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Option : *Production*

Submitted by: *TOUMI Sara*

- THESIS -

FORMATION DAMAGE BY FINES MIGRATION

Presented in :08/06/2015

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ABSTRACT:

we aimed from this study to make a comparison between two fields (HBK & HMD) to select the best treatment to well known characteristic and mineralogy of formation rock against the damage due to fines migration, we sought to do a triangular relationship. In this study, laboratory tests and their results are conducted to define the mineralogy and determine the characteristics of HBK field formation rock, acidizing tests by different acids systems (of BJSP and Halliburton) are performed and discussed to select the optimum fluids for HBK wells to be acidified .Visual observations of cores using SEM are also used as interpretation tools. Besides, optimum volume is predicted based on acid response curves. Other laboratory test is performed to define just the mineralogy of HMD field.

- Key words: HBK-HMD-Fines migration-BJSP-Halliburton-SEM

RESUME:

Nous avons cherchés à partir de cette étude de faire une comparaison entre les deux champs (HBK & HMD) en but de sélectionner le meilleur traitement pour des caractéristiques et minéralogie bien connues des roches réservoir contre l'endommagement dus à la migration des fines notre but est de faire une relation triangulaire . Dans cette étude, les tests de laboratoire et leurs résultats sont menées pour définir la minéralogie et de déterminer les caractéristiques des roches réservoir de champs de HBK. Des tests d'acidification des différents systèmes acides (de BJSP et de Halliburton) sont réalisés et discutées pour but de sélectionner les fluides optimales pour les puits de champs de HBK. Les observations visuelles des échantillons utilisant MEB sont également utilisées comme outils d'interprétation. En outre, le volume optimal est prédit sur la base des courbes de réponse d'acides. Un autre test de laboratoire est effectué pour définir la minéralogie de champ de HMD

- Les mots clés: HBK-HMD-Migration des fines--BJSP-Halliburton-MEB

:ملخص

نهدف من خلال هذه الدراسة إلى المقارنة بين الحقلين (حوض بركاوي و حاسي مسعود) من أجل تحديد أفضل علاج ضد الضرر الناجم عن هجرة الدقائق في صخور الخزان ذات الميزات و العدانة المعروفتين , ارتأينا أن نشكل علاقة ثلاثية . في هذه الدراسة، تم إجراء فحوصات مخبريه لتحديد عدانة و خصائص صخور خزان حقل حوض بركاوي ، وأجريت اختبارات التحميض لأنظمة مختلفة من الأحماض (BJSP و Halliburton) ومناقشتها لتحديد السوائل المثلى. كما تستخدم الملاحظات البصرية للعينات باستخدام SEM كأداة للتفسير. إلى جانب ذلك، الحجم الأمثل يتوقع على أساس منحنيات الاستجابة للحمض المجربة في المختبر. في حين انه تم إجراء اختبار آخر على مستوى المختبر لتحديد عدانة صخور الخزان لحقل حاسي مسعود.

- الكلمات المفاتيح :حوض بركاوي-حاسي مسعود-هجرة الدقائق-العدانة.

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Special thanks to Mahdi .

I also thank my lovely friends Boudouaya Chahra Zad , Braithel Ahmida , Benmir Mounir ,Djalmami Zakaria .

DEDICATION

I Dedicate my modest work

To my parents my Mum Aicha and lovely Dad Messouad , To my sisters Ilham, Aicha ,Djahida,Fairoz,Soundous,

To my little brother Mouhamed Cherif

To Chahra Zad and Noura

To my lovely fiance Mahdi and his kind family

To All my happy family, teachers and friends.

In the memory of my grand fathers and my grand mother

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Nomenclature :

S	Skin factor, dimensionless
K	non damage zone,md
Ks	damaged zone permeability, md
Rs	damaged zone radius (ft).
Rw	well radius (ft).
Q1	productivity of zone after damage, bpd
Qo	initial productivity of zone, bpd
Ki	initial permeability of Soltrol 130, (mD).
Kf	final permeability of Soltrol 130 after damage, (mD).
C	damage coefficient
K	Permeability in md
Q	Injection rate in ml/sec
L	Core length in cm
µ	Soltrol viscosity in cp
S	Core cross section in cm2
DP	Pressure gradient in psi

Abbreviations :

HBK: Haouad Berkaoui

HMD: Hassi Messouad

SEM : Scanning Electron Microscopy

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GENERAL INTRODUCTION

High permeability wells are normally characterized as high productivity wells which means high flow rates and velocities, there is an opportunity to bring “fines” (or very small material) into the wellbore causing formation damage which we explained briefly in the first chapter.

The movement of fine clays ,quartz particles or similar materials within the reservoir formation is due to drag forces during production in an unconsolidated or inherently unstable formation, and the usage of an incompatible treatment fluid by its properties are contributed to liberate fine particles which suspended in the produced fluid to bridge the pore throats near the wellbore ,reducing well productivity or injectivity ,the second chapter explain the major causes of fines migration and its types.

Fines as what is mentioned above can include different materials such as clays and Silts, Kaolinite and Illite are the most common migrating clays. Damage created by fines usually is located within a radius of 3 to 5 ft (1 to 2 m).

Stimulation have been used to enhance well productivity or injectivity. The third chapter is a brief elucidation of the main used treatments to remove the damage by eliminate fines and minimize their migration.

A comparative study is in the last chapter to understand which mineralogies (of HBK or HMD) are preferable to entrain fines migration and which acid system is more efficient to remove the damage without liberate fines or generate it. This is the experimental study which is the first party of the fourth chapter , in the second party we studied the example OKN#53 well as a real study ,from this two parties we concluded some conclusions and recommendations .

I . INTRODUCTION

Formation damage is a generic terminology referring to the impairment of the permeability of formation rock . It is an undesirable operational and economic problem that can occur during the various phases of oil and gas recovery from subsurface reservoirs including production, drilling, hydraulic fracturing, and workover operations. As expressed by Amaefule et al. (1988) "Formation damage is an expensive headache to the oil and gas industry."

Formation damage indicators include permeability impairment as mentioned above, skin damage, and decrease of well performance (productivity or injectivity).[1]

II. Formation rock definition:

Theoretically, any rock may act as a reservoir for oil and\or gas. In practice, the sandstones and carbonates contain the major reserves, although fields do occur in shale and diverse igneous and metamorphic rocks.

For a rock to act as a reservoir it must possess two essential properties: it must have pores to contain the oil and\or gas, and there must be good permeability. Remember that porous rock is not necessary permeable. To be permeable, rock must have pores that interconnect, allowing fluids to flow from one pore to another (Figure II.1). Even though most shale is porous, it is relatively impermeable, because its pores are not connected very well. [2]

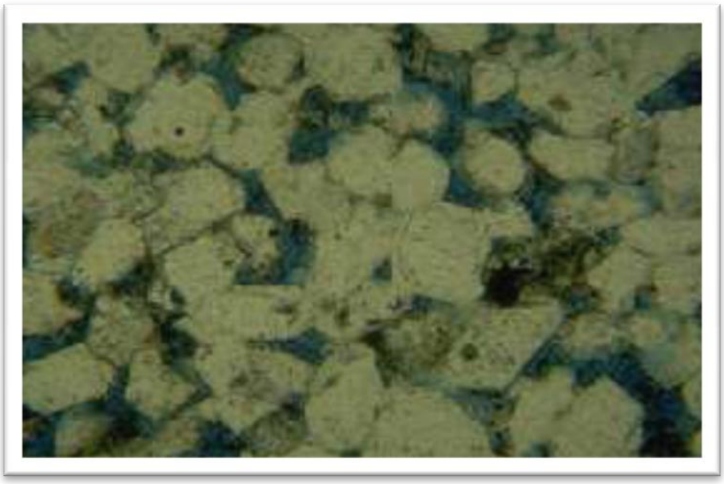


Figure (I-1): Primary pores (blue) in a sandstone partially filled with quartz diagenesis. [2]

II.2 Types of formation rock :

- ✓ *Sandstone :* Sand grains cemented by silica / calcium carbonate
- ✓ *Limestone :* Composed mainly of carbonate
- ✓ *Shale :* Clay mineral and quartz
- ✓ *Clay :* Kaolinite, Montmorillonite, Illite, Chlorite [3]

III. Damage Definition :

Partial or complete plugging of the near wellbore area which reduces the original permeability of the formation.

Damage is quantified by the skin factor (S). [7]

III.1. *Factors affecting formation damage:*

Amaefule et al. (1988) classified the various factors affecting formation damage as following:

- The invasion of foreign fluids, such as water and chemicals used for improved recovery, drilling mud invasion, and workover fluids;
- Gravel packing ;
- The invasion of foreign particles and mobilization of indigenous particles (clays), such as sand, mud fines, bacteria, and debris;
- Operation conditions such as well flow rates and wellbore pressures and temperatures; and Properties of the formation fluids .

III.2 *Formation damage mechanisms :*

Bishop (1997) summarized the seven formation damage mechanisms described by Bennion and Thomas (1991, 1994) as following:

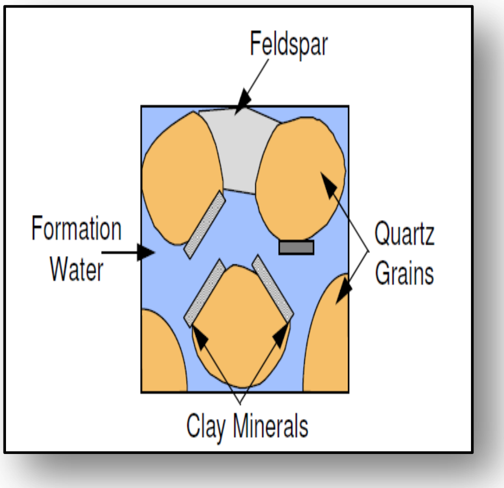
- Emulsions
- Solids invasion, for example the invasion of weighting agents or drilled solids.
- Water Block.
- Chemical adsorption/wettability alteration
- Organic deposits, Mixed deposits ,Scale formation
- Bacterial slime [1]

- **Fines Migration :**

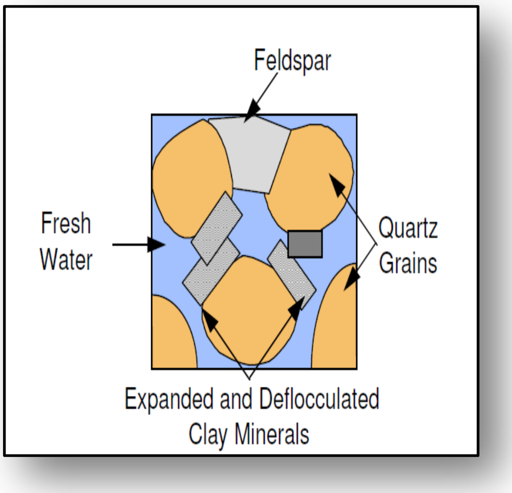
All clay types are capable of migrating when contacted with waters, which upset the ionic balance within the formation. Montmorillonite and mixed layer clays have increased probability of migrating due to swelling and water retention. Figure (I.2) illustrates clay particles in a balanced system, where the clays are in a stable unexpanded (flocculated) condition with formation water. Figure (I.3) illustrates clay particles in a fresh water system where they have an unstable, expanded (deflocculated) condition. It should be remembered however that high flow rates alone could be sufficient to cause particle migration.

The effect of aqueous fluids on clays and fines particles depends primarily on the following factors:

- Their chemical structure .
- The difference between the composition of the native formation fluid and injected fluid.
- Their arrangement on the matrix or in the pores.
- The way in which they are cemented to the matrix.
- Their abundance that are present.



Figure(I-2): Flocculated and Unexpanded Clays



Figure(I-3): Deflocculated and Expanded Clays

The movement of particles within a pore system is affected by the wettability of the formation, by the fluid phases present in the pore spaces and the flow rate through the pore spaces. Under normal circumstances, an oil-bearing zone contains both oil and water within the pore spaces. Where the formation is water-wet, water is in contact with the mineral surfaces, and oil flows through the center of the pore space. (Figure I.4).

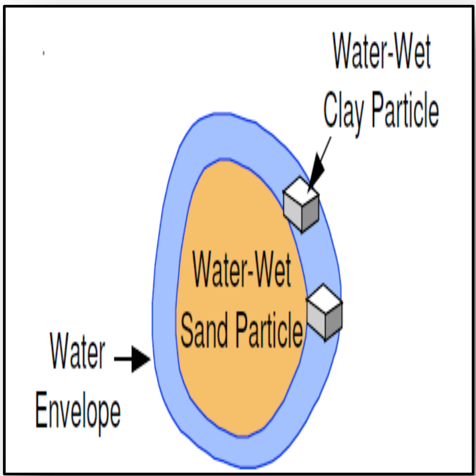


Figure I-4: Oil Flow through Sandstone

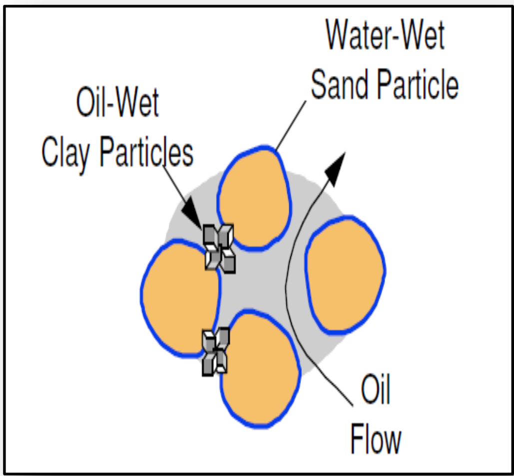


Figure I-5: Pore Blocking by Oil-Wet Clay Particles

Where clays and other fines are water-wet these particles are attracted to and immersed in the envelope of water surrounding the sandstone particles (Figure I.4).

In this case, the clay particles will only move with the flow of water, and where the water saturation is low, these particles are unlikely to cause problems with being mobile.

If the clay particles become oil-wet or partially oil-wet, due to some outside influence, the fines and clay particles are attracted to and immersed in the oil phase. The particles then tend to move with the oil and the resultant plugging of pore throats can be quite severe. (Figure I.5). [5]

III.3 *Damage location:*

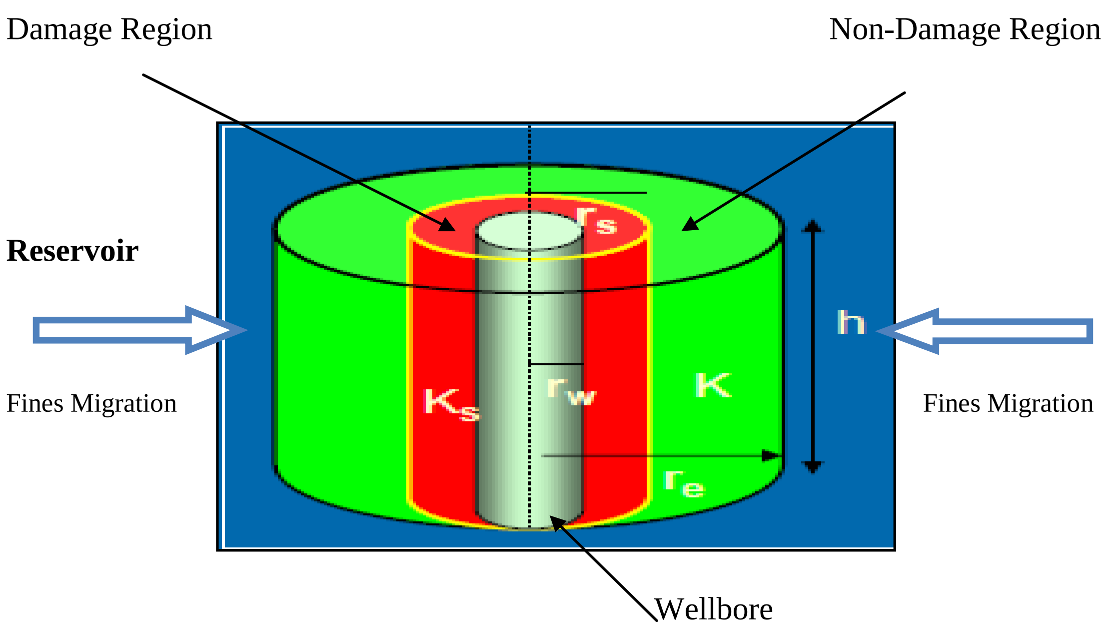


Figure (I-6) : Damage location [13]

IV. Measures of Formation Damage :

Formation damage can be quantified by various terms including but the most important is skin factor.

Skin factor definition :

The skin factor is a dimensionless parameter relating the apparent (or effective) and actual wellbore radius according to the parameters of the damaged region: [1]

$$S = \left(\frac{k}{ks} - 1\right) \times \left(ln\ \frac{Rs}{Rw}\right)$$

The total Skin (S_T) is the combination of mechanical and pseudo-skins. It is the total skin value that is obtained directly from a well-test analysis.

- Mechanical Skin:

Mathematically defined as an infinitely thin zone that creates a steady-state pressure drop at the sand face.

- $S > 0$ Damaged Formation
- $S = 0$ Neither damaged nor stimulated
- $S < 0$ Stimulated formation

- Pseudo Skin:
  - Includes situations such as fractures, partial penetration, turbulence, and fissures.

The Mechanical Skin is the only type that can be removed by stimulation. [7]

A. *Productivity and Skin factor :*

$$Q_1/Q\mathbf{o} = 7/(7+s)$$

Just an estimation, but not too far off skin numbers ,is range between zero and about 15.

The graph below present the variation of the productivity and the increase of skin factor.

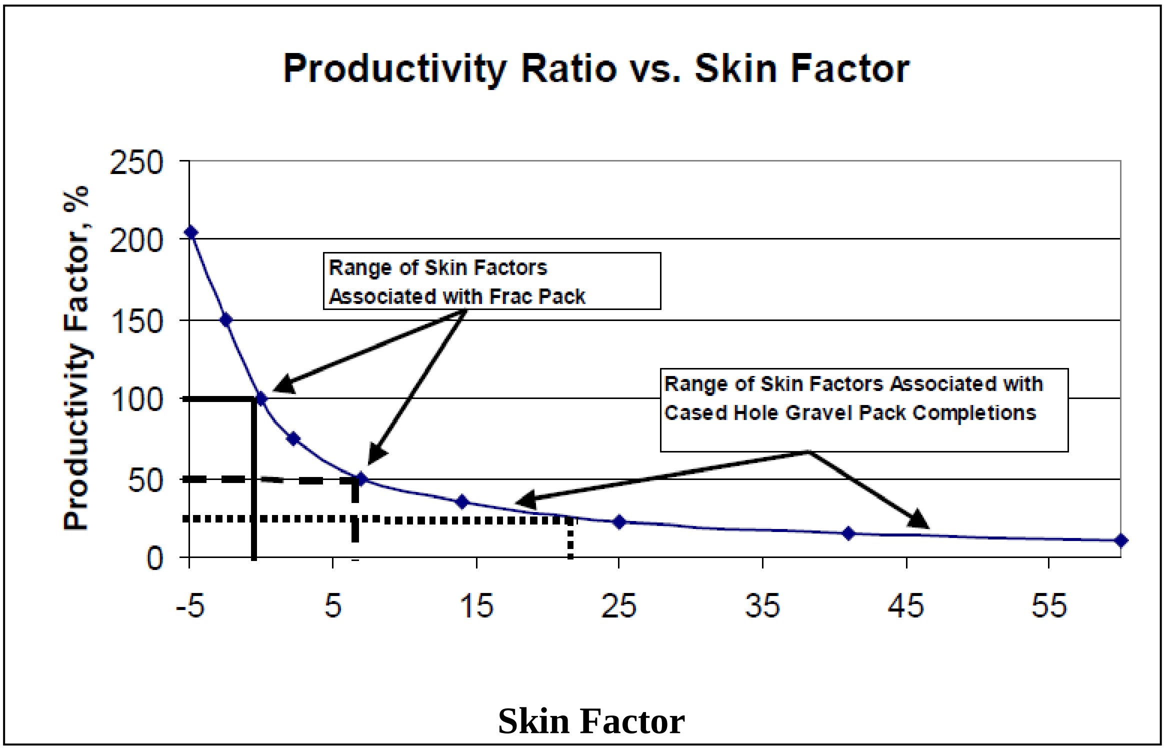


Figure (I-7) : Productivity and Skin Factor [6]

I. INTRODUCTION:

Very small particles are present in the pores spaces of all sandstone reservoirs. These particles, called formation fines, it can be incorporated and introduced into the formation during drilling and completion operations. Regardless of their mode of entry, they long have been recognized to cause severe formation damage. This is because these particles are not held physically in place by the natural cementation material that binds larger sand grains together, but instead are individual particles located on the interior surfaces of the porous matrix. Thus, these particles are free to migrate through the pores along with any fluids that flow in the reservoir. If these particles do migrate, but are not carried all the way through the formation by produced fluids, they can concentrate at pore restrictions, causing plugging and large reductions in permeability. [10]

II. Fines definition:

Fines are defined as particles having a diameter less than 44 microns, are ubiquitous in sandstone reservoirs. These fines are mineralogically diverse and range in composition from clay minerals to non-clay siliceous minerals (Quartz, feldspars, zeolites, etc). [11]

III. Fines types :

III-1 Clays :

III-1.a *Clay definition :*

A clay mineral can be defined as, any number of hydrous alumino-silicate minerals with sheet-like crystals structures, formed by weathering or hydration of other silicates; also, any mineral fragments smaller than 1/256 mm.

III-1.b *Classification of clays (main categories) :*

1. Detrital clays
2. Authigenic clays (diagenetic)

III-1.c *Clays types :*

1. *Illite :*

Illite appears as hairlike (capillary) structures lining pore walls, permeability reduction caused by dispersed Illite is primarily due to the resulting increase in tortuosity (pore friction).

* Illite is primarily a migrating clay.

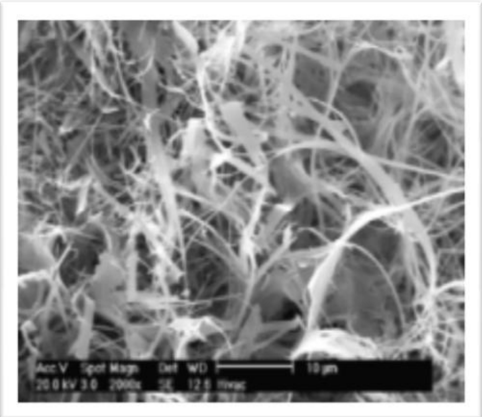


Figure (01-a): Illite Clay

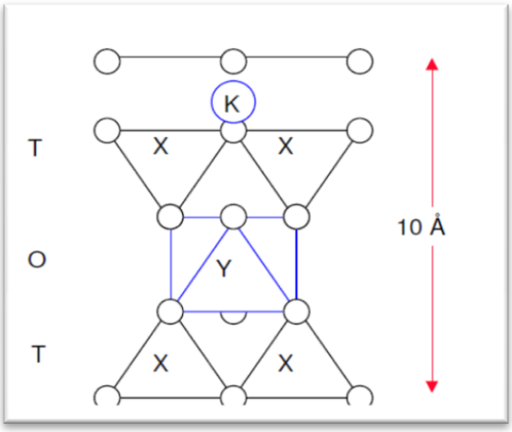
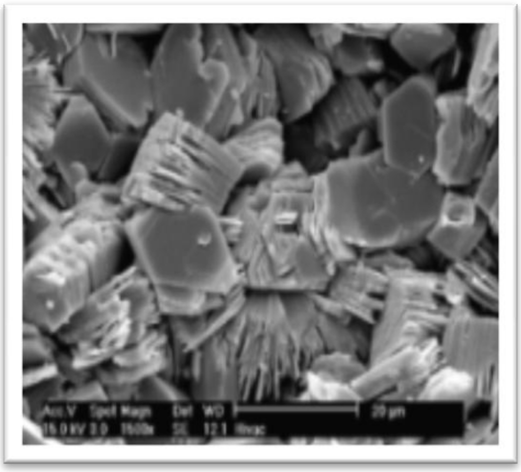


Figure (01-b): Illite Structure

2. *Kaolinite :*

The main permeability damage caused by kaolinite found in sandstone formation is due to its tendency to bridge off in pore throats once it has been dispersed and deflocculated .
Kaolinite particles tend to form discrete units it is a migrating clay (Figure 2-a).



Figure(2-a): Kaolinite Clay

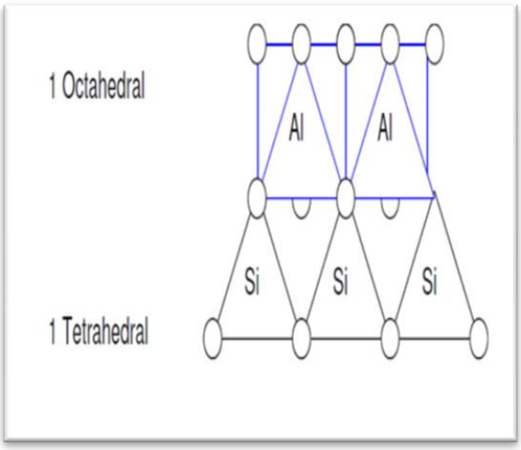
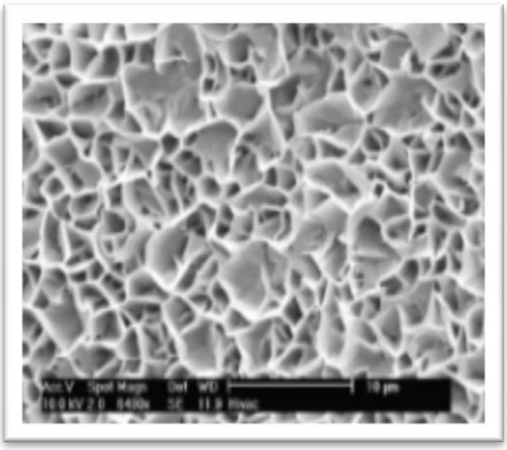
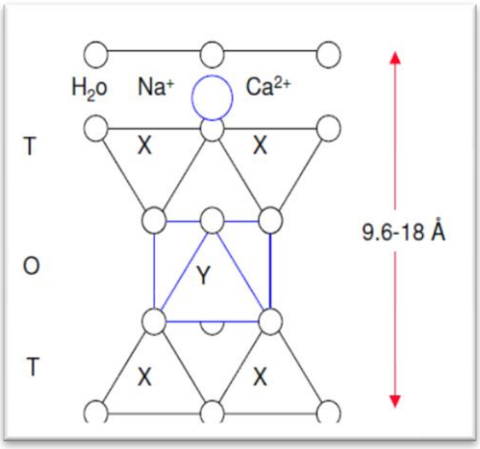


Figure (2-b): Kaolinite Structure

3. Smectite (Montmorillonite, Bentonite) :

Smectite has a structure and cation composition that gives it the ability to soak up large quantities of water, which spreads its sheet like layers apart. This tendency is the main reason montmorillonite can be so damaging to formation permeability when it is exposed to aqueous filtrates. In general fresh water and sodium ions tend to swell these clays, but potassium and calcium ions tend to shrink them.



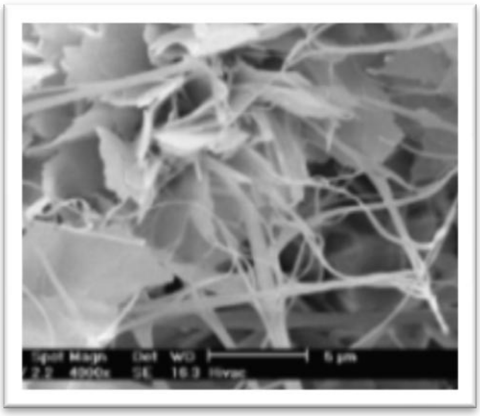


Figure(3-a): Smectite

Figure (3-b): Smectite structure

4. Chlorite :

Chlorite is diagenetic clay similar to Illite. Chlorite tends to found as a coating that lines the inside of pore throats. The dissolution by acid (chlorite being an iron-bearing mineral) could create the potential for the formation of pore plugging iron hydroxide precipitates.



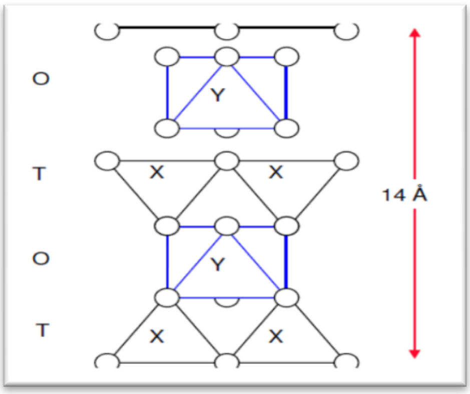


Figure 4-a : Chlorite Clay

Figure 4-b: Chlorite Structure

5. *Mixed Layer Clays :*

These are composed of layers of different clays. Irregular mixed layer clays usually contain montmorillonite and Illite and thus show marked swelling tendencies. Some tests show that permeability reduction is the greatest when montmorillonite and mixed-layer clays are present. Reduction is less with Illite, and least with kaolinite and chlorite.

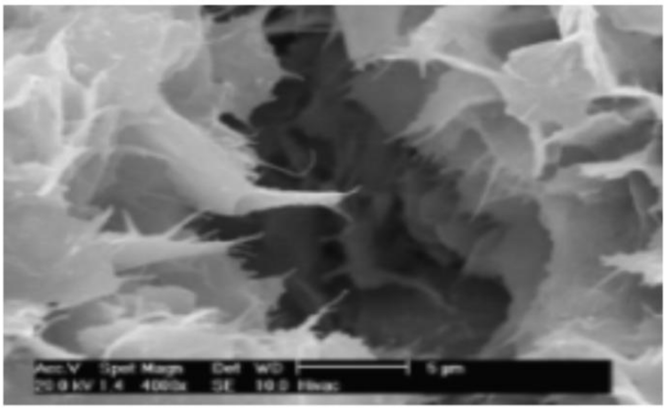


Figure 05: Mixed Layer Clays

II.2 *Quartz:*

Silicon Dioxide, hexagonal SiO_2 .The most common mineral in clastic sedimentary rocks and in sandstones it may occur as grains, cement, moveable fines in specific conditions of pressure and temperature because is very compact and stable mineral.
Quartz is not soluble in any acid except HF .

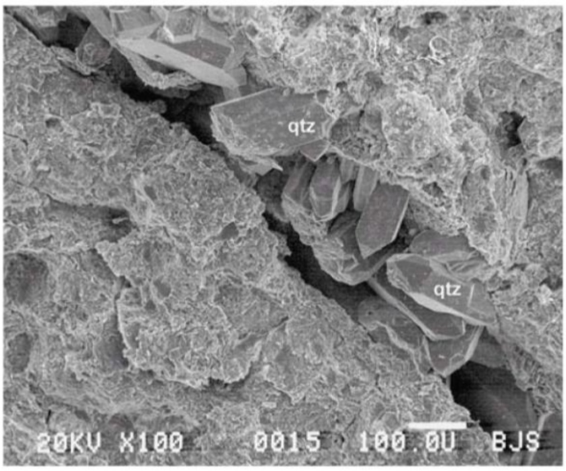


Figure 06: Quartz

III.3 *Feldspar:*

Framework aluminum silicates there is two main groups of feldspar minerals:

- Potassium Feldspars
- Plagioclase Feldspar group [5]

Figure 7-a : Feldspars – Potassium

Figure 7-b : Feldspars – Plagioclase

IV. Factors that causes Fines Migration:

Direct evidence of fines-induced formation damage in production wells is often difficult to come by. Although most other forms of formation damage have obvious indicators of the problem, the symptoms of fines migration are much more subtle. Indirect evidence such as declining productivity over a period of several weeks or months is the most common symptom. This reduction in productivity can usually be reversed by mud-acid treatments.

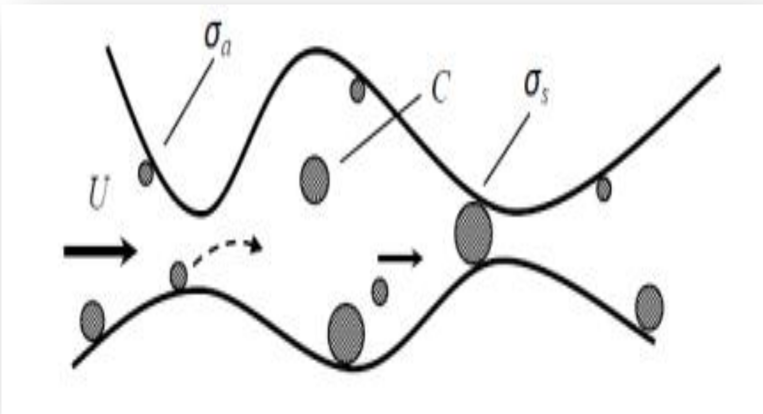


Figure 8: Fine particle attachment, detachment in porous media.

IV.1 <u>Low salinity brines :</u>

Core flow tests conducted in laboratory show that if low-salinity (< 2%) brines are injected into water-sensitive rocks, large reductions in permeability occurred ,It is a new well established ,so this dramatic reduction in permeability is almost entirely a result of fines migration. Reversal of flow results in a temporary increase in permeability as the fines plug pores in the reverse flow direction.

Fine-grained minerals are present in most sandstones and some carbonates formation , They are not held in place by the confining pressure and are free to move with the fluid phase that wets them (usually water). They remain attached to pore surfaces by electrostatic and van Der Waals forces. At "high" (> 2%) salt concentrations, the van Der Waals forces are sufficiently large to keep the fines attached to the pore surfaces. As the salinity is decreased, the repulsive electrostatic forces increase because the negative charge on the surfaces of the pores and fines is no longer shielded by the ions. When the repulsive electrostatic forces exceed the attractive van Der Waals forces, the fines are released from pore surfaces. There is a critical salt concentration below which fines are released. If a water-sensitive sandstone is exposed to brine with a salinity below the critical salt concentration, fines are released, and significant reductions in permeability are observed (Fig. 9). [12]

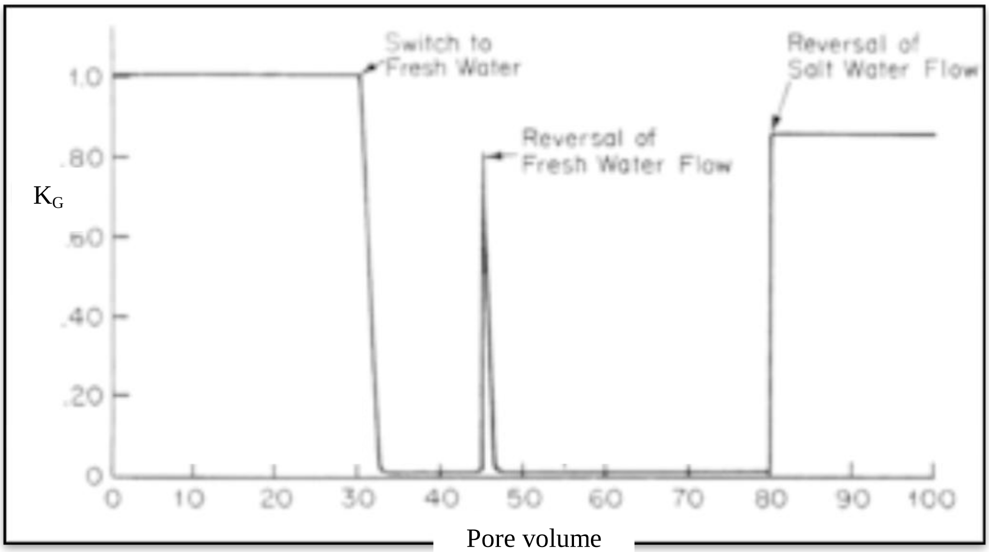


Figure 09 : Permeability reduction. Temporary and permanent permeability gain illustrating fines migration in sandstone formation.K_G is permeability gain, Pore volume refer to pore surface .

London-Van Der Waals Force :

This force is due to coupling of electron clouds around adjacent atoms. There is an assumption that considering fines as spheres and pore wall as plates . The force between a sphere and a plate it is Van Der Waals force it can be calculated. [4]

IV.2 Fluid velocity:

Fines migration can also be induced by mechanical entrainment of fines, which can occur when the fluid velocity is increased above a critical velocity. It have been measured for sandstones reservoirs .

Typical reported values of critical velocities are in the range of 0.02 m/s. This translates into modest well flow rates for most oil and gas wells.

It has been experimentally observed that critical flow velocities for fines migration phenomena are lower when the brine phase is mobile. This implies that fines migration will be more important with the onset of water production in a well. It is often observed that well productivities decline much more rapidly after the onset of water production. In such instances, more frequent acid treatments are needed to maintain production of oil after water breakthrough. See (Figure 10) [12]

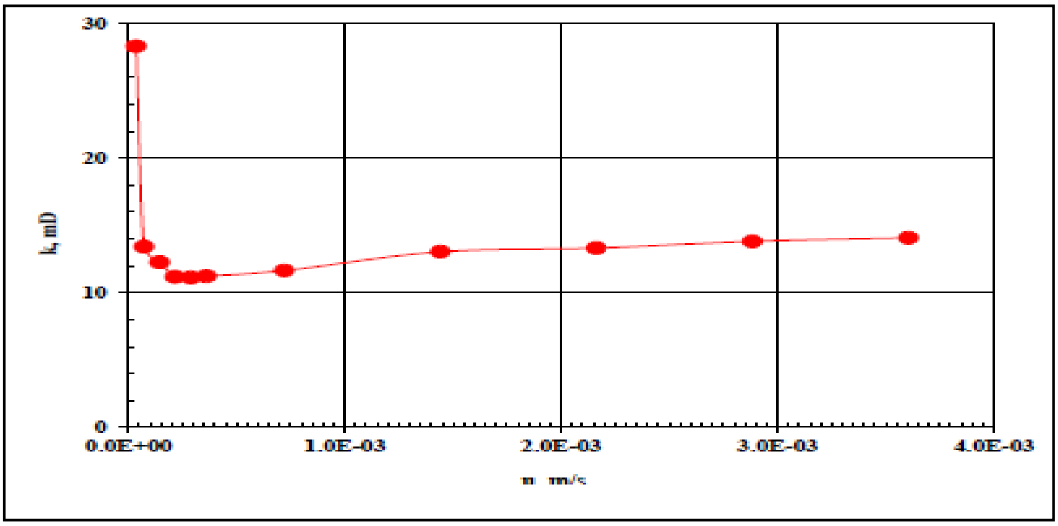


Figure 10 : Permeability variation for core sample with fluid velocity.

The impact of injection rate on a parameter named *erosion number* (When the fluid collide with high flow with formation is corroded its surface) is also studied.

The results of this study show that how introducing salts and injection rate can affect stability of fines on their locations.

When the erosion number reaches unity, the particle is in an unstable condition and able to release.[11]

Fluid flow through the pores makes several forces that could impact the movement of fines in the media. As shown in(Figure 9) this forces are:

1) electrical forces, *Fe*;
2) drag force; *Fd*,
3) lifting (buoyance) force, *F*l
4) gravity, *Fg* . [11]

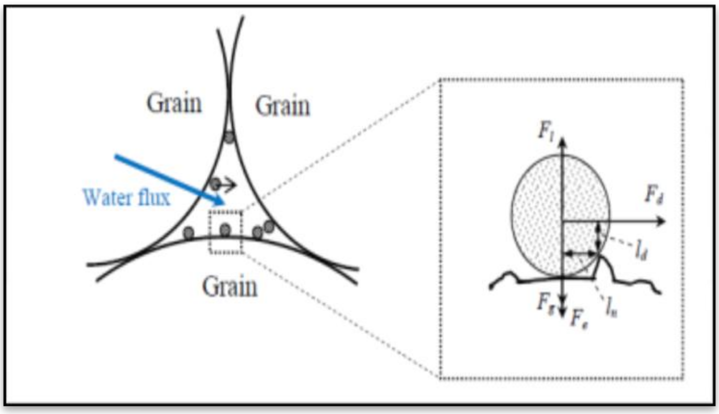


Figure 11: Cross section of a pore throat and forces acting on the attached particles.

IV.3 Wettability of rock :

When two immiscible fluids such as oil and water are together in contact with a rock surface, one of the fluids will preferentially adhere to the rock surface more than the other. The term wettability refers to a measure of which fluid preferentially adheres to the surface. Most producing reservoirs generally exist in a water-wet state, that is to say that connate water preferentially adheres to the rock surfaces. Figure 12 illustrates the condition that exists on a rock surface. The angle θ measured through the water is called the contact angle.

Wettability is described by the contact angle. If the contact angle θ is < 90°, then the rock surface is said to be water wet. On the other hand, if θ is > 90°, the rock surface is said to be oil-wet.

The extent of permeability reduction observed is also a function of the wettability of the rock. More oil-wet rocks tend to show less water sensitivity, maybe because the fines are partially coated with oil and are not as readily accessible to the brine. Significantly smaller reductions in permeability are observed when the rock is made less water-wet.[12]

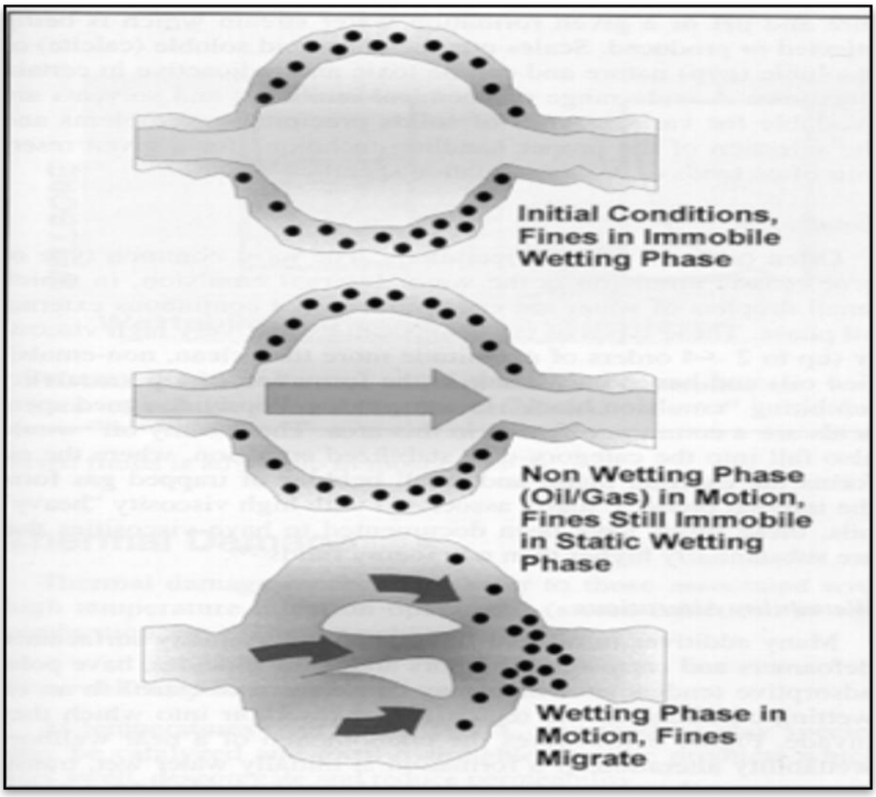


Figure 12: Fines migration mechanism (Wettability alteration)

IV.4 <u>Effect of pH :</u>

Clay migration is influenced by pH because it affects the Base Exchange Equilibrium, but its effect on a particular system depends on the electro-chemical conditions in that system. However, generally clay dispersion is detrimentally affected by alkaline waters with a pH of greater than 7.0 making the clays more mobile. At pH of 4.0, no disturbance is seen.

The pH of the filtrate may be the cause of impairment by another mechanism if the matrix cement is amorphous silica. Filtrates with a very high pH dissolve the silica, releasing fine particles, which may then block pores. Once clay is dispersed its particles become free to move and may cause plugging of the pore throats.

we observes that fines migration can be induced by any operation that introduces "low" (< 2%) salinity or "high" (> 9%) pH fluids into a water-sensitive formation. [12]

1. Definition of Stimulation:

We mean by stimulation in oil and gas industry all the operations that allows to enhance wells productivity or injectivity .It aim to restore the permeability of the near wellbore . [13]

Stimulation is a chemical or mechanical method of increasing flow capacity to a well as Dowell Schlumberger said. [7]

2. Types of stimulation :

I - Hydraulic Fracturing:

Hydraulic fracturing is a stimulation technique which consists to inject fluid into the formation at high flow rates, causing an increase in pressure and a subsequent formation breaking.

We use Hydraulic Fracturing for :

- By-pass near wellbore damage
- Increase well production by changing flow regime from radial to linear
- Reduce sand production
- Increase access to the reservoir from the well bore [3]

By its nature, radial flow is inefficient : **If properly created, hydraulic fractures can change flow regime from radial to linear** :

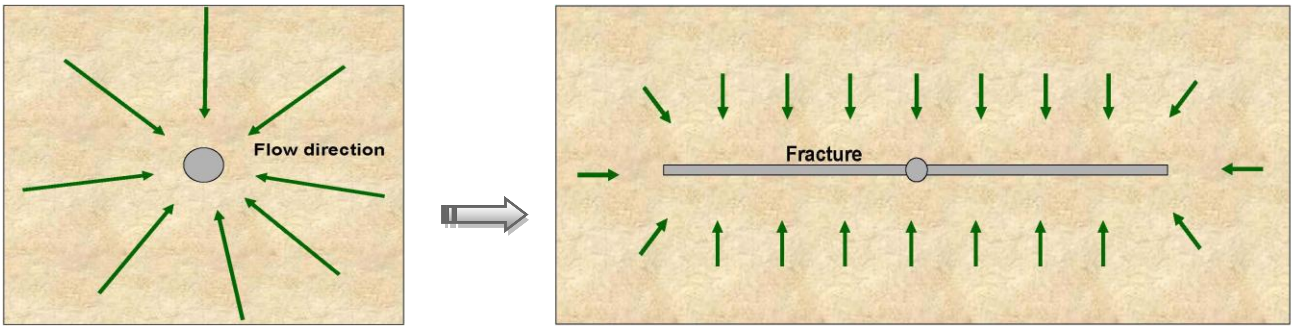


Figure 13: scheme of flow direction before and after fracturing .

II- *Treatment Categories:*

Non-Acid Treatments *:*

- Scale removal (Paraffins and asphaltenes),Water blocks / wettability changes , emulsions.

- *Versol I* and *II* are non-acid treating solution for removing formation damage caused by drilling muds. These water-based fluids contain a family of strong surfactants and chemical additives to effectively disperse mud solids, break emulsion and water blocks, and lower the viscosity of drilling muds. *Versol I* is designed for use with water-base drilling muds and *Versol II* is designed for inverted or oil-based mud. [5]

Acid Treatments :

3. **Acidizing:**

Acidizing involves pumping acid into a wellbore or geologic formation that is capable of producing oil and/or gas. The purpose of any acidizing is to improve a well's productivity or injectivity. There are three general categories of acid treatments: **acid washing; matrix acidizing; fracture acidizing. In acid washing**, the objective is simply tubular and wellbore cleaning. [9]

3.1 Mechnism of matrix acid job:

- To inject acid into formation at a pressure less than the pressure at which fracture can be opened
- To dissolve the clays, mud solids near the wellbore which had choked the pores
- To enlarge the pore spaces
- To leave the sand and remaining fines in a water -wet condition

3.2 Acidizing stages:

3.3.1 Tube clean and perforation cleaning

3.3.2 Matrix treatment:

A\ Preflush Stage (5% - 10% HCl or organic acid for fines treatment):

- To remove carbonates and to dissolve it
- To push NaCl or KCl away from wellbore

B\ Acid Stage (Main treatment BJSSA by stages with Foam diversion) :

- HF to dissolve clay / sand
- HCl to dissolve carbonates

C\ Over flush stage (10% HCl) :

- To make the formation water wet
- To displace acid away from wellbore

3.3.3 Placement of treatment fluids

3.3.4 Well disgorgement

We concerned by formation that is suffer from fines migration this is mean sandstone formation.

3.4 Sandstone acidizing:

- Mud acid (HCl + HF) is used as basic rock dissolution agent for acidizing of sandstone reservoir
- A Preflush of HCl or organic acid is normally used prior to injection of mud acid
- Additives are selected based on the rock mineralogy and reservoir fluid properties.
- An Over flush is injected to push all the mud acid to formation .

Reactions:

Clay : $Al_2\ Si_4O_{10}\ (OH)_2 + 36\ HF \longrightarrow 4H_2SiF_6 + 12H_2O + H_3AlF_6$

Sand : $4HF + SiO_2 \rightleftarrows SiF_4$ (silicon tetrafluoride)+ $2H_2O$

$SiF_4 + 2HF \rightleftarrows H_2SiF_6$ ((fluosilicic acid) SiF4 . [13]

3.5 *The additives :*

Fines Stabilization (stabilizaters):

Migration of non-swelling (kaolinite, fibrous Illite) clay and non-clay siliceous fines can be controlled by the use of an organosilane compound (FSA-1) and other stabilizaters see the table below . The organosilane it is the most important as it reacts with fines in the formation and then bonds them to the formation face. The compound is most effective with HCl-HF acid mixtures, where potential for mobile siliceous fines are the greatest because of the potentially damaging effects excessive mineral dissolution caused by HF.

This compound can be added directly to acid mixtures (HCl, HCl-HF, *Sandstone Acid* ™), and any preflush or displacement fluids. Normal concentrations range from one to ten (1.0 to 10) gallons per thousand gallons of treatment fluid. The best results obtained are with concentrations in the range five to ten (5.0 to 10) gallons per thousand-gallon range.

A spacer of KCl (not in conjunction with HCl-HF) or NH4Cl brine should be used to separate the treatment fluid from xylene or other solvents used for hydrocarbon dispersion during a clean up of the reservoir.

The organosilane material does not protect against clay swelling, and a stabilizer should be used in conjunction with this material to prevent swelling of clays. [5]

Table III.1: Clay Stabilizers Agents provide by BJSP Company. [5]

Stabilizing Agent	Product Type	Normal Usage
Clatrol-3	Quaternary Alkanol Amines	0.1% - 1.0%
Clay Master-FSC	Full Quaternary Amine	0.1% - 1.0%
Stabilizing Agent	Product Type	Normal Usage
Clatrol-3	Quaternary Alkanol Amines	0.1% - 1.0%
Clay Master-FSC	Full Quaternary Amine	0.1% - 1.0%
Stabilizing Agent	Product Type	Normal Usage
Clatrol-3	Quaternary Alkanol Amines	0.1% - 1.0%
Clay Master-FSC	Full Quaternary Amine	0.1% - 1.0%
Stabilizing Agent	Product Type	Normal Usage
Clatrol-3	Quaternary Alkanol Amines	0.1% - 1.0%

- Corrosion Inhibitor :

It is necessary to use it to prevent equipment corrosion there is factors affecting corrosion during an acid treatment for instance :(Temperature, Contact Time, Acid Concentration, Metal Type)

- Surfactant :

Can act to :

- Change surface and interfacial tensions
- Disperse or flocculate clays and fines
- Break, weaken emulsions, and Create or break foams
- Change or maintain the wettability of reservoir and prevent water blocks

- Non-Emulsifier :

- ✓ Contains water soluble group (polymer)
- ✓ More versatile as;
- Prevention of emulsion formation
- Lowered surface tension

- Anti-sludge Agent :

Sludge is a precipitate formed from reaction of high strength acid with crude oil

- ✓ Methods of sludge prevention :
  - Solvent (Xylene, Toluene), pre-flush to minimize physical contact of HF and Carbonate

- Iron Controller :

- ✓ Sources of Iron :
  - Scale: Iron oxide, Iron Sulfide, Iron Carbonate
  - Formation: Chlorite, Pyrite, Siderite
- ✓ Methods of Iron Control :
  - Chelating (iron chemically bound) e.g. Citric acid
  - Sequestering (iron retained in solution) e.g. EDTA, NTANTA
- ✓ The Precipitation of Iron:
  - Ferrous Ion (Fe++) pH 7 or Greater
  - Ferric Ion (Fe+++) pH 2 to 3

- Mutual Solvent :

- ✓ To maintain a water wet formation
- ✓ To water wet insoluble formation fines
- ✓ To reduce water saturation near the wellbore
- ✓ To help reduce the absorption of surfactants and inhibitors on the formation

- Diverting Agent :

  - ✓ To place the reactive fluid evenly in the right and the exact desire zone.

- Friction Reducer [13]

4. Equipment used for operation of acidification:

4.1 Surface equipment:

- Coiled Tubing Unit, 1" 1/4
- Data acquisition system
- Pumping Unit
- Nitrogen Unit
- 02 Transport for water
- 02 Transport for Acid
- Conventional BHA

4.2 Fluid requirements:

- 7.5% HCl Acid or Acetic Acid (Preflush / Overflush)
- Mud Acid
- Treated Water
- Foam spacer and diversion
- Soda ash . [8]

I. Methodology and experimental procedures (Tests):

In this chapter we will based on two important parameters, Firstly on the mineralogical of both formation of HBK field and HMD field, basing more on HBK formation in the first parameter and the second which is the used acid system of the two service companies BJSP and Halliburton on samples of this formation rock, on particular OKN#53 well samples, that we choice as practical case to specify the results and to facilitate the interpretation to be more understandable.

Before treating any formation, consideration should be given to the mineralogical characteristics of that formation. In all cases, it preferable to perform core flow tests on representative samples of the formation.

II. Mineralogical Analytic Procedures :

Mineralogical characteristic of HBK wells and HMD wells was performed by the radio crystallographic analysis (x-ray), and by a petrographic study. The study includes the following tests and analyzes:

a. Haoud Berkaoui Field :

1. Mineralogical Characteristic: Experimental results of mineralogical test:

a. Table -1: X-Ray Diffraction results

wells	Depth (m)	Non-clay minerals		clay minerals		
		Quartz (⁒)	Dolomite (⁒)	Illite (⁒)	Chlorite (⁒)	Interstrat.I-M (⁒)
OKJ#40 (POW)	3496.80	90	2	7.2	0.8	-
OKJ#50 (IOW)	3582.50	80	8	7.2	4.2	-
OKN#53(POW)	3512.10	82	8	8	0.5	1.5
OKJ#251(IOW)	3457.60	80	3	11.9	5.1	-
OKN#442(POW)	3479.50	80	7	7.8	5.2	-

b. Table -2 : Results of petrographic analyzes

Wells	Depth (m)	clay minerals and Non-clay minerals			linings and ciments	
		Quartz (٪)	Illite (٪)	Pyrite (٪)	Quartz Secondaire (٪)	Calcite (٪)
OKJ#40	3496.80	76	4	Tr.	8	1
OKJ#50	3582.50	74	5	-	4	12
OKN#53	3512.10	70	4	1	10	8
OKJ#251	3457.60	72	6	-	10	4
OKN#442	3479.50	70	5	Tr.	12	3

2. petrophysics measurements: It is the determination of the porosity and air permeability of wells samples.

Table -3: Experimental Results of petrophysical measurements

Wells	Depth(m)	Kair (mD)	Porosity(٪)	Density(g/cm^3)
OKJ#40	3397.30	242.78	12.77	2.61
OKJ#50	3550.25	139.18	13.04	2.64
OKN#53	3506.10	39.49	13.05	2.63
OKJ#251	3457.60	65.76	11.52	2.66
OKN#442	3499.05	34.08	7.43	2.66

Interpretation of mineralogical test results of HBK wells:

The results of petrophysics measurements show that the samples have variable permeability 6.05 to 601.53 mD (except the sample n^{o}1 of OKN#53 which have permeability of 1600 mD) and porosity between 5 and 17%.

- As regards the results of the X-ray diffraction; it appears that:
  - The composition of the samples is mainly sandstone where the quartz content ranges between 80-98 %.
  - Dolomite is present in virtually all samples; it varies from trace to 11%.
  - L'Illite (traces to 23.4 % and chlorite (traces à 5.2%) are two major minerals found in the clay fraction.
  - Traces of Halite, Calcite, Barytine, Anhydrite, Orthoclases and a small percentage of interlayered Illite-montmorillonite are present in the different samples.

b. *Hassi Messouad Field :*

Summary of Mineralogical Test Results of HASSI MESSOUAD Field:

Throughout the various zones, the formation are usually sandstones ,which contain two distinct grain sizes, medium to coarse sand grade grains and very fine to fine sand grains. The grains are usually subrounded.

The pore-filling phases in the sandstones are commonly kaolinite and quartz with rare occurrence of non-ferroan dolomite and gypsum or anhydrite. Kaolinite can mount for up to 10 - 15 % of the whole rock. This clay often occurs as a locally pore-filling phase, although it is occasionally responsible for widespread filling of porosity. Kaolinite is migratory clay.

Table - 4: Mineralogical test results of HMD wells

Sample Wells	Hand Specimen Description	X-Ray Defraction	Thin Section Description	Acid Solubility
MD175 **MD249** **MD276** **MD242** **MD20** **MD237** **MD306** **MD294** **MD221**	Light grey quarzitic sandstone. The sandstone is tightly quartz cemented with very poor visible porosity.	Quartz: 85 - 95 %. Kaolinite : 3 - 10 %. Illite : 2 % - 5 %.	**Grain (Quartz)** : Coarse sand grains cemented by secondary quartz. **Clays (Kaolinite & Illite)** : Filling most of the pores. **Cements (Quartz)** : Widespread overgrowth on all grains.	15% HCl 1.5- 3.5 %. RMA 10-17.2 %.

All HMD field zones present possibility of these following damages:

• Salt (NaCl): Zone has tendency to precipitate salt. Some wells are under continuous water injection through concentric pipe.

• Scales: Form due to incompatibility of waters mainly $BaSO_4$.

• Clays: Migration of clays is significant.

• Pressure depletion: Reservoir pressure dropped from + 450 kg/cm^2 in 1960 down to @ 270 kg/cm2 in 1995. The zone is under gas injection for pressure maintenance.

• Asphaltene: Zone has tendency to deposit asphaltene.

INTERPRETATION:

The formation of HMD field has grain of quartz which presents the higher percentage between (80% to 100%) . Coarse sand grains cemented by secondary quartz.

The percentage of Kaolinite is (2% to 15%) and Illite (traces to 5%) filling most of the pores, traces of Muscovite and Halite to 2%.

We can conclude that the mineralogy of both fields HBK and HMD formation mostly were the same in the high percentage of quartz and its placement in the formation rock, but different in the existence of Chlorite, Dolomite, and the traces of Mixed layer Clay in HBK field and its absence in HMD field contrary with the Kaolinite which exist in this last field with considerable percentage and is absent in the other one.

- Clays and Fines Migration in HMD field :

As mentioned earlier Kaolinite exists in abundance in the formation rocks as pore filling material, also some Illite exists as pore lining material. Kaolinite has the tendency to break up from the host grain in large size particles plugging the pore throats. Illite on the other hand retains water thus creating large volume of microporosity causing water blocking. In addition it can break, migrate to the pore throats and act as a check valve. Damage due to clays and fines is located in the near wellbore area within a three to four feet radius. So both of these fields mineralogy favorite fines migration despite of the differences in the composition of the two formation rock.

Table -5: Comparison between both of the mineralogy of HMD and HBK:

Minerals	**HBK** field	**HMD** field
Quartz %	80 - 90 %	80 - 100 %
Illite %	Traces - 23,4	Traces - 5%
Kaolinite %	/	2 - 15 %
Calcite %	Traces	/
Mixed layer Clay %	Traces	/
Dolomite %	Traces - 11%	/
Halite %	Traces	Traces - 2 %
Muscovite %	/	Traces – 2 %

we conclude that the phenomena of fines migration happen in different mineralogy which have different types of clays with various percentages.

III. Analytical procedures Acid system:

1. Solubility Tests:

These tested is to define for a given sample, its solubility in acids, indicating the soluble amount of carbonates and silicates.

Table -:6 Results of Solubility Tests:

Well	Depth (m)	Type of Acide	Solubility In «HC1» (%)	Solubility In «HC1/ HF » (%)	Solubility Of silicates (%)
OKJ #40 (POW)	3496.80	*MA (BJ-SP)*	5.837	16.76	10.92
	3503.80	*SA (BJ-SP)*	2.8	17.4	14.6
	3508.40	*SCA (Halliburton)*	14.3	23.5	9.2
OKN #50 (POW)	3559.60	*SCA (Halliburton)*	6.73	10.0	3.27
	3567.50	*MA (BJ-SP)*	12.83	14.68	1.85
	3585.90	*SA (BJ-SP)*	16.59	19.76	3.17
OKN #442 (POW)	3490.00	*SCA (Halliburton)*	5.989	11.9	5.911
	3493.13	*SA (BJ-SP)*	6.244	14.68	8.436
	1398.25	*MA (BJ-SP)*	4.705	7.747	3.042
OKN #53 (POW)	3506.45	*MA (BJ-SP)*	8	13.8	5.8
	3512.10	*SA (BJ-SP)*	2.8	17.4	14.6
	3506.30	*SCA (Halliburton)*	14.3	23.5	9.2

Interpretation of solubility test results of HBK wells:

The solubility of HBK wells samples in the various acid systems is averages of :

- 9.08% in the Preflush (7.5% HCl) , 12.33% in the Mud Acid (HCl / HF: 6 / 1.5) of BJ.
- 6.8% in the Preflush (7.5% HCl) , 17.15% in the Sandstone Acid (HCl / HF: 10/2) of BJ.
- 9.58% in the Preflush (7.5% HCl) , 14.72% in the completion Sandstone Acid (HCl / HF: 13 / 1.5) of Halliburton.

3. *Compatibility tests:*

The most common adverse effects and sometimes severe of acidizing process is result from the incompatibility with the acid in place and this leads to the formation of sludges or emulsion.

2.a. Precipitation tests of sludges:

Some categories of oil when it is in contact with acid solutions tend to form precipitates named sludges.

2.b. Emulsion tests :

This test allows apprehending selecting the best demulsifier, is designed to verify the compatibility. To avoid a stable emulsion is to protection the formation rock from wettability alteration as a result, we avoid fines migration and pores plugging.

Results of Compatibility tests:

a. Table –7: Results of sludge tests:

System	Preflush 7.5 (1/41HC1 (BJ-SP)	Mud Acid (6-1.5) (BJ-SP)	Sandstone Acid (10-2) (BJ-SP)	Clay Fix-5 (Halliburton)	Preflush 7.5 °/0HC1 (Halliburton)	Sandstone completion Acid(13-1.5) (Halliburton)
Results	Absent	Absent	Absent	Absent	Absent	Absent

b. Table – 8: Results of emulsion tests:

System	Preflush 7.5 (% HC1 (BJ-SP)	Mud Acid (6-1.5) (BJ-SP)	Sandstone Acid (10- 2) (BJ-SP)	Clay Fix-5 (Halli)	Preflush 7.5 %HC1 (Halli)	Sandstone completion Acid (13-1.5) (Halliburton)
60 mn % 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	clear	clear	clear	clear	clear	Absent (Emulsion total)

Interpretation of Compatibility Tests:

Compatibility tests are performed in order to detect any precipitation of sludge or emulsion between the different acid solutions and formation fluid (Oil). The tests showed that no sludge formation is detected. Furthermore, the emulsion tests revealed that the matrix processing on the system "Sandstone completion Acid" form total emulsion outer oil phase.

3. Core Flow Tests:

a. *Damage Tests:*

- These tests are conducted in wellbore conditions (temperature and pressure) ,consist simulation the invasion of rock samples from the mud, this last should be well homogenized, is heated in the cell and the entire circuit (sample- holder, tubing etc.) to reach a temperature of 80 ° C.
- Inject through the sample the mud at a pressure of 30 Kg / cm^2 and against pressure of 10 Kg / cm^2.
- Reports every 15 min using a graduated test tube, the volume of filtrate elapsed while maintaining the same conditions of temperature and pressure. Once the filtration is completed, performs the sample pulse cleaning with inert oil "Soltrol 130" in the direction of production.
- Once the flow of this oil is constant, determining the permeability Kf Soltrol after damage.

b. Acidizing Tests :

Acidification tests are performed under a temperature of 80 ° C, a confinement pressure of 1000 psi and against pressure of 10 kg / cm^2. The permeability of each fluid is calculated from the following equation:

$$K = \frac{Q.\mu.L}{DP.s}$$

The results of acidification tests obtained for the different samples and using three acid sequences are illustrated by the response curves (Ka/Ki according to the acid injected volume).

Acidizing tests comprise the following steps:

- Saturation rock samples with formation water
- Determination the initial permeability (Ki)
- Determining the final permeability (Kf)

Deduced damage coefficient generated by the mud, estimated from the following relationship:

$$\%\ C = \frac{Ki - Kf}{Ki} \times 100$$

• Injection acid solutions:

The solutions were injected into three sequences: (Preflush, Main treatment, Overflush).

- Determining the final permeability (Kfa)
- Determination permeability gain (Kr = kfa/Ki)

Results of damage and acidizing tests:

a. Table-9: Acidizing and Damage tests results of HBK wells samples by Halli Acid System:

Well	Depth (m)	Kair (mD)	Ki (mD)	System Of Mud	rate of Damage (%)	System of tested Acid	Kr
OKJ#50	3559.60	567.98	197.8	*Versadril*	37.6	Sandstone Completion acid	2.0
OKJ#40	3492.50	48.79	9.6	*Versadril*	62.5	Sandstone Completion acid	3.9
OKN#53	3505.60	117.03	40.3	*Versadril*	40.2	Sandstone Completion acid	5.2
OKN#442	3498.25	236.12	70.9	*Invermul*	37.4	Sandstone Completion acid	38.2
OKN#251	3438.42	32.86	10.5	*Invermul*	42.9	15 % HCl	0.7

b. Table-10: Acidizing and Damage tests results of HBK wells samples by BJSP Acid System:

Well	Depth (m)	Kair (mD)	Ki (mD)	System Of Mud	rate of Damage (%)	System of tested Acid	Kr
OKJ#50	3585.90	60.11	3.2	*Versadril*	46.9	Sandstone acid (10-2)	4.9
OKJ#40	3494.75 3493.80	37.01 59.21	10.5 18.6	*Versadril*	47.6 36.6	Mud acid (6-1.5) Sandstone acid (10-2)	2.2 3.1
OKN#53	3506.30 3506.10	67.87 39.49	11.2 5.9	*Versadril*	60.7 38.9	Sandstone acid (10-2) Mud acid (6-1.5)	6.4 8.7
OKN#442	3499.05 3493.15	34.08 48.14	17.9 6.7	*Invermul*	39.1 49.3	Mud acid (6-1.5) Sandstone acid (10-2)	7.0 4.6
OKN#251	3438.75	44.46	32.9	*Invermul*	39.8	Mud acid (6-1.5)	1.3

Interpretation the results of damage and acidizing Tests:

Damage tests by both of oil mud system Versadril and Invermul report H / E of 80/20 reveal that they have the same damaging ability. Damage degrees of both systems are 45.3 and 42.9 % respectively.

«ARC » curves show that the first stage of treatment, relative to Prefiush is generally upward reflecting HCl reaction with carbonates (Dolomite).

Permeability ratio Ka/Ki is generally greater than unity for samples with a considerable percentage of dolomite.

In the case of OKN # 251 samples, ammonium chloride 2% used as a preflush, it does not contribute any significant improvement in permeability as the value of this processing sequence is rather clay inhibiter.

Regarding the Main Acid of acid systems tested, we found different behaviors for each type of acid and the present mineralogy.

Mud Acid BJSP matrix treatment shows a good response of rock to acid, except the first Sample of OKN # 251 well, probably there is a precipitation of fine particles.

Moreover, the second sequence of BJ-SP Sandstone Acid system shows a similar behavior for all samples, characterized by a decline after the Preflush treatment, followed by stabilization. This is supported by the nature of the acid (delayed type).

Indeed, hydrofluoric acid is generated as the injection of Sandstone Acid, allowing it to act more deeply into the rock and reduce the chance of secondary reactions.

As for the Completion Sandstone Acid Halliburton system proposed by the matrix treatment contributes to a slight improvement; however the ratio of Ka / K in this step does not exceed 1.5.

The last phase of treatment "Overflush", whose role disgorging products from the dissolution, is increasing in most cases. However, a gain drop is observed for samples treated with BJ-SP Mud Acid system. As well as OKN#251 Sample N^0 4 which treated by 15% HCl, this is probably due to migration of fine particles or secondary precipitates formed after the matrix treatment.

IV. Visualization Scanning Electron Microscope:

Overview at low magnification (20X) of the various HBK wells samples selected for treatment with acids proposed confirms the dominance of quartz.

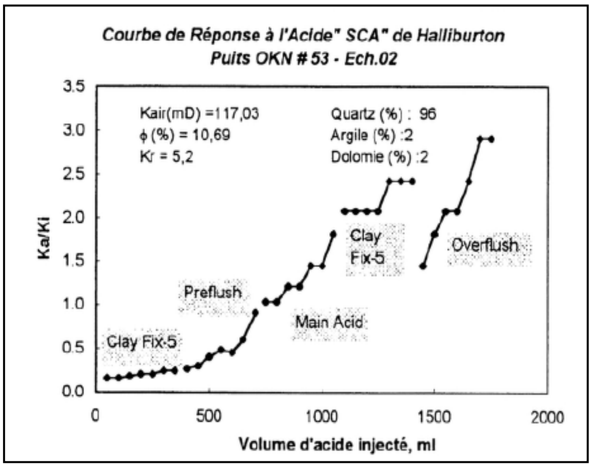
Pictures taken with large magnifications can observe the quartz grain nourishment by secondary silica, as well as different types of clays and their distribution in the matrix.

The clay minerals provided by chlorite and Illite lining the pore walls and therefore control the porosity of the rock.

The SEM observation of the samples treated with different acid solutions shows usually the dissolution of carbonates and salts by the action of hydrochloric acid and the alteration of aluminosilicates (clays, feldspars and quartz) with hydrofluoric acid. However, it is found that all the acid systems contribute to form fine particles. See the appendix B.

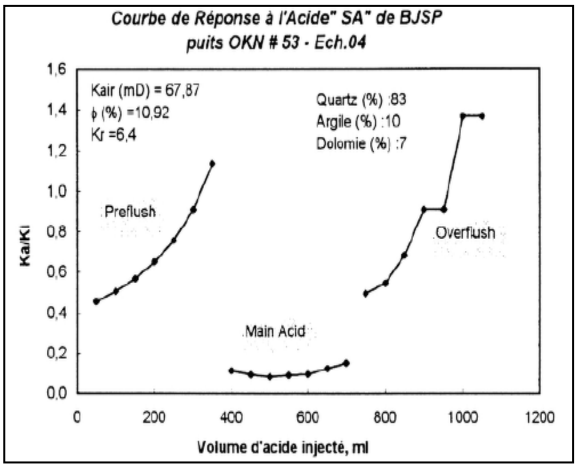
Acid Response Curves (ARC CURVES of OKN#53 well) :

ARC- Sandstone Completion Acid



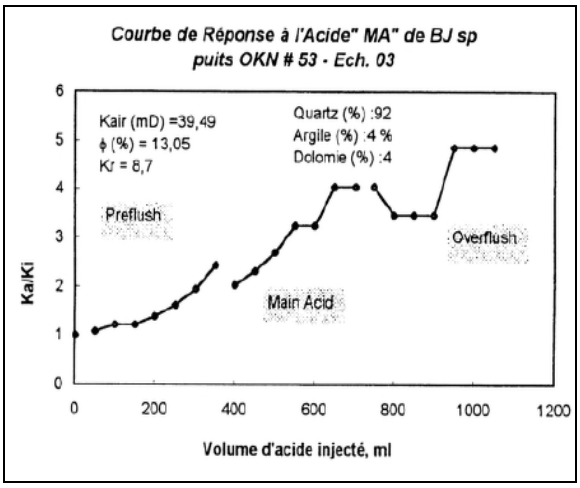
Sample N^0 2 depth: 3505, 60m

ARC-BJ Sandstone Acid



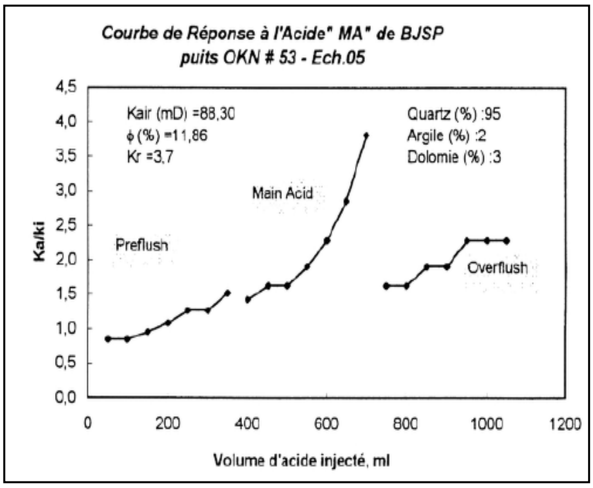
Sample N^0 4 depth: 3506, 60m

ARC- BJ Mud Acid



Sample N^0 3 depth: 3506, 10m

ARC-BJ Mud Acid



Sample N^0 5 depth: 3438, 75m

Figure 14: AR Curves of OKN#53 well.

V. REAL CASE FOR STUDY OKN#53 :

V.1 ***Well history:***

OKN#53 well is situated in Haoud Berkaoui Field, Algeria. The well was drilled and completed in September 2000. The well was currently producing oil in that time.

V.2 ***Well data:***

Reservoir & Production Data : (2003)

- Formation(s): Série Inférieure (SI)
- Perforated Interval: 3496.5m – 3516m
- Gross Interval: 19.5m
- Net Interval: 9.5m
- Porosity: $\Phi_{Ave} = 10.7$ %
- BHT: 120 ºC (approximately)
- BHP: 4240 psi (approximately)
- Reservoir Pressure: 4370 psi (approximately)
- Wellhead Pressure : 512 psi
- Production Rate: 7.1 m3/h
- GOR: 115 m3/m3
- Skin: + 37 (SBU test, 22-25/11/2001)
- Perforated intervals: 3496.5 – 3498 m, 3505- 3508 m, 3511 - 3516 m.

V.3 ***Damage Mechanisms:***

Analysis of well data gives a skin factor of +37.4 .The well production history shows a progressive reduction in output over time. However the production decline is slight and suggest that formation damage has been present since the well was initially placed on production .Therefore ,it is assumed the primary cause of formation damage comes from drilling ,cementing and perforating operations as we know that this operations were resulting fines migration.

V.*4* ***Treatment recommendation:***

The treatment aims to eliminate the damage of the formation.

4.1 Treatment Summary:

- Well cleanout
- Perform multi-stage BJ Sandstone Acid treatment.
- Evacuate treating fluids.
- Place well on production.

4.2 Acid Design:

An extensive core analysis program has been undertaken by CRD. This has yielded an abundance of petrophysical and mineralogical data on Berkaoui field. In particular, cores from OKN-53 were used in the study. This data, in conjunction with BJ Service company's design recommendations (***BJ Services Mixing Manual, Section I-B-3***) has been considered when designing the BJ Sandstone Acid treatment.

The presence of clays, up to 11% in some instances, has prompted the inclusion of formic acid in the formulation. High quartz content, including secondary precipitation of quartz, permits the use of regular strength BJ Sandstone Acid. This has a higher HF content allowing for greater silica dissolution and greater penetration.

The expected reservoir temperature requires the use of corrosion inhibitor intensifier in the HCl Overflush. The formic acid in the preflush and main treatment will act as a corrosion inhibitor intensifier as well as providing greater clay control.

Fines migration has been identified as a concern by the CRD study. To address this problem formic acid (10%) will be used for the preflush.

The combined over flush volume, acid and treated water, will be sufficient to displace the main treatment at least 5 ft (1.5m) from the wellbore. In conjunction with the inhibition properties of the HV Acid this will minimize the risk of precipitation of harmful reaction products during the shut-in period.

V.5 ***Fluid requirements:***

Table-11: fluids requirements for the first day: Tube Clean and Perforation Wash

1-Treated water m3 60

Additive	Description	per m3	For 60 m3
Fresh Water		979 Lts	58711 Lts
NH4Cl	Clay Stabiliser	30 Kgs	1800 Kgs
NE 118	Surfactant	2 Lts	120 Lts

2- Gel Pill m3 1

Additive	Description	per m3	For 1 m3
Fresh Water		979 Lts	979 Lts
NH_4Cl	Clay Stabiliser	30 Kgs	30 Kgs
NE 118	Surfactant	2 Lts	2 Lts
HEC 10	Gelling Agent	3 Kgs	3 Kgs
Na2CO3	Soda Ash	0.5 Lts	1 Lts

3-Tube Clean (HCl 7.5%) m3 2

Additive	Description	per m3	For 2 m3
Fresh Water		786 Lts	1572 Lts
CI 15	Corrosion Inhibitor	5 Lts	10 Lts
HCl (32 %)	Hydrochloric Acid	209 Lts	418 Lts

4-Neutralising Solution m3 2

Additive	Description	per m3	For 2 m3
Fresh Water		998 Lts	1996 Lts
Na2CO3	Soda Ash	5 Kgs	10 Kgs

Table-12: fluids requirements for the second day: BJSS Acid Matrix Treatment

1-Treated Water m3 60

Additive	Description	per	m3	For 60	m3
Fresh Water		979	Lts	58711	Lts
NH4Cl	Clay Stabiliser	30	Kgs	1800	Kgs
NE118	Surfactant	2	Lts	120	Lts

2-Versol I svstem m3 2

Additif	Description	par	m3	Pour 2	m3
Eau	Eau douce	868	Lts	1737	Lts
NH4Cl	Stabilisateur d'argile	20	Kgs	40	Kgs
F 900	Agent sequestrant	25	Kgs	50	Kgs
NE118	Surfactant	2	Lts	4	Lts
FAW 25	Stabilisateur d'argile	2	Lts	4	Lts
Inflo 40	Solvent Mutuel	100	Lts	300	Lts

3-Preflush –Overflush (HCl 7,5 %) m3 3

Additive	Description	per	m3	For 3	m3
Fresh Water		723	Lts	2169	Lts
F 300	Sequestring Agent	10	Kgs	30	Kgs
CI 15	Corrosion Inhibitor	5	Lts	15	Lts
NE118	Surfactant	3	Lts	9	Lts
Clatrol6	Clay Stabiliser	4	Lts	12	Lts
Inflo 40	Mutual Solvent	50	Lts	150	Lts
HCl (32 %)	Hydrochloric Acid	209	Lts	627	Lts

4-BJ Sand Stone Acid (Half Strength m3 3

Additive	Description	per	m3	For 3	m3
Fresh Water		837	Lts	2511	Lts
F 300	Sequestring Agent	10	Kgs	30	Kgs
ABF	Amonium Bifluride	24	Kgs	72	Kgs
CI 15	Corrosion Inhibitor	5	Lts	15	Lts
NE118	Surfactant	3	Lts	9	Lts
HV	Phosphonic Acid	15	Lts	45	Lts
MMR 2	Surfactant	3	Lts	9	Lts
INFLO 40	Mutual Solvent	100	Lts	300	Lts
HCl (32 %)	Hydrochloric Acid	15	Lts	45	Lts

5-Neutralising Solution m3 2

Additive	Description	per	m3	For 2	m3
Fresh Water		998	Lts	1996	Lts
Na2CO3	Soda Ash	5	Kgs	10	Kgs

V.6 ***Results of stimulation by acidizing for OKN#53 well:***

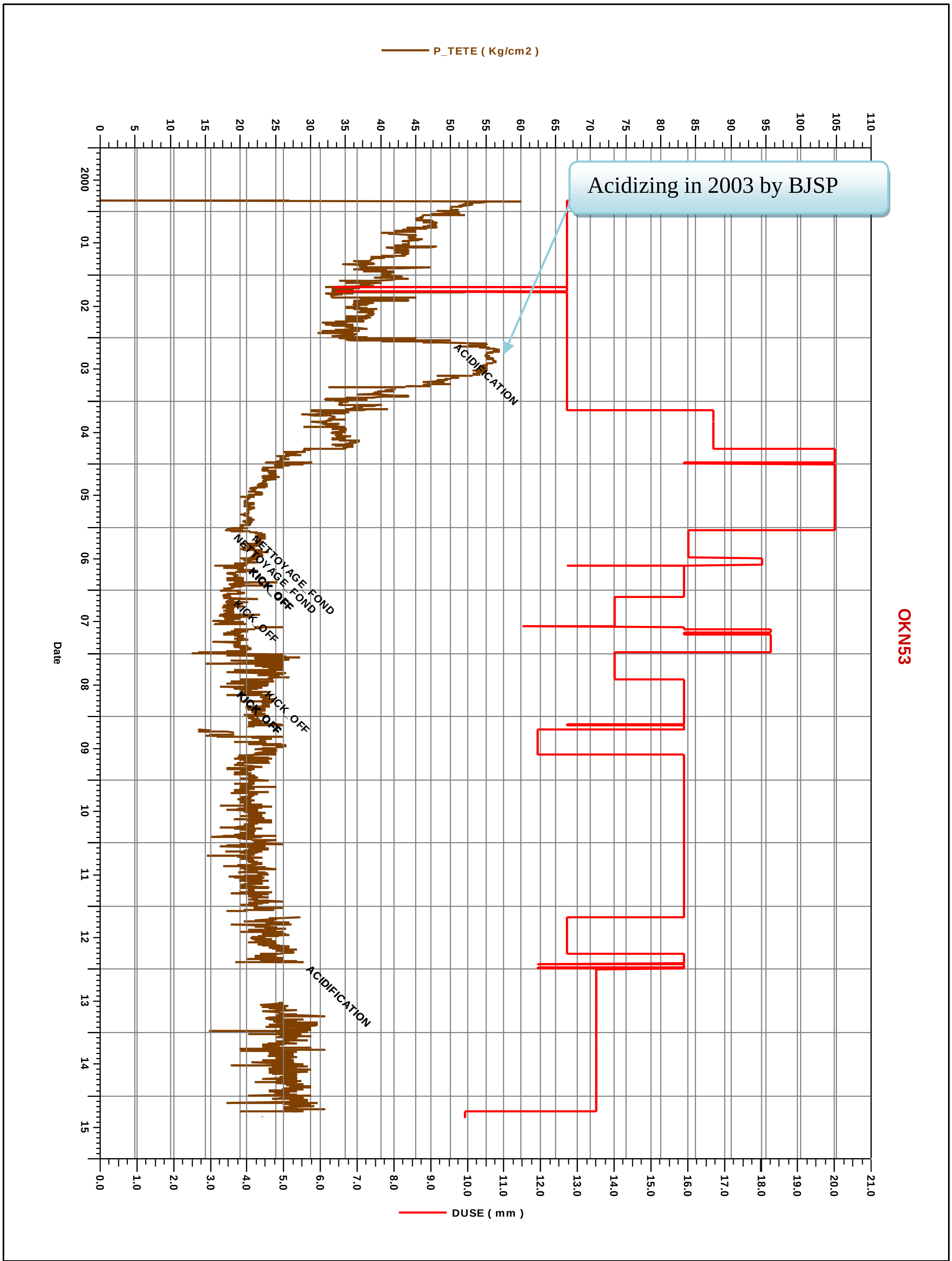


Figure 15: Graph show the variation of the head pressure well and choke diameter with the execution of acidizing operations over the time.

- The value of flow rate before the stimulation by acidizing was 7,651 m^3/h ,
- The value of flow rate enhanced to 10,685 m^3/h after acidizing.

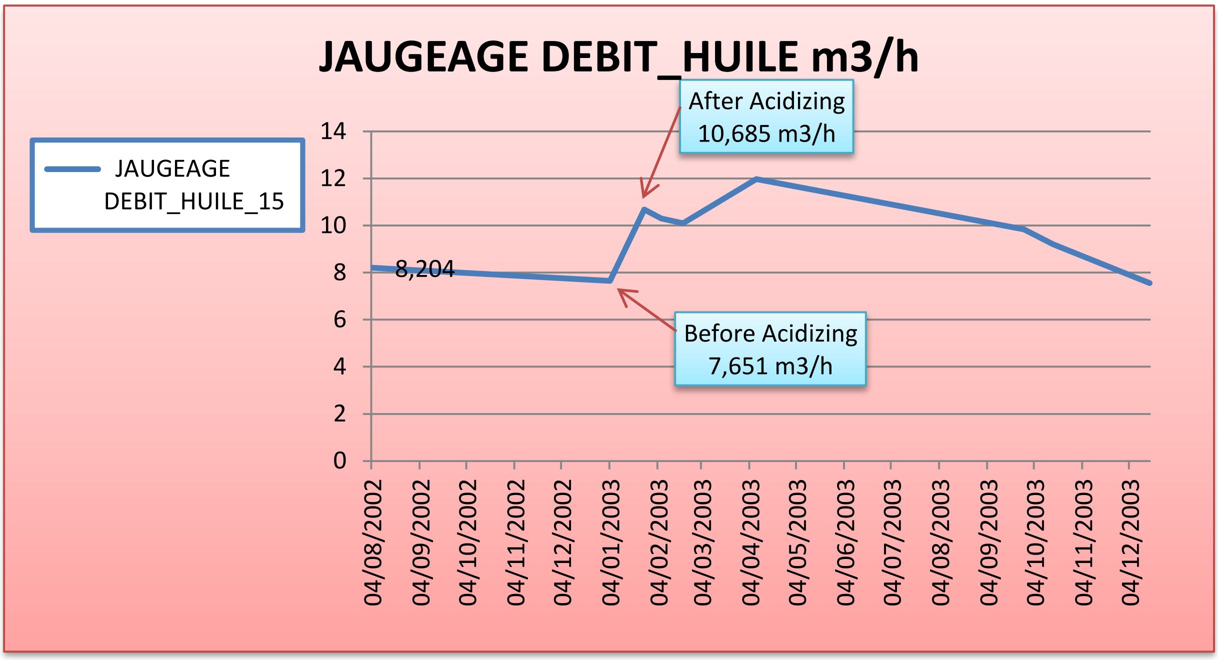


Figure 16: Graph show the variation of oil flow before and after acidizing .

V.7 ***Economic approach:***

Payout is equal to the number of production days to cover the cost of the operation by the net gain after treatment:

- Services & Equipements : 2 767 090, 41 DA
- Produits : 3 477 971, 45 DA
- Total Cost : 6 245 061, 85 DA

- 1 barrel ≈0,159 m^3
- 1 m^3 ≈ 6,29 barrel

$$Payout(Days) = \frac{Total\ Cost\ equivalent\ volume\ on\ m^3}{\text{Net Gain of Oil Production } (m^3/Day)}$$

The Price of one Barrel: According to websites it range from 30 \$ to 42 \$ (of USA) in 2003, so from 2970 DA to 4158 DA.

The total cost equivalent volume on m^3 = Total Cost\ the Price of one Barrel × 6, 29

TCQV: 6 245 061, 85÷ (2970× 6,29) = 334,295 m^3

TCQV: 6 245 061, 85 ÷ (4158× 6,29) = 239, 16 m^3

The net gain of oil flow production on (m^3/Day)= (10,685 - 7,651) × 24 =72,816 m^3/Day

- Firstly for 30 $: Payout (Days) =334,295 ÷ 72,816

  Payout (Days) = 4 days, 14 hours, and 10 min

- Secondly for 42 $: Payout (Days) = 239,16 ÷ 72,816

  Payout (Days) = 3 days, 6 hours, 49 min

Acid volume can be estimated using the following equation:

$$V_{acide} = V_{cylindre} = \pi\,(r_d^2 - r_w^2).H_{net}.\Phi_{eff}$$

V_{acid} **:** volume of acid used for the main treatment (m^3)

r_d **:** damage radius (m),(determined by well testing) ;

H_{net} **:** the net height of the reservoir (m);

r_w **:** well radius (m) ;

Φ_{eff} : the effective porosity of the reservoir (%).

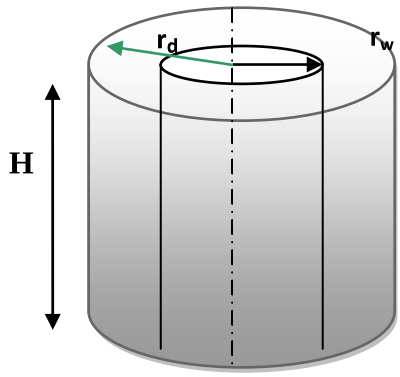


Figure 17: Wellbore (the path of the treatment)

V.8 ***Safety:***

Any services company should conduct a pre-job safety meeting to discuss all aspects of the job with all the personnel on location, and ensure that all its personnel have the proper personal protective equipment (PPE) and well knowing the dangers of the chemical fluids that will be inject in the well during the operation, persons in operation site must ovoid the contact of this fluids and wear the safety tools. The personnel that may come in to direct contact with any hazardous materials or any events during the course of the job should be advised and well formed to react against any dangers.

Also operators should follow the job planning to get the job objectives.

CONCLUSION

CONCLUSION

Post-treatment fines migration is quite common in sandstone acidizing. It may be difficult to avoid in many cases. The reaction of HF with clays and other aluminosilicates minerals, and quartz, can release undissolved fines. Also, new fines may be generated as a result of partial reaction with high-surface-area minerals, particularly the clays. Post-acidizing fines migration problems can be reduced by bringing a well on slowly after acidizing (one to two weeks).

After acidizing tests performed on HBK wells well samples with different acid systems, it appears that:

- The Sandstone Acid BJSP system gives the best performance in terms of permeability gain; Nevertheless, the phenomenon of fine particles is detected (if only for a single sample three observed SEM) which could invalidate the hypothesis of the matrix micro-diversion. For this reason other tests in this direction should be considered.
- The completion Sandstone Acid Halliburton has a stimulating power relatively large because the formation of emulsions problem with crude greatly affects its performance. To remedy this problem, the service company proposes to increase the concentration of AS-7 anti-sludge agent up to 12 gal / Mgal in preflush 7.5% HC1 and 14 gal / Mgal in the Completion Sandstone solution -acid and eliminate demulsifier Losurf 300. It is also found that this system contributes to the formation of fine.

Finally, to address the problem of fine particles, it would be wise to use in the preflush phase an organic acid instead of hydrochloric acid and an ammonium chloride solution to inhibit the reactivity of certain clays. As It is obviously that the mineralogy of HBK field formation are HCl sensitive.

After the stimulation by acidizing performed on OKN♯53 well which was had a positive skin (+37) due to fines migration resulting from drilling, cementation and completion operations ,the well gave best response to the designed treatment by the service company BJSP the flow rate increased from 7,651 m^3/h to 10,685 $m^{3/}h$.

So we can conclude that the Mud Acid is efficient to remove formation damage resulting from fines migration.

RECOMMANDATIONS

- It is necessary to clean the well before and after any operation may causes particles invasion.

- The usage of the organic substance is practical to avoid wettability alteration . The organic acid is convenient better than hydrochloric acid for treatment in the case of sandstone formation that suffer usually from fines migration.

- Proppant with larger grain size provide a more permeable pack and law closure stress in this case there is an opportunity to damage the reservoir more than the previous. However, sandstone formations, or those subject to significant fines migration, are poor candidates for large proppants. The fines tend to invade the proppant pack, causing partial plugging and a rapid reduction in permeability.

  In these cases, smaller proppants, which resist the invasion of fines, are more suitable. Although they offer less conductivity initially, the average conductivity over the life of the well will be higher and will be more than offset the initial high productivity provided by larger proppants, which is often followed by a rapid production decline. .But it is recommended to switch to big proppant size in the near wellbore to avoid the early plugging by fines migration (Schlumberger-Reservoir Stimulation Michael. J. Economides ,Kenneth G. Nolte 1989.) .

- Timing of diversion fluid is very important to do its job at the best face it can be also the timing of injection of the is so important in the execution of acidizing operation.

- FSA-1 (Fines-Stabilizing Agent) it is an additive provide great suspension and stabilization of clay and non-clay siliceous fines, It is more practical than clay stabilizers .

It can be included in all stages of acidizing operation, If it is necessary it act as HF acid retarder when added to HF stage.

This additive is successful in gravel pack acidizing to remove fines, also compatible in aqueous fluids throughout pH range and with mutual solvents, alcohols and broad range of additives. It forms fines-stabilizing binding "film" *in situ* to protect the formation surface from erosion.

- The quality should be high ,percentage should be optimal of salt in the injected fluids.
- An advanced HV:HF Acid System has been specifically designed and applied for the purpose of removing fines from gravel packs and near wellbore areas.
- To apply the rules and all the important points in the long-term of well life is better than dissolve problems with expansive prices .

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