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Laboratory Study and Field Matching of Matrix Acidizing of Petroleum Reservoir Rocks

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Abstract. In this paper, a laboratory method was developed to contaminate rock core samples with drilling fluids and test formation damage caused for these cores. The surface of the contaminated core samples was treated with different acid solutions to simulate matrix acidizing, remove damage and restore the original permeability. The acid volume and concentration, reaction speed and reaction products of different acid types and acid mixtures used in acidizing are presented. The amount of acid injection volume required to remove the formation damage near the wellbore region was calculated for different acid concentrations and acid solutions.

Field data from some fields in one of the Arabian Gulf Countries were collected and analyzed and matched with the laboratory results obtained. Moreover other processes to remove or to minimize formation damage are mentioned. It was found that 0.8 Pore Volume (PV) of 15% HCl is adequate to remove formation damage and to restore the permeability or 1.3 PV of 12% HCl; 0.93 PV of a mixture of 15% HCl and 15% formic acid; 1.1 PV of a mixture of 15% HCl and 15% acetic acid; 2.3 PV of 10% formic acid or 3.5 PV of 10% acetic acid. Matching the results obtained with the collected field data shows that the acid injection volume is overestimated which increases the operation cost and affects the economical factors of the operation.

Introduction

Formation properties have a significant effect on the flow behavior of reservoir fluids especially in the near-wellbore region. The most important property in this respect is the permeability. A reduction in permeability occurring around the wellbore resulting from drilling, completion and/or workover fluids increases the flow resistance to the reservoir fluids and is defined as formation damage. Acidizing process removes near-wellbore damage and enhances hydrocarbon production from producing wells. Two different acidizing processes have been utilized in oil industry, namely matrix acidizing and acid fracturing.

In the oil industry efforts are always made to increase the productivity of a well using different technologies such as horizontal and multilateral drilling in all types of reservoirs. However, recent research is concentrated on minimizing or even avoiding formation damage to maximize well productivity. Underbalanced drilling technology is one of these methods. This technology faces some technical problems and is also limited in its application. Therefore the most applicable method is still the conventional overbalanced drilling in which formation damage especially in the near-well region, is not avoidable. The intensity of this damage varies and depends on several factors, such as drilling fluid, overbalance pressure, formation permeability and penetrating depth of mud solids into the formation.

However, the severity of the formation damage can be determined after conducting a pressure drawdown or buildup tests (transient test) and is characterized as skin factor. The skin factor describes the formation damage as the total pressure drop (ΔP_{skin}) required to overcome the damaged zone. The formation damage should be removed before putting the well into production. Different methods are available to treat the damaged zone of a formation. Acidizing process is one of these methods, which is widely used to restore the formation permeability [1]. Acidizing processes are either matrix acidizing or acid fracturing.

In Saudi reservoirs, matrix acidizing and acid fracturing are widely used [2]. However, matrix acidizing is applicable in sandstone reservoirs as well as in limestone reservoirs that have permeabilities more than 10 md [1]. Both type of reservoirs exist in Saudi Arabia.

This paper describes the optimization of matrix acidizing to remove the formation damage caused by drilling fluid and to improve well productivity. The effects of acid volume, concentration, reaction speed and reaction products of different acids and acid mixtures on restoring the permeability are investigated. Also, it is devoted to evaluate the optimum acid volume of different acid types and concentrations to restore the original permeability. It also presents the matching of laboratory with practical field operations.

Formation Damage Evaluation

In general the fluid invasion and fluid loss-control materials while drilling causes a temporary or a permanent formation damage, which leads to impairment of well productivity or injectivity. Well productivity is one of the most important factors in reservoir economics. Maximizing well productivity as well as maximizing ultimate hydrocarbon recovery are the main challenges of a petroleum engineer. This should be achieved by taking into account the operating costs of the selected method.

In Saudi reservoirs, different methods have been applied to improve the well performance, such as horizontal drilling and acidizing. However, it could be found that acidizing is the most effective and economical method contributing to improvement of well performance. Before the selection of the acidizing type, several factors should be taken into consideration. The cause, the severity and the penetration depth of formation damage are the most important factors. The skin factor can be considered as a measurement of the severity of the formation damage [3-5] and is given by:

$$S = \left(\frac{K}{K_S} - 1 \right) \ln \frac{r_S}{r_W} \tag{1}$$

The skin factor can be positive or negative. The damage case is defined as ideal, normal or severe for positive value. Ideal case is defined when skin factor equals zero. Increasing skin factor to greater than 3 shows a normal damage. Severe damage is identified when skin factor becomes greater than 10. Negative value of skin factor means improvement in permeability higher than the original permeability of the rock. This improvement can be caused by acidizing where skin factor has a value from –1 to –3. Improvement by acid fracturing brings skin factor lower than –3 [6,7].

The skin factor value evaluated from well testing includes different sources of damage and is given by:

$$S_T = S_{fd} + S_t + S_{pc} + S_{perf} \tag{2}$$

The factors S_t, S_{pc}, and S_{perf} are described in the literatures [3,6,8] as pseudo-skin factors.

It is important to determine the exact sources of damage to decide if acidizing is required. This can be done through different calculations of the factors of pseudo-skin [3]. Table 1 shows the type of formation damage and the recommended treatment methods [6].

The skin factor causes an additional pressure drop across the damaged zone. This pressure drop is given by [3,4,7]:

$$\Delta P_S = \frac{141.2 \cdot q \cdot B \cdot \mu \cdot S}{K \cdot h} \tag{3}$$

By taking the skin factor into account, the production rate takes the form:

$$q = \frac{K \cdot h \cdot \Delta P}{141.2 \cdot B \cdot \mu \cdot \left[\ln\left(0.472 \frac{r_e}{r_w} \right) + S \right]} \tag{4}$$

Table 1. Type of formation damage and recommended treatment methods [11]

Type of damage	Treatment
Emulsion	Mutual solvent ± De-emulsifier
Wettability	Mutual solvent, ± water wetting
Water block	• Oil Well ▪ Low-medium T ≤ 250°F 1. Acid + Solvent, 2. Acid + Surfactant ▪ Hi T > 250°F 1. Non-aqueous Acetic acid
	• Gas Well 1. Acid + Alcohol
Scales	• **Carbonate $CaCO_3$:** 1. Hi T >250°F Aqueous acetic acid, 2. Low T<250°F HCl, 3. FeCO3-HCl and reducing /sequestering • **Sulfates**: 1. $CaSO_4$-EDTA 2. $BaSO_4$-EDTA 3. $SrSO_4$-EDTA • **Fe Scales** 1. FeS-HCl + reducing + sequestering 2. Fe_2O_3-HCl +EDTA 3. $FeCO_3$-HCl + reducing and/or sequestering • **Chloride** NaCl-H2O 1-3% HCl • **Hydroxide** 1. $Mg(OH)_2$-HCl 2. $Ca(OH)_2$-HCl • **Silica** Mud acid
Organic deposits	Aromatic solvent
Mixed organic / inorganic deposits	1. Solvent in acid 2. Dispersion
Silts & clays	Depends on mineralogy

The reduction of the skin factor will lead to increase the productivity of a well. Matrix acidizing provides an effective method of removing the formation damage. This method has been proven by many years of successful application around the world. One of the main advantages of the matrix acidizing is the comparatively low cost of performing a treatment in relation to alternative stimulation method such as hydraulic fracturing [9].

Matrix Acidizing

Most of the recent attention to matrix acidizing is devoted to sandstone reservoirs. Matrix acidizing in carbonate formation is beneficial with formation permeability more than 10 md [1]. In limestone and dolomite formations with permeability less than 10 md, acid fracturing is generally used [6]. Different concentrations of Hydrochloric acid (HCl), Formic acid (HCOOH), Acetic acid (CH_3COOH) and different mixtures of those acids are used in the industry. Hydrofluoric (HF) acid can also be used in sandstone formations to remove clay deposits in the formation. The selection of the suitable type and concentration of the acid depends mainly on the following factors: Type of formation and cementing material; type of drilling fluid and mud properties; and penetration depth.

The type of formation is an important factor for the selection of the acid solution, acid volume as well as the additives. The cementing material should be known, especially in sandstone formation, before performing an acid job. If the cementing material in sandstone formation is acid reactive (e.g. Calcite), the acid will react with this material. If all the cementing materials around the sand grains have been dissolved, the grains will be lose and movable and can be pushed through the pores causing more damage. Moreover the reaction products of the acid solution with the formation, especially the produced salts type and its solubility in water, should be considered. Table 2 shows the reaction products (salts) of different acid solutions with $CaCO_3$ and their solubility in water [10].

Table 2. Reaction products of different acid solutions and their solubility in water [10]

Acid solution	Salt product	Solubility at 100 °C
Hydrochloric acid (HCl)	Calcium chloride	(159 g/100ml H_2O)
Hydrofluoric acid (HF)	Calcium fluoride	(0.0017 g/100ml H_2O) at 26°C
Acetic acid (HCOOH)	Calcium acetate	(29.7 g/100ml H_2O)
Formic acid (CH_3COOH)	Calcium formate	(18.4 g/100ml H_2O)

The solids in drilling fluids are necessary to block the channels around the wellbore and to build the mud cake. They are often responsible for the formation damage occurring in the near-wellbore region. Any particle equals or greater than one-third of a pore size will effectively bridge that pore [11]. Particle sizes between one-tenth and one-third of the pore are the most damaging ones [11]. This damage occurs relatively close to the borehole and is referred to as skin damage. The type of these solids should be known to select a suitable acid solution for the removal of the damage.

The penetrating depth of the solids into the formation or the radius of the damaged zone depends on the pressure difference (ΔP) between mud hydrostatic pressure and formation pressure. Figure 1 shows the influence of the radius of damaged formation on the well productivity calculated using Equations 1 and 4. It shows that the production rate decreases by increasing the radius of the damaged zone.

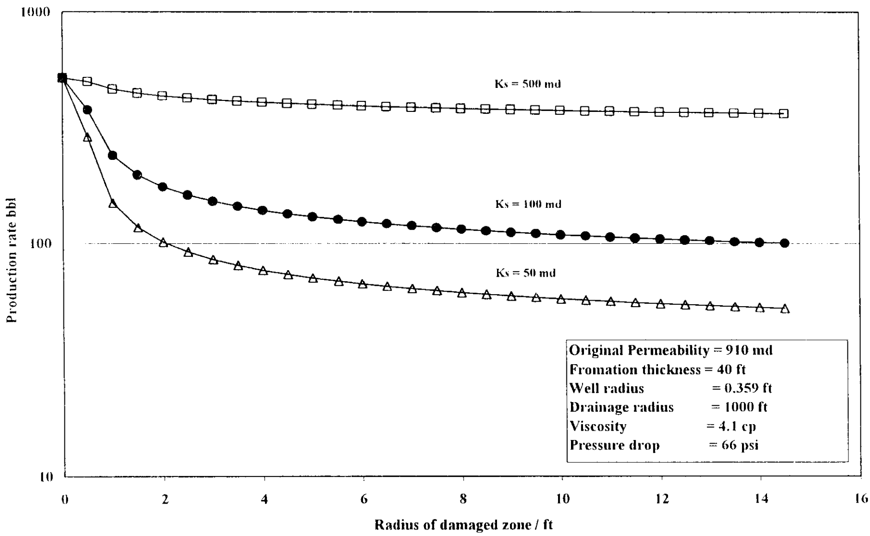

Fig. 1. Influence of the radius of damaged zone on the well productivity.

The drilling time can also affect the formation damage. Figure 2 shows the skin damage in a vertical well, which is constant through the drilled formation. This is because at the top of the vertical section the contact time is higher than that at the bottom, while the hydrostatic pressure is vice versa. Therefore the total damage will be the same [12]. Figure 3 shows the distribution of the damage in a horizontal well; in which the maximum damage would be at the beginning of the horizontal section due to the long contact time of drilling fluid with the formation while the hydrostatic pressure is constant [12]. To fulfill the objectives of this work, the following experimental procedure has been established and three different sections of experiments have been conducted.

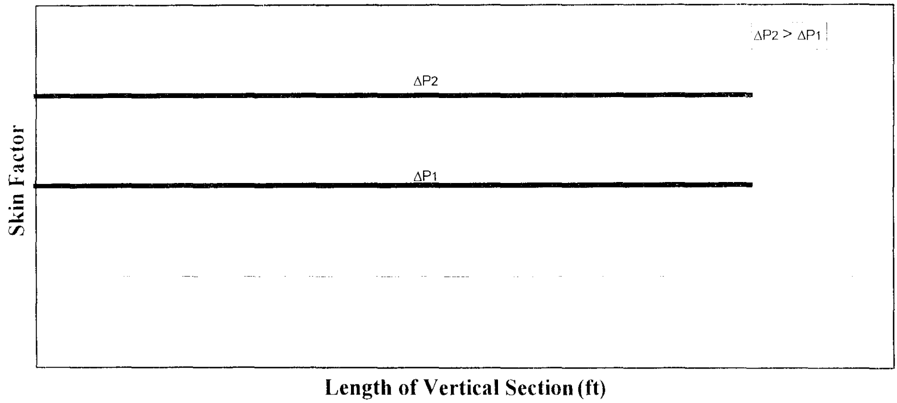

Fig. 2. **Relationship between the severity of formation damage, amount of overbalance pressure, and length of vertical section [12].**

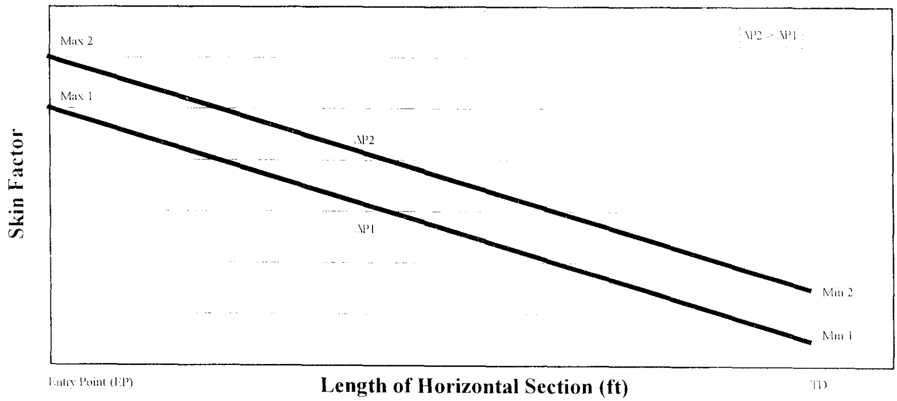

Fig. 3. **Relationship between the severity of formation damage, amount of overbalance pressure, and length of horizontal section [12].**

Experimental Procedures

The experimental program was divided into three main sections:

- Determination of the factors affecting the reaction of different acid solutions and their mixtures with 100 % $CaCO_3$ by chemical reaction in glass beakers.

- Flooding experiments to contaminate the formation and cause damage, then injecting acids to remove damage and restore the original permeability.
- Investigation of the formulation of wormholes in a real core sample recovered from a Saudi reservoir.

In the first section, certain amount of calcium carbonate was weighed up and put in glass beaker. Using a pipette acid solution or mixtures given in Table 3 was added to the calcium carbonate in the glass beaker. The minimum volume of acid solutions to dissolve the calcium carbonate was evaluated.

Table 3. Type of acids and mixtures used in the experiments

	Type of pure acid		
	HCl	**Acetic acid (HAc)**	**Formic acid (FAc)**
Concentration (% -wt/wt)	5%, 10%, 12%, 15%, 18%	5% , 10%, 12%, 15%	5%, 10%, 12%, 15%
	Type of mixtures .		
Concentration (% -wt/wt)	10% HCl +10% (Hac)	15%HAc+10% HCl	15% FAc+10% HCl
	10% HCl +10% Fac	15%HAc+12% HCl	15% FAc+12% HCl
		15%HAc+15% HCl	15% FAc+15% HCl
		15%HAc+18% HCl	15% FAc+18% HCl

The total volume of acid determined in the previous part of this section was added to the same amount of calcium carbonate. The total time for complete reaction of acid with calcium carbonate was then measured and noted as the spending time. The effect of formation water (brine) on the reaction was also tested. In this section the surface area to volume ratio was very high (maximum).

The second section includes the flooding experiments to simulate dynamic and static formation damage on core samples. Figure 4 is a schematic diagram of the experimental apparatus. A modified Hassler type core holder is used for the experiments. The core holder is designed for core samples up to 10 cm in length and 5.4 cm in diameter. The maximum rated pressure of the core holder is 10000 psi (69 MPa). Core samples were cut from a long core of a representative carbonate well. The core consists of 80% $CaCO_3$ and 20 % non-HCl reactive minerals. Before placing it in the core holder, it was dried in an oven for one day at 120 °C to remove any moisture inside the rock matrix. A hand pump was used to apply a confining pressure of 1000 psi (6.9 MPa) on the core. The core was then evacuated and saturated with synthetic $CaCl_2$/NaCl brine. The rock porosity was measured using the volumetric method. After ensuring complete saturation of the core by pumping about 10 PV at a constant flow rate of 30 ml/hr (1 ft/day) and monitoring the pressure, that was recorded using a pressure transducer and a digital display panel, the initial permeability of the core is calculated using Darcy's Law.

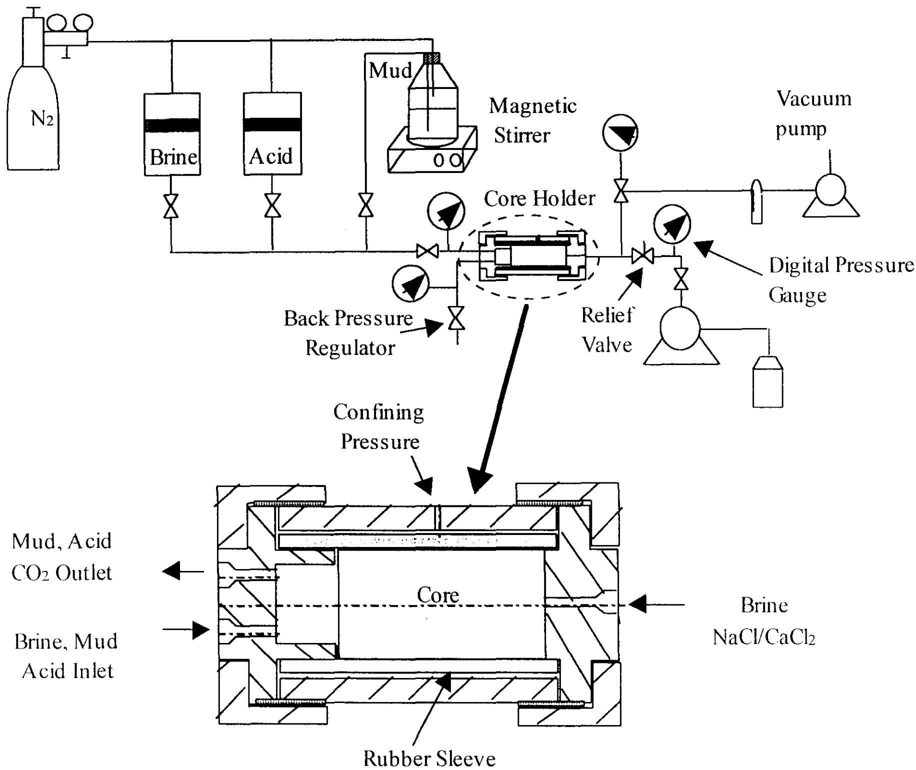

Fig. 4. Experimental set up and cross section in core holder cell.

To simulate the formation damage, a drilling fluid similar to that used in drilling the pay zones of Saudi reservoirs was used. It consists of $CaCO_3$ as weighting material, hdroxyethylcellulose (HEC) to improve the rheological and filtration properties and $CaCl_2$/NaCl brine. Table 4 shows the properties of this drilling fluid. The drilling fluid is circulated into the low side of the core holder to contact the core sample face. The drilling fluid is kept in contact with the core sample for 24 hours. It is kept agitated during circulation to avoid settling of mud solids. An overbalance pressure up to 100 psi is applied on the low side of the core using N_2-gas. After that, the core sample was dismantled and the mud filter was then removed from the surface of the core. The cell was mounted again and the permeability was measured. The formation damage was calculated by the difference of pressure drop before and after the contamination of the core at constant flow rate. A total of 6 different experiments have been conducted on 12 core samples. Each experiment was repeated at least one time to test the reproducibility. Table 5 shows the petrophysical properties and the type of acid solutions used.

Table 4. Mud properties used in this study

Property	Value	
Density	70	pcf
PV	12-15	cp
YP	15-18	$lb/100ft^2$
Gels 10 sec/10 min	4/8	$lb/100ft^2$
Filtrate	6-8	cc/30 min API

Table 5. Petrophysical properties and acid solution used in the flooding experiments

Core No.	Bulk volume [cm^3]	Porosity [%]	Original permeability [mD]	Type of acid solution
1	216	25	10	12 % HCl
2	212	27	9.9	15 % HCl
3	229	26	10	15 % HCl + 15 % Formic Acid
4	229	25	11	15 % HCl + 15 % Acetic Acid
5	236	28	9.9	10 % Formic Acid
6	231	28	10	10 % Acetic Acid

Acid solution was injected into the contaminated core sample. Each contaminated core sample was treated with different types of acid solutions at different concentrations. The effect of the acid solution on the removal of formation damage was investigated. About 50-120 ml of acid solution (depending on the type of acid) was injected into the core sample to remove the particles that caused formation damage. The effluent was collected for further analysis. The permeability was then measured using synthetic brine. The acid treatments were repeated until the original absolute permeability of the core was restored. In this part of the flooding experiments the parameters; overbalance pressure; volume and type of acid; acid concentrations and mud contact time (static and dynamic) have been changed. The concentrations of acid ranged from 10% to 15%. Those factors have been changed to find out the optimum conditions for removing formation damage that occurred during the circulation of drilling fluids.

In the third section, the formulation of wormholes was monitored in a real core sample recovered from a Saudi reservoir. Inner part of the core was drilled and a hollow cylinder of rock was initiated to simulate the wellbore. The dimensions of the hollow cylinder were 10 cm outside diameter and 5.4 cm inside diameter. A length of 7 cm from the inlet face of the core indicates a permeability of 15 md while the section in the outlet side showed a permeability of 7 md. This hollow cylinder was filled with 1.5 PV (750 ml) 15 % HCl. The acid solution was left for 3 hours. The core was then analyzed and evaluated.

Result and Discussion

The first section of the experimental part fulfilled the proposed goal. The experiments of the HCl as pure acid solution show that the minimum required amount and the spending time of HCl decrease with increasing the concentration up to 18 % HCl. Figure 5 shows the minimum volume of HCl in [ml] required in different concentrations to dissolve one gram of $CaCO_3$. A concentration higher than 18 % is not recommended due to the intensity of the reaction and due to corrosivity. In the experiments with higher HCl concentrations, the particles of $CaCO_3$ were floated immediately on the surface of the acid just after adding the acid to $CaCO_3$ due to high reaction speed and due to high rate of evoluted CO_2 decreasing the reaction process. Figure 6 shows a comparison of the amount of acetic acid and formic acid required to dissolve one gram of $CaCO_3$. It shows that more volume of acetic acid is required than formic acid. However, it is not recommended to use organic acid in a concentration higher than 15 %, especially in the case of formic acid. At higher concentrations of formic acid, the salt as product of the reaction with the carbonate will precipitate due to poor solubility of calcium formate, Table 2. When brine is used instead of distilled water to adjust the acid concentration a precipitation of salt could be clearly observed by the reaction of acid and formation.

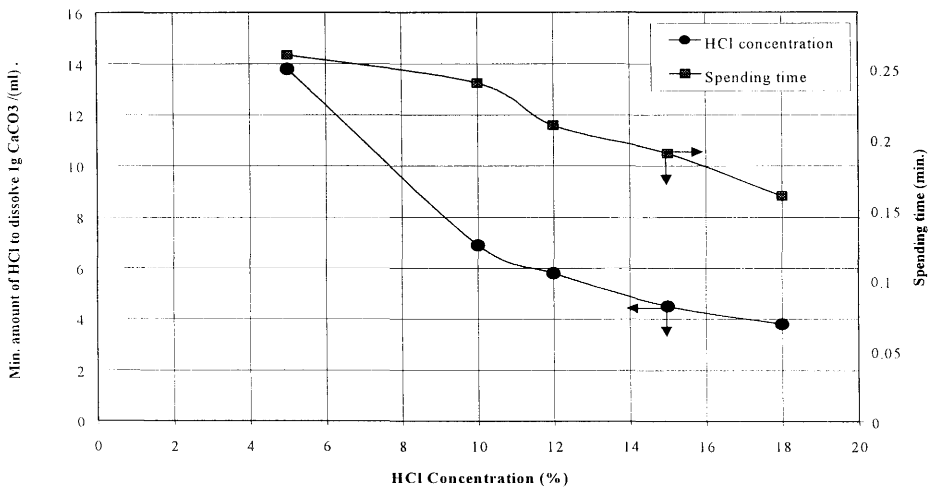

Fig. 5. Minimum amount required and spending time of HCl in different concentrations to dissolve 1g of $CaCO_3$.

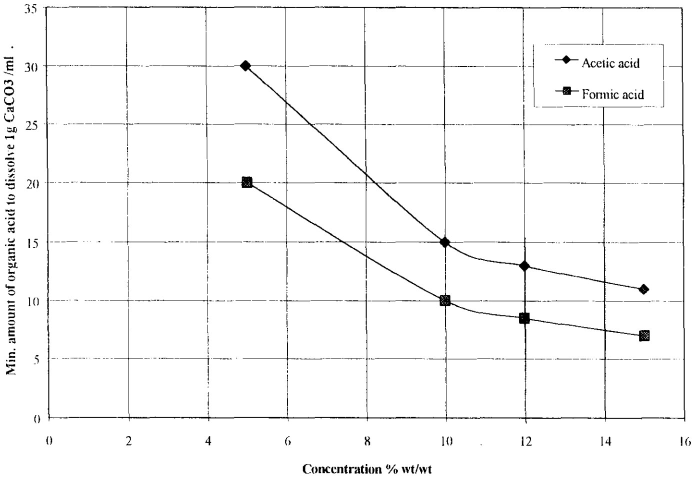

Fig. 6. Minimum amount of organic acids required to dissolve 1g of $CaCO_3$.

Figures 7 and 8 show the influence of the organic acid on the amount of acid mixture required to dissolve the same amount of $CaCO_3$. In these Figures the volume of acid mixture (HCl/organic acid) required is higher than that of the pure HCl in both types of organic acids. However, the volume of mixtures of organic acids (Acetic/Formic acid) required to dissolve the same amount of $CaCO_3$ is higher than their pure solutions. Figures 7 and 8 indicate clearly that the acetic acid existing in any mixture would lead to slow the reaction and the volume required of the mixture to dissolve carbonate particles will increase rapidly.

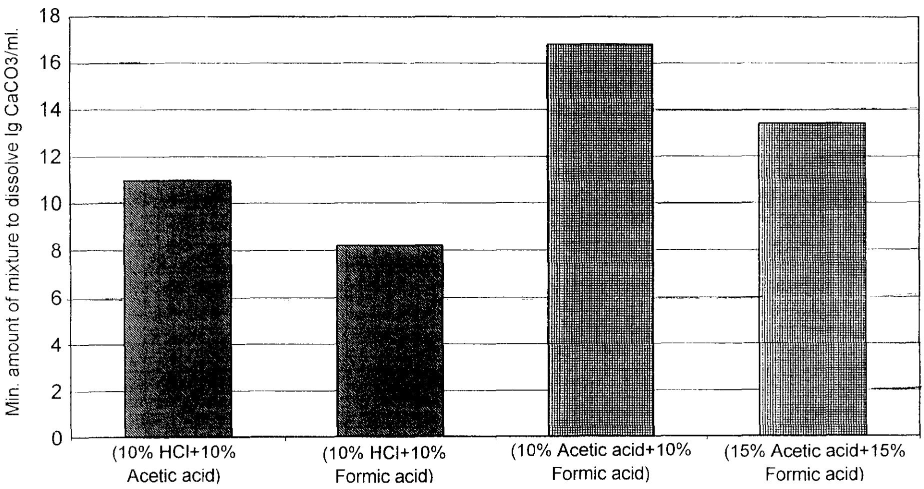

Fig. 7. Comparison between different acid mixtures.

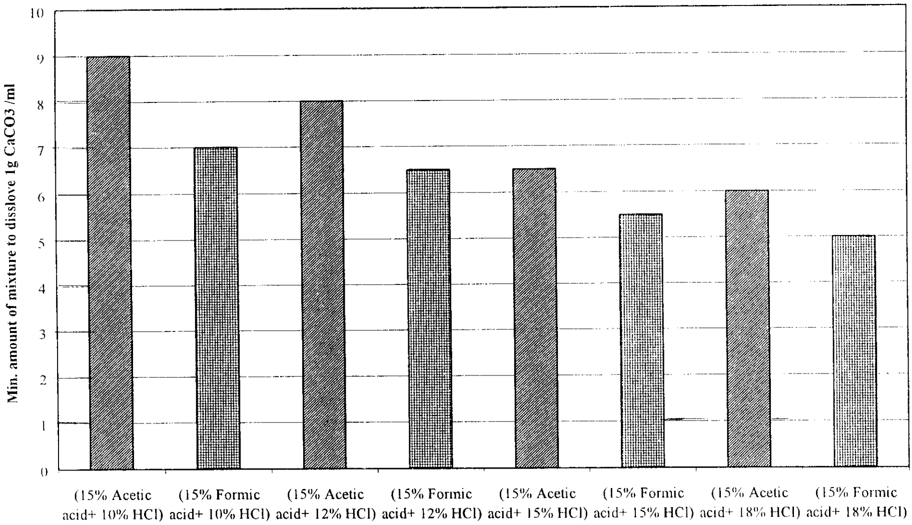

Fig. 8. Comparison between acid mixtures containing high concentration of organic acid.

Formic acid in a mixture with HCl in different concentrations shows no significant effect on the volume required of pure HCl. The only factor changed in this case is the spending time, which increased. This means that applying organic acid in a reasonable concentration as mixture with HCl can be used as a retarder to penetrate deeper formation.

Flooding experiments

The cores used in this section have almost the same petrophysical properties and represented the Saudi carbonate reservoirs. The Porosity varied between 25% and 28%, while the permeability was about 10 md. After the circulation of the drilling fluid on the face of the core samples the permeability was measured again. The permeability decreased by 10 – 20% depending on the contacting time of the fluid with the formation as well as on the overbalance pressure. The maximum days the core was left with the drilling fluid is 5 days with an overbalance of 80 psi. In this experiment the reduction of permeability was 20%. However, this damage could be removed with pure 15% of HCl. The amount of the acid required was 0.8 PV. In case of using 12% HCl to remove the damage, an acid volume of 1.3 PV was required. In case of a mixture of 15 %HCl and 15% formic acid the volume required to restore the permeability 0.93 PV, which is close to the volume required in case of 15% HCl solution. An acid volume of 1.1 PV of the mixture 15% HCl and 15% acetic acid was required. The using of pure organic acid showed that higher acid volume is required. In case of 10% formic acid the volume required is 2.3 PV while the volume of 10% acetic acid reaches a value of 3.5 PV. This confirmed the trend of the results in the first part of this study under the consideration of the surface area-volume ratio, which is very high in the first part while it is very low in the flooding experiments. All acids and acid mixtures used in this work are able to restore the original permeability but at different volumes. A good agreement was found with the repeated experiments.

Wormhole experiment

The formulation of the wormholes is a subject of many recent researches [13,14]. In this part of experiment an investigation of the formulation of the wormholes could be conducted. The goal of this experiment was to evaluate the influence of the permeability on the formulation of the wormholes in a certain Saudi reservoir. Three wormholes could be observed. At one position a breakthrough of a wormhole has been formed. The length of other two wormholes is ± 1 cm. These wormholes have been monitored in the section with higher permeability, while in the section with low permeability the acid reaction is restricted on the core surface. In this part of experiment it was observed that part of non-reactive minerals dropped to the bottom of the section. These particles can cause formation damage in that section of the well if cleaning operation is not performed.
In order to achieve an optimization of matrix acidizing in the field the matching of the laboratory experiments is done below.

Matching Laboratory Experiments with Field Data

Matrix acidizing is applied in many reservoirs of the Arabian Gulf Countries after well completion as well as in workover operations. A number of matrix acidizing jobs of certain fields has been collected and analyzed. Figure 9 shows a comparison between acid injection volume of 15 % HCl that used after well completion in vertical wells and in horizontal wells. The data of vertical wells represent two layers with different rock properties. In order to obtain a skin factor of –4 for the vertical wells with a porosity of 11.2 %, 20 gal/ft of acid is required, while an acid volume of 40 gal/ft will be required for the vertical wells with a porosity of 25.5%. In case of horizontal wells an acid volume of 50 gal/ft has been used to obtain a skin factor of –4. As previously mentioned the contact time of the drilling fluids with the formation in a horizontal drilling is higher than that in a vertical drilling, therefore the severity of formation damage will be higher than that in the vertical especially at the beginning of the horizontal section (Fig. 3).

To establish an economical design of the optimum acid injection volume required to obtain an appreciable skin factor the results of this work is matched with the real field data. In the laboratory experiments it was found that an acid injection volume of 0.8 PV of 15 % HCl is enough to remove the formation damage and to achieve a negative skin factor. However, the amount of acid required depends on the penetrating depth of the acid into the formation. As in Fig. 1 the considerable depth to be stimulated with acid varies between 2 and 4 ft. In this respect to transfer the laboratory data to real field operation an acid volume of 21 to 42 gal/ ft in case of vertical wells in E-layer and 48 to 97 gal/ft in case of G-layer is enough to remove formation damage and improve well productivity. The acid injection volume of 39 to 78 gal/ft is also enough for the case of horizontal wells. Exceeding these acid volumes is not recommended and will not lead to significant change in the skin factor.

Figure 9 shows that the acid injection volume used in the selected field exceeded in some cases 300 gal/ft. This amount means that the volume of acid is overestimated. This overestimation means that more acid will be reproduce and cause corrosion for wellhead equipment and need treatment to be removed. However, for case of horizontal wells the amount of acid injection volume can be reduced drastically if the severity of formation damage in the horizontal section will be considered. In this case less amount of acid will be required to remove formation damage at the bottom part of the horizontal section in which the severity of damage is minimum. Moreover, a jetting operation can be conducted to minimize the acid injection volume. This method has been successfully applied in some Middle East fields to remove the filter cake and can also remove a part of formation damage after well completion. It is applicable in open-hole section of horizontal wells and it leads to minimize the acid volume required in horizontal wells.

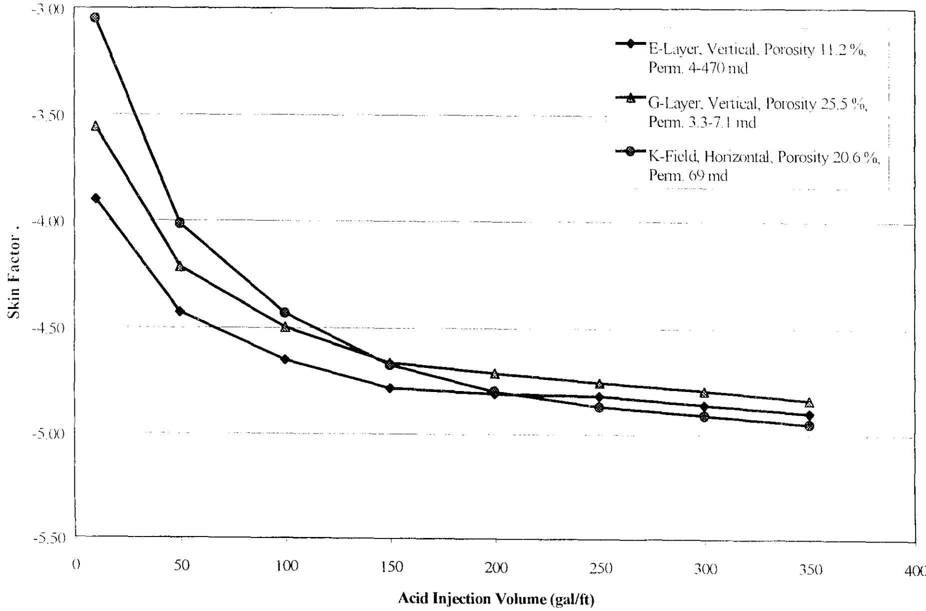

Fig. 9. Skin factor vs. acid injection volume after well completion for vertical and horizontal wells.

Conclusion

Based on the experimental results obtained the following conclusions are reached:

- The more rock surface exposed to a unit volume of acid, the faster acid will spend.
- Suspending agent should be used especially by any using of organic acid or by using of HCl in concentration more than 12%.
- Formation water and the type of salts in the water are important factors and should be considered before performing an acid job. This is to avoid a precipitation of salts after the reaction between acid and matrix. In presence of $CaCl_2$-brine more acid will be required to remove $CaCO_3$ particles
- Wormholes are observed in high permeable sections than low ones.
- The acid volume must be considered for 2-4 ft penetrating depth into the formation to achieve an optimum skin factor. More volume is not recommended especially in sandstone reservoir with calcite as cementing material to avoid matrix unconsolidation.
- The severity of formation damage especially in horizontal wells should be taken into consideration to select the suitable acid volume. At the beginning of the horizontal section more acid volume should be used.
- Laboratory investigation before acidizing job is recommended to avoid over-estimation of acid volume.
- Jetting operation is highly recommended to reduce the amount of acid.

Notations

h = Formation thickness, ft
K = Original permeability, md
K_s = Permeability of the damaged zone, md
q = Flow rate in bbl/d
r_e = Radius of drainage area, ft
r_s = Radius of damaged zone, ft
r_w = Well radius, ft
S_{fd} = Skin factor due to formation damage
S_{pc} = Skin factor due to partial completion of the pay zone
S_{perf} = Skin factor due to perforation
S_T = Total skin factor
S_t = Skin factor due to turbulence flow
ΔP = Pressure drop during production, psi
ΔP_s = Pressure drop due to skin damage, psi
B = Formation volume factor, bbl/stb
μ = Viscosity, cp

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دراسة معملية ومطابقة حقلية للمعالجة بالأحماض لصخور مكامن النفط

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ملخص البحث. في هذا البحث، تم تطوير طريقة مخبرية لتغيير نفاذية عيّنات صخرية بواسطة استخدام سائل حفر معيّن وتحديد التدني في النفاذية ومعالجتها بواسطة أنواع مختلفة من الأحماض لاسترجاع النفاذية الأصلية. كما تمت دراسة الحجم والتركيز اللازمين لعدة أنواع من الأحماض ومخاليطها بالإضافة إلى سرعة التفاعل لهذه الأحماض التي تستخدم في إذابة المادة اللاحمة بصخور المكامن. وكذلك تحتوي الورقة على مطابقة عملية بين النتائج المخبرية وعمليات معالجة المكامن بالأحماض في حقول إحدى دول الخليج العربي. وتقدم هذه الورقة أيضا طرقًا أخرى لإزالة أو تجنب التلف الذي يلحق بالمنطقة المحيطة بالبئر أثناء الحفر.

وجد أن حجم الحامض اللازم لاسترجاع النفاذية الأصلية لا يتجاوز ٠,٨ من حجم المسامات في حالة استخدام حامض الهيدروكلوريك بتركيز١٥٪ ولا يتجاوز ١,٣ في حالة استخدام نفس الحامض بتركيز١٢٪ كما لا يتجاوز ٩٣,. في حالة استخدام مخلوط من حامض الهيدروكلوريك بتركيز ١٥٪ مع حامض النمليك بنفس التركيز ، أما في حالة استخدام حامض النمليك بنسبة ١٠٪ فإن الحجم المطلوب يصل إلى ٢,٣ من حجم المسامات كما يصل إلى ٣,٥ في حالة استخدام حامض الخليك بنسبة ١٠٪. وبمضاهات النتائج المخبرية بعمليات المعالجة الحقلية وجد أن حجم الحامض المستخدم يفوق الحجم الحقيقي اللازم للمعالجة بالأحماض والذي ينجم عنه زيادة تكاليف عمليات المعالجة وخسارة اقتصادية يمكن تجنبها في حالة استخدام هذه النتائج .