

- When coil tubing jetting element a 10 m above top sediment, reduce the coiled tubing speed and increase treated water pump rate to 0.8 bbl/min, nitrogen at 400 scf/min
- Pull out (POOH) to top of perforations and make jetting with 7.5 % HCl and treated water across perforation interval.
- When coil tubing jetting element (CT) at bottom pump 2 m^3 of gel, followed by treated water followed with quick flow back
- Once all treatment fluids flowed back, POOH CT to surface.
- Close the well, flush the CT with soda ash followed by fresh water and displaced with Nitrogen liquid, Rig down equipment and secure wellhead.

B. Matrix treatment (second day)

In second day, matrix stimulation treatments are injecting acid fluids below fracturing pressure down with coiled tubing usually include a sequence of several fluids. A minimal treatment consists of a preflush stage with a no damaging, nonreactive fluid to establish an injection rate, a stage of the main treating fluid and an overflush stage to clear the main treatment fluid out of the coiled tubing and displace it into the near-wellbore area. The operation procedure is operated as follow:

- Hold pre-job safety meeting. Ensure all personnel are present.
- Flush coil with treated water and leave filled for pressure testing and RIH.
- Rig up equipments and treating lines.
- Make standard jetting tool to the coiled tubing and connector.
- Rig up Injector head on wellhead.
- Pressure test equipment and lines to 5000 psi for 10 minutes with treated water. Test wellhead valves. All non-essential personnel should be clear of lines and equipment during pressure testing
- Pressure up the annulus as follows: 7" x 3-1/2" to 1200 psi, and 9"5/8x 7" to 500 psi (recording the pressure).
- With well rigged up to receive returns to flare line, open well to permit flow/circulation.
- RIH CT to TVD pumping treated water at minimal rate. Perform regular weight checks while running in every 500 m.
- CT to top of sediment, continue pumping Nitrified Treated water.
- Run in hole coil tubing to bottom at minimum speed and pump treated water 0.8 bbl/min and 20 l/min of Nitrogen.
- Pull out of hole coil tubing to top of perforation and pump required volume of preflush (i.e. 7.5 % HCl formic acid 10 %) followed by required volume of main acid treatment while the operation Real time operation is illustrated several parameters such as wellhead pressure, coil tubing weigh, flow rate and nitrogen flow rate.
- Shut the annulus and Squeeze the main acid treatment (do not exceed formation fracture).
- After displacement with treated water, flow back immediately spent acid up to the surface (avoid secondary precipitation).

- Start pull out of hole the coil tubing while keeping the well close and continue pumping the treated water in order to compensate the volume of string and displace the fluids in reservoir.
- Coil tubing at surface, close the well, flush the CT with 2 m^3 of soda ash followed 2 m^3 of fresh water and displaced with 600 litres of Nitrogen liquid.
- Rig down equipments.
- Place the well on production line for production wells or water injection for water injection wells.

III.6. The different steps of acid treatment

The main objective of an acid treatment is the elimination of formation damage and the restoration of well productivity. The type of acid used depends mainly on the type and location of the damage. Once these are identified, the acid type is easily selected and volumes are calculated based on reservoir parameters and laboratory results. The main stages of matrix acidifications performed on the Haoud Berkaoui wells are:

III.6.1. Clean Tube and Hole Cleaning

Before each matrix processing operation, a clean tube is required for cleaning the production tubing. The Clean Tube is pumped through the concentric Coiled Tubing. Its objective is to remove all the debris soluble in HCl (sediment, rust) and all kinds of undesirable products to enter the formation, and that would be glued to the walls of the tubing and liner, during the squeeze of the main treatment.

The main fluids used are: Tube clean which is HCl (7.5 %, 10 %, 15 %), MSR100, Reformat and Gel.

It is advisable to use a solvent like Reformat for wells that suffer from frequent deposits of asphalts, it must be circulated initially before diluted acid because of the incompatibility of asphalts with acid.

The cleaning of the perforations is essential for the wells equipped with cemented and perforated liner, the «clean sweep» or the Reformat or even the HCl acid are used for the cleaning, and to have a better operation, one makes several passes in front of the perforations.

The nitrification of the fluids allows the cleaning of the well in underbalance for a better evacuation of the non soluble incrustations.

III.6.2. Matrix processing : The processing includes:

III.6.2.1. The preflush

Preflush is used in all treatments. The main fluid used in this step is HCl (7.5 % and 10 %) and MSR100. The preflush has several important functions:

It reacts with carbonates in formation to avoid their reaction with HF and to minimize HF consumption. It isolates and moves the formation water away from the vicinity of the well to avoid contact between the HF and water rich in K^+, Na^+ and Ca^{+2} to prevent damage due to sodium or potassium fluosilicates.

III.6.2.2. The main treatment

Mud-acid is the main treatment fluid. It consists of a mixture of HCl et HF acid with inhibitors and all other special additives required to process the formation.

Hydrofluoric acid (HF) reacts with clays, cement filtrate and drilling mud to improve permeability around the well.

Hydrochloric acid (HCl) does not or does not react with these products and is present only to maintain a strongly acidic pH, thus avoiding the precipitation of certain compounds.

Other types of acid concentration fluids are used depending on well conditions and the nature of the damage, among those used are MSR 10:2, MSR 12:3, MA 6:1.5, etc.…

Most volumes of process fluids are calculated at the base of (1 or 1.5) meter penetration radius.

III.6.2.3. Overflush

This step is used in all acidification operations after the main treatment; the fluid used is HCl 5 % or 7.5 %, MSR100 or a light hydrocarbon, such as gasoline or diesel. Its purpose is to move damaging precipitates away from the vicinity of the well. A penetration radius of 4 ft is usually sufficient.

Necessary additives are added to the volume of acid to:

*Facilitate disgorgement of spent acid and reaction products;

*Restore rock wettability to formation water;

*Avoid the formation of stable emulsions.

III.6.2.4. Flow back

Flow back must be carried out as soon as possible after treatment using usually nitrogen and coiled tubing for lifting spent fluids. The products of chemical reactions, are not stable, they turn into other products that would precipitate and clog the pores of the matrix if they are not immediately disgorged.

III.7. Placement of Process Fluids

The placement of the treatment fluids can be done by Coiled Tubing (the most used), by concentric or by bull heading depending on the case. The use of inflatable packer (Figure 33) is taken into consideration in the case of communication of annulars for injection in training.

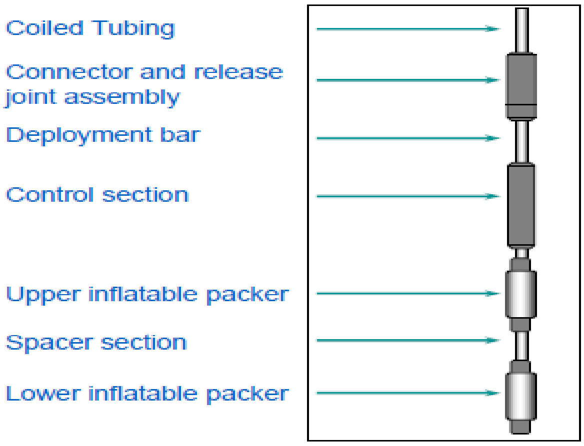


Figure 33 : Dual Inflatable Packer (Pratap 2005).

III.7.1. Diversion of Treatment

When acid is injected into a formation, it will choose the easiest path (it will penetrate into the most permeable pores), that is, finally those that have the least need to be stimulated. To avoid this problem, diversion agents are used, which are intended to temporarily close the most open or permeable pores or perforations and force the treatment fluid to penetrate in the least permeable or most clogged areas. Diversion consists in successively treating the clogged benches by isolating them from each other (Figure 34). This can be achieved in different ways:

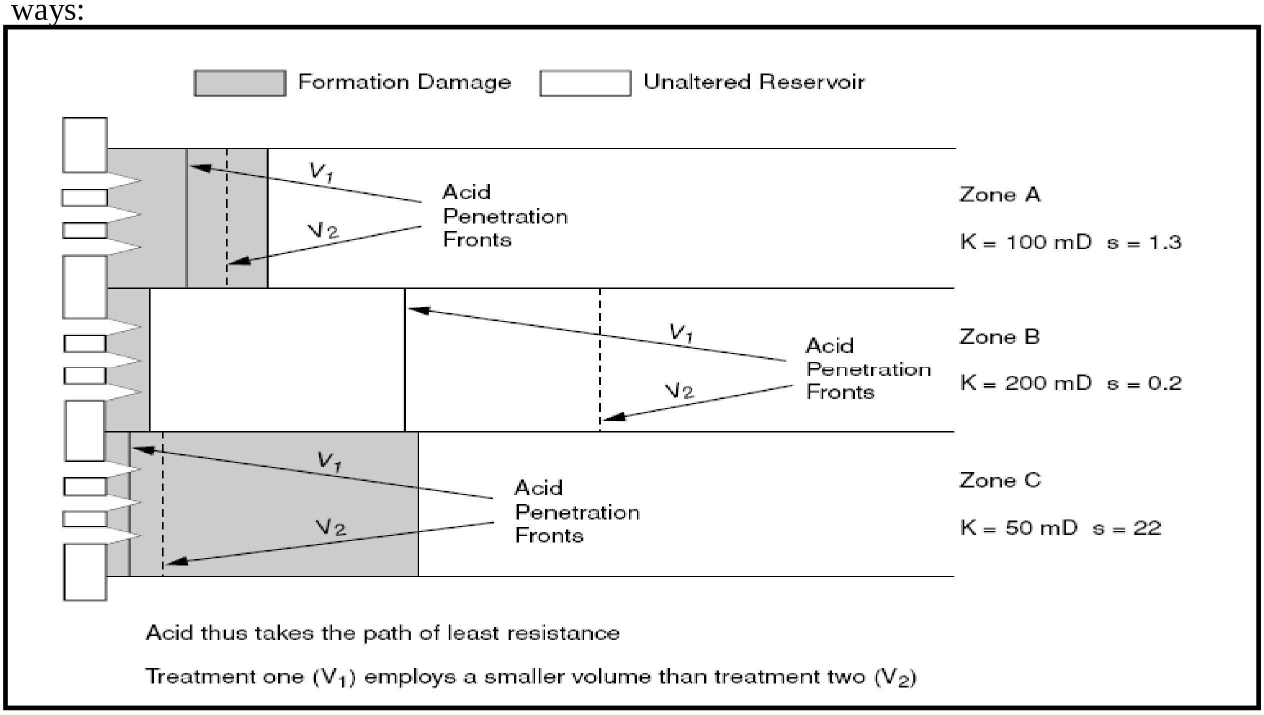


Figure 34 : Diversion technique (Sonatrach/ EP HBK, 2020).

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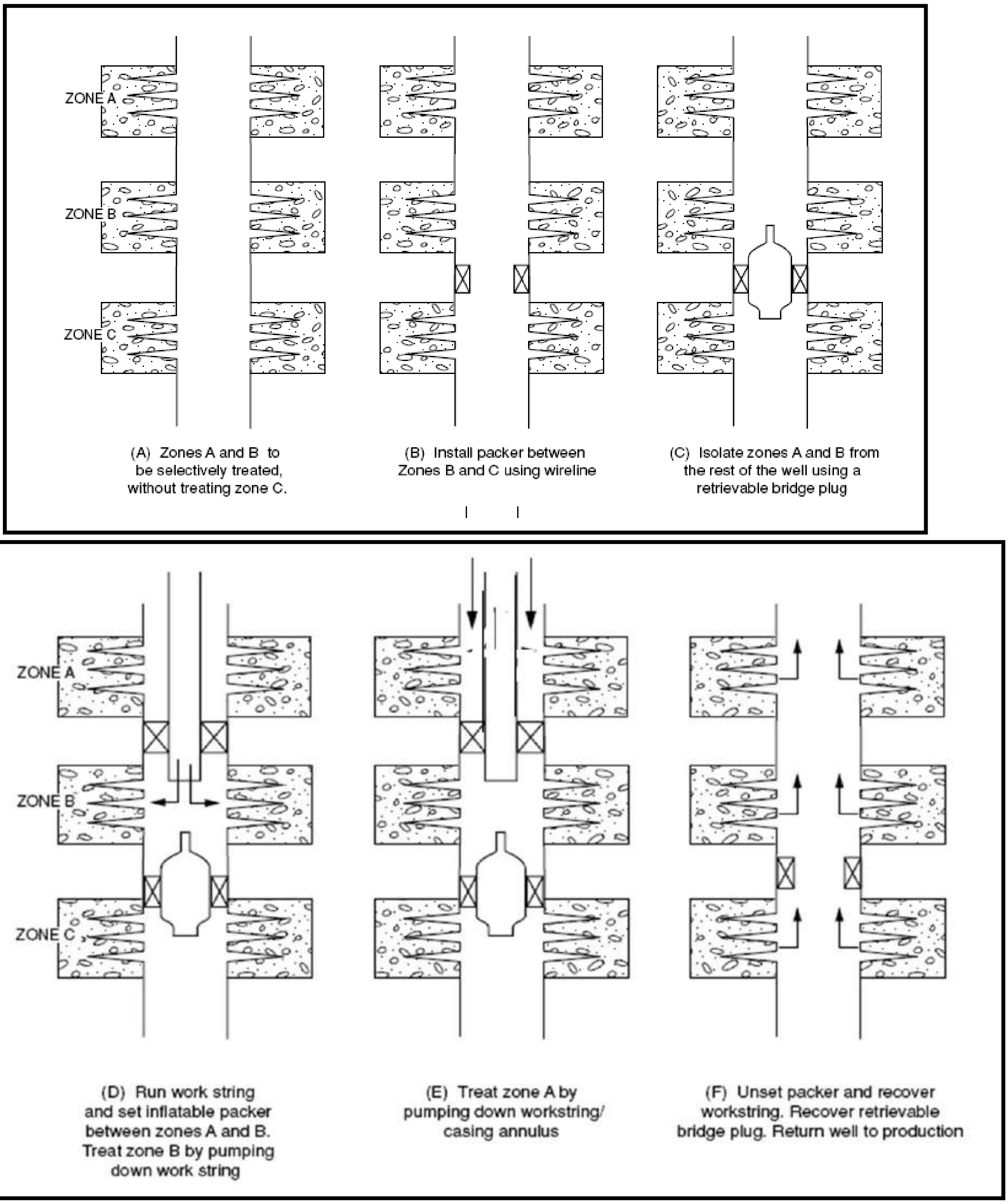
III.7.1.1. Mechanical Diversion (rarely used): The principle is to lay a packer to isolate the area of interest from the risk areas and route the treatment fluid to the targeted area; it is a selective treatment (Figure 35). This type of diversion is applied for wells equipped with a concentric, and it is not possible in open hole.



(A) Zones A and B to be selectively treated, without treating zone C.

(B) Install packer between Zones B and C using wireline

(C) Isolate zones A and B from the rest of the well using a retrievable bridge plug

(D) Run work string and set inflatable packer between zones A and B. Treat zone B by pumping down work string

(E) Treat zone A by pumping down workstring/ casing annulus

(F) Unset packer and recover workstring. Recover retrievable bridge plug. Return well to production

Figure 35 : A schematic illustration of mechanical diversion (Sonatrach/ EP HBK, 2020).

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III.7.1.2. Foam diversion (most commonly used)

This technique is done by the injection of balls (plugs) in the diversion fluid which ensures the selectivity of the treatment by temporarily limiting the flow of injected fluids in the most permeable (less damaged) areas, to homogenize the distribution of acid along the reservoir layer. Equipment used is showed in Figure 36.

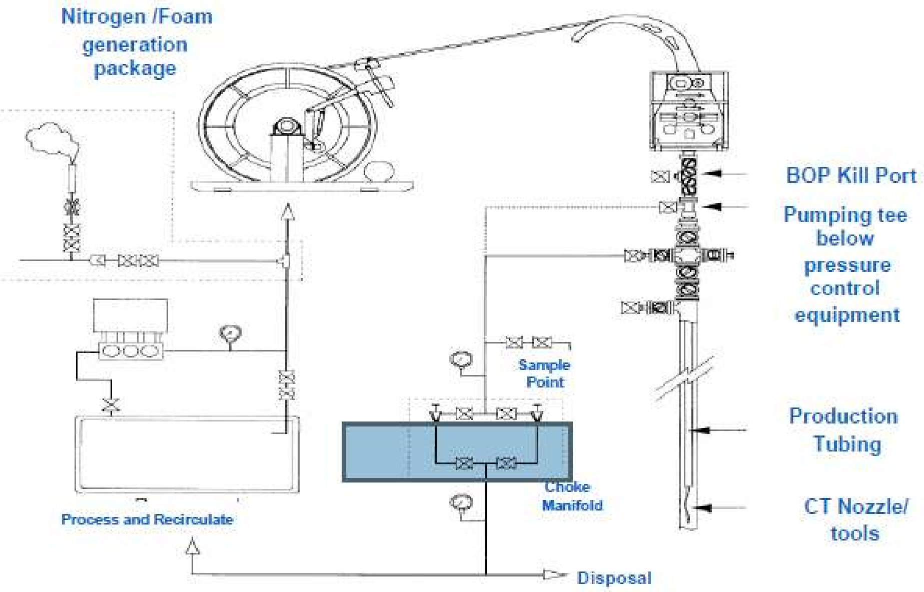


Figure 36 : Foam diversion CT Rig Up (Pratap 2005).

IV. Acids used in Haoud Berkaoui

The choice of acid systems is based on the mineralogical content of the reservoir, the characteristics of the acid mixtures, and the reactions between selected acids and drilling mud (Kalfayan 2008).

IV.1. Mud acid acetic (AS1) (13 % HCl, 1.5 % HF)

Mud acid acetic has been used to treat damage and inhibit fine migration and stabilize clays with A261 as a corrosion inhibitor. It is a mixture of chelate agents, anti-emulsifier, and acetic acid L400. The main treatment is preceded by cleaning with foam gel and then reforming and acetic acid.

IV.2. BJ Sandstone Acid (AS2) (10 % HCl, 2 % HF)

Organic acid was chosen rather than HCl to provide a more delayed acid, to minimize the potential for asphaltene flocculation, and to provide less costly corrosion inhibition using Cl-15 with an acid system. It is a mixture of 13 % acetic organic acid and 9 % formic acids, which has approximately the same dissolving power as 8% HCl. The acid steps had a polyacrylamide gelling agent for friction reduction, retardation, and fluid loss control.

Sandstone Acid is composed of an active product; phosphonic acid that contains five groups of hydrogen capable. It is released under different stoichiometric conditions to generate HF. This system promotes the reaction of HF with quartz and the limit with clays by forming a film of alumina silicate phosphonate (by chemical adsorption) poorly soluble in water and hydrofluoric acid, thus allowing the acid to act more deeply in the formation and a more uniform manner. This phenomenon is called BJ matrix micro-diversion. The temporary film would be removed by low-concentration hydrochloric acid during Overflush.

IV.3. Sandstone completion acid SSCA (AS3) (6 % HCl, 1.5 % HF)

This is the safest system when the mineralogy and nature of the damage are uncertain. They have the maximum dissolving power of HF, without secondary precipitation; in addition, they prevent aluminium precipitation better than acetic acid and help in maintaining formation compatibility. The corrosion inhibitor HAI-85M is also used to protect oil field pipes when contacted by hydrochloric acid solutions.

IV.4. M.S.R (Mud and silt Remover): MSR is an acid solution, either HCl or Mud Acid, containing a surfactant (F78) and an iron complexant (L41 or L42). The combination of these two additives gives this solution remarkable dispersion and suspension properties of the fines released by the action of the acid.

The application of MSR is in areas clogged by solid particles (mud, cement...). There are three formulations of MSR:

- MSR 100 and MSR 150 formed of HCl acid containing a surfactant and iron complexant with different volumes;

- MSR 123 mud acid (12 % HCl – 3 % HF) containing a surfactant, iron complexant and demulsifier (U66).

IV.5. B.D.A (Break down Acid): is a solution of hydrochloric acid, generally low concentration (5-7.5 %) containing a surfactant (F78). Higher acid concentrations can be used up to 15 %. It is used mainly for cleaning, it has the advantage of dispersing and suspending solids.

IV.6. D.A.D (Dowell Acid Dispersion): this acid is an emulsion of solvent in acid stabilized by emulsifying agent (U 74). Various acid solutions can be used (HCl, Mud Acid, Organic Acid) as well as several solvents whose concentration in the solution can vary from 10 to 50 %. The solvent may be kerosene, xylene or other aromatic solvents.

The DAD is used for cleaning perforations, bottom equipment plugged by hydrocarbon deposits and stimulation of oil producing wells.

IV.7. Sandstone 2000 formulation: it is an acid formulation developed by the Halliburton service company, it has been used in many sandstone reservoirs and the results are encouraging. The acid formulation is 9 % HCl and 1 % HF. Acid Sandstone is used to restore the initial permeability of formation by dissolution of the damaging materials and to increase the permeability by partial dissolution of clays, silicates and quartz. This formulation can be used with different additives to form one of the following acids:

- Fine control acid: Treats deep damage caused by migration of fines and swelling of clays;

- Silica acid: dissolves silicates in high temperature wells;

- Volcanic acid: treats HCl-sensitive formations;

- K- Spar acid: protects high-potassium formations from damage due to secondary precipitation.

- Sandstone completion acid: treats all sandstone formations. The additives used give this formulation an improved injection rate.

The properties of this acid are:

- Rapid and limits reactions with clays;

- Accelerates reaction with quartz

- Strong dissolution of deposits;

- High penetration.

Treatment of the matrix with Sandstone acid consists of three parts:

- Prefluch: Acid HCl, acetic acid, claysafe5 or formic acid are used;

- Sandstone acid: treatment acid;

- Overfluch: The acids used are: Acid HCl, formic acid, clayfix5 or acetic acid (3-10 %).

V. Some chemical additives used in HBK field

HAI-85M

HAI-85M inhibitor has been blended to provide improved corrosion protection to oil field pipe when contacted by hydrochloric acid solutions. It shows improved performance in comparison to other organic inhibitors in 10 % HCl at elevated temperatures but is particularly effective in 28 % HCl. Under sulfide cracking conditions, SCA-130 should be used with HAI-85M inhibitor. SCA-130 lowers the corrosion rate in the presence of H_2S and provides cracking protection. HAI-85 inhibitor provides protection up to 400 deg F and has excellent application in sandstone acidizing as well as in carbonate reservoirs. It is compatible with mutual solvent and anionic surfactants, which are recommended in sandstone acidizing.

LOSURF-300

LOSURF-300 nonionic surfactant is exceptionally versatile and effective. Low concentrations of LOSURF surfactant yield excellent emulsion breaks in 30 minutes or less in a variety of treatment and formation fluids. This low concentration effectiveness makes LOSURF surfactant comparatively economical. This surfactant has been proven effective in a number of applications including inhibited hydrochloric acid solutions and sandstone stimulation treatments. LOSURF-300 not only helps prevent emulsions, but also reduces both surface tension and interfacial tension. This reduced tension provides better wetting of the rock surface during treatment and faster cleanup after treatment.

WG– 11

WG-11 is a chemically modified, low-residue hydroxypropyl guar (HPG) gelling agent for aqueous fluids. An economical, versatile material, WG-11 may be used in most of our aqueous gel systems. WG-11 has been designed to hydrate slowly above pH 8 to minimize lumping. WG-11 can be used for batch or continuous mixing operations. Although the lumping tendencies of WG-11 are greatly diminished, the use of an eductor is recommended. WG-11 does not contain internal gel breakers. Therefore, it is essential that a breaker be added to the gel prior to its injection into a well. In coiled tubing work, WG-11 is used as an economical viscosifying agent to form gel pills that are used to separate fluid stages. Fluids viscosified with WG-11 are capable of better cuttings transport then non-viscosified fluids. Foamed WG-11 gels are more stable, viscous and resistant to oil and gas cutting then non-viscosified fluids. A small amount of WG-11 added to water acts as an excellent friction reducer for coiled tubing operations.

FE-1A

Fe-1A primarily functions as a pH control agent to control the precipitation of iron compounds from spent acid. Since FE-1A spends at a much slower rate than the acid that it is dissolved into, it is able to hold or “Sequester” the pH at a level that Iron will not fall out of solution. Along with FE-2 form the basis of FE Acid.

FE-2A

Fe-2A is an iron-chelating agent, which is used in conjunction with Fe-1A to make Fe acid. Fe-2A also can be used alone as an iron control agent. This additive "folds" itself around the ferric iron ion and prevents the iron from reacting to form iron hydroxide precipitate.

HC-2

HC-2 is an amphoteric surface-active agent that is much more versatile as an additive to acid than many of the products Halliburton stocks. Primarily, it is a suspending agent for acid-insoluble fines that become dislodged during acidizing. This property aids in a more efficient well cleanup after treatment. HY-CLEAN (HC-2) is also a foaming agent that adds to the dispersability of insoluble’s and the speed of cleanup, particularly in gas wells and when used with CO_2 and N_2. HC-2 is a surface tension reducer and in many instances a non emulsifying agent. It leaves contacted formations in a water-wet condition.

To obtain best suspending properties, use HC-2 in the concentration of at least 5 gal/Mgal acid (0.5 %). However, HC-2 may still perform as a good foaming agent, N.E. agent, or surface tension reducer at lower concentrations. Most all surfactants Halliburton stocks adversely affect HC-2 to some extent. As much as 2 ft of solids have been found in the bottom of a reservoir after the cleanup of a well treated with acid containing HY-CLEAN.

VI. Acidizing history of oil wells of Haoud Berkaoui

VI.1. Data collection: the data used were collected from Haoud Berkaoui producing wells in Ouargla region-Algeria-, Engineering Production unit of HBK field and Laboratories Division (SONATRACH) of Boumerdes. This field is part of the Bloc 438c and together with the structures of Benkahla and Guellala, a main pole of the Oued Mya depression. It was discovered in 1965 by the HB1 well and produced in the sandstones of the lower Triassic clay-sandstone series. The reservoir of this field is Triassic age and consists of bottom to top by: the Lower Series: main object, the intermediate andesitic series, the T1: secondary object and the T2: compact reservoir. The majority of wells are producing oil from the Lower series reservoir that is formed by grano-descending sequences, with clay-siliceous at the base and clay-siliceous carbonate at the top. It has an average thickness of 40 meters, of which 26 meters are useful height. These wells are suffering since many years from damage (fine migration, scale deposition and emulsion generation) due to several operations (drilling, completion, workover, snubbing and stimulation). Several wells are chosen to compare these acids using different analysis.

VI.2. Acidizing history of oil wells of Haoud Berkaoui field

Well N1: it is an oil producing well, drilled and completed in 2000, located in the field of Haoud Berkaoui. After a time of production, a lifting system, and lining by a tubing 2'7/8 has been set up, for the lightening of the production column. The well underwent several acidification treatments in 2006, 2008 and 2012, respectively, after it experienced a drop in production.

Well N2: it is an oil-producing well drilled in 2010. The reservoirs (T1 +LS) were crossed by a slurry with Oil density 1.48, and on 01/2011 underwent an initial puncture in the reservoir «T1» the perforated intervals is 8.5 m. The table 1 shows the different characteristics of this well .The intervention of the coiled tubing in 2011 for an attempt to start the well but without result; it was decided to fracture the well at the end of 2011 after a certain time of production. The well experienced a gradual drop in production; therefore, it was decided to treat the matrix. Table 22 shows the characteristics of reservoir of two wells N2 and N1.

Parameters	Well N1	Well N2	Unit
Reservoir	Lower Series	Lower Series +T1	-
Well status	Flowing	Flowing	-
Total thickness	23	25	m
Effective thickness	10.5	8.5	m
Average porosity	9.30	9	%
Permeability	67	72	md
Average saturation	20	21	%
Water saturation	50.1	20	%
Temperature	100.2	103	°C

Table 22: The initial characteristics of the wells N1 and N2 (Sonatrach/ EP HBK, 2020).

Well N3: it is an oil producing well, drilled and completed at HBK in 2003, after a production time, a concentric 1'660 was set up to lighten the hydrostatic column. The well experienced a gradual drop in production in 2008, which requires stimulation. A snubbing operation was made for the ascent of the concentric 1'660, and after, a coiled tubing unit was set up in order to stimulate the well, then the snubbing would resume work for the concentric. The Table 23 shows its characteristics.

Reservoir	Htot(m)	Heffec (m)	Φaver (%)	Sw aver(%)	Vsh aver(%)	T°(°C)	PG initial at 3500m (Kg/cm²)	formation
Lower Series	35,5	15,5	9,15	14,16	4,25	100	280	Alternation of sandstone and clay

Table 23: The initial characteristics of the well N3 (Sonatrach/ EP HBK, 2020).

Well N4: it is an oil producing well drilled in the OKN zone in 2003 to determine the extension of the triassic reservoir in this part of the field. Based on the history of the well, the oil production flow decreased gradually; from 9.8 m³/h in 2003 to 4.51 m³/h in 2008. The Table 24 shows its characteristics.

Reservoir	Htot(m)	Heffec (m)	Φaver(%)	Sw aver(%)	Vsh aver(%)	T°(°C)	PG initial at 3500m (Kg/cm²)	formation
Lower Series	49	23,5	8,92	32,79	6,03	100	285	Sandstone

Table 24: The initial characteristics of the well N4 (Sonatrach/ EP HBK, 2020).

Well N5: it is a new well Oil producer (initially it was intended as a water injector), it was drilled from July 12 to August 31, 2007. The 7" casing was installed in the TAG T2, total mud losses during the circulation, the return to 100 % of the mud was observed only after having installed two plugs of cements. The TAG T and Lower Series reservoirs were crossed in phase 6’ with a high density mud d = 1.48. The Table 25 shows its characteristics.

Reservoir	TAG (T1)	Lower Series
Total thickness of sandstone (m)	6	40
Effective thickness of sandstone (m)	4,5	7
Average effective porosity (log)(%)	8,77	11,49
Average Clay content (Vsh) (%)	0,00	8,59
Average water Saturation (%)	22,63	18,06

Table 25 : The initial characteristics of the well N5 (Sonatrach/ EP HBK, 2020).

Well N6: it is an oil producing well completed in January 2005. The well is stimulated (by acidification) in August 2005 because of the gradual decline of its flow from its production in April 2005 (damage to the well confirmed by the result of the build-up test which gave a positive skin: S = +2.1). In 2008, well flow decreased rapidly (from 8.26 m^3/h in 10/02/2008 to 4.73 m^3/h in 27/04/2008) which requires further stimulation. The Table 26 shows its characteristics.

Reservoir	Lower Series
Total height (m)	40
Total Height of sandstone (m)	25,90
Effective height (m)	13,35
Average effective porosity (%)	8,9
Average Clay content (Vsh) (%)	15,5
Average Water Saturation Sw (%)	2,9
Initial Reservoir Pressure (Kg/cm²)	247

Table 26 : The initial characteristics of the well N6 (Sonatrach/ EP HBK, 2020).

Well N7: it was drilled in 2004. It was planned as a water injector well in the East part of theOKN area. It was intended to determine the extension of the triassic reservoir in this part of the field. In 2007, well flow dropped significantly (from 9 m³/h at the end of 2006 to 5.66 m³/h in 2007). The Table 27 shows its characteristics.

Reservoir	Htot(m)	Heffec (m)	Φaver(%)	Sw aver(%)	Vsh aver(%)	T°(°C)	PG initial at 3500m (Kg/cm²)	formation
Lower Series	42,5	25,6	13	20	19	100	264	Sandstone

Table 27: The initial characteristics of the well N7 (Sonatrach/ EP HBK, 2020).

VI.3. Acidizing history of oil wells of Benkahla

Well B1: is an oil well located in the southern part of the Bin Kahla field. Drilled on 15/07/2011, put into service on 25/02/2012, through a space of 9.12 mm. Its main reservoir of 50 m of low gross thickness is 19.50 m useful in oil. The Table 28 shows its characteristics.

Type of Well	Oil Producer Field HAOUD BERKAOUI
Formation Sandstone Total Depth (m)	3380
Perforations (m)	3422,00 - 3426,50 [4,50 m] 3431,50 - 3434,50 [3,0 m] 3438,00 - 3439,50 [1,5 m] 3443,00 - 3447,50 [4,5 m] 3448,00 - 3450,00 [2,0 m]
Reservoir Pressure (kg/cm^2)	346,54
Reservoir Temperature (°C)	100,21
Porosity (%)	11,21
Permeability (mD)	6, 93
Effective height (m)	19,50
Clay content Vsh (%)	6,87
Average Water Saturation Sw (%)	26,82

Table 28: The characteristics of the well B1 (Sonatrach/ EP HBK, 2020).

Well B2: is an exploration well for El-Hamra quartzites that have proven to be of no oil interest. This well, which is fed by the TAG SI, was drilled with a reverse emulsion mud (invermul) of density 1.52. The well erupted until today. The Table 29 shows its characteristics.

Date	Model	Reservoir	Pressure (kg/cm^2)	Kh (md.m)	K (md)	Skin
From 21/04 to 10/05/2009	Infinite	Radial Composite	291.46	34.5	2.65	- 1.65

Table 29 : The characteristics of the well B2 (Sonatrach/ EP HBK, 2020).

Well B3: is a Vertical Oil well Producer completed with 4”1/2 Production Liner. This Well has showed a decrease in daily oil production, it is suspected that this drop in production is due to existing mixed organic and mineral deposit in the near wellbore area restricting the Oil production. The objective of this intervention is to remove the associated damage caused by organic deposits and fine migration. The perforated interval covers 22 m of The Targeted zone of treatment (from 3421 m to 3443 m). The Table 30 shows its characteristics.

Type of Well	Oil Producer Field HAOUD BERKAOUI
Formation Sandstone Total Depth (m)	3506
Landing Collar (m)	3480.48
Perforations (m)	3421.0 – 3423.4 /3425.0 – 3426.5 3427.3 – 3428.0 /3430.0 – 3432.0 3438.5 – 3439.2 /3440.0 – 3443.0
Reservoir Pressure (kg/cm^2)	356.23 [5067.28psi]
Reservoir Temperature (°C)	98 [208.4 F]
Porosity (%)	6.67
Permeability(mD)	5

Table 30: The characteristics of the well B3 (Sonatrach/ EP HBK, 2020).

Well B4: it is a newly drilled Vertical Oil well Producer that showed Mud drilling losses. The objective of this intervention is to remove the associated damage caused by this loss of drilling mud during drilling phase and bring the well to Production. The well was completed by 4”1/2 Production Liner.

The perforated interval covers 5.5 m of The Targeted zone of treatment (from 3469 m to 3474.5 m).

In this zone several oil based mud losses have been occurred during the drilling phase.

The loss of the oil-based mud in the formation may have caused some emulsion between the mud and the reservoir fluid. The Table 31 shows its characteristics.

Type of Well	Oil Producer Field HAOUD BERKAOUI
Formation Sandstone Total Depth (m)	3504
Reservoir	Lower Series
Landing Collar (m)	3480.48
Perforations (m)	3421.0– 3423.4 /3425.0 – 3426.5 3427.3 – 3428.0 /3430.0 – 3432.0 3438.5 – 3439.2 /3440.0 – 3443.0
Reservoir Pressure (Psi)	4626.7 [319 bar]
Reservoir Temperature (°C)	101 (214 F)
Porosity (%)	10.03
Permeability (Md)	5
Clay content (%)	20.98
Frack Gradient (psi/ft)	0.7
Estimated Wellhead Pressure (Psi)	1186

Table 31: The characteristics of the well B4 (Sonatrach/ EP HBK, 2020).

VI.4. Acidizing history of the wells of the periphery region

Well P1: it is a newly drilled Exploration Vertical Oil well Producer that showed Mud drilling losses. The objective of this intervention is to remove the associated damage caused by this loss of drilling mud during drilling phase and bring the well to Production. The well was completed by 4"1/2 Production Liner. The perforated interval covers 15 m of The Targeted zone of treatment (from 3544 m to 3559 m). In this zone several oil based mud losses have been occurred during the drilling phase. The loss of the oil-based mud in the formation may have caused some emulsion between the mud and the reservoir fluid. The Table 32 shows its characteristics.

Rock Type of the reservoir	Sandstone
Reservoir Pressure (Psi)	5020 [346 bar]
Reservoir Temperature (°C)	102 [216 F]
Average Rock Porosity (φ) (%)	9
Average Water Saturation (Sw) (%)	28
Rock Permeability(md)	30. 6
Skin	19
Frac Gradient (psi/ft)	0.7
GOR (scf/bbl)	1580
Daily Production (bbl/day)	1600 [10.559 m^3/hr]
Well Completion	Production Tubing 4-½" 9.6# N80 from surface to 3,250.83 m. Production Liner 4-½" 9.6# N80 from 3,252.1 m to 3,724 m.
Water Oil Contact (m)	3564

Table 32: The characteristics of the well P1 (Sonatrach/ EP HBK, 2020).

VII. Laboratory tests

The objectives of laboratory study are to analyze the rock, to evaluate its characteristics and to select optimum treating fluids. This study consists of testing 3 systems of acid commonly applied in Haoud Berkaoui fileds through different tests to investigate their compatibility with rock. After core preparation and characterization, cores from each well are selected in a manner so that the experiment can be conducted using approximately the same samples of rock. Plug selection criteria for each well are based essentially on similar permeability and a similar composition with slight difference in some samples.

To achieve the previous objectives the following tests are conducted:

- X-Ray diffraction is done to determine mineralogical composition of the rock.
- Solubility test to estimate the rock soluble fraction in different acids. Total acid solubility with or without ion analysis.

- Compatibility test to investigate the formation of emulsion and sludge precipitation tendency.
- Damage test to determine permeability variation versus damaging fluids.
- Matrix injection core flow test to quantify the influence of acid on the permeability andon the consolidation of the core (before and after acid application).
- Scanning Electron Microscope (SEM) to observe the repartition of minerals in the rock to determine the nature of the inter-granular cement and localized clays. This study was made by thin section analysis and photography.

VII.1. Sample preparation (Figure 38)

VII.1.1. Plugs: they have the following characteristics: a diameter of 4 cm and a length of 6 cm. The porosity, air permeability, and density of the studied samples range between 10 and 15 %, between 9 and 50 mD and between 2.4 and 2.8 g/cm^3, respectively. The mineralogical composition of these plugs is mainly represented by Quartz and other elements at trace levels, such as mica, halite, anhydrite, and carbonate (Figure 37). The clay minerals are mainly composed of Illite.

Figure 37 : Some sandstone plugs from well N1 and its dimensions (Sonatrach/ EP HBK, 2020).

Before the displacement tests were performed, the plugs underwent some preparations according to American Petroleum Institute (API) standards. They are first washed by Soxhlet extraction with a solvent mixture of "15:15:70 Methanol/acetone/toluene" to extract the organic material (hydrocarbon fluids) and the impurities. The Soxhlet washing is stopped when the solvent becomes transparent. It is followed by a second wash with methanol to dissolve the salts. The presence of salt in the solution is controlled by the silver nitrate test.

After washing steps, the samples are dried in an oven at 65 °C until a constant mass and the porosity and air permeability are then determined.

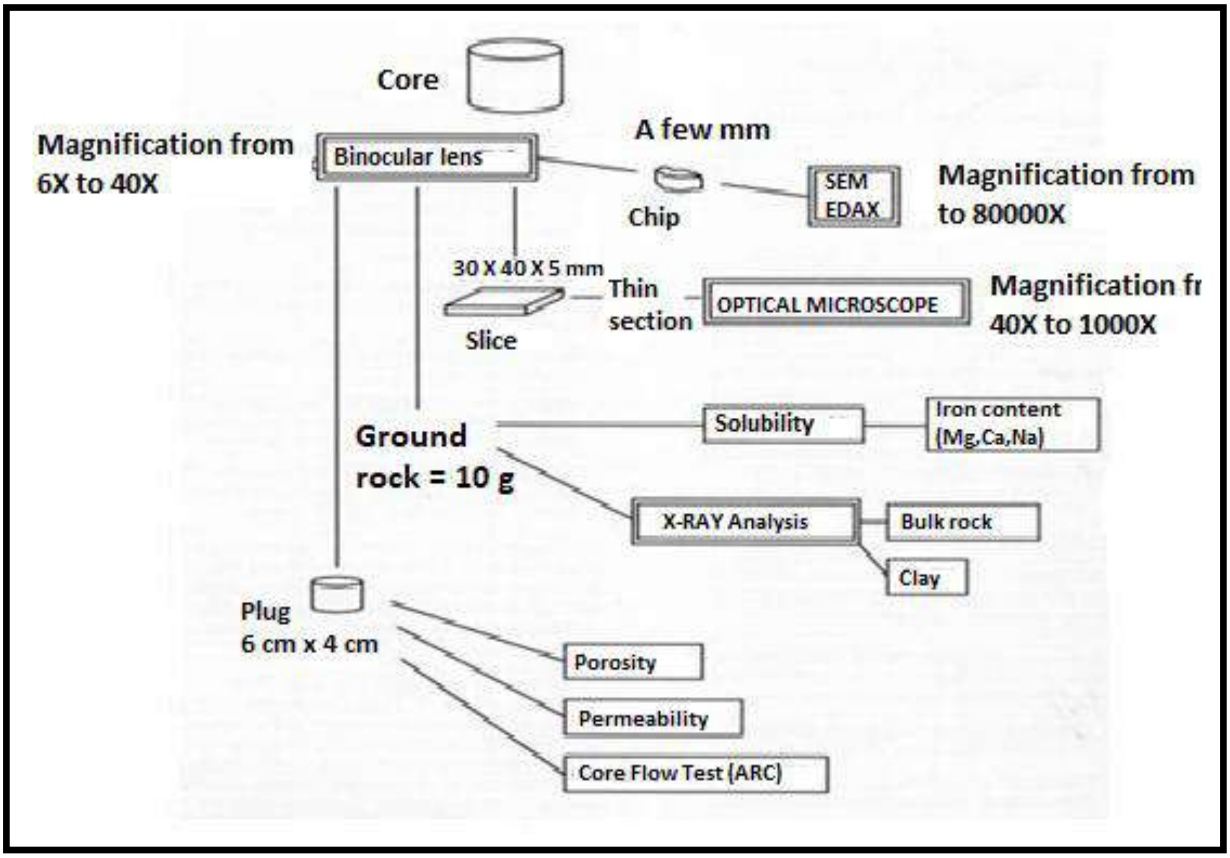


Figure 38 : Sample preparation (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

VII.1.2. Samples for fluid and formation interaction

Sample preparation for conventional analysis on fresh or diesel-washed samples, which are generally geometrically shaped with a diameter of 40 mm. First, Wash with Toluene or Methanol to extract hydrocarbons and impurities from the rock, then with methanol to remove salts. After washing, the samples are placed in an oven for drying at a temperature of 110 °C "DKN810 device" (Figure 39) until the weight is stabilized. The samples are then stored in a desiccator containing a silica gel to prevent moisture absorption with a moisture content of 40 %.

Figure 39 : DKN810 device (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020)..

VII.2. The X-Ray diffraction analysis

The X-Ray Powder diffraction analysis using Philips PW 3710 XRD (Figure 40) is a non-destructive technique. XRD can be used on mineral mixtures (rocks, sediments, etc.) (Ali Khoudja et al. 2020) to indicate rapidly the materials and deposits of crystals smaller than 4 microns and gives a mineralogical description as well as their distribution and location within the sandstone matrix. The examination of thin sections (steps of its preparation are showed in Figure 41 provides information on the origin and quality of the cementation of the grain.

Figure 40 : XRD equipment (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

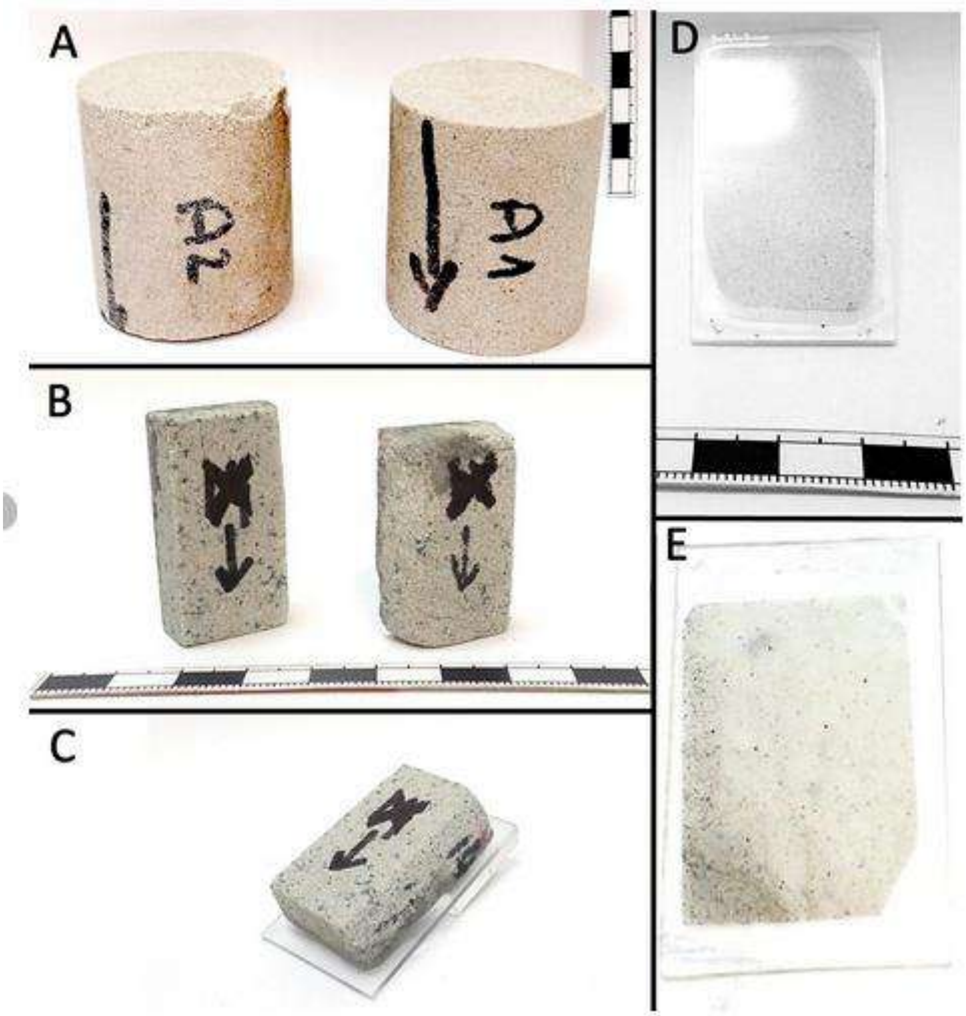


Figure 41 : Steps in preparation of rock (sandstone) thin section A -samples of a drill core, B -cuboid-shaped chips of rock, C -a smaller slice of rock in a cuboid shape mounted in a glass-slide, D -sandstone thin section ready to be polished, E -final sandstone thin section (Grain segmentation in sandstone thin-section based on computer analysis of microscopic images) (Dąbek Przemysław et al. 2023).

VII.3. Scanning Electron Microscope (S.E.M) (Figure 42)

The S.E.M operates based on the detection and analysis of the radiation emitted by a sample when a beam of light energy electron is focused on the sample. The principal is to coat a sample with gold. Gold acts as a reflector for electron beam directed at the sample. This process takes place in a vacuum, and one can see the rock and how it is physically made up and where the clays exist. Scanning Electron Microscope photos showed porosity improvement after acidizing for all systems.

Figure 42 : Microscope Electronique à Balayage (Quanta 650) (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

VII.4. Porosity and permeability measurement

After the washing and drying of the plugs, the porosity is measured in the laboratory using the Ultra-pore 300 (Figure 43). The device is manufactured to perform measurements on 1" and 1.5" plugs. This equipment is designed based on Boyle and Mariotte'slaw. The procedure consists of calibrating the device and then checking the solid volume of each plug. The permeability was measured with an Ultra-permeameter 500 (Figure 44) under a confining pressure of 200 psi.

Figure 43 : UltraPore Porosimeter - UPore 300 (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

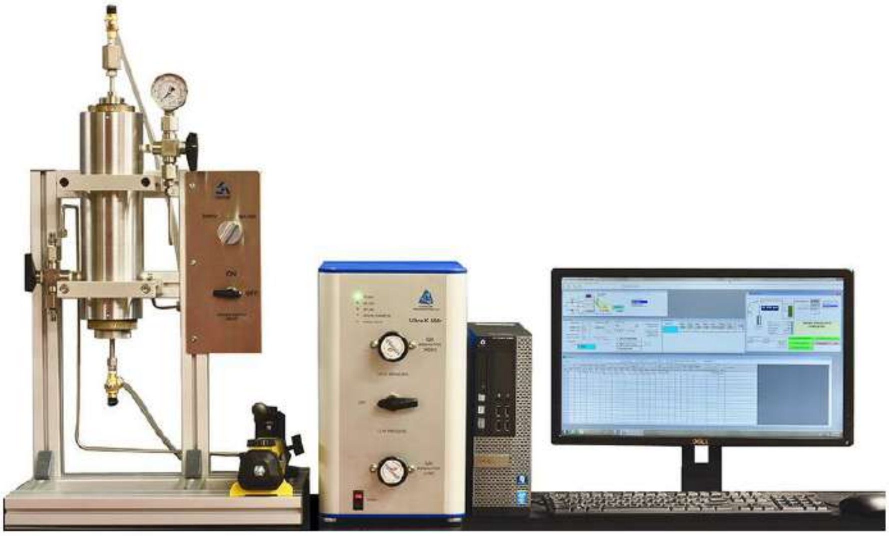


Figure 44 : Ultra-permeameter 500 (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

VII.5. Clogging Test: These tests take place in underground conditions (temperature and pressure) and consist of simulating the invasion of the rock samples by the mud. The sludge, well homogenized, is heated in the cell and the whole circuit. To reach the temperature of 80 °C. The sludge is then injected through the sample at a pressure of 30 kg/cm^2. Every 15 min, using a graduated cylinder, the volume of the filtrate is measured while maintaining the same temperature and pressure conditions. Once the filtration is complete, the sample is cleaned with a SOLTROL 130 (Figure 45) inert slurry in the direction of production. Once the flow of this oil is constant, the permeability to Saltrol is determined after Kf clogging according to Darcy's law. The clogging rate is given by the Formula 19.

$$\mathbf{C\ \%} = \frac{K_i - K_f}{K_i} \mathbf{X\ 100} \qquad \mathbf{(19)}$$

Where:

$\mathbf{K_i}$ is the initial permeability.

$\mathbf{K_f}$ is the final permeability.

Chemical–physical data:

Consistency: clear, colorless liquid

Lightning bridge: > 61.7 °C (143 F)

Density: 0.77 g/ml (20°C)

Boiling range: 180 °C to 205 °C

Evaporation index: about 80

Kauri-alcoholindex: about 25

Figure 45 : Soltrol 130 and its characteristics**.**

VII.6. Acid preparation

For various acidizing treatments, various acid mixtures in varying concentrations have been prepared. In order to achieve the desired effect, a mixture of HF and HCl acid is typically applied when acidifying sandstone matrix. While in the preflush stage, calcium, magnesium, and sodium positive ions are typically removed using HCl acid (Mian Umer Shafiq, 2018). Different concentrations of HCl acid are applied when acidifying sandstone. You can calculate acid volume using the formula in Equation 20.

$$M_1V_1 = M_2V_2 \tag{20}$$

VII.7. Acid solubility test

Its purpose is to assess the level of carbonates and clay. Weigh 1 to 10 grams of sifted powder to 40 mesh (0.42 mm) and react in an excess of acid at the temperature of 70°c for 1hour.After filtration, drying and weighing, determine the weight loss for each acid tested and deduce the solubility expressed in weight percentage. Formation acid response tests (if permeability permits), as well as water sensitivity tests, will demonstrate the benefit or danger of acidification.

VII.8. Acid Response Test (ARC)

Its purpose is to check if the acid formulation increases the permeability, if the acid formulation does not destroy the matrix and which formulation gives a better ratio of (K_a/K_i).

Core flow tests are performed in a high-pressure, high-temperature device purchased from Temco, Inc., Tulsa, Oklahoma, USA. A schematic diagram in Figure 46 represents the experimental apparatus .It is designed to determine the effects of different fluids on formation samples while simulating treatment conditions in the well. The effects of sequential injection of different fluid stimulation can be evaluated. The tests are usually carried out on the diameter of one inch, taken by one inch in length. The execution and the performance of this device are as follows:

-Injection Pressure: 0 to 1500 Psi.

-Flow rate: 0.2 to 10 ml/min.

-Imprisonment Pressure: adjustable from 300 to 1500 psi.

-Back pressure: adjustable from 75 to 1500 psi.

-Temperature: from ambient temperature to 194F (90 °C).

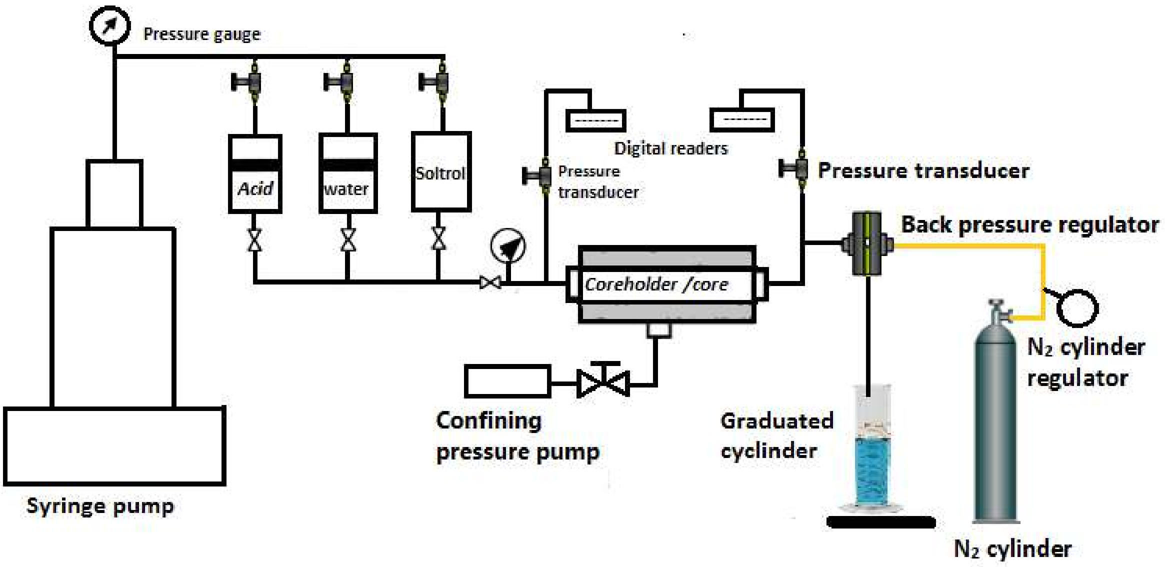


Figure 46 : Schematic of matrix acidizing laboratory set-up.

A syringe pump (Figure 47): that powers the device used to force fluids through the acidizing agent. The connecting tubes are forced through by the pump's hydraulic oil. A piston that is housed in an accumulator component is in turn pushed by the oil. The fluid to be pumped is located on the other side of the piston.

Figure 47 : Syringe pump Continuous Flow 260D Teledyn ISCO Dual Syringe Pump and controller (Grabski, 2012).

A coreholder (Figure 48): The main component of the experimental setup is the core holder, through which acid is injected and the core is inserted (Sohn, 2018). The outer casing, sleeve, and plugs are the three main components that make up the hardware. The outer casing is a cylinder with a temperature rating of up to 300 F and a pressure rating of up to 3000 Psi.

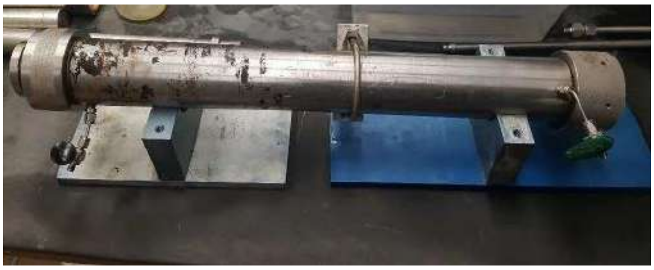
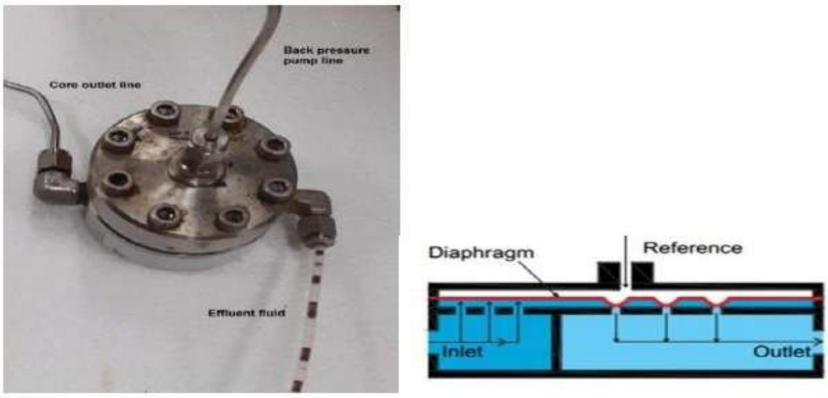


Figure 48 : Core holder (Sohn, 2018).

A back pressure regulator (Figure 49): to maintain the required level of pressure at the coreholder's outlet. Additionally, it serves to maintain a high enough pressure inside the coreholder to guarantee that the carbon dioxide generated by the acidizing reaction stays dissolved in solution.



(a) (b)

Figure 49 : (a) Backpressure regulator used (b) Mechanism of the backpressure regulator (Abhishek 2014).

Pressure transducers (Figure 50): are connected to a computer in order to track the decrease in core pressure.

Figure 50 : Pressure transducers (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

Nitrogen cylinders (Figure 51): were used as the source of the gas that will pass through the acidized cores.

Figure 51 : Nitrogen tanks (Grabski, 2012).

Pressure Gauges (Figure 52)

They are composed entirely of stainless steel metal components and have a pressure range of 0-6000 psi. Included are a 1/4" ale NPT back mount, a glycerin-filled case, and a safety glass window. To connect the pressure gauge to the tubing, a stainless steel straight union with a 14" FNPT and 1/8" Swagelok thread is needed. They are located at the top of the backpressure regulator, the injection pump's outlet, the overburden pump's outlet, and the inlet and outlet of both core holders. They are essential for monitoring pressure increases during an experiment, spotting leaks, and keeping people safe (Grabski, 2012).

Figure 52 : Pressure gauges (Grabski, 2012).

A flow test can be used to determine the liquid processing volumes, only if we know the type and radius of damage. However, tests are still necessary, as they are the basis of the treatment-fluid choice methodology. Permeability is measured by the Darcy Equation 21:

$$\mathbf{k=\frac{Q.L.\mu}{A.\Delta P}} \qquad \mathbf{(21)}$$

K is the permeability of the sample (Darcy).

µ is the viscosity of test fluid at test temperature (cP).

Q is the flow rate (cm^3/s).

L is the length of the sample (cm).

A is the cross-sectional area perpendicular to flow (cm^2).

ΔP is the pressure drop (atm).

Permeability measurements were done in the following sequences:

– Saturation of the core with water under vacuum and at ambient temperature.

– Holding the core sample in the permeability measurement cell at 80 °C.

– Flooding the Soltrol 130 (PVN = 20) through the core at pressure of 100 psi, and measuring the initial permeability (K_i), under steady state conditions.

– Draining the crude oil (PVN = 30) through the core and measuring the flow rate (Draining Acid)

– Displacing the crude oil by the Soltrol and measuring the final permeability K_a under similar conditions used for measuring K_i. The process consists of injecting 350 ml of the acid solution to be examined in each treatment step. A flow measurement is taken each 50 ml to calculate the permeability after k_a acid. Then, the ARC curve of K_a/K_i as a function of the volume of acid injected is plotted.

Finally, the change in permeability before and after acidification is expressed as $K_r = K_a/K_i$. The results of the acidizing tests obtained for the different samples using the three acid sequences will be illustrated by the response curves (K_a/K_i) as a function of the volume of acid injected).Photos were taken using the Quanta 650W (FEI) before and after acidification to see better the change in reservoir rock characteristics.

VII.9.Emulsion and sludge tests

The use of acidic aqueous solutions and under the effect of turbulence due to pumping or pore size, can generate a viscous and stable emulsion reducing or cancelling well productivity. The emulsion is either Direct: oil in water or Inverse: water in oil. The procedure to realize emulsion test consists of preparing the used acid by reacting a quantity of acid with the solids in the form of grains. The solution was let to react for 24 hours then it was decanted and after that 2.5 g was dispersed in 25 ml of spent acid solution; 75 ml of crude oil was added and the solution was emulsified with the mixer. Finally, oil and acid volume were recorded for each time interval.

Sludge test consists of putting a certain volume of acid in a clean bottle and a same volume of oil was added. It was closes and shaked vigorously. Then, it was heated in a water bath for 24 hours at a temperature of 60 °C. It was poured into hot water and soltrol 130 and the result was described as follows:

- No sludge: no particles
- Sludge trace: presence of small particles in small amounts

- Average sludge: average particle size
- Significant sludge: amount of large particles

VII.10. Qualitative and quantitative deposition analysis

Qualitative and quantitative knowledge of the elements present in the deposits is essential to diagnose the origin and type of damage. For the choice of a good treatment, specific physical and chemical analyses are necessary. These analyses are justified by the actions and interactions of the following parameters listed:

Organic matter: Asphalt deposits cause a very serious production problem. These deposits are located in the tubing, in the strainers, in the perforations and in the formation.

Salt: The change of temperature and pressure associated with production, generates the precipitation of salt from richly salted formation fluids. This type of precipitation causes matrix damage and blockage of production tubing.

Calcium, Magnesium: Ca^{2+} and Mg^{2+} ions are easily combined with CO_3^{2-} carbonates to form ESM or deposits.

Iron [Fe_2O_3, FeS, $Fe(OH)_2$] that can cause blockages.

HCO_3^- and CO_3^{2-}:associate with certain cations (Ca^{2+}, Mg^{2+}), formation of insoluble deposits.

Sulphates SO_4^{2-} : Sulphates are deposits that are difficult to chemically remove. They are form primarily because of the incompatibility between the injection water, either for softening of salt wells or for pressure maintenance, and formation water. They can be present in the tubing, in the perforations and even in the formation. The most common sulphate deposits are $BaSO_4$, $CaSO_4$, $SrSO_4$.

VII.10.1. Organic matter content

The sample dried in the oven at a temperature of 150° C to 200° C for about 2 hours and ground in a porcelain mortar.

Equipment used:

- Platinum crucible and an oven (Figure 53)
- Analytical balance
- A desiccator

Procedure:

5 g is taken from a platinum crucible, dried and weighed with an analytical scale. The deposit will then be charred in an 800 °C muffle oven for one hour.

Cools the platinum crucible in a desiccator and weighs it.

Figure 53 : Muffle oven with platinum crucible (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Expression of results (Equation 22):

$$M.org(\%) = [p-(n_v-n_c)].\ 100/\ p \tag{22}$$

-p: The test portion

-n_v: Weight of empty platinum crucible

-n_c: weight of crucible in platinum after calcination

VII.10.1.1. Quantification of the crude paraffin content by the method UOP 46-64

Principle

The technique of precipitation of paraffins are numerous and based on the crystallization process of low temperature paraffins. Precipitation agents may be acetone, ethanol, methyl-ethyl-acetone.

Among the techniques, the method of precipitation of paraffins by acetone known as standard name UOP 46-64, which consists in precipitating total paraffins.

Recovery of pure paraffin occurs by elution in a silica gel column using hexane as a solvent.

Procedure

1. Weigh 2 g of the sample to be analyzed in a beaker
2. Add about 35 cm^3 of petroleum ether and stir with a rod until dissolution of the sample.
3. Add about 110 cm^3 of acetone and stir.
4. Place the sample in a bath at -20 °C for 2 hours.
5. Vacuum filter the sample, using special wattman filters 934.
6. Decant vacuum, remove filter with pliers.
7. Solubilize paraffin crystals with a solvent that is toluene in a cup, we already know its empty mass, after solubilization we evaporate toluene and weight of paraffins.

Calculation of the mass of paraffins M (Equation 23)

$$M=m_2-m_1 \quad (23)$$

m_2: Basin mass and paraffin crystals

m_1: Empty bowl mass

M: Mass of paraffins in 2 g crude oil

VII.10.2. Determination of chloride

Principle

To realize this objective we need equipment (some of them are showed in Figure 54 and reagents showed in Table 33. It is relatively simple to apply. The MOHR method is a precipitation assay. We have a chloride ion solution of unknown concentration. Silver nitrate is added to this solution. At each quantity of silver ion added, a silver nitrate precipitate is formed: ion Ag $(I)^+$ chloride ion AgCl (solid). This happens until all the chloride ions have precipitated. This is then the equivalence: n (Ag^+) = n (Cl^-)

But there is no way to visualize this equivalence. The white disorder has been present since the beginning and nothing changes anymore. This is why we use a coloured indicator of the presence of silver ions (I).

Potassium chromate is used in aqueous solution. It is a red silver chromate precipitate that forms.

Equipment used	reagents used
- Burette - Stirrer and magnetic bar - Analytical balance sheet -5 ml pipette. - Beakers previously washed in distilled water and oven dried at 105°C.	- Distilled water - Silver nitrate solution $AgNO_3$ to 0.1 N. -This solution is obtained by dissolution of 17 grams of $AgNO_3$indistilled water and dilute to 1000 ml -Colour indicator: Potassium chromate solution is prepared by dissolving 100 g K_2CrO_4 in distilled water and diluting to 1000 ml

Table 33: The equipment and reagents used during chloride determination (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Figure 54 : A conical flask with filter and a burette (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Reactions:

Titration reaction (24 and 25)

$$NaCl + AgNO_3 \longrightarrow Agcl + NaNO_3 \qquad (24)$$

$$Ag^+ + Cl^- \longrightarrow Agcl \quad \text{(white precipitate)} \qquad (25)$$

Indicator reaction (26)

$$2\ Ag^+ + \ CrSAg_2 \longrightarrow CrSO_4 \text{ (brick red colour at turn)}(26)$$

General reaction (27)

$$K_2\ CrO_4 + NaCl + 3AgNO3 \longrightarrow AgCl + Ag_2CrO_4 + 2\ KNO_3 \qquad (27)$$

• **Expression of results:** using the following Expression 28

$$NaCl\ (\%)=2.N.V.58,\ 45 \qquad (28)$$

V: Volume of $AgNO_3$ poured in ml

N: Normality of the $AgNO_3$ solution

Acid attack

Operating mode

Once the sample is dried and crushed we proceed to the acid attack using the equipment and reagents showed in Table 34, we place 1 g of our sample in the bottom of a beaker and gently add the acid (here the aqua regia (40 ml of HCl + 20 ml of HNO)), place it on a hot plate and let evaporate completely. We take the remaining residue and add 20 ml of chloridric acid HCl, let evaporate dry, add 10ml of distilled water to our residue and bring it to a boil for 1mn.Repeat the operation by adding 20 ml of distilled water for 10 minutes then 100 ml for 15 minutes still boiling, then filter. After filtration the precipitate and the filtrate are recovered. The titration is started until the turn (coloring of the mixture from pink to purple) notes volume V1 on the burette. We take the filtrate and place it in a 250 ml volumetric flask and complete our solution up to gauge with distilled water.

Equipment used	**Reagents used**
-Hot plate -Agitator and magnetic bar -Analytical balance -Burette - Specimens. - 500 ml beaker previously washed with distilled water and - oven-dried at 105°C.	- Distilled water - HCl hydrochloric acid and HNO Nitric Acid (Figure 55) - Filter.

Table 34 : The equipment and reagents used during acid attack (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Figure 55 : HCl hydrochloric acid and HNO nitric acid (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

VII.10.3. Calcium determination

Procedure:

To realize this procedure we need equipments and reagents showed in Table 35. Before dosing the Ca^{2+} and Mg^{2+} , we must neutralize the annoying ferric ions, we add to our test sample nitric acid

HNO concentrated hot until oxidation of Fe^{2+} in Fe^{3+} we let cool for a moment and we precipitate with NHOH concentrated at pH=8, filter in a volumetric flask and complete with distilled water then dose. Place in an erlenmeyer 25 ml of the filtrate, add 5ml of solution (NaOH), and a pinch of MUREXIDE. Put it under agitation. The burette is filled with the solution (EDTA).

Equipment used	Reagents used
-Burette - Stirrer and magnetic bar - Analytical balance sheet - 1 ml pipette and 20 or 25 ml pipette - Erlenmeyer. - 25 ml beakers pre-watered - distilled and dried	- Distilled water - NaOH solution (pH=13) prepared by dissolving 2 g NaOH in distilled water and diluting to 100 ml. - EDTA solution at 0.1 M and Indicator colored the MUREXIDE (Figure 56)

Table 35: The equipment and reagents used for calcium determination (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Figure 56 : Solution d'EDTA et Indicateur coloré la MUREXIDE (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Reactions (29, 30 and 31):

The indicator is characterised by the Formula H_2R:

$$R^{-2}+2H^{+}\rightarrow H_2R \quad (29)$$

$$H_2R+Ca^{2+}\rightarrow \mathrm{CaR}+2H^{+} \quad (30)$$

$$\mathrm{Na}[H_2N_2C_{10}H_{12}O_8Na_2]+\mathrm{CaR}\rightarrow \mathrm{Na}[CaN_2C_{10}H_{12}O_8Na_2]+H_2R \quad (31)$$

Expression of results: using the following Expression 32

$$Ca^{2+}(\%) = 4.08.V1 \tag{32}$$

VII.10.4. Dermination of magnesium

Procedure:

To realize this test we need equipment and reagents showed in Table 36. Place 25 ml of the filtrate in a beaker. Add 5 ml of the buffer solution. Introduces a pinch of the colored indicator Black Eriochrome. The mixture is stirred. The burette is filled with the solution (EDTA).The titration is started until the turn (colouring of the mixture from brownish red to blue). Note on the burette the volume of EDTA poured V2.

Equipment used	Reagents used
- Burette - Agitator and magnetic bar -5 ml pipette - 50 ml beakers previously washed with distilled water and dried in oven at 105 °C - Analytical balance	- Distilled water - pH 10 buffer solution (Figure 57): Prepared by dissolving 67.5 g of ammonium chloride (NH_4Cl) in 570 ml of ammonia solution (NH_3). This mixture is stirred until homogenisation and then adjusted to one liter with distilled water. When the solution is ready, the pH is checked. - EDTA Solution - Eriochrome Black coloured indicator.

Table 36: The equipment and reagents used for magnesium determination (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Figure 57 : Buffer solution (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Expression of results:

The magnesium ion content of the following Expression 33 is calculated:

$$\%Mg^{2+}=2,4312\ .(V2-V1) \qquad (33)$$

V2: Volume of EDTA in ml needed for titration of sum Ca^{+2}+Mg^{+2}
V1: Volume of EDTA in ml needed for titration of calcium Ca^{+2}.

The reactions (34 and 35):

$$(H_2Y)^{-2} + Mg^{2+} \rightarrow (MgY)^{-2} + 2H^{+} \text{ (rouge brunâtre)} \qquad (34)$$

$$N_2[H_2\ \text{EDTA}] + \text{Mg-R} \rightarrow Na_2\ [\text{Mg EDTA}] + H_2\text{R} \text{ (bleu)} \qquad (35)$$

VII.10.5. Determination of iron

Procedure

To realize this procedure we need equipment and reagents showed in Table 37. The iron parameter is monitored by colorimetric method where the reagent (Ferrover) reacts with all dissolved iron and most insoluble forms of iron present in the sample, to produce soluble ferrous iron. Ferrous iron reacts with the (1,10- phenanthroline) of the reagent to form an orange coloration proportional to the concentration of iron.

Equipment used	Reagents used
-Spectrophotometer DR 3900 (Figure 58)	- Distilled water - the reagent (Ferrover HACH)

Table 37 : The equipment and reagents used for iron determination (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Figure 58 : DR 3900 spectrophotometer with iron cell (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

VII.10.6. Determination of sulphate

To realize this procedure we need equipment and reagents showed in Table 38. Turn on the spectrophotometer DR 3900 and enter the program number stored for sulphate (SO_4^{2-}) [680 sulphate].We fill a sample cell with 10 ml of our prepared solution and place it in the spectrophotometer DR 3900 and apuit on the ZERO. Add the contents of one reagent capsule (sulfaver 4) to the sample cell. Close the cell and stir several times. In the presence of sulphate, white turbidity precipitates. After 5 minutes it was clear on read to read the result.

Equipment used	Reagents used
- Spectrophotometer DR 3900 (Figure 59)	- Distilled water - reagent (sulfaver 4)

Table 38: The equipment and reagents used for sulphate determination (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Figure 59 : DR 3900 spectrophotometer with sulphate cell (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

VII.10.7. Phosphate determination

To realize this procedure we need equipment and reagents showed in Table 39. Turn on the spectrophotometer DR 3900 and enter the program number stored for Phosphate (PO_3) [535]. Fill a sample cell with 10 ml of our prepared solution and place it in the spectrophotometer DR 3900 and on the ZERO. Add the contents of a reagent capsule (Phosver3) to the sample cell. Close the cell and stir several times. In the presence of phosphate, white turbidity precipitates. After 2 minutes it was clear on read to read the result.

Equipment used	Reagents used
- Spectrophotometer DR 3900	- Distilled water - Sample of filtered solution - Phosphate reagent (Phosver3)

Table 39: The equipment and reagents used for phosphate determination (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

VII.10.8. Determination of nitrite

To realize this procedure we need equipment and reagents showed in Table 40. Turn on the spectrophotometer DR 3900 and enter the program number stored for Nitrite (NO_2). Fill a sample cell (1) with 10 ml of our prepared solution and add the contents of a reagent capsule (Nitriver3) to the sample cell. Close the cell and shake it several times. We leave a reaction period of 20mn, when the timer sounds, we fill another cell (2) with the same sample (the white). Place it in the spectrophotometer DR 3900 and it was apuit on the ZERO. We replace the cell (2) by the cell (1) with the reactif in the presence of Nitrite, a pink stain develops. read to read the result.

Equipment used	Reagents used
- Spectrophotometer DR 3900 (Figure 60)	- Distilled water - Sample of filtered solution Nitrite reagent (Nitriver3)

Table 40: The equipment and reagents used for nitrite determination (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Figure 60 : DR 3900 spectrophotometer with nitrite cell (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

VII.10.9. Determination of Barium Sulphate

Procedure

To realize this procedure we need equipment and reagents showed in Table 41. The insoluble residue obtained during the acid attack is taken back and then calcined in a 800 °C muffle furnace in a platinum crucible, the contents of the crucible are weighed and approximately 5 g of sodium carbonate is added, the fusion is made with the muffle at 900 °C for 30 minutes.

The crucible is removed and cooled in a dryer. During this time 200 cc of distilled water is boiled in a beaker. after cooling the crucible is introduced into the beaker and boiled until it takes off. We thus obtain in the filtrate silica, sodium sulphate and in the filter barium carbonate, we dissolve the continuous with concentrated HCl, we recover them in a beaker. Spread with distilled water and boil.We add H_2SO_4 10N, a white precipitate is formed energetically which indicates the presence of barium sulfate, we let rest 24 h then in filter, lava, dry, and we calcine at 800 °C.

Equipment used	**Reagents used**
- A platinum crucible - Agitator and magnetic bar - Analytical balance - A dryer - Oven - Filter -250 ml beakers previously washed with distilled water and dried in the oven at105 °C.	- Distilled water - HCl concentrated - Sodium carbonate and H_2SO_4 solution 10N (Figure 61)

Table 41: The equipment and reagents used for Barium Sulphate determination (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Figure 61 : Sodium carbonate and Solution H_2SO_4 (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

VII.10.10. Determination of Carbonates and Bicarbonates

This measure is based on the neutralization of a certain volume by a mineral acid, Presence of a pH meter to monitor the pH.

Procedure

To obtain the percentage of Carbonates and Bicarbonates we need equipment and reagents showed in Table 42. In a beaker 25 ml of water to be analysed is introduced and its pH determined, if the pH reading is greater than 8.3, the acid is poured slowly until this value is obtained and the volume V_1 read on the burette is noted. We continue to pour the acid slowly until pH=4.3 and we note the volume V_2 read on the burette.

Equipment used	Reagents used
- Burette - Stirrer and magnetic bar - pH meter (Figure 62) - 20 to 25ml pipette - 50 ml beakers previously washed with distilled water and dried in the oven at 105 °C	- Distilled water - Hydrochloric acid 0.05 N (Figure 62)

Table 42: The equipment and reagents used for Carbonates and Bicarbonates determination (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

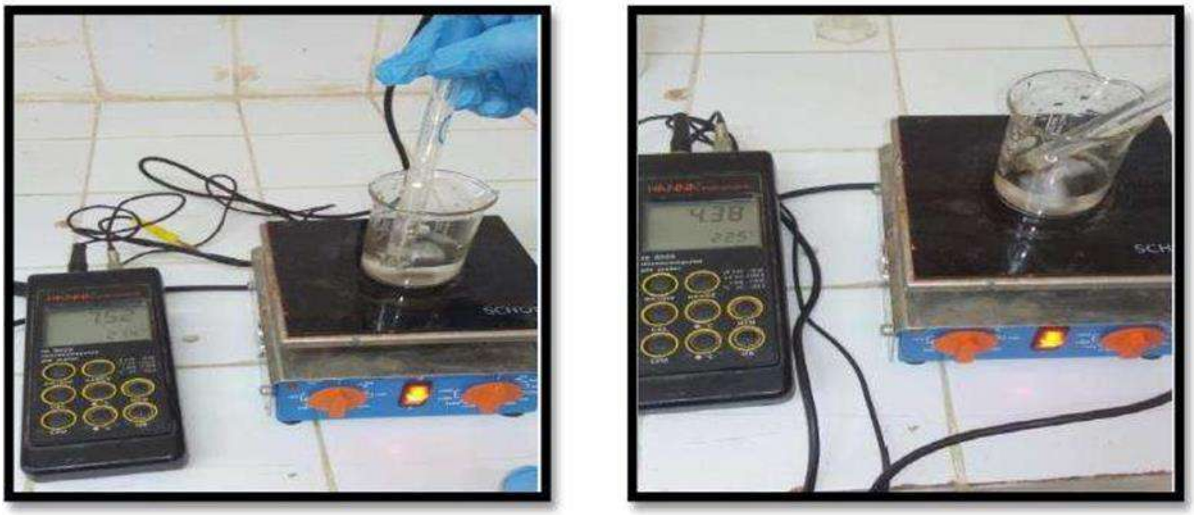


Figure 62: Hydrochloric acid and pH meter (Matrix acidizing technique, laboratory testing-Sonatrach, 2020).

Expression of results:

The concentrations of carbonates and bicarbonates expressed are given by the following Expressions 36 and 37:

$$[CO_3^{-2}]\ (\%) = 0.1V_1.60.10^3.\ N/PE \qquad (36)$$

$$[HCO_3^{-}]\ (\%) = 0.1V_2.61.10^3.\ N/0.1.PE \qquad (37)$$

V_1: Volume of acid in ml needed for neutralization at pH=8.3

V_2: Volume of acid in ml necessary for neutralization at pH=4.3

N: Normality of acid solution

PE: Test portion of water to be tested in ml

60.10^3: Atomic mass of carbonates in milligrams

61.10^3: Atomic mass of bicarbonates in milligrams.

VIII. Economic evaluation

The economic evaluation of acidification operations is essential to justify their application on wells. This consists on the one hand; to calculate the total cost of the operation, and on the other hand to know the production of the well (expressed in currency) before and after the stimulation, to be able to calculate the gain in flow and the depreciation (the number of days needed to recover the value of the investment). In this way and with simple calculations (shown below), one could judge the profitability of operations.

VIII.1. Annual acidizing gain

The annual acidification gain is calculated as the difference between the actual production cumulation of the well and the projected one, determined by extrapolation of the behaviour of the damaged well, as would have been the well had it not been treated. The calculation of the gain is as follows (Equation 38):

$$\boxed{\textbf{Cumulative gain} = \sum_{i=1}^{n}(Qi*Tpi) - \sum_{i=1}^{n}(Qs*Tpi)} \qquad (38)$$

Where :

Qi: monthly flow (m^3/h);

Qs: flow before acidification (m^3/h);

Tpi: monthly production time (h).

For the calculation of the fictitious cumulation, the flow rates prior to stimulation were used.

As an example, the graphs below show the difference between the actual production cumulation and the fictitious cumulation of two wells N17 for the year 2000 (Figure 63) and N9 for the year 2007 (Figure 64).

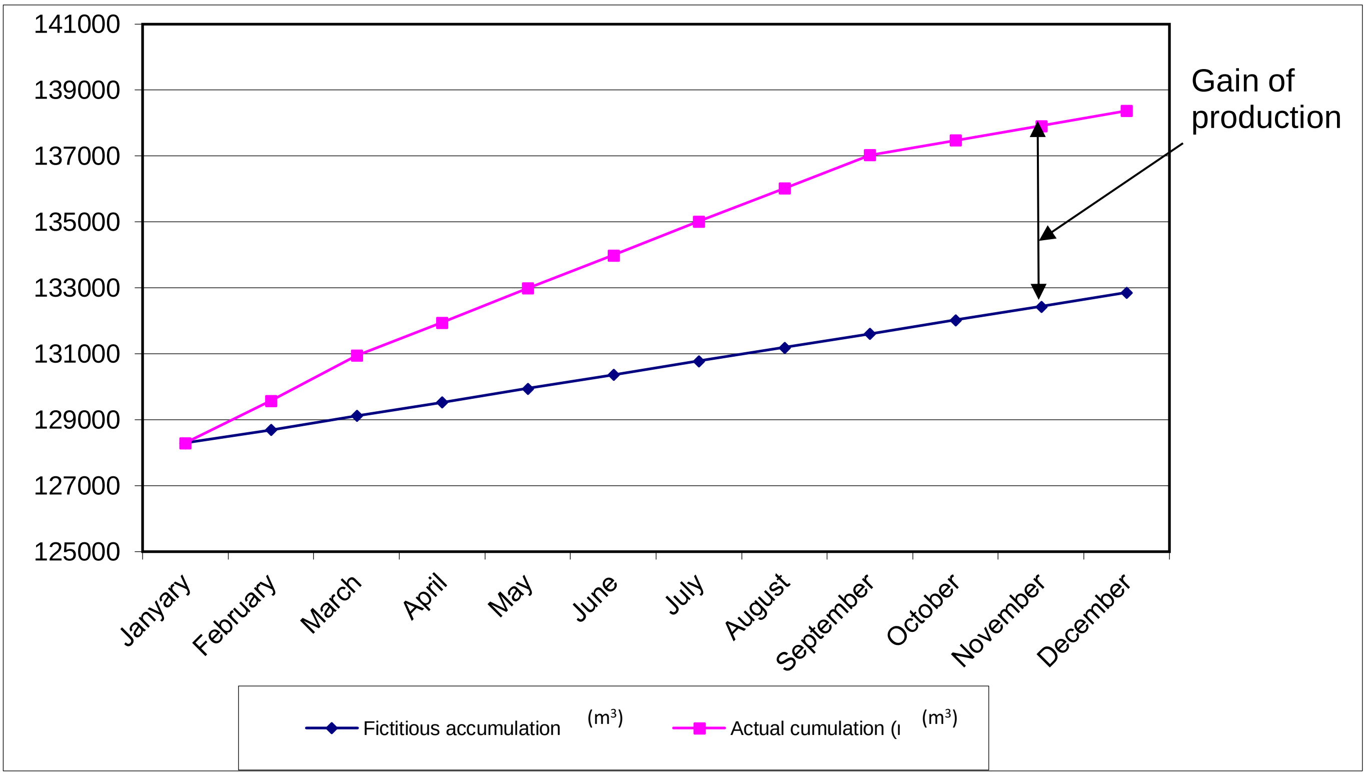


Figure 63 : Cumulation in production of two wells N17 for the year 2000.

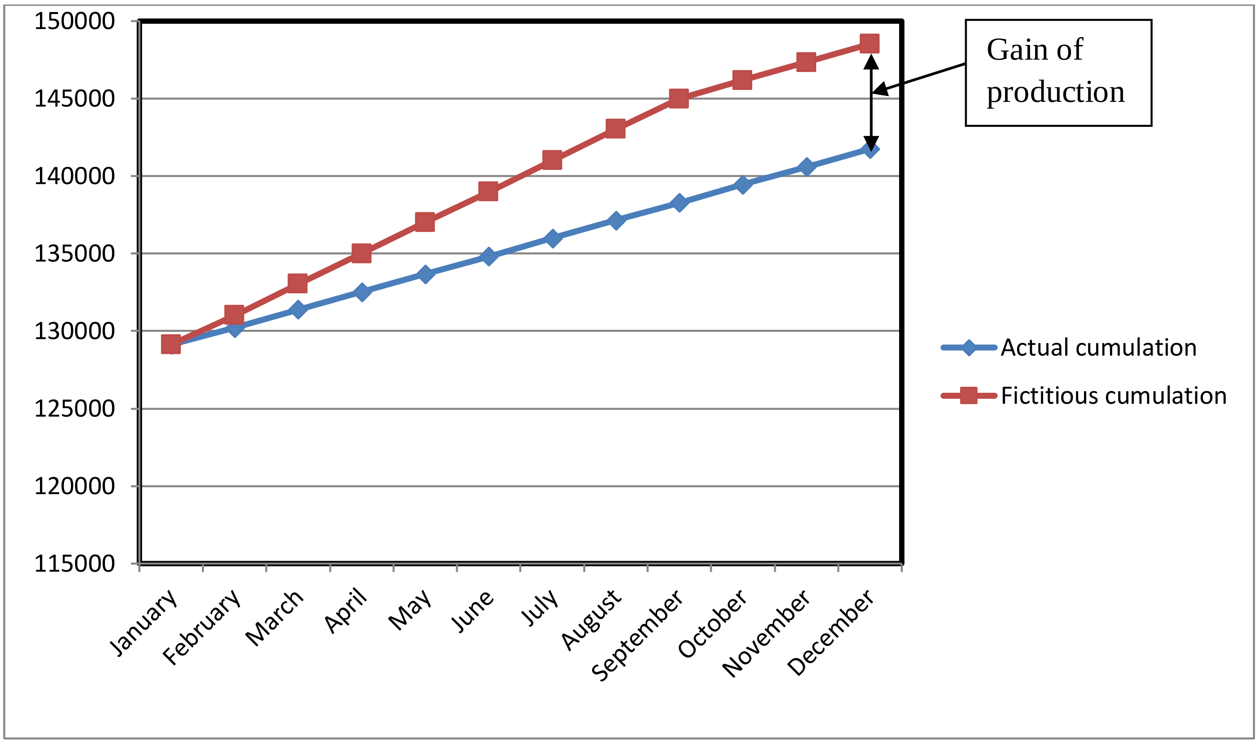


Figure 64 : Cumulation in production of two wells N9 for the year 2007.

It is noted that the monthly production time varies because of the different interventions on the well (work on the gas lift network, clogging by salts, etc.). To do this, we must study the state of the wells for the calculation of the monthly production time.

VIII.2. Calculation of the payout (Equation 39):

The Payout of an operation is equal to the number of production days that a treated well must deliver after treatment, to cover the cost of the operation by the net gain realized following treatment:

$$\boxed{\boldsymbol{Payout(days)} = \frac{\boldsymbol{equivalent\ volume\ cost(m^3)}}{\boldsymbol{net\ production\ gain(m^3/day)}}} \quad \textbf{(39)}$$

Conclusion

The combination of wells history data, different laboratory tests and an economic evaluation of matrix acidizing technique is essential before any decision to stimulate the wells and participates efficiently for better finding out the best acid system adapted to the reservoir formation, avoiding the operation failure and the creation of another damage around the wellbore region.

Chapter IV

Acidizing evaluation and laboratory results

Introduction

To achieve the goals of this study, acidizing operations were analyzed and different types of laboratory experiments were conducted. The laboratory work was carried out ranged from the acid and samples preparation to the execution of many tests then their results are presented and discussed in detail. This is followed by a presentation of different ARC test curves interpretation and some microscopic photos to understand more the chemical reactions between minerals and acid systems in order to find out the efficient one which leads to better reservoir permeability amelioration, minimizes the damage around the well area and reduces the percentage of the failure of this operation.

I. Acidizing operations analysis

I.1. Haoud Berkaoui field wells

I.1.1. The well N1

Fine migration and deposition of salt were the cause of its damage and the skin was estimated using transient well test (pressure build-up analysis) (Table 43). The high skin value (+10.7) explains the drop in flow and damage to the N1 well, causing degradation of the oil permeability. In addition, based on well history and experience, damage can be caused by Migration of fines (solids, salts, etc.) near the matrix and gradual accumulation around the well and partial blocking of perforations by salt. The well is acidified by the service company using AS2. The formation didnot react well with acid and matrix treatment resulted in a loss of 0.38 m^3. After acidification, the skin remains constant according to the value of the new skin (10.7); the well can be selected for another acidification because damage is not eliminated.

Date	**Type**	**T (°C)**	**Psb (Kgf/cm^2)**	**Kh (mD)**	**K (mD)**	**Skin**
18/05/2011	SBU	99	168,2	837	67	+10,7

Table 43: Well test data (Build-up 18/05/2011) of the well N1 (Sonatrach/ EP HBK, 2020).

Acidizing using AS1 on 23/11/2015

The well produced with a flow rate of 4.78 m^3/h for some time then the flow rate relapsed and the skin increased from 10.7 to 11.5, which requires stimulation. The well was acidified using AS2. A low permeability to oil after the acidification of this well with the AS2 system is due to a water inflow that is detected late; therefore, treatments are not necessary. These inflows are a result of the reservoir mechanism and the bad result of CBL (bad cementation), as well as the small distance 750 m that separates N53 from the first OKN441 injector well. This contributed to the problem of arrival, thus introduced a significant decrease in oil volume which implies an instauration and relative permeability to water. The skin is not due to matrix damage (the well was not a candidate for acidification).

Acidizing using AS2 on 23/11/2017

Build-up (of 21/10/2017) results gave a positive skin. This damage around the well was fine clay migration, deposition and reservoir invasion by drilling fluids was the cause of its damage. This well was acidized in two days. The first day: cleaning of tubing, liner and perforations by treated water and tube clean (HCl 7.5 %) nitrified. In the second day: treatment of the matrix with AS1 acid with different additives. Well production decreased from 4.7 m^3/h to 2.99 m^3/h and skin increased. This explains the inefficiency of this acid system. Figure 65 shows the evolution of oil rate before and after matrix acidizing operations done using different acid systems

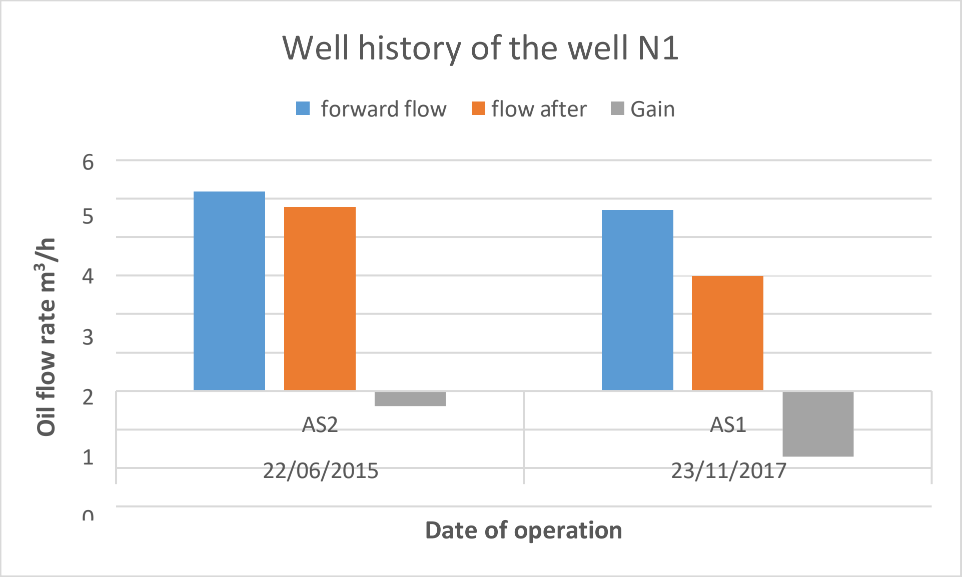


Figure 65: Acidizing history of the well N1.

I.1.2. The well N2

Acidizing using AS2 on 01/05/2014

The results of the build-up (of 02/04/2014) gave a positive skin. This shows that there is damage in the vicinity of the well, the latter causes a drop in the flow of 0.7665 m^3/h (gauge 26/ 01/ 2014). Migration of fine clay and deposition around the well and reservoir invasion by drilling fluids was the cause of its damage. It was acidified by the service company AS2 in two days. The first day: cleaning of tubing, liner and perforations by treated water and tube clean (HCl 7.5 %) nitrified. In the second day: treatment of the matrix with AS2 acid with different additives. After acidification, well production decreased from 2.85 m^3/h (31/03/2014) to 2.5 m^3/h (24/01/2015) and skin increased. This reflects the inefficiency of this acid system.

Acidizing using AS1 on 23/05/2016

The interpretation of the build-up 18/2/2016 gave a high skin equal to +13.2 that is to say; an additional loss of load (ΔPskin= 54.66 kg/cm^2) between the far zone and the bottom of the well (Pdb); this shows the damage of the edges of the well. It makes the flow efficiency low. Clogging of perforations by sand and clay deposits was the type of its damage. The well was acidified in two steps: the first phase: cleaning and washing of perforations (HCl 7.5 %).

Second phase: Treatment of the edges of the well with SA1 and start-up at nitrogen for the removal of all process fluids. After acidification, the well did not start (zero flow at the surface). After a restart by the KICK OFF system, the flow rate was deprived until it reached the value of 0.95 m^3/h. This qi shows that this acid system caused the appearance of secondary damage.

Acidizing using AS3 on 01/05/2015 and 06/05/2017

Clogging of perforations by sand and clay deposits was the damage of the well. It was acidified bythe cleaning and washing of perforations (HCl 7.5 %) first and the treatment of the vicinity of the well with AS3 and start-up using nitrogen for the removal of all process fluids. There is an increase in flow, so the acid reacted well with formation for AS3; this is justified by the good choice of acid. Figure 66 shows the evolution of oil rate before and after matrix acidizing operations done using different acid systems. Figure 67 shows a microscopic photo of a sample before and after acidizing.

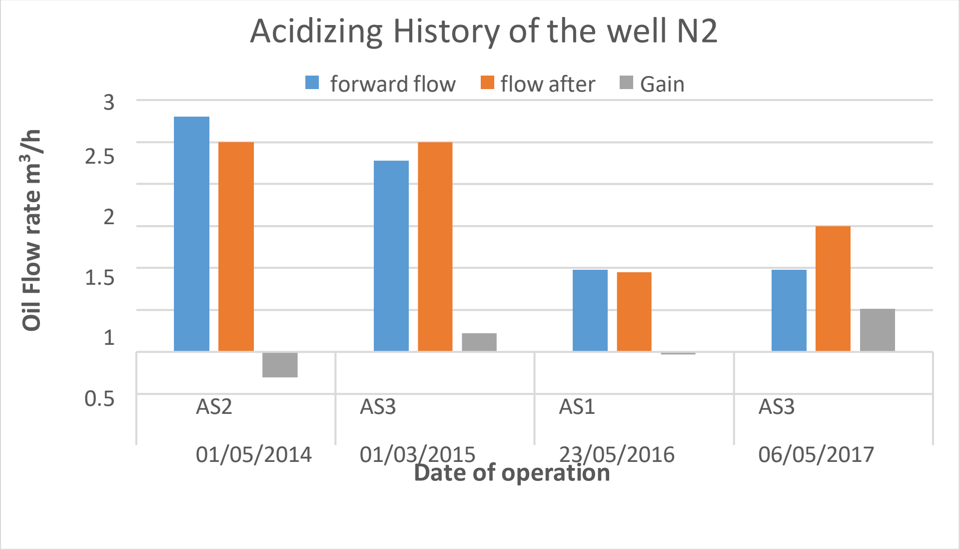
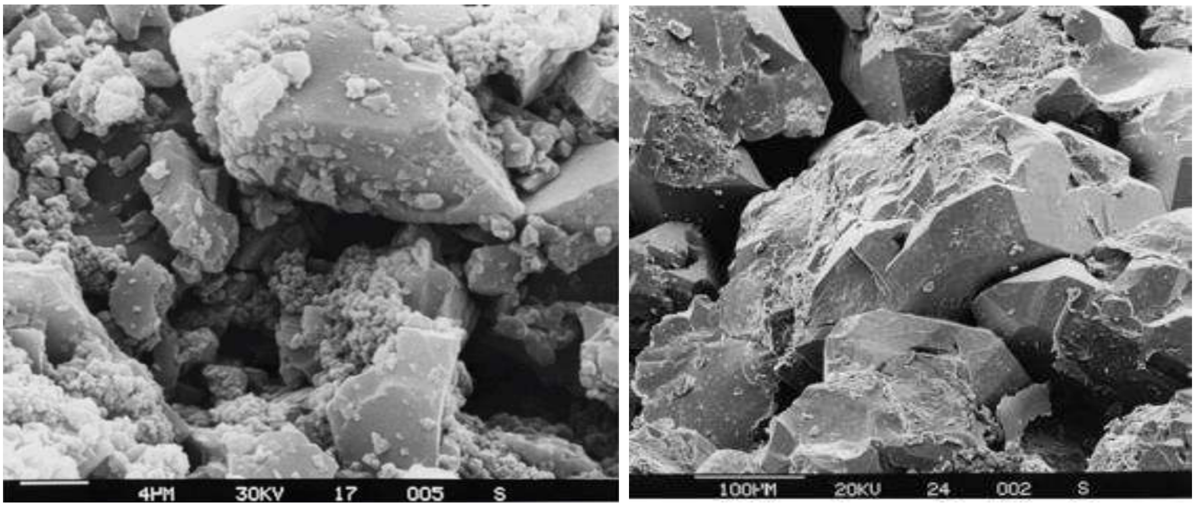


Figure 66 : Acidizing history of the well N2.



a b

Figure 67 : a. Sandstone with fines **b.** Clean sandstone (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

I.1.3. The well N3

The Build-up results on 06/03/2004 gave a positive skin (Table 44). From PLT data (Table 45) we note that most of the production comes from the first bench with a participation rate of 83.02%. Benches N5 and N6 produce with a very low rate and benches N2, N3 and N4 sound completely blocked.

Date	type	CM	T°	Pfs	Kh	K	skin
		m	°C	Kg/cm²	md.m	md	+5,74
06/03/2004	SBU	3500	100,45	220	415	11,7	

Table 44: Build up results of the well N4 (Sonatrach/ EP HBK, 2020).

Benches	Interval Perforated(m)	H(m)	Oil flow (m³/h)	Rate if participation (%)
N1	3508-3510,5	2,5	4,89	83,02
N2	3515-3516	1	-0,03	-0,51
N3	3517-3518,5	1,5		
N4	3519,5-3521	1,5		
N5	3528-3530	2,0	0,80	13,58
N6	3535-3537,5	2,5	0,23	3,9
Total		**11**	**5,89**	**100%**

Table 45: Well PLT Test of the well N4 (Sonatrach/ EP HBK, 2020).

The nodal analysis based on the results of the Build-Up (gauge of 02/03/2004) gave a positive skin estimated at +8 (gauge of 13/06/2007) which shows that there is damage around the well, the latter causes a fall in the flow of 0.72 m^3/h (Table 46).

Based on well history and field experience, damage may be of the following type:

*Fine clay migration and deposition in the vicinity of the well;

*Invasion of the reservoir by snubbing fluids.

*Partial blockage of the perforations by the salt deposit.

Well condition	Date	Skin	Qoil (m^3/h)	Phead (Kg/cm^2)	GLR (m^3/m^3)	Duse (mm)
Build Up	06/03/2004	**+5,74**	3,28	20,8	139	12,7
Before stimulation	13/06/2007	**+8**	2,56	16,6	278	16,8
After stimulation	04/10/2008	**+2,5**	4,56	15,2	142	16,8

Table 46: The characteristics of the well N4 before and after stimulation (Sonatrach/ EP HBK, 2020).

The recommended treatment was the following:

- Intensive cleaning of tubing and perforations with a CTU equipped with a Jet Blaster in order to eliminate all encrustations with circulation of the Tube clean and nitrified treated water.
- Treatment of the well edges with "Fines Control Acid" with three stages separated by a foam diversion plug.

The well is acidified by the Halliburton service company in two days on 16 and 17/07/2008

1st day: Cleaning of tubing, liner and perforations by nitrified treated water and Tube clean (HCl 7.5 %) nitrified.

2nd day: matrix treatment with «Fines Control Acid» with different additives.

The fluid system used is as follows:

Treated water 35.2 m^3

Foam base 8.33 m^3

Gel Pill 1.89 m^3

Tube Cleaning 1.89 m^3

Claysafe - 6.62 m^3

Fine Control Acid 6.62 m^3

Diveter/Spacer Foam 1.23 m^3

Nitrogen 15.7 m^3

After acidification the production of the well increased from 2.56 m^3/h (13/06/2007) to 4.56 m^3/h (04/10/2008) (a gain of 2m^3/h) and the skin is reduced from +8 to +2.5.

The formation reacted well with acid and matrix treatment reported a gain of 2 m^3/h.

After acidification, the skin decreased considerably (from +8 to +2.5), this shows the good identification of the damage and the good choice of the acid. The decrease in head pressure after acidification is justified by the decrease in GLR due to the removal of the lift gas system.

I.1.4. The well N4

The Build-up results on 08/03/2008 gave a positive skin (Table 47). The result of the PLT (Table 48) shows that the majority of flow produced came from sixth bench with a participation rate of 42.06 %, benches N1, N3 and N5 contribute with average rates respectively 13.59 %, 15.69 %, 11.09 % and 17.57 % and zero flow for bench N4. The high value of the skin (+24.9) estimated by the nodal analysis based on the Build-Up results (gauge of 27/02/2008), indicates the presence of severe damage near the well, especially at the N4 bank where the production flow is zero (based on LTP results of 30/04/2007).

The clogging of the matrix in the vicinity of the well is probably caused by the migration of the fine particles of the formation, this damage occurred gradually as the flow of oil production gradually dropped from the start of production of the well until today.

Date	**type**	**CM**	**T°**	**Pfs**	**Kh**	**K**	**skin**
		m	°C	Kg/cm²	mD.m	mD	**+24,9**
08/03/2008	SBU	3480	99,22	185	2743,2	117	

Table 47: Build up results of the well N4 (Sonatrach/ EP HBK, 2020).

Benches	**Interval Perforated(m)**	**H(m)**	**Oil flow (m^3/h)**
N1	3497-3498	1	13,59
N2	3499-3501	2	15,69
N3	3502-3506	4	11,09
N4	3512-3513	1	0,00
N5	3519-3521	2	17,57
N6	3523,5-3528	4,5	42,06
Total		**14,5**	**100%**

Table 48 : Well PLT Test of the well N4 (Sonatrach/ EP HBK, 2020).

The acidification operation is carried out on 25 and 26/03/2008 by the service company in two days:

Day 1: Washing of the production column and perforations by nitrified treated water and Tube Clean (HCl 7.5 %) nitrified.

Day 2: matrix treatment by Acetic Acid System & Mud Acetic Acid.

After acidification, the well did not start (zero surface flow) until restarted by the GLS lift gas system (a concentric lifting system) where the flow rate increases until it reaches the value of 4.51 m^3/h (26/04/2008). The oil production rate did not increase despite the considerable decrease of the skin (from +24.9 to +13.7) and despite the gas lift system. This negative result is probably due to the low reservoir pressure or the skin (+24.9) is not due to matrix damage (the well was not a candidate for acidification).

I.1.5. The well N5

The interpretation of the Build-Up of 06/12/2007 by the HORNER method gave a high skin equal to +13, 2 (Table 49) that is to say; an additional pressure loss (ΔPskin=54.66 kg/cm^2) between the distant zone (P*) and the bottom of the well (pfd), which shows the damage of the sides of the well, the latter makes the flow efficiency low.

The value of skin indicates a clogging of the formation near the well. Following the latter, the flow rate decreased from 3.6 m^3/h (BU date) to 2.91 m^3/h (before acidification).

The slope	4,76(kg/cm^2)/(cycle-log)	**k**	36,9 mD
P*	249,3 kg/cm^2	**skin**	+13,2
P1hr	241,72 kg/cm^2	**ΔPskin**	54,66 kg/cm^2
k.h	258 mD.m	**pfd**	183,14 kg/cm^2

Table 49: the interpretation of the BU by the HORNER method (well N5) (Sonatrach/ EP HBK, 2020).

In view of the above, the damage mechanism is attributed to the combination of the following:

*Invasion of the formation by drilling mud due to pressure difference during drilling;

*Wettability change: presence of surfactants in drilling mud can change wettability;

*Formation of emulsion due to invasion of formation by mud filtrate during drilling;

*Liner completion operations (cementing, perforation, etc.).

The well is acidified by service company in two days (25 and 26/03/2008) .The first day: Cleaning and washing of perforations and liner with Tube Clean (HCl 7.5 %) nitrified with foam gel to make the suspension of the cuttings. In the second day: treatment of the well edges with the **MUD CLEAN OB** and **MSR100** system. Well opening and nitrogen start for evacuation of all process fluids. The well flow rate increased from 2.91 m^3/h before acidification to 3.75 m^3/h after acidification, a gain of 0.84 m^3/h; this is justified by the good choice of the treatment acid and the smooth running of the acidification operation (a good disgorgement of the spent acids) (Table 50);

The new value of the skin (+7.4) shows that the damage is not completely removed and the well can be candidate for another stimulation (S =7.4 >0 => damaged formation).

Well condition	Date	Skin	Qoil (m^3/h)	Phead (Kg/cm^2)	GLR (m^3/m^3)	Duse (mm)
Build Up	06/12/2007	**+13,2**	**3,6**	15,1	107	11,5
Before stimulation	20/03/2008	**+13,8**	**2,91**	15,8	98	11,5
After stimulation	15/04/2008	**+7,4**	**3,75**	14,9	102	11,5

Table 50 : The characteristics of the well N5 before and after stimulation (Sonatrach/ EP HBK, 2020).

I.1.6. The well N6

The petrophysical characteristics of the well are average and lower than those of nearby wells. A drop in well pressure for the lower series by input to the nearby wells is probably explained by the introduction of nearby wells and the absence of injector wells for pressure maintenance.

Following the positive skin (+2.1) given by the build-up of 24/07/2005, the well is selected for an acidification stimulation using **«BJ Sandstone Acid»,** which was done on 24-25/08/2005. This acidification yielded a flow gain of 1.68 m^3/h.

From the well test data (Table 51),there is a significant depletion of reservoir pressure of the order of 44.11 kg/cm^2, this can be explained by the production of nearby wells and the absence of injector wells for pressure maintenance.

The significant decrease in permeability (from 59.8 md in 2005 to 21.8 md in 2008) is justified by damage to the well edges (see skin increased from +2.1 in 2005 to +3.73 in 2008) which requires further stimulation.

Date	type	C.M (m)	Pfs (Kg/cm^2)	Kh (mD.m)	K (mD)	skin
24/07/2005	SBU	3100	217,41	798,33	59,8	**2,1**
09/04/2008	LBU	3100	173,30	291,03	21,8	**+3,73**

Table 51 : Build up results of the well N6 (Sonatrach/ EP HBK, 2020).

The results of the Build-Up before acidification (05/04/2008) showed the existence of damage near the well ($S = +3.73 > 0$), the latter justifies the decrease of the flow rate from 8.26 m^3/h (10/02/2008) to 4.51 m^3/h (05/04/2008).

The sudden drop in production and a drop in reservoir pressure indicate damage to the matrix region. The mechanism of damage is attributed to the combination of the following:

Migration of fines (solids, salts, etc.) near the matrix and gradual accumulation of these near the well;

*Blockage by salt deposition;

*Progressive organic deposition near the well;

*Partial closure of perforations by fine particles;

The well is acidified by service company in two days (21-22/04/2008) .The first day: prior to treatment of the formation, the well will be cleaned with HCl to wash and remove all scales and deposits in the tubing and bottom of the well soluble in HCl. Treated water and gel are used to remove all debris and sediment from the bottom of the well. Treatment volumes were calculated to ensure a minimum radial penetration of 5 feet (1.5 m). In the second day: treatment of the well edges with Sandstone Acid BJSSA. The treatment is moved into the formation by treated water (NH_4Cl). The well was closed for one hour at the end of treatment. Kick-off is used to help start wells.

Despite the decrease of the skin (+1.78), acidification did not report the expected result (a very small gain: 0.09 m^3/h) (Table 52), this can be justified by the low reservoir pressure.

A snubbing took place on 27/06/2008 for the installation of a gas-lift system to lighten the producing column, which explains the increase in GLR and head pressure after acidification.

After 4 months of lifting, the flow rate of the well is increased to 5.55 m^3/h (gauge of 27/10/2008).

Well condition	Date	Skin	Qoil (m^3/h)	Phead (Kg/cm^2)	GLR (m^3/m^3)	Duse (mm)
Build-Up before stimulation	05/04/2008	**+ 3,73**	4,51	18,7	152	15,88
After stimulation	22/07/2008	**+1,78**	4,59	22,20	220	15,88

Table 52: The characteristics of the well N6 before and after stimulation (Sonatrach/ EP HBK, 2020).

I.1.7. The well N7

The Build-Up results gave a skin of +4 (22/05/2027), this value of the skin indicates that clogging may occur near the well, the latter was confirmed by the interpretation of PLT (14/09/2006). Production throughput fell to half its initial value (from 10.83 m^3/h in 2004 to 5.66 in 2007). Due to the gradual drop in flow, damage can be caused by migration of fine clay particles, destabilized by water and effluent flow and partial sealing of perforations by these particles.

The well is acidified by the service company Schlumberger in two days: **1st day:** washing of the production column and perforations with nitrified treated water and Tub Clean (HCl 7.5 %) nitrified.

2nd day: matrix treatment with Organic Clay Acid Regular with additives.

After acidification, the production flow of the well increased slightly from 5.66 m^3/h (Duse 18.26 mm) to 7.03 m^3/h (Duse 19.05 mm) despite the skin decreasing from +4 to +2 (Table 53), this can be interpreted as low reservoir pressure. The increase in head pressure, dynamic bottom pressure and GLR is due to the gas-lift system installed in the well after treatment.

Well condition	Date	Skin	Qoil (m^3/h)	Phead (Kg/cm^2)	GLR (m^3/m^3)	Duse (mm)
Build Up	27/06/2004	**-1,98**	10,83	50,7	121	12,7
Before stimulation	22/05/2007	**+4**	5,66	19,5	137	18,26
After stimulation	24/01/2008	**+2**	7,03	23,6	213	19,05

Table 53: The characteristics of the well N7 before and after stimulation (Sonatrach/ EP HBK, 2020).

I.2. Benkhla field wells

I.2.1. The well B1

The gauging and LTP data are shown in Table 54 and Table 55. Most of the production comes from benches N°1, N°4, and N ° 5 with rates of 20.66 %, 32.90 %, 38.49 % respectively, benches N ° 2 and N ° 3 produce with a very low rate. The water-cut sucks on all the benches. From the monthly production data, the flow curve and the diameter of the well inlet were plotted in Figure 68.

Date	Duse (mm)	P_{head} (kgf/cm²)	Oil salinity (mg/l)	Q.oil (m^3/h)	GOR (m^3/m^3)
27/03/12	9,12	143,00	18,00	14,53	159
03/06/12	9,12	133,10	12,00	13,93	159
01/02/13	9,12	105,40	187,00	11,06	162
11/06/13	9,12	82,10	12,00	8,71	159
22/03/14	9,12	60,70	23,00	6,67	153
04/12/14	9,12	52,90	10,00	5,74	150
14/05/15	5,95	63,10	12,00	2,63	136

Table 54: Results of gauging 2012-2015 of the well B1 (Sonatrach/ EP HBK, 2020).

Benches	Perforations (m)	Q_{oil} (m^3/h)	Taux (%)	Q_{water} (m^3/h)
N°1	**3422,00 - 3426,50**	2,99	20,66	0,00
N°2	**3431,50 - 3434,50**	0,27	1,87	0,00
N°3	**3438,00-3439,50**	0,88	6,08	0,00
N°4	**3443,00-3447,50**	4,76	32,90	0,00
N°5	**3448,00 -3450,00**	5,57	38,49	0,00
Total		14,47	100	0,00

Table 55: Well PLT Test of the well B1 (Sonatrach/ EP HBK, 2020).

Acidification by AS3 on 29/11/2015:

Precipitation of carbonate and sand deposits was the damage of the well. Since the commissioning of wells, until 25/02/2015, the oil flow of the well B1 has continued to fall (Figure 68), and in an accelerated way, as it appears in the curve above. We may think that this would be an accelerated depletion, especially since in this new area of the Benkahla field, pressure maintenance has not yet begun. In 1/10/2015 a change of duse was made after which a considerable revival of flow was observed. But this gain is not satisfactory when compared with the high potential of the reservoir P*=320.6 kgf/cm^2. According to the results of SBU (20/10/2015) it can be concluded that the well flow drop can be due to a blockage of the cracks by fine particles. Indeed, an acidification operation was implemented on 07/11/2015 by AS3, but the gain is still low value. This result does not reflect the incompatibility of the acid, but it is the consequence of the compact origin of the reservoir. This is why a hydraulic fracturing operation is recommended in 12/03/2016.

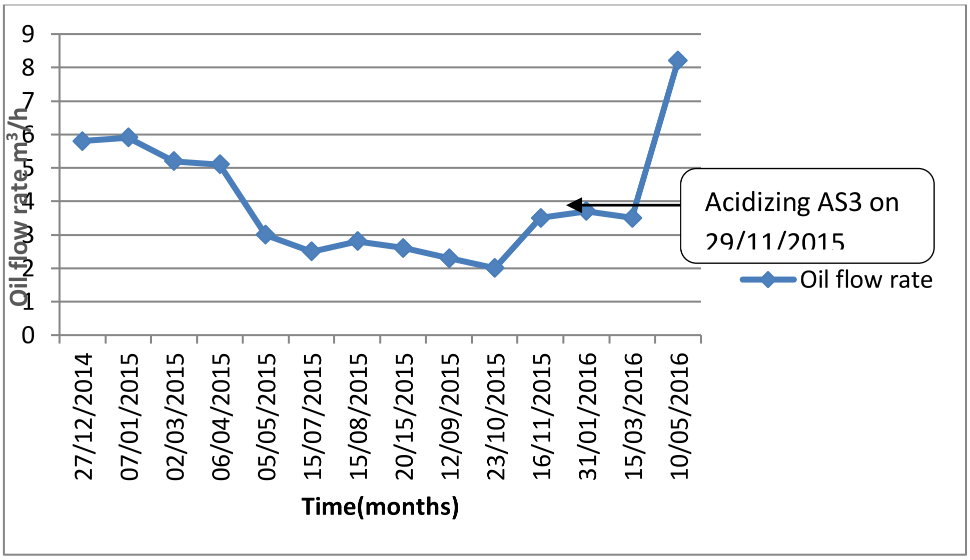


Figure 68 : Well flow rate curve of the well B1.

I.2.2. Well B2

Drilling mud (d=1.52, P drilling= 170 kg/cm²) and the fluid of completion (d=1.12) which remained in the well since the end of the completion on 23/11/2005 until the commissioning on 22/02/2009, a duration of more than 3 years. This situation led to its damage. After that, a sample of this well was analyzed to know the its nature (Table 56).

Deposits	Percentage (%)
Organic	5.64
NaCl	47.18
Iron deposit	14.3
Dry residue	31.28

Table 56: Results of deposit analysis (Deposit analysis 26/03/2009) (well B2) (Sonatrach/ EP HBK, 2020).

The results from the calculation of the pseudoskin (Table 57) reveal that the skin damage is large; equivalent to 2.77, it is probably due to the drilling mud, (d=1.52 sg, DP drilling = 190 kg/cm²), and as a result of the completion fluid (Invermul mud d=1.12 sg) which remained in the well from completion on 23/11/2005 until commissioning on 22/02/2009, a period of more than 3 years**.**

Figure 69 shows well flow history from 04/2009 to 02/2011.

Well	S_t	S_p	S_{pp}	S_L	S_{RC}	S_m	S_{dp}	S_w
BKRE1	-1.65	0.38	0.289	0.262	-4.4	-0.41	-0.549	2.777

Table 57 : The pseudo-skins of the well B2 (Sonatrach/ EP HBK, 2020).

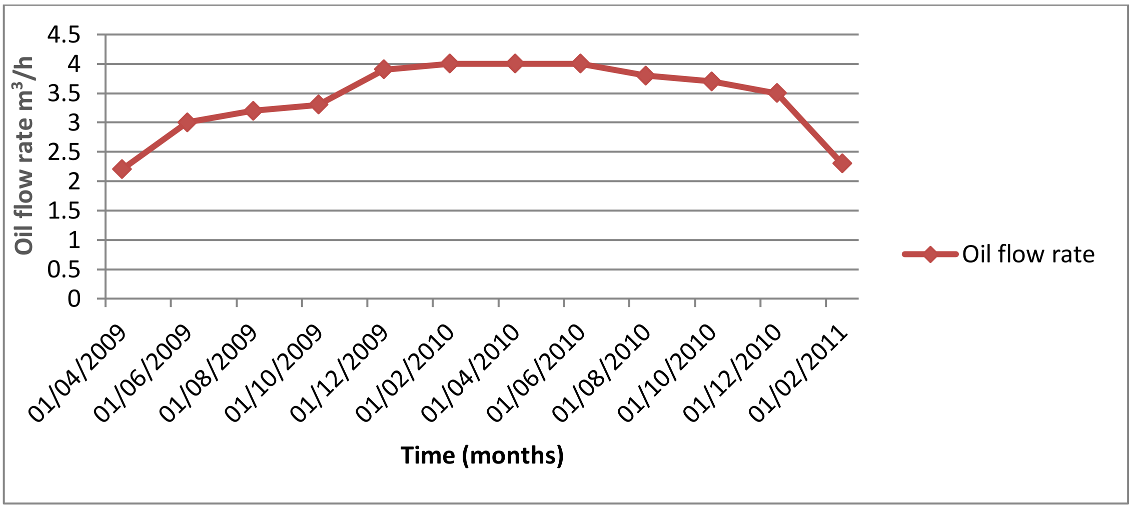


Figure 69: Flow rate history of the well B2.

The treatment adopted to eliminate or reduce this damage was as follows:

*Cleaning of perforated areas with 4 m^3 of Tube Clean HCl 7.5 % and treated water;

*NSO $_3$ m^3 squeeze to clean and extract mud from well edges and flow back matrix;3 m^{3}of Preflush (ClayFix-5 +ClaySafe-5);

*Matrix treatment of the well edges with 6 m^3 of SSCA;3 m^3 Overflush (ClayFix-5 + ClaySafe-5);

Filling the well will be done with foam, evacuation of all fluids and return to service of the well. After calibration of the model by the software, the IPR analyses show a skin that decreased from -1.65 to -3.25 after acidification. So the well was stimulated more than before. The production gain equal to 2.28 m^3/h (Figure 70).

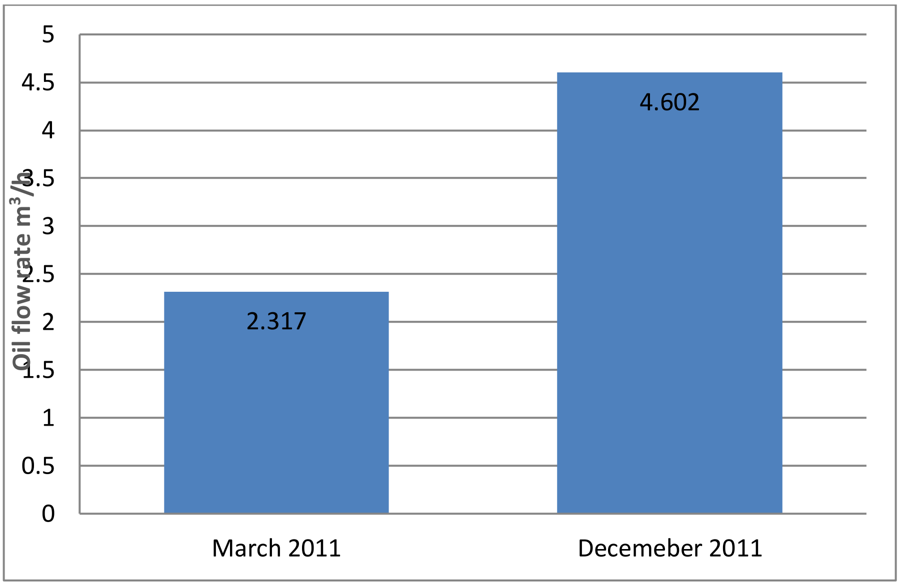


Figure 70: Changes of oil flow rate before and after acidizing of the B2 well.

Before and after acid bench production given by PLT and illustrated in the Figure 71 below:

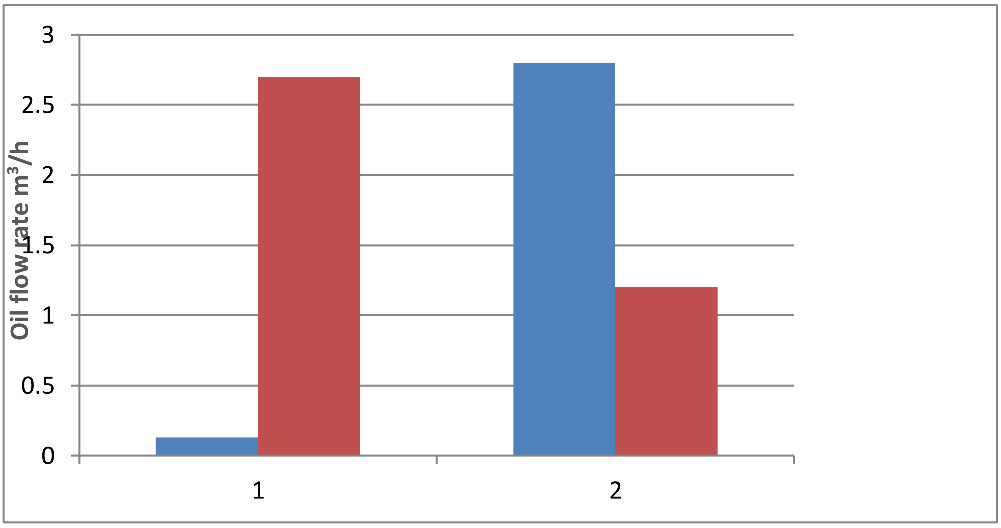


Figure 71 : PLT before and after acid well B2.

We see an inversion of the production profile of the benches. Production of bench N°1 is improved due to the dissolution of siliceous cement (Study CRD OKN53).

*On the other hand, the production of bench N°2 fell because of the deposition of fine particles clogging pores destabilized by HCl at a concentration of 13.5 %. Knowing that their percentage of clay is raised (see Table 58 below).

*For this acid, the phenomenon of the formation of fine particles sealing pores is also present (well OKN 53, CRD study confirms). This is attributed to the alteration of feldspars or the dissolution of illites because this clay tends to form fines under the action of acid.

Bench	Mineralogy	Vsh
1	Light grey to white, fine, friable, silico-clayey, pyriteus sandstone in places.	0%
2		4%

Table 58 : Mineralogical characteristics of the benches (Sonatrach/ EP HBK, 2020).

I.2.3. The well B3

Acidizing using AS1 on 28/08/2013 : Mixed organic and mineral deposit was the damage of this well. Build up results gave a positive skin +3.5. The well is acidified using AS1 in two days (27-28/08/2013). First day: washing of the production column and perforations with nitrified treated water and Tub Clean (HCl 7.5 %) nitrified. **2nd day:** matrix treatment with AS1 with additives. The formation did not react well with acid and matrix treatment is not satisfactory causing a diminution of oil flow rate from 13.79 m^3/h to 13.7 m^3/h which needs another intervention later.

Acidizing using AS3 on 22/01/2015 : The results of the Build-Up (18/04/2014) gave a positive skin estimated at 4.48 (Table 59). This shows that there is damage near the well; the latter caused a drop in flow. The well showed a decrease in daily oil production, this decrease in production is due to the existence of a mixed organic and mineral deposit near wells, as well as the migration of fine particles limiting oil production. The operation was carried out according to the work program, in two days.

Day 1: Wellhead pressure was nearly 700 psi before preflush acid injection (HCl 7.5 %), and pendent injection head pressure increased up to 1100 psi**.**

***Day 2:** Once the TC reached the TD, the well began to fill with treated water. Then it was followed by the main solution pumping. It was rinsed with treated water and then followed with nitrogen only. After acidification, flow increased considerably, which shows the right choice of acid.

Date	Type	CM	T°	Pfs	Kh	K	Skin
		M	°C	Kg/cm²	mD.m	mD	
18/04/2014	SBU	3400	103	314	386	33.6	**4,48**

Table 59: Build-up data (18/04/2014) of well B2 (Sonatrach/ EP HBK, 2020).

From LPT data (Table 60), the fourth bench B4 is the best producer, while the B1 saw its participation improved from 4.66 % to 11.69 %. Bench B2 participates with 12.21 % while the other benches B3, B5 and B6 contribute weakly. Table 61 shows the gauging data of this well during the period from 2013 to 2015 and Figure 72 shows the flow rate evolution during the period 06/05/2013 to 06/03/2016.

Benches	**Perforations (m)**	**PLT of 01/01/2015 Ø Duse = 13.49**				**PLT of 24/09/2013 Ø Duse = 15.88**			
		Q_o (m3/h)	**Taux (%)**	**Q_w (m^3/h)**	**Q_g (m^3/h)**	**Q_o (m^3/h)**	**Taux (%)**	**Q_w (m^3/h)**	**Qg (m^3/h)**
B1	**3421 - 3423.4**	1.14	11.69	0.00	194.06	0,68	4.66	0.00	110.42
B2	**3425 - 3426.5**	1.19	12.21	0.00	201.62	1.76	12.05	0.00	284.51
B3	**3427.3 - 3428**	0.72	7.38	0.00	122.24	1.03	7.05	0.00	165.96
B4	**3430 -3432**	6.69	68.62	0.00	1133.35	9.53	72.12	0.00	1705.3
B5	**3438.5 - 3439**	0.00	0.00	0.00	00	0.059	0.40	0.00	9.65
B6	**3440 -3443**	0.008	0.08	0.00	1.40	0.54	3.70	0.00	87.60
Total		9.75	100	0.00	1652.66	13.6	100	0.00	2363.5

Table 60: LTP data 2013 and 2015 of the well B3 (Sonatrach/ EP HBK, 2020).

Date	**P_{head}**	**P_{pipe}**	**Duse**	**Oil salinity**	**Qo**	**Qg**	**WC**	**GLR_{form}**
	Kgf/cm²	**Kgf/cm²**	**mm**	**mg/l**	**(m^3/h)**	**(m^3/h)**	**%**	**(m^3/m^3)**
22/01/2013	56.20	14.90	13.49	12.00	13.79	1986,81	0	144.00
06/03/2014	43.70	15.00	13.49	10.00	10.56	522,97	0	149.00
12/04/2014	52.20	14.20	13.49	129.00	11.34	632,33	0	167.00
01/12/2014	41.30	14.30	13.49	12.00	10.06	484,82	0	145.00
17/05/2015	42.50	14.30	13.49	12.00	10.14	488,95	0	145.00
18/10/2015	45.80	15.10	13.49	12.00	10.45	1586,00	0	152.00

Table 61: well gauging data B3 (Sonatrach/ EP HBK, 2020).

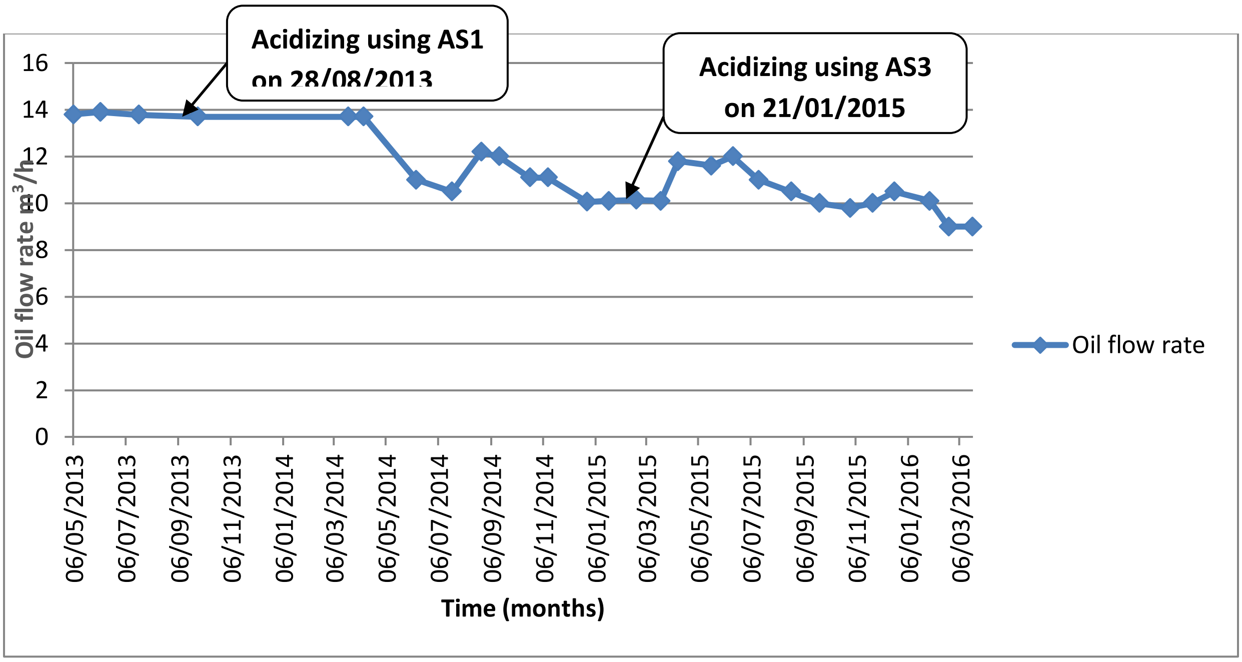


Figure 72: Flow rate variation well B3.

I.2.4. The well B4

Acidizing using Organic Clay Acid on 30/05/2016

Build-up results gave a positive skin. This damage around the well was rust and salt deposit around the perforations and near wellbore region. This well was acidized in two days. The first day: a **PreAcid Preflush** was used first before the preflush which is a **MudCLEAN-OB**. It is a water base solution used as cleanup fluid for the removal of oil base mud damage prior to a stimulation treatment by reducing viscosity, dispersing fines and returning the formation to a water-wet state. The MudCLEAN OB solution will be staged with a good cleanup acid OCA HT, The staging is made so that MudCLEAN OB is the first fluid to contact the formation. Most successful treatments use 100 to 300 gal of total treating fluid per foot of perforated interval. Approximately 30 to 40 % of the total treating fluid should be MudCLEAN OB.

Shut-in times on wells treated with MudCLEAN OB and acid should be short. Rapid return of treating fluids will minimize settling and re deposition of fines. After that the **Preflush:** fluid is 10 % Acetic acid containing F105 Surfactant. The primary advantage of aqueous acetic acid is that it can be inhibited for use at high temperatures for extended exposure times. In addition, it offers a slow rate of reaction with carbonate minerals, provides buffered action for clay control, and effectively controls the precipitation of ferric iron from spent acid solutions. In the second day: treatment of the matrix with **Organic Clay Acid** Concentration suggested is for 3 ft radial penetration. The Organic Clay Acid (OCA) system is designed for acidizing sandstones containing high clay content and HCl sensitive minerals, such as zeolite and chlorite when used in matrix acidizing applications, OCA has the following functions:

- Remove formation damage caused by clay and other aluminosilicate minerals.
- Minimize hydrated silica precipitation, a secondary reaction.
- Prevent migration of undissolved fines after acidizing treatments.

The final stage is the Overflush: fluid is also 10 % Acetic acid containing F105 Surfactant. Its main function is to keep the pH favorable to avoid ferric hydroxide precipitation and to have faster cleanup of stimulation fluid during flowback. The **Displacement** fluid is the **Spacer** fluid, **3 %** Ammonium Chloride. It is pumped in behind the Main Treating fluid.

After the operation, well production decreased from 1.922 m^3/h to 1.437 m^3/h and skin increased. This explains the inefficiency of this acid system.

I.3. Perehery zone wells

I.3.1. The well P1

Acidizing using Organic Clay Acid on 09-10/05/2014

Drilling mud used was the cause of its damage, the oil flow rate was 4.038 m^3/h (gauge on 4/3/2014) and the skin was estimated before stimulation (+19).The high skin value explains the drop in flow and damage to the N1 well, causing degradation of the oil permeability. The well is acidified by the service company using AS in two days. The formation reacted well with acid and after the operation the flow rates increases to 7.533 m^3/h (gauge on 11/6/2014).

Acidizing using Mud Acid (AS3) on 04-05/11/2015

Clogging of perforations by sand and clay deposits was the damage of the well (the oil flow rate decreased to Q_o= 3.635 m^3/h (Gauge on 08/10/2015)). It was acidified by the cleaning and washing of perforations (HCl 7.5 %) first and the treatment of the vicinity of the well with AS3 and start-up using nitrogen for the removal of all process fluids. There is an increase in flow (Q_o= 6.257 m^3/h), so the acid reacted well with formation for AS3; this is justified by the good choice of acid.

II. Assessment of damage rates

Damage types are divided into two categories:

* Damage following an intervention (workover, completion, cementation, etc.).

*Damage caused by formation (salt deposits, migration of fines, etc.).

The Table 62 below illustrates the types of damage, skins before and after acidification and flow gain for the wells studied.

Well	Skin before	Type of damage	Skin after
N3	**+8**	-migration of fine clays -swelling of clays	**+2,5**
N4	**+24,9**	- Migration of fines of different kinds;	**+13,7**
N5	**+13,8**	- Invasion by drilling mud; - swelling of clays - completion operation	**+7,4**
N7	**+4**	- Migration of fines of different kinds;	**+2**
N1	**+10,7**	-accumulation of particles near the well -salt blocking	**+5,1**
N6	**+3,73**	-Organic deposit -Fine migration -Salt deposit	**+1,78**
N2	**+13.2**	- Migration of fine clay and deposition -Sand and clay deposits	**+6.7**
B1	**+4.5**	-Precipitation of Carbonate and sand deposit	**-1.71**
B2	**-1.65**	-Organic deposit /NaCl/Iron /Dry residue	**-3.25**
B3	**+4.48**	-Mixed Organic and mineral deposit -Migration of fines	**+4.1**
	+3.5	-Mixed Organic and mineral deposit	**+3.1**
B4	**+2.3**	- Rust and salt deposit	**+2**
P1	**+19**	- Drilling mud	**+13**

Table 62: Assessment of well damage rates.

The estimated skins, whose values differ depending on the type of well, attest to the damage that has been sustained in each one. It is observed that, following acidification, the skins of the wells under study are thinner, albeit to differing degrees. The two primary sources of damage that impact production in the Haoud Berakoui fields are drilling mud invasion and workover fluid. It should be noted that in this field, injection wells can also become acidic. This is because the impurities in the injected water cause the clay to swell and clog its pores. These impurities are the result of bacterial corrosion. These anaerobic bacteria are known as sulfate-reducing bacteria, and they typically grow in humid soils. By means of a chemical process, sulfate-reducing bacteria attack the metal. As a byproduct of reducing the sulfate (SO_4) in the water, they release hydrogen sulfide (H_2S), which is highly caustic to metallic infrastructure below ground (Derradji M.M 2003). Iron sulfide FeS is the byproduct of this attack that plugs the perforation. In order to stop the growth of bacteria in the injected water, a corrosion inhibitor known as "Bactericides" was injected into the Haoud Berkaoui fields. However, due to the exponential growth of sulfate-reducing bacteria and their capacity to adapt to inhibitors, this preventive strategy is not very effective.

II.1. Deposit laboratory analysis

A deposit sample collected (OKN70) on 19/04/2022 recovered from the pipe HBK has been entrusted to us in order to know the nature of this deposit. For this, physical and chemical analyses were performed, the results of which are illustrated as follows (Table 63):

Composition	Percentage (%)
Dampness	2.55
Organic matter	29.06
Mineral material	68.39

Table 63 : Physical analysis results of the repository (Sonatrach/ EP HBK, 2020).

II.1.1. Results of chemical analysis of the deposit

The qualitative and quantitative knowledge of elements present in the deposits is paramount, to diagnose the origin and type of damage. For the choice of a good treatment of physical and chemical analyses specific are required. The formation of deposits depends on several conditions. So before preventing it is necessary to make a specific study of favourable deposit formation conditions. These conditions change also with the nature of deposit, each type of deposit requires analysis.

An N70 deposition sample taken is recovered from the oil pipe of a well of HBK, has been entrusted to us in order to know the nature of this deposit. For this physical and chemical analyses were performed with the following results:

-In the light of the results obtained by the physical analyses carried out on the sample deposit

on 19/04/2022 at the HBK oil pipe, it can be concluded that the deposit consists of 68.39 % mineral matter and a content equal to 29.06 % material organic.

- After the chemical analysis, the mineral part of the deposit taken on 19/04/2022 at HBK oil pipe level is composed of: Iron, and insoluble materials (Table 64).

Composition	Percentage (%)
NaCl	3.507
Ca^{2+}	1.632
Mg^{2+}	4.376
Fer	53
So_4^{2-}	0.025
PO_4^{3-}	0.005
NO_2^-	0.000225
$BaSO_4$	0
CO_3^{-2}	0
HCO_3^-	3.05

Table 64 : Results of chemical analyses of the repository of the well N70 (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

III. Assessment of flow rates

The chosen wells in the Haoud Berkaoui fields (Figure 73) can be classified according to the results of acidifications carried out on these wells during the years 2007, 2008, 2011, 2013, 2014, 2015, 2016 and 2017 in three groups (Table 65):

- Successful wells.
- Wells with average to low gain.
- Wells giving negative results.

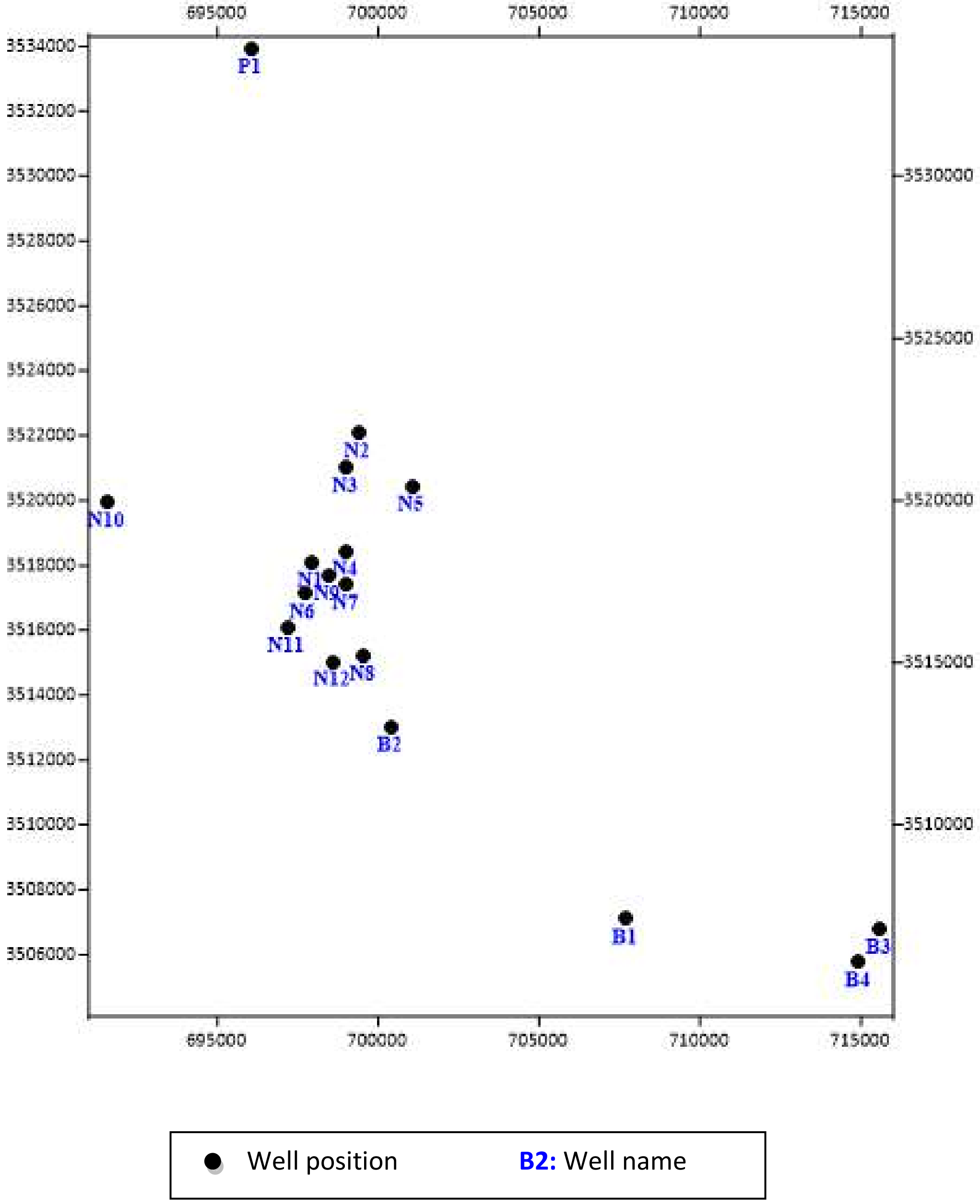


Figure 73 : Position map of selected wells.

	Well	**Date of acidification**	**Acid System Used**	**Qbefore (m^3/hr)**	**Qafter (m^3/hr)**	**Gain / loss (m^3/hr)**
Good results	**N3**	16/07/2008	-Fines Control Acid	2,56	4,56	**+2,00**
	N7	09/08/2007	-Organic Clay Acid Regular (OCA)	5,66	7,03	**+1,37**
	N1	19/07/2008	-Fines Control Acid	4,87	6,20	**+1,33**
	N8	02/01/2007	-BJ Sandstone acid (AS2)	1,57	2,72	**+1,15**
	B2	19-20/11/2011	-SCCA (AS1)+Clay fix-5	2.317	4.602	**+2.285**
	P1	4-5/11/2015	- Organic Clay Acid	3.635	6.257	**+2.622**
Medium to low gain	**B1**	6-7/11/2015	-AS3 (Mud ACID 6 Hcl 1.5 HF)	2.625	3.517	**+0.892**
	N4	25/03/2008	- Acetic acid -mud Acetic acid	4,47	4,51	**+0,04**
	N5	27/03/2008	-mud clean OB -MSR 100	2,91	3,75	**+0,84**
	N6	22/04/2007	- BJ Sandstone acid (AS2)	4,51	4,59	**+0,09**
	N2	01/05/2014	-AS2	2.85	2.5	**+0.35**
		01/05/2015	-AS3	2.25	2.5	**+0.25**
		23/05/2016	-AS1	0.95	0.92	**+0.03**
		06/05/2017	-AS3	0.95	1.5	**+0.55**
	B3	21-22/01/2015	-AS 3	10.053	10.144	**+0.091**
Negative results	**N9**	12/08/2007	- Mud Acid-Acetic acid (6:1.5:10)	3,97	2,15	**-1,82**
	N1	23/11/2017	-AS2	4.7	2.99	**-1.71**
	N10	04/06/2007	-Mud Acid-Acetic acid (6:1.5:5)	3,48	1,36	**-2,12**
	N11	07/07/2007	- Organic Clay Acid Regular (OCA)	2,19	1,86	**-0,33**
	N1	23/11/2015	-AS1	5.1	4.72	**-0.38**
	N12	27/06/2008	-BJ Sandstone acid (AS2)	1,08	1,02	**-0,06**
	B3	28/08/2013	-AS1	13.79	13.7	**-0.09**
	B4	1-2/06/2016	- Mud CLEAN-OB -Organic Clay Acid (OCA)	1.922	1.437	**-0.485**
	N2	23/05/2016	-AS1	0.99	0.95	**-0.04**

Table 65 : Flow gains/losses from the acidified wells at HBK.

According to the results of the gauges, it is noted that the flow in most of the wells studied increases using different types of acids with the exception of some wells which had a decrease of the flow. The rate of improvement varies from one well to another, from the change in the type of acid each time. Some wells have had good results (N3, N7, N1, N8, B2 and P1).This reflects the good choice of the acid system that removed the damage well and helped improve the petrophysical parameters. Others having medium results (B1, N5, N6, N4, N2 and B3) and low results (N2, N1, N9, N10, N11, N12, B3 and B4) this can be related to the absence of a rigorous bill of lading of the damage or the mineralogical composition of the reservoir. Several parameters affect the efficiency of acidifications in the Haoud Berkaoui field, including:

***Hole layer binding:**

Some wells in the HBK field are completed with strainers. The latter (strainers) have the following disadvantages:

*Selective treatment is uncontrollable due to areas with wide intervals;

*Difficulties in ensuring good acid coverage of areas of interest.

***Low reservoir pressures:**

Given the heterogeneity of the Haoud-Berkaoui deposit, pressure maintenance is not felt on allwells. Low reservoir pressure has the following disadvantages:

-Difficulty disgorging

-For oil-producing wells, the acid may flow to water-producing areas.

***Low permeability:**

The low permeabilities do not favour a good injectivity (low flow rates) of the treatment fluids and therefore the acid runs out before reaching the damage at depth.

***Reservoir heterogeneity:**

The lower series is the main reservoir to HAOUD BERKAOUI; it is composed of several units of different petrophysical characteristics. Therefore, the penetration of the acid is not always homogeneous even with the diversion to the foam.

***The reservoir temperature:**

The literature indicates that some types of clay destabilize in contact with HCl hydrochloric acid at temperatures above 80 °C. Systems composed of HCl should be used with caution because the average temperature of the reservoir is 100 °C, and mineralogical analyses indicate the presence of Chlorite and Illites on the cores of the Haoud Berkaoui wells.

IV. Laboratory results

IV.1. Diffraction RX

The results of Diffraction RX showed that the formation of Haoud Berkaoui is a sandstone. The high proportion of quartz with an average value of 91.27 % characterizes this formation. Some samples have a significant percentage of clay. We also found a very low percentage of carbonate (dolomite) in almost all samples. The detailed composition of the reservoir of five wells is showed in (Tables 66, 67, 68, 69 and 70).

Well N1										
Depth(m)	**Non-clay minerals**					**Clay minerals**			**Liants and ciments**	
	Quartz %	**Dolomite %**	**Siderite %**	**Anhydrite %**	**Pyrite %**	**Illite %**	**Chlorite %**	**Interstrat I-M %**	**Secondary Quartz %**	**Calcite %**
Sample 1	88	2	1	1	1	6	2	-	12	3
Sample 2	96	2	-	-	Tr	2	-	-	9	8
Sample 3	92	4	-	-	1	4	-	-	10	8
Sample 4	83	7	-	-	-	9	-	1	-	-
Sample 5	95	3	-	-	-	1	1	-	-	-
Sample 6	82	8	-	-	-	8	0.5	1.5	-	-

Table 66 : Mineralogy Data of the well N1 (Matrix acidizing stimulation technique,laboratory testing Sonatrach, 2020).

N° Sample	**Depth (m)**	**Non-clay minerals (%)**			**Clay minerals (%)**		
		Quartz	**Dolomite**	**Halite**	**Illite**	**Chlorite**	**Interstrat**
1	**3496.80**	90	2	Tr	7.2	0.8	-
2	**3503.10**	80	11	-	7.65	-	1.3
3	**3503.80**	90	-	-	9	1	-
4	**3508.40**	93	1	-	5.1	-	0.9
5	**3509.90**	70	2	2	23.4	2.6	-
6	**3492.50**	80	6	-	9.8	4.2	-
7	**3493.80**	98	-	-	0.8	1	0.2
8	**3494.75**	97	1	-	1	1	-

Table 67: Mineralogy Data of the well N2 (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

N° Sample	**Depth (m)**	**Non-clay minerals (%)**			**Clay minerals (%)**		
		Quartz	**Dolomite**	**Pyrite**	**Illite**	**Chlorite**	**Interstrat**
1	**3490.00**	97	-	-	2.7	0.3	-
2	**3493.15**	90	2	-	5.6	1.6	0.8
3	**3498.25**	88	-	10	1.9	0.1	-
4	**3463.50**	85	3	-	7	3	-
5	**3479.50**	80	7	-	7.8	5.2	-
6	**3498.55**	98	1	-	1	-	-
7	**3498.05**	94	3	-	1	-	-

Table 68: Mineralogy Data of the well N14 (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

N° Sample	Depth (m)	Non-clay minerals(%)			Clay minerals(%)	
		Quartz	Dolomite	Halite	Illite	Chlorite
1	**3559.60**	95	-	-	5	-
2	**3567.50**	98	-	1	1	-
3	**3585.90**	85	7	-	8	-
4	**3550.25**	97	1	1	1	-
5	**3582.50**	80	8	-	7.2	4.8

Table 69: Mineralogy Data of the well N11
(Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

N° Sample	Depth (m)	Non-clay minerals(%)			Clay minerals(%)			
		Quartz	Dolomite	Sidérite	Illite	Chlorite	Kaolinite	Interstrat
1	**3439.05**	97	-	-	2.7	-	-	0.3
2	**3457.20**	86	-	2	9	-	3	-
3	**3460.05**	86	2	-	9.6	1.8	0.6	-
4	**3438.40**	94	-	-	4.2	1.8	-	-
5	**3438.75**	98	1	-	-	-	-	-
6	**3457.60**	80	3	-	11.9	5.1	-	-

Table 70: Mineralogy Data of the well N15 (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

IV.1.1. The different cements of the lower series

a-Siliceous cement: early and late siliceous cement are distinguished.

a-1-Early siliceous cement: formed by a feeding of silica quartz grains in the form of a halo and some grains have two halo which translates two phases of feeding. Quartz grains show in most cases straight contact, punctual to floating, which would promote the precipitation of this early cement during the circulation of silica-rich waters.

a-2-Late siliceous cement : represented by cryptocrystalline secondary silica (Figure 76.a)that precipitates in porous spaces, this cement is due to:

-The progressive burial translating the compaction phenomena, which leads to the release of silica from the original quartz grains and its restoration in porous spaces.

-Alteration of micas and feldspars, transformation of clays and dissolution of quartz during burial under temperature conditions high and basic PH.

b- Carbonated cement (Figure 74): represented mainly by dolomite (Figure 75) which is distributed irregularly in theseries and it is abundant in the most clayey levels, it appears:

- Nodules or isolated beaches in which quartz bathe in certain clay levels.

-In zoned rhombohedra underlined by microfilm of iron oxide indicating several growth phases.

-In fine sandstone levels, speckled and scattered rhombohedra.

-Sometimes in the form of large crystal beaches and vein lets.

c-Evaporated cement: it is less widespread compared to previous cements, its distribution is irregular. It is mainly represented by anhydrite, barite and halite which precipitate from condensed naturalwaters.

-Anhydrite (Figure 77): manifests as beaches and nodules or filling intergranular spaces by corroding quartz, secondary silica and dolomite, sometimes it is affected by dissolution that improves petrophysical parameters, it is probably due to the circulation of water from the higher evaporative series or to the dehydration of gypsum in the sandstone levels, it precipitates from the diagenetic waters of thebarrym .

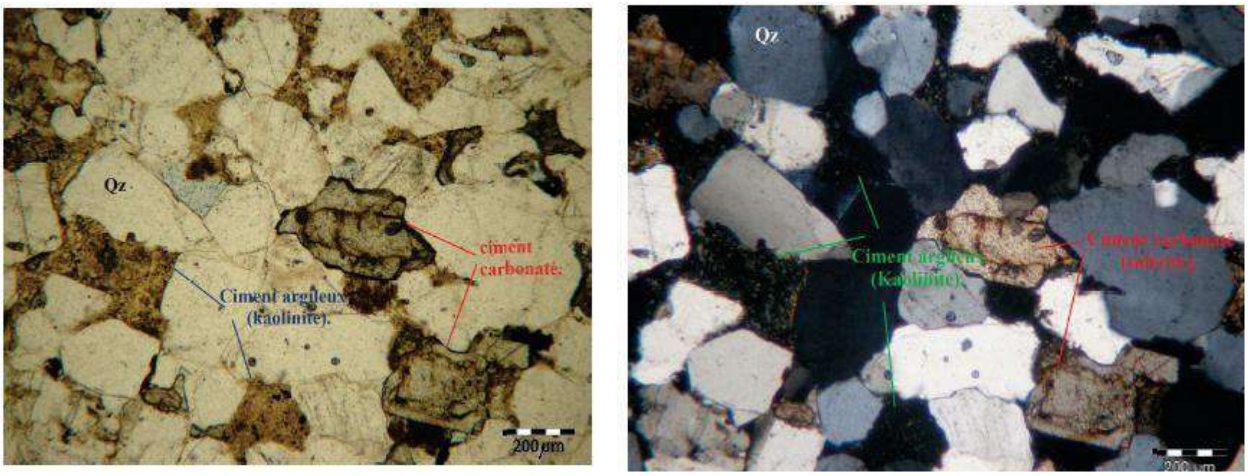
-Halite: presents as ghosts due to dissolution, it comes from the infiltration of water from the overlying Triassic salt deposits, its rate is very low (<5 %).

d- Ferruginous cement: is found in clays, its average rate varies from 2 to 5 %, it is represented by the underlined hematite in the secondary silica aureoles, in the zonations of certain dolomites sometimes in the form of fine pellicules by blocking the quartz grains and in the form associated with the clay, the sources of this cement are surface oxidizing conditions, late evolution of ferrous compounds, dissolution of carbonates.

e- Pyrite cement (Figure 76.b): pyrite appears in the form of small scattered cubes or clusters in the intergranular void and in the form associated with clay and organic matter, it lies at the base of the lower series and is probably related to the reworking of the very Pyritic Gothic underlying series.

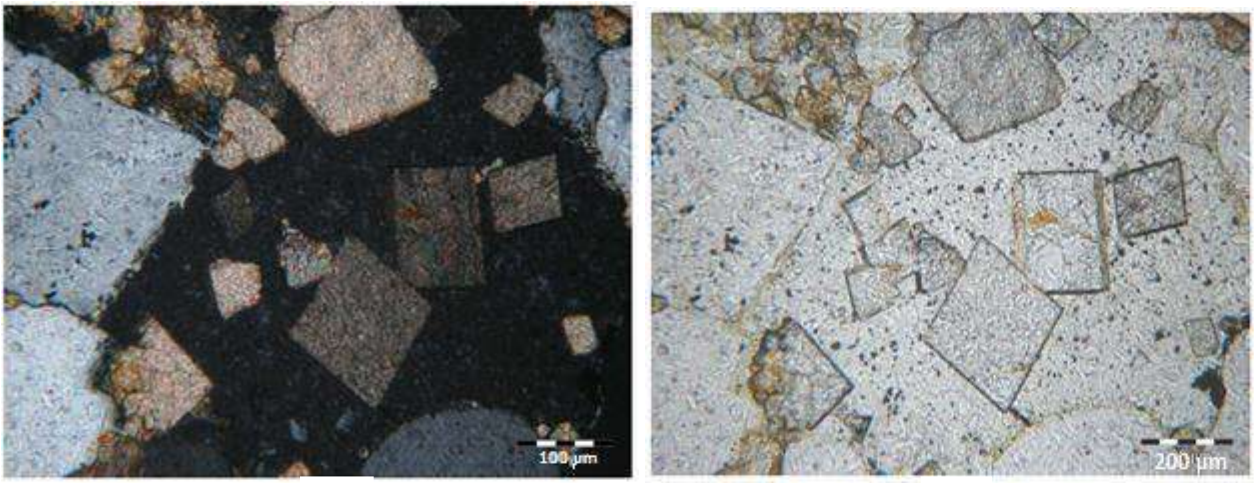
f- Clay cement : The clay fraction of the lower series represented mainly by illite and chlorite and incidentally by illite-montmorillonite-chlorite interstratifies, which explains the transformation of clays and alteration of feldspars. The central part of this reservoir remains the most clayey, this can be explained by the relatively high position of this part and thus favoring the decantation of clay particles, its rate varies from 10 to 32 %, it contributes adversely to the preservation of primary intergranular porosity.

Illite is found in all wells with a significant proportion along the entire lower series (from 50 to 100 %). It is encountered in all surveys and is distributed almost throughout the lower series with a relatively considerable rate (5 to 15 %). In the upper part it sometimes reaches 40 % and in the basal part it reduces to (5 to 10 %) or disappears completely in places for the illite.Illite is a main component of the clay fraction, it is of detrital origin and occurs in large proportions in the north and south-east zones of the field, porosity and permeability are practically reduced in these regions.



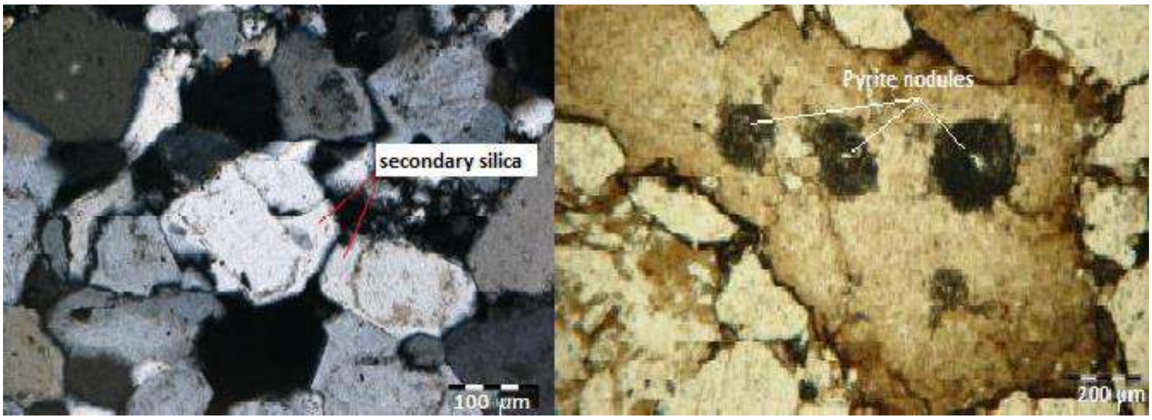
a b

Figure 74: a. Clay and carbonate cement from a sample well N15 (X2 NL) **b.** Clay (showed with green arrows and carbonate cement showed with red arrowsfrom the well N15 (X2 PL) (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).



a b

Figure 75 : A sample from the well N15 showing crystals of dolomite and Kaolinite mineral in PL (Figure a) and in NL (Figure b) (X10) (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).



a b

Figure 76 : a. Secondary silica in sample 1 of the well N1 **b.** Pyrite nodules in sample 3 (well N1) (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

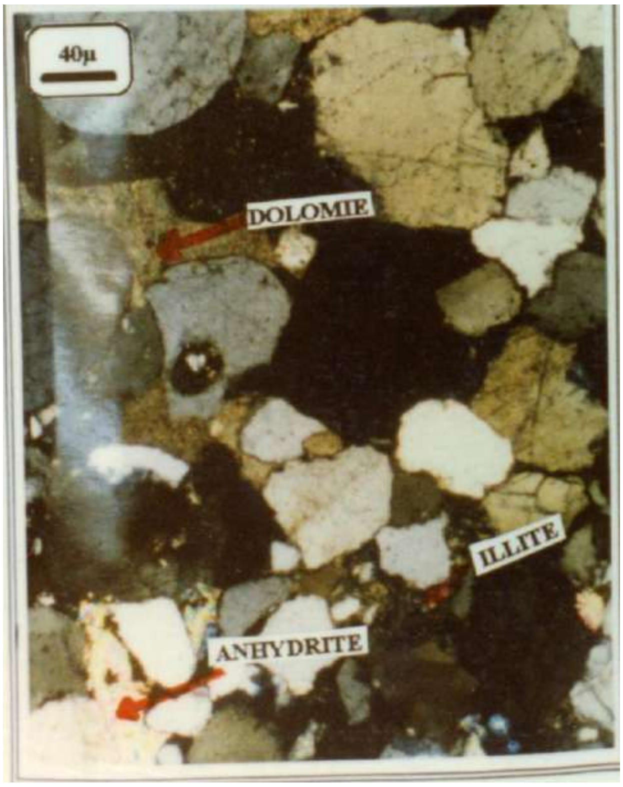


Figure 77: Photo of thin section at 3522.5 m of the well OKJ13 (LP x 40) showing the presence of medium grains with cracks and the cementing is dolomitic and anhydritic (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

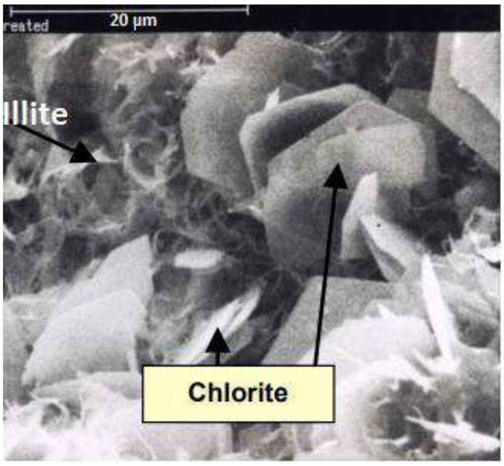
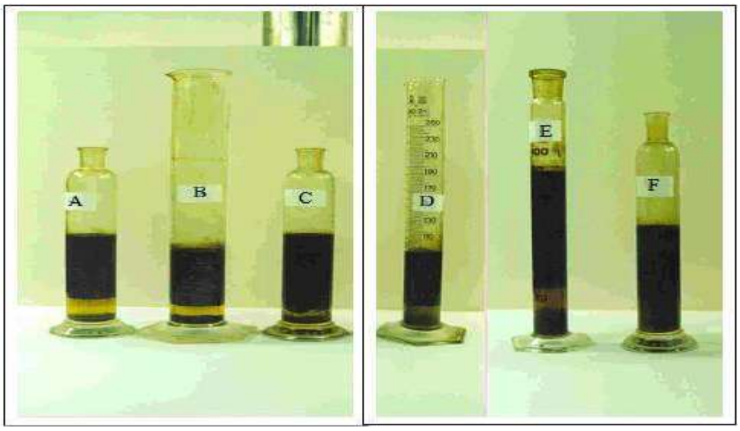


Figure 78 : A SEM photo of the sample 6 from the well OKN 251 showing chlorite and Illite (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

IV.2. Sludge and emulsion test

Tests have shown that no sludge formation is detected (Table 71). Furthermore, the emulsion tests revealed that the matrix treatment of the Sandstone completion Acid system together with the crude oil from two HBK oil-producing wells forms a total external oil-phase emulsion (Table 72). Compatibilities tests, the deferential acid systems show the absence of formation of emulsions or sludge except the acid system 1(Figure 79). The Figure 80 shows a water in oil emulsion and oil in water emulsion.



Types of acids

A : preflush of AS3

B: solution principale of AS3

C : preflush of AS2

D : solution principale of AS2.

E : preflush of AS1

F : solution principale of AS1

Figure 79: Results of emulsion test using three types of acids (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

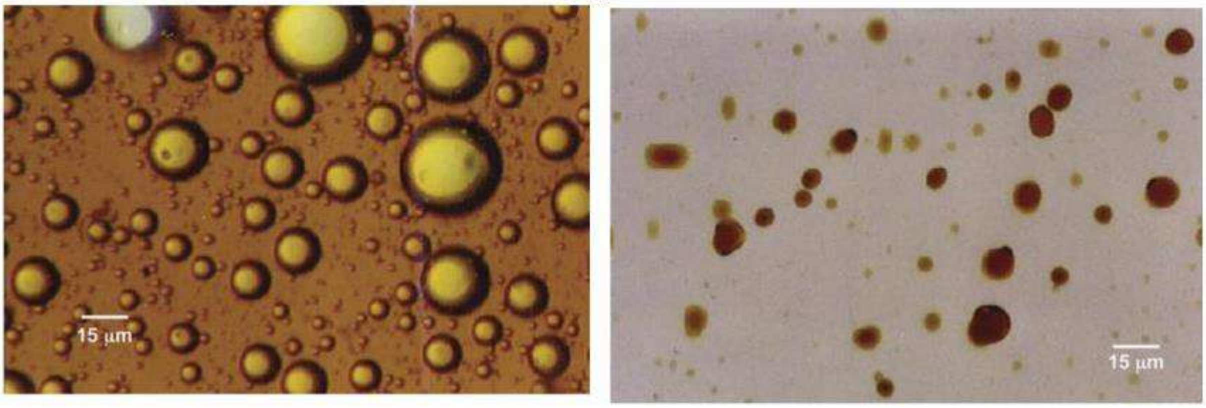
:

Acid System	**Preflush 7.5%HCl (for : AS2 and AS1)**	**AS1 (13-1.5)**	**AS2 (10-2)**	**Clay Fix-5 (for : AS3)**	**Preflush 7.5 % HCl (for : AS3)**	**AS3 (6-1.5)**
Results	absent	absent	absent	absent	absent	absent

Table 71 : Sludge test results (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

System	**Preflush 7.5%HCl (for : AS2 and AS1)**	**AS1 (13-1.5)**	**AS2 (10-2)**	**Clay Fix-5 (for : AS3)**	**Preflush 7.5 % HCl (for : AS3)**	**AS3 (6-1.5)**
60 min **Oil %** **Water %**	74.40 24.60	73.20 26.80	78 22	74 26	74.50 24.50	Total
24 h **Oil %** **Water %**	75 25	75 25	75 25	75 25	75 25	Total
interface	net	net	net	net	net	total Emulsion

Table 72 : Results of emulsion tests (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).



a b

Figure 80: a. Water in oil emulsion (Kokal 2006) **b.** Oil in water emulsion (Kokal 2006).

IV.3. Solubility test

Solubility tests showed quartz solubility values ranging from 4.18 % to 33.5 %. Acid System 3 (6 % HCl- 1.5 % HF) has the lowest values due to its low concentration. Acid System 2 has the highest percentage of solubility due to its high HF concentration (2 %) (Table 73). High concentration may cause deconsolidation of the rock by attacking the natural cement where the precipitation of solid particles can clog the pores.

Well	Depth (m)	Acid System	Solubility (%)
N2	3490.00	AS1	11.9
	3493.15	AS2	14.68
	3498.25	AS3	7.74
N1	3438.75	AS1	32.4
	3438.80	AS2	44.37
	3439.52	AS3	21.1

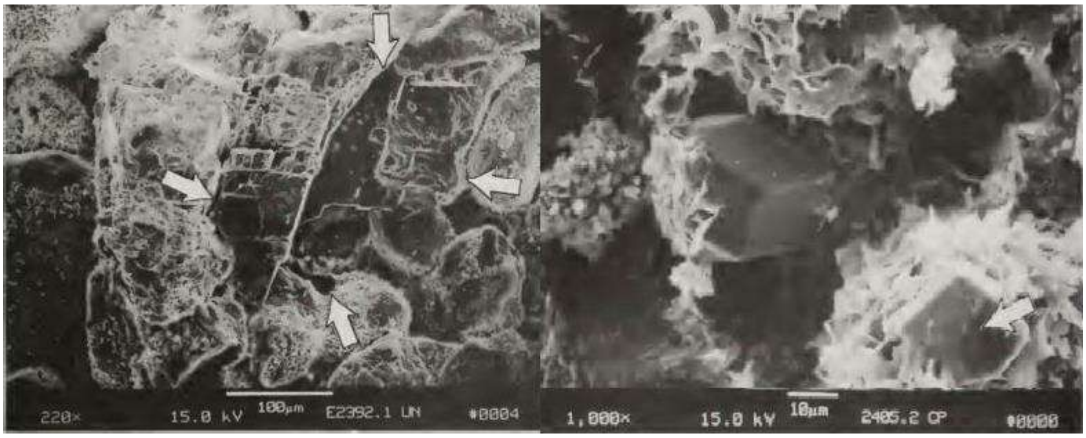
Table 73 : Solubility test results (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

IV.4. Matrix acidizing test

IV.4.1. Acid response curve using AS1 (Figure 82)

During the preflush stage, the graph shows amelioration of the relative permeability after the injection of HCl (Figure 81) due to its reaction with minerals containing Ca, K, and Na ions as shown in thefollowing Equation 40:

$$CaCO_3 + 2HCl \longrightarrow CaCl_2 + CO_2 + H_2O \qquad (40)$$



(a) (b)

Figure 81 : (a) Arrows indicate calcite accumulations within pores. The acid attack on this type of calcite should result in a notable permeability increase; **(b)** Arrows indicate individual calcite crystals that have precipitated on clay minerals (Haggerty and Seyler, 1997).

The volume of HCl can be calculated from the solubility test (Economides and Michael 1987) as follows (Equation 41):

$$V_{HCl} = \pi \left(r_d^2 - r_w^2\right) h \left(1 - \Phi\right) \frac{S}{X} \qquad (41)$$

Where:

S is the rock solubility in HCl.

X is the dissolving power of acid.

Φ is the rock porosity.

rd is the damaged zone radius (ft).

rw is the wellbore radius (ft).

In the second stage, a large amount of acid not only enters the pores and eliminates the cement that exists before (Figure 83.a) but also causes the crumbling of natural quartz minerals until the volume of 112 mL/cm^3 of the main acid. After that, the small decrease observed in the third stage of the ratio K_a /K_i explains the presence of fine particles clogging the pores (Figure 83.b) and a few times later, it is improved and stabilized at 2.9. The results showed that the preflush acid used is essential to create channels (Figure 84) that participate efficiently to the permeability increase during the main acid stage (Thomas et al. 2001).

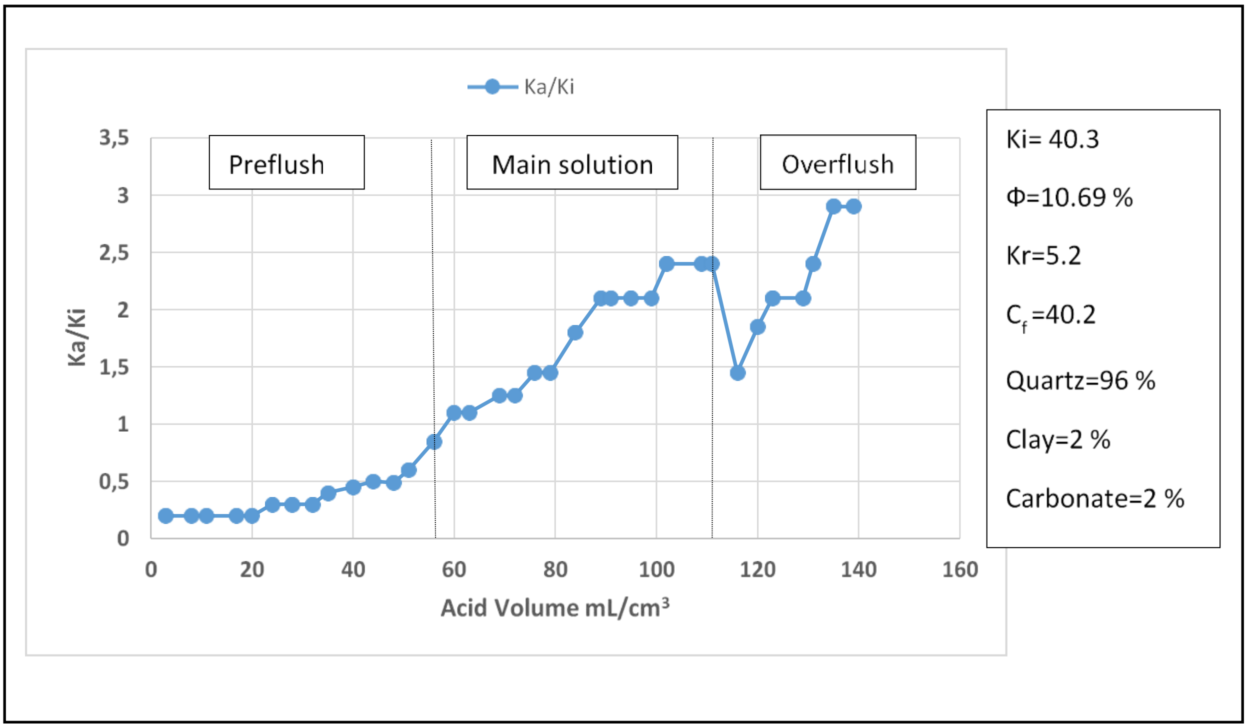
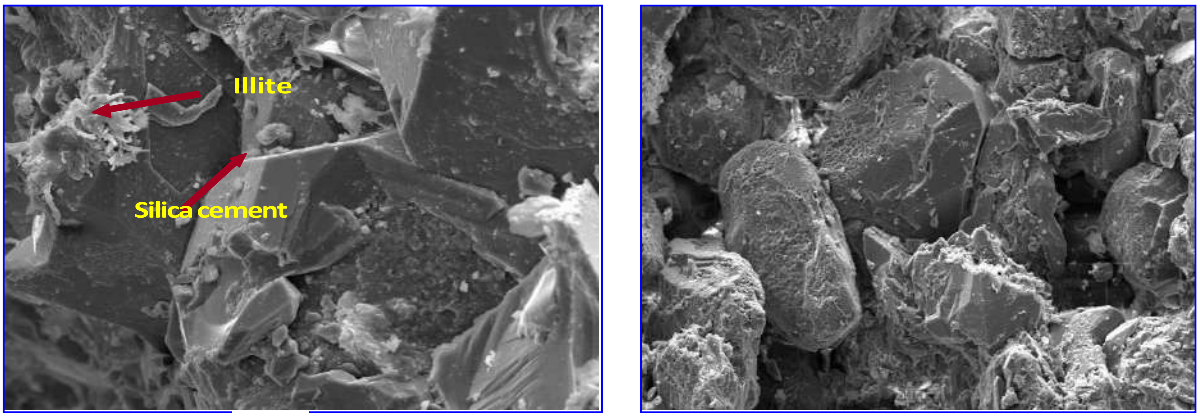
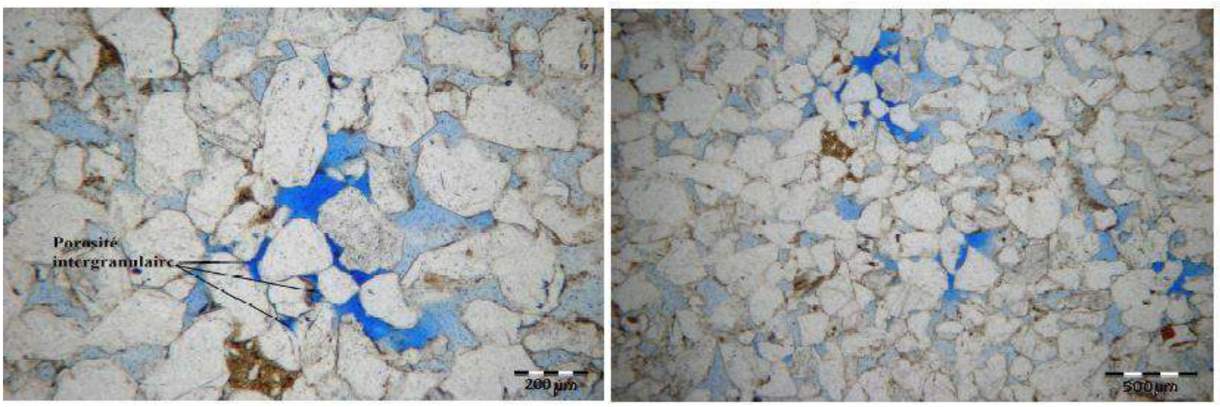


Figure 82: ARC curve of the sample (well N1) using AS1.



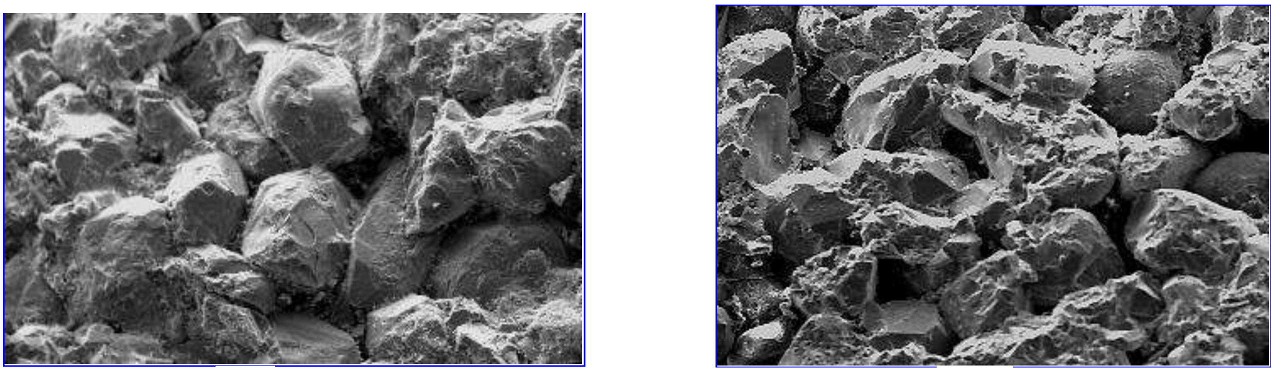
a **Grx 336** **b** **Grx 134**

Figure 83 : a : A sample of the well N1 before acidizing using AS1. **b :** A sample of the well N1 after acidizing using AS1 (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).



a **b**

Figure 84 (a and b): A sample of the well N1 using AS1 showing the interganular porosity (in NL) after acidizing using AS1 (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).



a **Gr x 20** **b** **Gr x**

Figure 85 : a. A sample of the well before acidizing using AS1. **b.** A sample of the well after acidizing using AS1 (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

IV.4.2. Acid response curve using AS2 (Figure 87)

In the preflush, the acid injected leads to an enhancement of the relative permeability by dissolving carbonate minerals that may be present before (Figure 88.a) and displacing the connate water from the sample (Shafiq MU et al. 2013). The main treatment indicates a severe decrease of the ratio K_a/K_i when injecting a mud acid (Kr = 0.1) and it remains stable until the volume is 55 mL/cm^3. The reaction precipitates resulting from the reaction between acids and minerals can block the pore channels and lead to a low permeability (Shafiq MU et at. 2022). A slow amelioration of the relative permeability after is related to the high damage presented and the delayed reactions of acid with clay minerals in the core sample an example of them is shown in the following Equation 42.

$$Al_2SiO_{10}\,(OH)_2 + 36\,HF \rightleftharpoons 4\,H_2\,SiF_6 + 12\,H_2O + 2\,H_3AlF_6 \qquad (42)$$

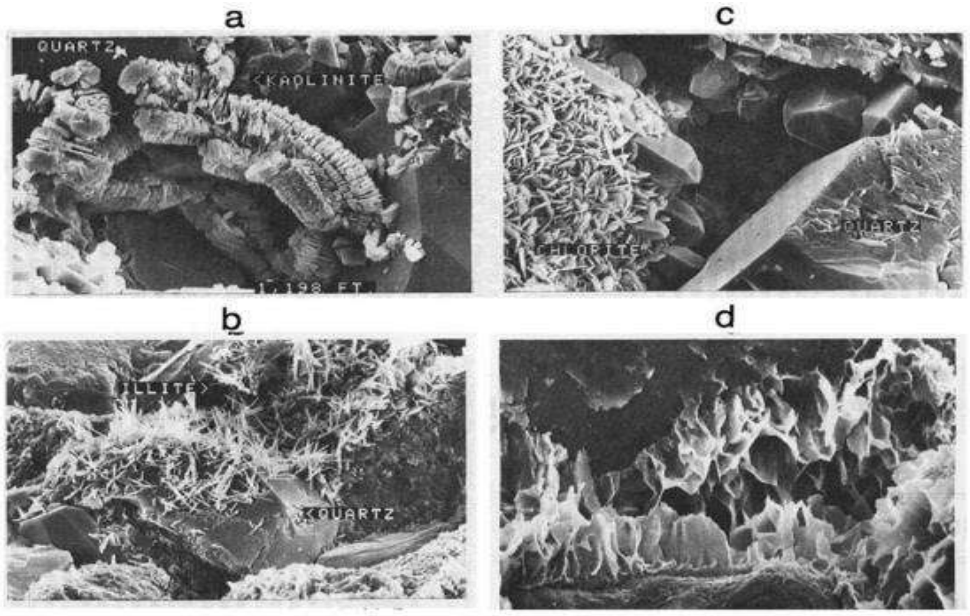


Figure 86: Scanning electron microscope (SEM) photograph of different clay minerals content presented in sandstone rock as illustrated by McLeod (1984).

In overflush stage, the organic deposits and other minerals are flowed out participating in an improvement of Kr and local porosity improvement and the existence of Illite (Figure 88.b).

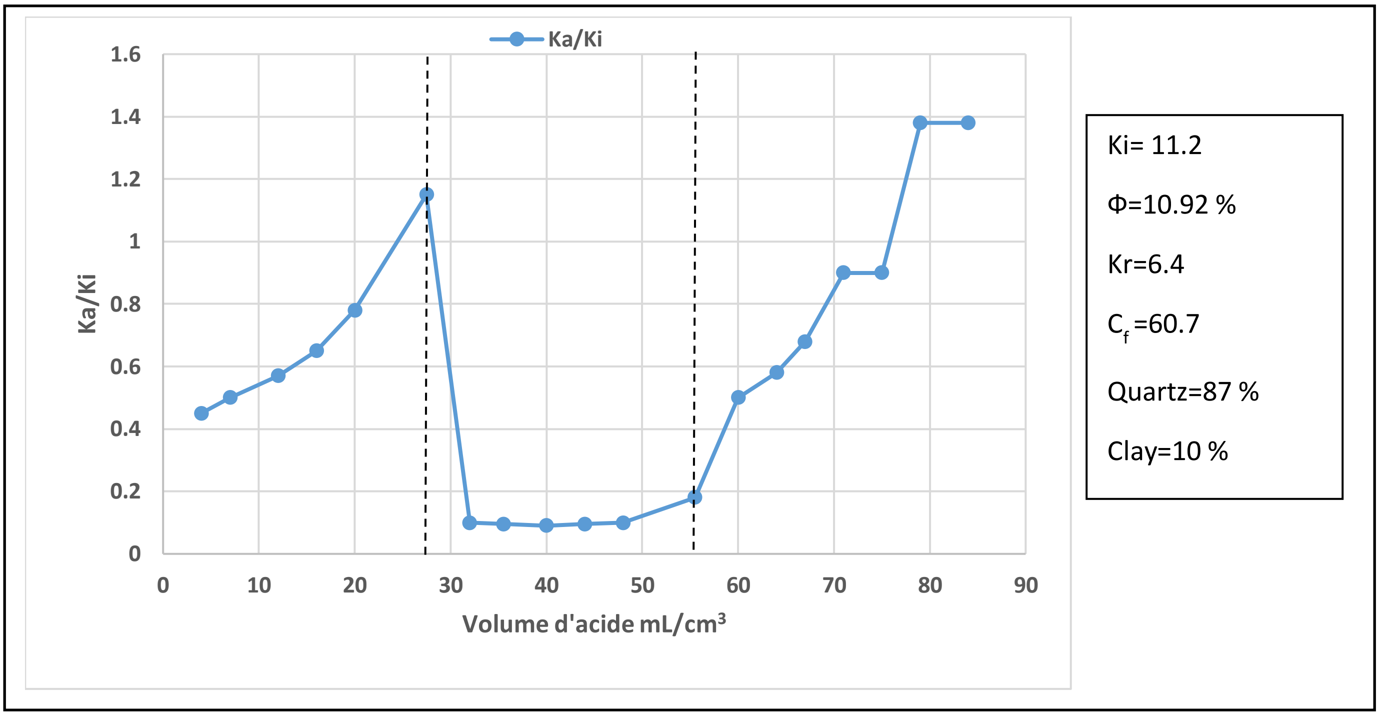
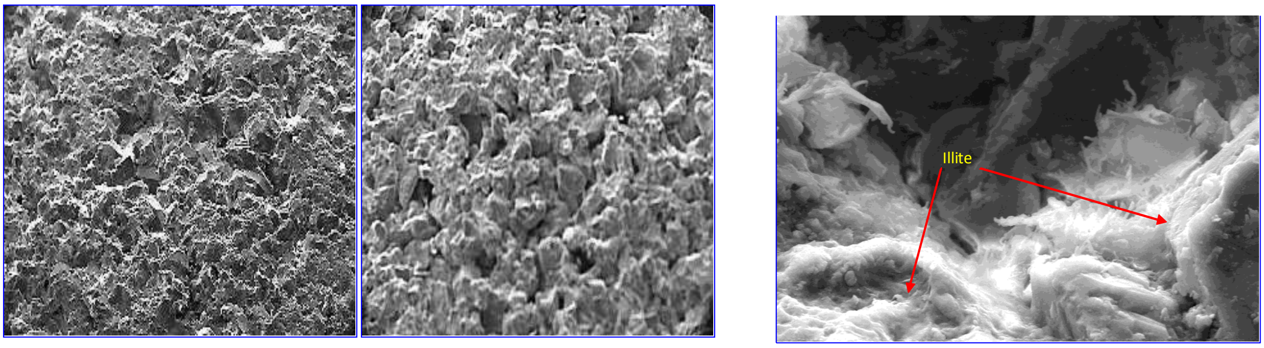


Figure 87: ARC curve of the sample (well N1) using AS2.



Gr x 20

Gr X20

Gr x 1280

a

b

Figure 88 : a: A sample of the well N1 before acidizing using AS2. **b** : A sample of the well N1 after acidizing using AS2. (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

IV.4.3. Acid response curve using AS3 (Figure 89)

A significant increase of Kr occurred during the preflush by eliminating Ca, K, and Na ions that may create another damage after. This minimises the risk of insoluble products by ensuring a lowpH environment (Shafiq and Hisham 2017). In the main stage, from the volume of 27 mL/cm^3 to 54 mL/cm^3 by increasing the amount of mud acid injected through the sample, the relative permeability was gradually improved until the volume of 54 mL/cm^3. A remarkable reduction of Kr entering the postflush stage reflects the formation of some insoluble organic or mineral precipitations like CaF_2 and Equation 43 shows its formation.

$$2HF + CaCO_3 \longrightarrow CaF_2\downarrow + CO_2 + H_2O \qquad (43)$$

It can be seen that the values ok Kr were ameliorated due to the partial crumbling of quartz minerals and the rapid sample clean up at the end of the test.

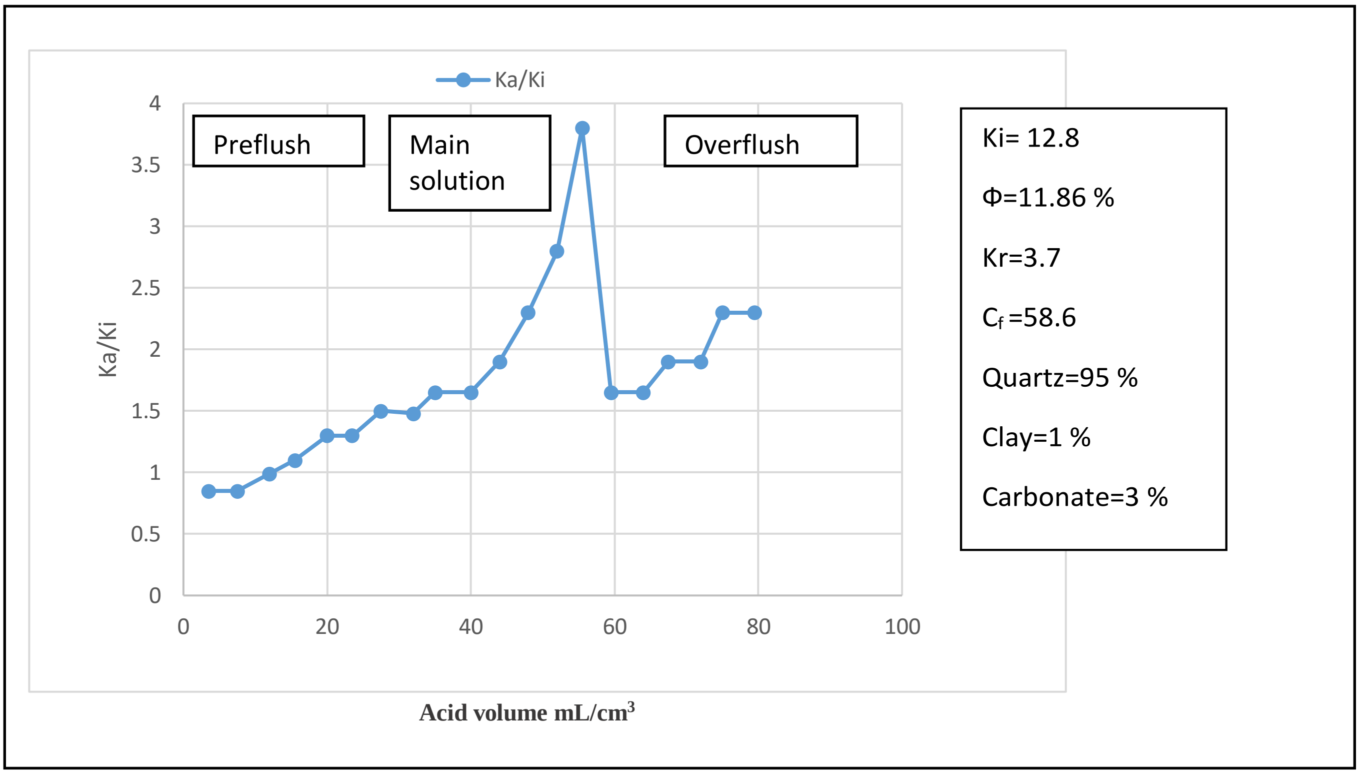
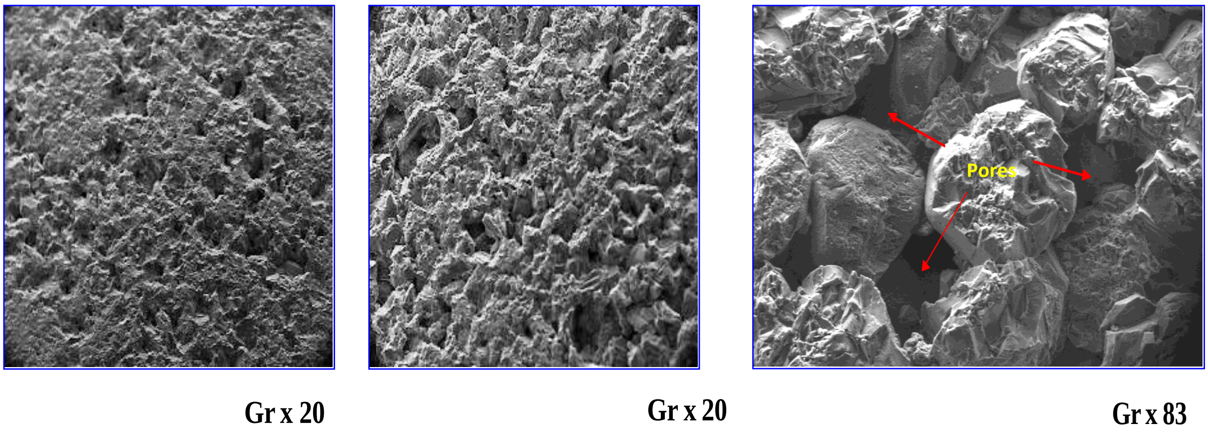


Figure 89: ARC curve of the sample (well N1) using AS3.

The average relative permeability values (Table 74) and ARC curves indicate that damage was minimized using the three types of acids. SEM photo shows porosity before (Figure 90.a), an improvement and creation of pores after acidizing (Figure 90.b).



a **b**

Figure 90 : **a.** A sample of the well N1before acidizing using AS3 **b.** A sample of the well N1 after acidizing using AS3. (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

Wells	N° sample	Ki (md)	Acid System	Kf (md)	Kr
N2	1	40.3	AS1	209.5	5.2
	2	11.2	AS2	71.6	6.4
	3	12.8	AS3	47.3	3.7
N1	1	3.9	AS1	148.9	38.2
	2	6.7	AS2	30.8	4.6
	3	17.9	AS3	125.3	7

Table 74: Results of matrix acidizing test (Matrix acidizing stimulation technique, laboratory testing Sonatrach, 2020).

By considering all the results and analysis done in this study, the AS3 (6 % HCl - 1.5 % HF) is the optimal and the most effective acid system. It has a good permeability improvement ratio; it does not present any risk of emulsion and sludge formation compared to other systems. This deduction agrees with McLeod's results obtained in 1984 (See Table 75 in Appendix).

And if we want to calculate the volume of acid for treatment at the Vap well scale, we use the Equation 44:

$$\frac{\mathbf{Vap}}{\mathbf{Sp}} = \frac{\mathbf{Vae}}{\mathbf{Se}} \qquad (44)$$

Where

Vap: Volume of acidic hand to be injected at well scale (m^3);

Vae: Volume of acidic hand to be injected at sample scale (m^3);

Sp: The surface to be treated by acid in the well (m^2);

Se : The transfersale section of the sample (m^2).

Calculation of **Sp :** we use the Equation 45 :

$$\mathbf{Sp = 2\Pi \, . \, Re \, . \, Hu} \qquad (45)$$

Where

Re is the damage radius;

Hu is the useful height of the reservoir.

V. Economic results

Some wells are economically evaluated for a period of one year, taking payout time, net present value and profit to investment ratio as yardsticks to measure the value of the project.

We note from the Table 76 that the monthly production time varies because of different interventions on the well (work on the gas lift network, salt capping, etc.). To do this, we must study the condition of the wells for the calculation of the monthly production time.

Month	Tpi	Qreal	Qreal×Tpi	$Q_{fictitious}$	$Q_{fictitious}$× Tpi	fictitious Cumulation	Actual Cumulation (m^3)
	(hr)	(m^3/h)	(m^3)	(m^3/h)	(m^3)	(m^3)	
January	526,21	1,57	826,15	1,57	826,15	129127,15	129127,15
February	696	2,72	1893,12	1,57	1092,72	130219,87	131020,27
March	744	2,72	2023,68	1,57	1168,08	131387,95	133043,95
April	720	2,72	1958,4	1,57	1130,4	132518,35	135002,35
May	744	2,72	2023,68	1,57	1168,08	133686,43	137026,03
June	720	2,72	1958,4	1,57	1130,4	134816,83	138984,43
July	744	2,72	2023,68	1,57	1168,08	135984,91	141008,11
August	744	2,72	2023,68	1,57	1168,08	137152,99	143031,79
September	720,25	2,72	1959,08	1,57	1130,79	138283,78	144990,87
October	744	1,6	1190,4	1,57	1168,08	139451,86	146181,27
November	720	1,6	1152	1,57	1130,4	140582,26	147333,27
December	744	1,6	1190,4	1,57	1168,08	141750,34	148523,67

Table 75: Annual gain of acidizing operation of the well N9 (Sonatrach/ EP HBK, 2020).

Thus the annual gain of acidification of this well (N9) is of the order of 50310,44 m^3.

Similarly, the gain in annual production can be determined for all acidified wells.

The Table 77 below shows the cumulative gains calculation results for the stimulated wells in 2000 and 2001:

Well	Date of acidification with acid system	Actual Cumul (m^3) [1]	fictitious Cumul (m^3) [2]	Time of production (hour/ year)	Gain/ Loss (m^3) [1]- [2]	Cost of the operation in US $	Cost of the operation in DA	Gain/ Loss in US$	Gain/ Loss in DA
N17	11/01/ 2000(AS3)	138373.2	132862.21	8542.5	5510.99	85291.41	6396855.7	830602.8	62295213.6
J 01	06/01/2000 (AS3)	422001	409689.2	7564.8	12311.7	234867.98	17615098.3	1855619.4	139171456.8
N42	13/01/2000 (AS2)	399870	403005.6	7238.7	-3135.6	176124.48	13209336.2	-472597.6	-35444822.4
N442	13/09/2000 (AS1)	5611	6359.4	5755.1	-748.4	197513.38	14813503.7	-112798.8	-8459913.6
N452	08/08/2000 (AS3)	5705	3520	3464	2185	129970.23	9747767.30	373023.2	27976740
N344	08/09/2000 (Organic Clay Acid)	7592	2518.1	3356.7	5073.9	253939.63	19045472.1	764738.2	57355365.6
N771	06/08/2001 (AS2)	54119	50808.8	5202.6	3310.6	122018.3	9639445.70	498973.63	39418916.92
N46	13/09/2001 (AS1)	-	-	-	-	83267.592	6578139.7	-83267.592	-6578139.8
N54	16/09/2001 (AS3)	4578	1688.2	1754.6	2889.9	648472.46	51229324.5	435565.7	34409692.5
J40	13/12/2001 (Organic Clay Acid)	2932	1775.0	1443.1	1156.9	167616.58	13241709.7	174367.9	13775069.4

Table 76: The cumulative gains calculation results for the stimulated wells in 2000 and 2001 (Sonatrach/ EP HBK, 2020).

Similarly, for all acidified wells, their annual production gain can be determined. The Table 78 below presents the results of the calculation of cumulative gains for a few stimulated wells in 2007 and 2008.

Well +acid system used	Date of acidizing	Tpi (hr)	fictitious Cumulation (m^3)	Actual cumulation (m^3)	Operation cost ($)	Gain/Loss per (m^3)	Gain/Loss per ($)
N7 (AS3)	26/05/2008	8542,50	39039,22	57132,24	2812000	18093,02	10242620
N11(Organic Clay Acid)	04/06/2007	5755,10	20056,52	7809,67	3206421	-12246,85	-6933051
N8(AS2)	08/08/2007	5202,60	29472,73	36569,07	6700000	7096,34	4017301,5
N10 (Mud Acetic Acid)	12/08/2007	1754,60	6974,53	3775,90	4267085	-3198,63	-1810773
N9 (Mud Acetic Acid)	02/01/2007	8566,46	13449,34	20222,67	5607800	6773,33	3834442,7

Table 77: The results of the calculation of cumulative gains for a few stimulated wells in 2007 and 2008 (Sonatrach/ EP HBK, 2020).

The results of the payout calculation are presented in the Table 79 below:

Note: Calculations are made by taking the price of a barrel of oil $65.

Well	Operation cost($)	equivalent cost (m^3)	Gain/Loss (m^3/d)	Payout (days)
N4(Mud Acetic Acid)	113092,91	276,61	48	6
N5(Mud Clean OB+ MSR 100)	65936,09	161,27	0,96	168
N6(AS2)	75267,80	184,10	20,16	10
N8(AS2)	96066,67	234,97	32,88	8
N1(AS3)	110000,00	269,05	31,92	9
N9(AS3)	101437,33	248,10	27,6	9
N7(Organic Clay Acid)	104160,00	254,76	2,16	118
N10(Mud Aid-Acetic Acid)	56894,47	139,16	-43,68	/
N11(Organic Clay Acid)	69418,95	169,79	-50,88	/
N12(AS2)	106506,71	260,50	-7,92	/
N13(AS1)	89333,33	218,50	-1,44	/

Table 78: The results of payout of some wells (Sonatrach/ EP HBK, 2020).

The profitability of an acidification is all the more beneficial as the amortization of the cost of the operation is done at small periods of time.

Based on this analysis, we have determined that the project is economically feasible in the majority of cases even with the company facing significant tax obligations (20 % royalty rights and 80 % production division taxes) (Fateh Meddahi 2002). It can be concluded also that the acidifications carried out at Haoud Berkaoui are profitable (specially using AS3), but efforts still have to be made to eliminate the problems of the flow drop over time and achieve the expected objectives.

Conclusion

The analysis of wells history and the laboratory results allow to choose the optimal acid system (AS3) that minimizes the damage and improve the permeability with benefecial economic returns.

General conclusion

In order to guarantee maximum production, it is imperative to perform matrix acidizing on sandstone or carbonate reservoirs. This involves eliminating any damage and creating new pathways or wormholes surrounding the wellbore.

Numerous studies that have been conducted to date emphasize how crucial acidizing treatment is for various formations. To achieve the best results in terms of permeability, porosity, and precipitation, many researchers created various acid combinations; however, there are still certain drawbacks, such as rapid acid spending, precipitation reactions, low acid penetration, and pipeline corrosion.

In comparison to the same previous works, the detailed mineralogical composition of the sandstone reservoir, laboratory results, particularly the interpretation of ARC, when combined with historical field data, are more methodical in better understanding the reaction mechanism in oil wells and improving the petrophysical parameters. As a result, the success of an acid stimulation procedure can be guaranteed by selecting the ideal acid system.

According to this study, the Haoud Berkaoui field's acid systems can cause a number of issues for the reservoir rock AS1 (13 % HCl-1.5 % HF) or AS2 (10 % HCl- 2 % HF). For field application, one system AS3 (6 % HCl ,1.5 % HF) is advised because it offers a good relative permeability improvement of many oil wells (7 for the well N1 and 3.7 for the well N2) and a flow rate gain (0.25 m^3/h for the well N2) with less harmful precipitates and no risk of emulsion. This study also makes it possible to analyze and interpret treatment outcomes in order to increase their efficacy and lower investment costs.

A thorough and methodical mineralogical analysis is necessary for the whole HBK area. This entails selecting the right acid and suggesting the best course of action while accounting for any unfavorable side effects. The secret to a successful acidizing project is a combination of a thorough laboratory study, a thorough examination of the causes of the damage, an accurate wells performance analysis, and an appropriate treatment design without forgetting to evaluate the cost of the operation to increase profit and minimise its failure.

Recommendations

In order to optimize the gain while minimizing the treatment drawbacks we suggest:

- A thorough study of mineralogy distribution, both vertically and horizontally of the whole region for a good estimation of the operation.
- Perform selective measurement of reservoir parameters (skin, permeability….) in order to better quantify and localize the damage and its variation.
- More best selection of acid to be injected to reach satisfactory skin damage values. The volume of overflush solution should be increased in order to push acid reaction by products far from the wellbore.
- The use of mechanical diversion to acidize wells having more than one layer, and those experienced zonal isolation (plugs). In the same time chemical diversion should be kept at the same interval.
- Acid concentration should be weakened sometimes , in order to limit unconsolidation effects, reduce corrosion, and decrease the risk of secondary reactions that can leave precipitates in the tubing and the formation, especially in the case of layers that contain high percentage of anhydrite, clay, iron and sometimes feldspar content.

- Corrosion inhibitor injection before each flow back is necessary, because of long acidizing treatment periods and high injected acid volumes. This allows a better completion protection during flowback.
- Fluid samples should be examined and analyze their composition and pH regularly after flowback, to understand the reaction of injected solutions with rock minerals and for better flowback control.
- Post-acid PLT’s and completion equipment control should be performed six months after acidizing job to get a reliable results and reduce the unavailability time of the wells.
- Newly completed or worked-over wells should be cleaned up before the start of production with coiled tubing in order to evacuate mud deposit that can affect well production.
- Estimate regularly the cost of the operation and evaluate the causes of flow rate losses by increasing laboratory tests and test the performance of acids used.

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Appendix

Condition	Acid
HCl solubility>20%	Use HCl Only
High permeability (100 md plus)	
High Quartz (80%), low Clay (<5%)	12% HCl – 3% HF (1)
High Feldspar (>20%)	13.5% HCl – 1.5% HF (1)
High Clay (>10%) High Iron	6.5% HCl – 1% HF (2)
Chlorite Clay	3% HCl – 0.5% HF
Low permeability (10 md or less)	
Low Clay (<5%)High	6% HCl – 1.5% HF (3)
Chlorite	3% HCl – 0.5% HF (4)
Notes: 1) Preflush with 15% HCl. 2) Preflush with sequestered 5% HCl. 3) Preflush with 7.5% HCl or 10% acetic acid. 4) Preflush with 5% acetic acid.	

Table 79 : McLeod (1984) results for acid use.

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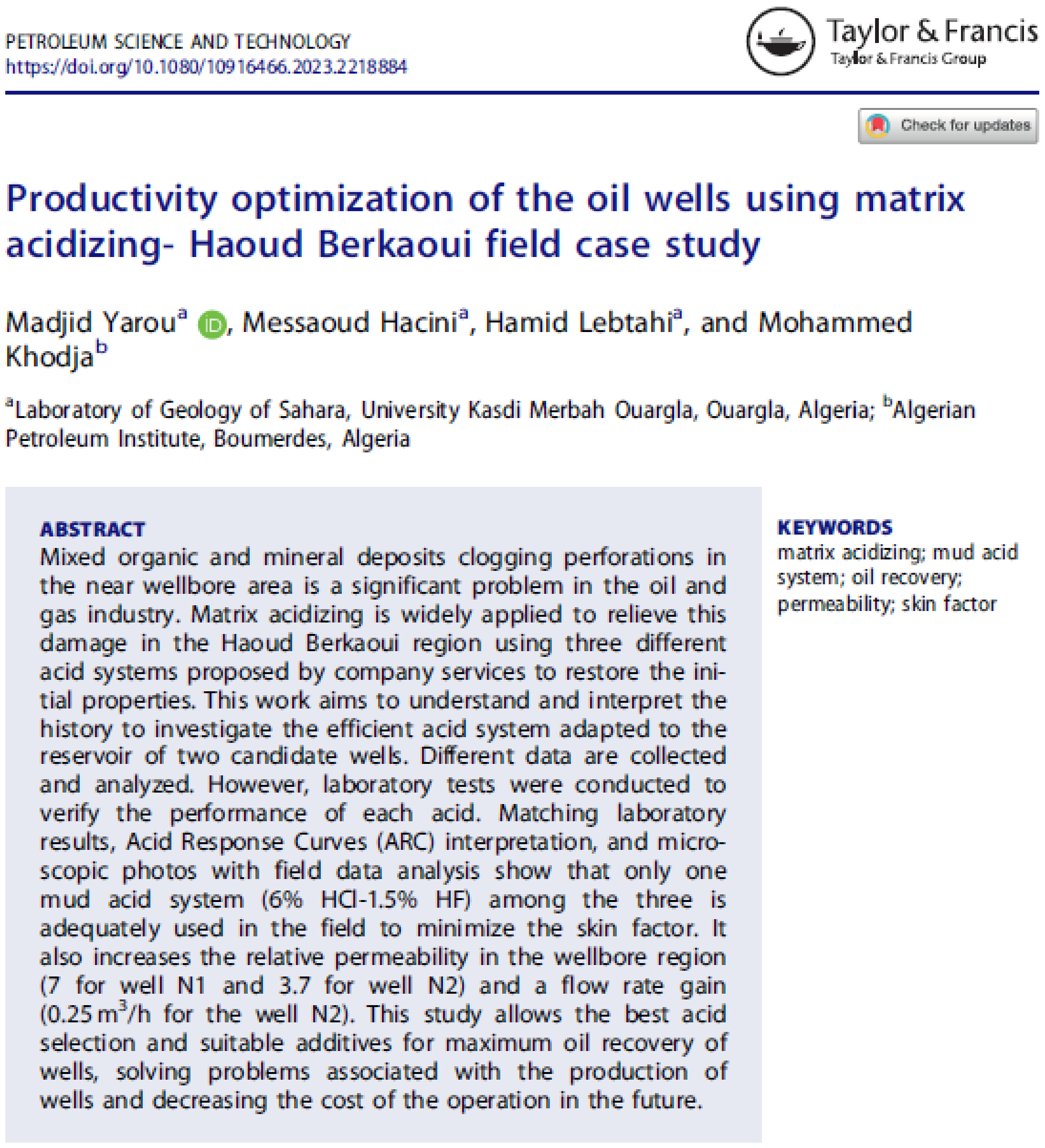

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Productivity optimization of the oil wells using matrix acidizing- Haoud Berkaoui field case study

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ABSTRACT

Mixed organic and mineral deposits clogging perforations in the near wellbore area is a significant problem in the oil and gas industry. Matrix acidizing is widely applied to relieve this damage in the Haoud Berkaoui region using three different acid systems proposed by company services to restore the initial properties. This work aims to understand and interpret the history to investigate the efficient acid system adapted to the reservoir of two candidate wells. Different data are collected and analyzed. However, laboratory tests were conducted to verify the performance of each acid. Matching laboratory results, Acid Response Curves (ARC) interpretation, and microscopic photos with field data analysis show that only one mud acid system (6% HCl-1.5% HF) among the three is adequately used in the field to minimize the skin factor. It also increases the relative permeability in the wellbore region (7 for well N1 and 3.7 for well N2) and a flow rate gain (0.25 m^3/h for the well N2). This study allows the best acid selection and suitable additives for maximum oil recovery of wells, solving problems associated with the production of wells and decreasing the cost of the operation in the future.

KEYWORDS
matrix acidizing; mud acid system; oil recovery; permeability; skin factor

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