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THE EFFECT OF MATRIX ACIDIZING ON THE COMPRESSIVE STRENGTH OF SANDSTONE FORMATION

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Abstract. This paper discusses the effect of matrix acidizing on the compressive strength of a sandstone formation. The laboratory works involved two main systems, namely the acidizing-permeability apparatus and servo hydraulic equipment. The mud acid with 1-9% HF concentrations was used to treat the damaged Berea sandstone core samples using different injection pressures ranging from 30 psi (206 KN/m^2) to 660 psi (4550 KN/m^2) at room temperature. The Berea sandstone core sample was initially damaged using drilling mud before the matrix acidizing took place. After the acidizing process, the value of improved permeability of the acidized core sample was compared with the damaged permeability, which was measured using the acidizing-permeability apparatus. The compressive strength of sandstone formation after the acidizing process was also evaluated using the Servo Hydraulic Equipment. The experimental results revealed that acidizing could improve the permeability of the damaged core sample but would affect the compressive strength of the core sample, especially when using 9% HF-12% HCl. The volume of mud acid required to achieve ARC 1.0 reduces when injection pressure increases, which should be greater than 30 psi (206 KN/m^2) in order to achieve ARC greater than 1.0. It was also noted that higher injection pressure would reduce the overall effectiveness of the acid treatment due to insufficient reaction time.

Keywords: Berea sandstone; compressive strength; matrix acidizing; permeability

Abstrak. Artikel ini membincangkan kesan pengasidan matriks terhadap kekuatan mampatan sebuah formasi baru pasir. Kajian makmal terbabit melibatkan dua sistem utama, perkakasan pengasidan-kebolehtelapan dan kelengkapan hidraul servo. Asid lumpur dengan kepekatan HF 1-9% telah digunakan untuk merawat sampel teras batu pasir Berea yang rosak. Rawatan ini melibatkan tekanan suntikan dari 30 psi (206 KN/m^2) hingga 660 psi (4550 KN/m^2) pada suhu bilik. Sampel teras batu pasir Berea pada asalnya dirosakkan menerusi penggunaan lumpur gerudi sebelum bermulanya kerja-kerja pengasidan matriks. Selepas berakhirnya proses pengasidan, nilai kebolehtelapan tertingkat sampel teras yang telah dirawat menggunakan asid lumpur dibandingkan dengan kebolehtelapan rosak, yang diukur menggunakan perkakasan pengasidan-kebolehtelapan. Kekuatan mampatan formasi batu pasir selepas pengasidan juga dinilai menggunakan kelengkapan hidraul servo. Hasil kajian menunjukkan bahawa pengasidan berupaya meningkatkan kebolehtelapan sampel teras yang rosak, tetapi akan menjejaskan

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kekuatan mampatan sampel teras terbabit, lebih-lebih lagi jika menggunakan 9% HF-12% HCl. Isi padu asid lumpur yang digunakan untuk mencapai ARC 1.0 berkurang bila meningkatnya tekanan suntikan, tetapi tekanan terbabit mesti lebih besar daripada 30 psi (206 KN/m^2) untuk mencapai nilai ARC yang lebih besar daripada 1.0. Tekanan suntikan yang terlalu tinggi boleh mengurangkan keberkesanan pengasidan secara menyeluruh berikutan masa tindak balas yang terhad.

Kata kunci: Batu pasir Berea; kekuatan mampatan; pengasidan matriks; kebolehtelapan

1.0 INTRODUCTION

In the upstream activities of oil and gas industry, acidizing is one of the stimulation techniques used to improve well productivity by removing near wellbore impairment due to drilling, completion, and production operations. The formation of this positive skin is due to the deposition of materials and invasion of solid particles entrained in the fluids used that has invaded into the formation. This acidizing technique involves injection of acid into the well and will penetrate deep into the targeted formation of porous medium around the wellbore. Apart from removing the deposited materials and solid particles, an acid treatment also enlarges pores by dissolving part of the formation which later allows insoluble fines to be flushed out after the respective oilwell is released to production [1]. This phenomenon reveals that acidizing technique is designed to eliminate any effects of damaged permeability around the wellbore.

Acidizing process gives an impressive production assurance if properly designed and applied into the well formation. Acidizing treatments are divided into two categories, namely matrix acidizing and fracture acidizing [2]. Matrix acidizing is the common method used in the field to restore or enhance the permeability of the damaged formation near the wellbore areas with targeted radius of 8 to 24 in. (20.3 to 61 cm) without fracturing the producing formation [2]. Meanwhile, fracture acidizing is known as a stimulation process in which formation rocks leaves unevenly etched fracture faces that creates lasting conductivity after fracture closure by acid dissolution along the face of the hydraulically induced fracture [3]. Nevertheless, fracture acidizing treatments have been mostly confined to carbonate formations and it has never been seriously considered as a stimulation method for sandstones formation [4].

In general, matrix acidizing can enhance the well production considerably (i.e., in the range of 10 to 100 times), however, the actual achievement depends on the reservoir pressure, severity of damaged zone around the wellbore, etc. According to McLeod [5], a successful acidizing treatment depends on the presence of damage and its location and intensity; whereby, the closer the damage is to the perforations, the more easily acid can get to it. The acid penetration distance into the reservoir is one of the key parameters that also considered for a successful matrix acidizing treatment [6]. It is often desirable for the acid to penetrate as deep into the formation as possible in order to treat the damaged region. Nevertheless, matrix acidizing is not able to treat or overcome near wellbore damaged which is due to sulfate scales, paraffin, tar, water of emulsion blocks, as they are largely unaffected by mineral or organic acids.

In matrix acidizing, the acid formulation that commonly used is the mixture of hydrochloric acid (HCl) and hydrofluoric acid (HF)–known in the field as mud acid [7]. This mud acid is regularly used to remove the drilling mud residual and clay impairment. In the sandstone formation, the mud acid is capable to dissolve and break part of the minerals that bond the sand particles together since the acid penetrates and reacts with the formation minerals, leading to greater pore throats. In spite of the importance and capability of mud acid, without a proper design and application, the mud acid injected into the nearby damaged wellbore will ultimately affect the strength and stability of the formation structure and subsequently causes the formation around the wellbore to collapse. Excessive formation dissolution due to high HF acid concentration would also cause the release of fine solids and collapse of the near-wellbore formation due to reduction in rock strength. It might also destroy the cementing materials in the rock and thus, reducing permeability due to compaction. In extreme cases, it may cause surface subsidence.

Most of the studies failed to take into account the significance of both phenomena. Much research and laboratory testing of acid stimulation have been performed on permeable Berea sandstones cores; however, little research has been performed on severely damaged cores [5]. Thus, a research study was conducted to investigate the effect of matrix acidizing on the strength of sand formation. The information from this research work is very useful to oil and gas industry because acidizing job involves huge budget and thus establishes a proper plan of acidizing job is of utmost importance.

2.0 MATERIALS AND METHODS

This laboratory work involved two sets of equipment, namely the Acidizing-Permeability Apparatus (APA) and Servo Hydraulic Equipment (SHE). The APA was used to perform acidizing process and also to determine the value of permeability of the tested core samples. While SHE was used to carry out the uniaxial compressive test on the Berea sandstone core samples before and after the acidizing process to obtain the value of compressive strength of the core samples. All the experimental works were conducted at room temperature.

2.1 Saturating Core Samples using Pekasin

The core samples used in this study were Berea sandstone of 2.5 in. (63.5 mm) long and 2.0 in. (50.8 mm) diameter. These samples were dried in a hot rolling oven before being used for further study. After had been dried for three hours in the oven, the samples were taken out and placed into the saturation chamber for saturation process using Pekasin (sodium chloride solution of 30 000 ppm concentration). Time allocated for the saturation process was 24 hours with constant pressure of 2000 psig (13 789 KN/m^2).

2.2 Saturating Core Samples using Paraffin

The saturated core samples with Pekasin (NaCl) was completely encapsulated with rubber sleeve and placed into the core holder. In conducting the experimental work, the 200 psi (1378 KN/m^2) of load pressure was imposed on the rubber sleeve which encapsulating the core sample in order to avoid leakages or channels between the core sample and inner body of the core holder. The core sample then saturated with paraffin oil in order to simulate sandstone formation in the production zone. The flow of this paraffin oil was also used to determine the value of initial permeability which could be computed using Darcy's equation [8]. The following Darcy's equation could be used to calculate permeability, K.

$$K = \frac{Q \, \mu \, L}{A \, (P_1 - P_2)}$$

Where,

K=Permeability, milidarcies (mD)
Q=Flowrate, (ft/sec)
μ =Fluid viscosity, cp
L=Distance along the path, ft
A=Cross-sectional area, ft^2
$P_1 - P_2$ = Differential pressure, psia

2.3 Damaging Core Samples

The water-based mud sample which was prepared using field's formulations was injected into the core holder for 30 minutes to damage the core. The mud injected must be from the opposite direction as compared to the flow of paraffin oil in order to simulate the real situation in the formation.

After the core had been damaged, the mud cake formed on the surface of the core sample was cleaned to determine the value of damaged permeability. In this case, paraffin oil was used as a flow medium, while Darcy's equation [8] was used to calculate the damaged permeability.

2.4 Acidizing Process

The acidizing process on the damaged core samples was conducted by injecting the mud acid into the core holder with different injection pressures ranging from 30 psi (206 KN/m^2) to 60 psi (4550 KN/m^2) at different concentrations of HF acid ranging from 1 to 9% whereby 12% HCL was kept constant throughout the study. The mud acid used comprised mixture of HF-HCl. The reaction of two formulations HF/HCL mixture that typically contains 3 wt% and 12 wt% are normally used in field [9, 10]. The injected acid must be in the same direction as mud injected to simulate the acidizing operation in the field. After the acidizing process, the improved permeability was measured again using paraffin oil and Darcy's equation.

2.5 Measurement of Compressive Strength of Core Samples

The Servo Hydraulic Equipment (SHE) was used to determine the initial strength of the core samples and also after treatment by imposing the uniaxial compression load towards the core samples. This equipment was controlled using a computerized control panel with all the tested parameters were pre-set prior to conducting the laboratory works. The loads imposed were from 0.7 KN/m^2 until the core sample broke or failed.

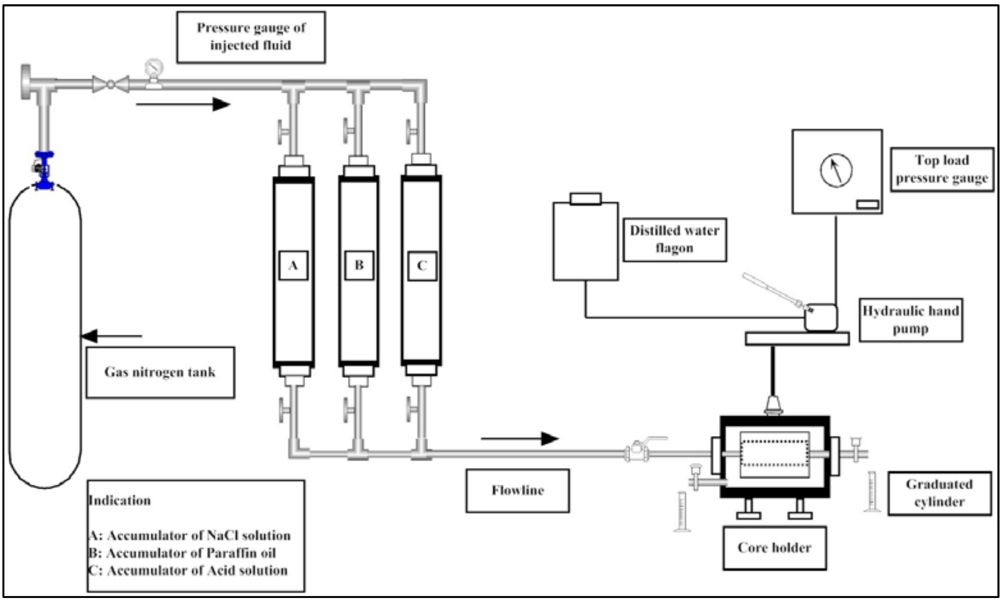

Figure 1 The acidizing-permeability apparatus

3.0 RESULTS AND DISCUSSION

The experimental results was analyzed and discussed under three segments, namely the effect of HF-HCl concentration, effect of injection pressure, and effect of acidizing on compressive strength of core samples.

3.1 Effect of HF HCl Concentration

The concentration of HCl was kept constant at 12% (by volume) while concentration of HF was varied from 1 to 9%. Figure 2 shows that at the early stage of acidizing process, the value of acid reaction constant (ARC) or permeability of the core reduced for all concentrations of mud acid used. In general, ARC is defined as the ratio of improved core permeability at any time to damaged core permeability.

The reduction of core permeability at the early stage of a acidizing process was only a temporary effect and this was due to the early reaction between acid solution with mud clay and fine particles that presence in the sandstone. The residue from this early setback migrated and thus affected the core permeability. When more volume of mud acid was pumped and penetrated the sample core, it succeeded in increasing the ARC gradually due to further reaction between acid solution with acidized mud clay and fine particles in the sandstone, before it became constant.

The results of this research work also revealed that acid reaction increases with increase in concentration of HF. As shown by Table 1, the volume of mud acid used in this research work to achieve the value of ARC 1.0 could be reduced from 1119.9 ml to 817.4 ml if concentration of HF was increased from 1% to 9% respectively. It also need to be noted that the objective of acidizing is only at dissolving damaging particles, mainly clays or very fine silicates [10]. However, effect of formation incompatibility with a treatment fluid has been an issue which ultimately produces a byproduct from HF acid dissolutions or also known as 'acid-sensitive' precipitates. These byproducts will cause precipitates to develop and finally block or reduce the rock permeability [10]. It is important to note that the effect of formation compatibility with treatment fluid was not considered in this research work.

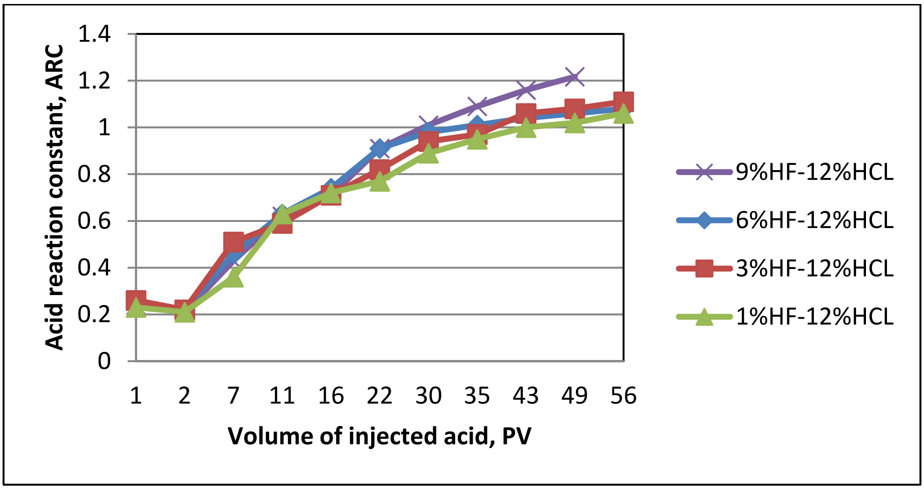

Figure 2 Effect of different HF concentrations on ARC at an injection pressure of 60 psi (413 KN/m^2)

Table 1 Volume of mud acid required to achieve ARC 1.0 at an injection pressure of 60 psi (413 KN/m^2)

Acid treatment	Volume of acid (ml)
9% HF-12% HCL	817.4
6% HF-12% HCL	913.0
3% HF-12% HCL	981.7
1% HF-12% HCL	1119.9

3.2 Effect of Injection Pressure

In general, volume of acid required to achieve ARC 1.0 reduces when injection pressure increases. Table 2 shows the volumes required for acid solution of 6% HF-12% HCL at 40 psi (275 KN/m^2), 50 psi (343 KN/m^2) and 60 psi (413 KN/m^2) were 1177.6 ml, 1079 ml and 913.0 ml respectively. From Figures 2 to 4 at the same acid concentration of 6% HF-12% HCL, we could observe that, as the injection pressure decreased from 60 psi (413 KN/m^2) to 40 psi (275 KN/m^2), there was a slight increment occurred on the volume of the acid required to achieve ARC 1.0. Even though, the volume of acid used was found to increase but the percentage of treatment ratio (k_f/k_d) at injection pressure of 40 psi (275 KN/m^2) and 50 psi (343 KN/m^2), as given in Appendix A, was totally higher compared to other injection pressures. It means that, the range between 40 psi (275 KN/m^2) and 50 psi (343 KN/m^2) was the optimum injection pressure required to achieve a deep penetration as possible without causing any severity to the formation structure. This findings was supported by Bazin [9], through an experimental study of matrix acidizing to acid fracturing on the evaluation of acid/rock interactions. He conducted the study through a core length of 5 to 40 cm. He found that as the injection rate (pressure) increased, the wormhole extension in length increased and ultimately thin tortuous structure was developed and further increased the injection rate might cause loss of rock structure. However, different result occurred at injection pressure of 30 psi (206 KN/m^2), even though the volume of acid solution used was 1500 ml, it is still failed to achieve ARC 1.0 (Figure 5). Apart from a large amount of residue which was formed from the longer early reaction between acid solution with mud clay and fine particles in sandstone, insufficient of force was another major factor that prevented the mud acid from penetrating deeper into the core sample. It is important to note that higher injection pressure would also reduce the overall effectiveness of the acid treatment and this was due to insufficient reaction time. In other words, the mud acid flowed past the reactive materials at such a rate that it was not able to react sufficiently with those materials.

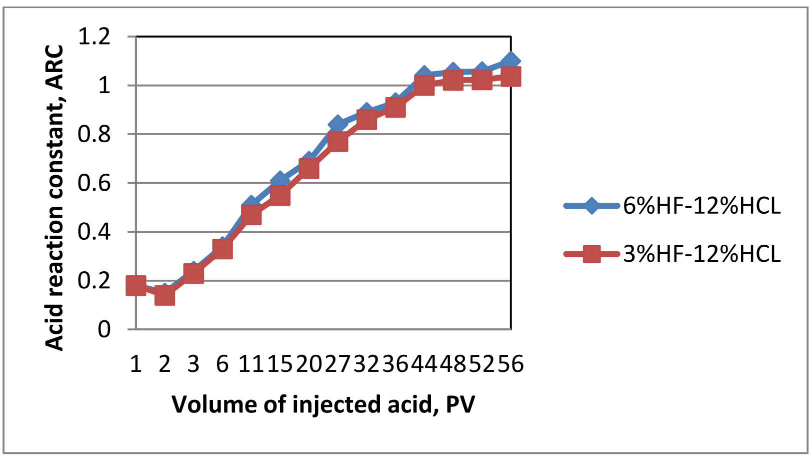

Figure 3 Effect of different concentrations of HF on ARC at an injection pressure of 50 psi (343 KN/m^2)

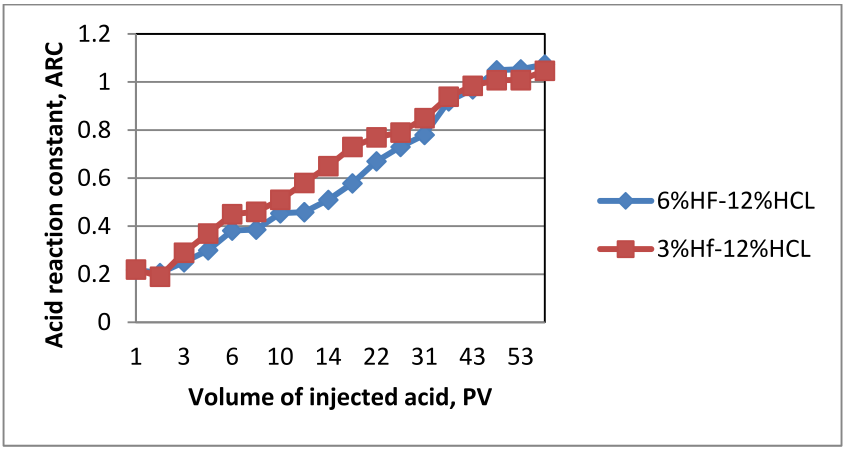

Figure 4 Effect of different concentrations of HF on ARC at an injection pressure of 40 psi (275 KN/m^2)

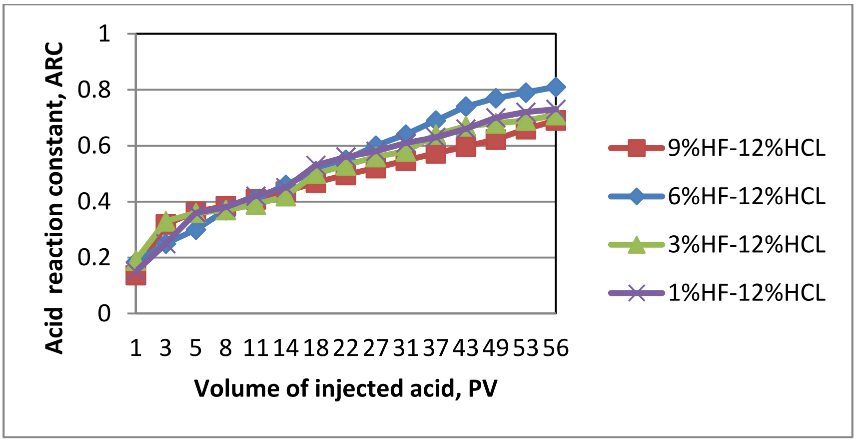

Figure 5 Effect of different concentrations of HF on ARC at an injection pressure of 30 psi (206 KN/m^2)

Table 2 Effect of mud acid's injection pressure on ARC

Acid treatment	Injection pressure (psi)	Volume of acid (ml)
6% HF-12% HCL	30	-
6% HF-12% HCL	40	1177.6
6% HF-12% HCL	50	1079.0
6% HF-12% HCL	60	913.0

3.3 Effect of Acidizing on Compressive Strength of the Core Samples

Uniaxial compression test was done on the core samples using SHE to evaluate the effect of acidizing process on the compressive strength of the treated core samples. Generally, after the acidizing treatments, the core's compressive strength reduces especially when the injection pressure decreases.

Mud acid concentration of 9% HF-12% HCL showed a significant reduction in compressive strength of the core sample. At injection pressure of 30 psi (206 KN/m^2), the compressive strength of the acidized core was 23.9 kN as compared to its original compressive strength (i.e., before acidizing process) of 47.3 kN. While mud acid concentration of 1% HF-12% HCL shows a minor reduction of compressive strength which was 46.8 kN at injection pressure of 30 psi (206 KN/m^2). This phenomenon occurred because at higher acid concentration, it would increase the reaction rate of the mud acid with clay, certain minerals in the rock, and cementing materials which bond all the grains together in the core samples. Cementing materials dissolution was the main cause which broke the bonding between the grains, and thus contributed to the reduction of the core sample's compressive strength. Opposite phenomenon happened in Figure 9, the experimental results of 1% HF-12% HCL show the use of lower HF acid concentration to stimulate the formation did not affect formation's compressive strength significantly because of limited reaction between acid and reactive minerals. Whereby, based on Figure 9, at 30 psi (206 KN/m^2), the compressive strength was found to decrease marginally as compared to 60 psi (413 KN/m^2). This is due to lower concentration of HF acid and most importantly insufficient pressure to force the mud acid to penetrate deeper into the formation to dissolve the clay or reactive minerals. Compared to Figure 8, lower HF acid concentration of 3% HF-12% HCL indicated that as pressure was further reduced to 30 psi (206 KN/m^2), the compressive strength of the core weakened because this lower pressure (i.e., 30 psi (206 KN/m^2)) gave sufficient time for the mud acid to react with the clay and reactive minerals.

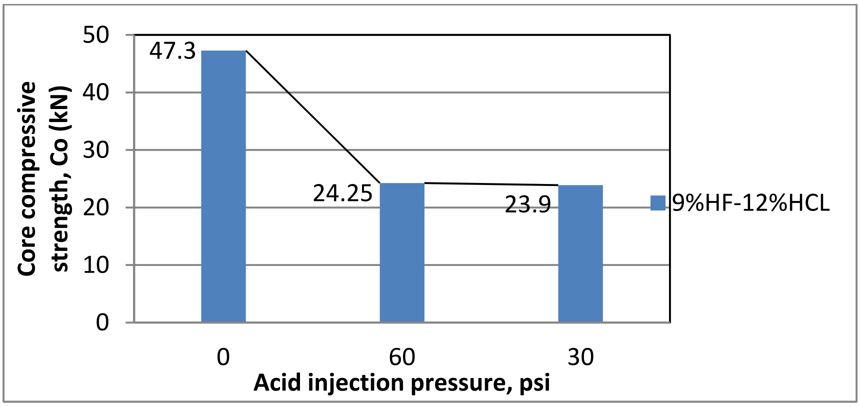

Figure 6 Effect of injection pressure on compressive strength at acid concentration of 9% HF-12% HCl

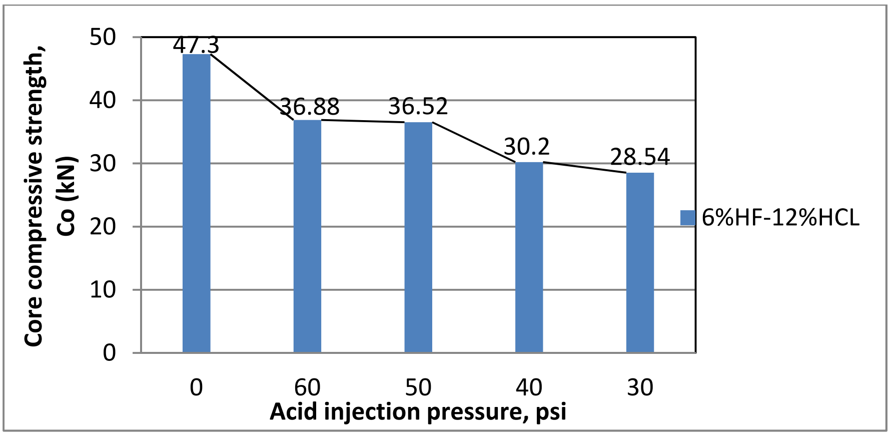

Figure 7 Effect of injection pressure on compressive strength at acid concentration of 6% HF-12% HCl

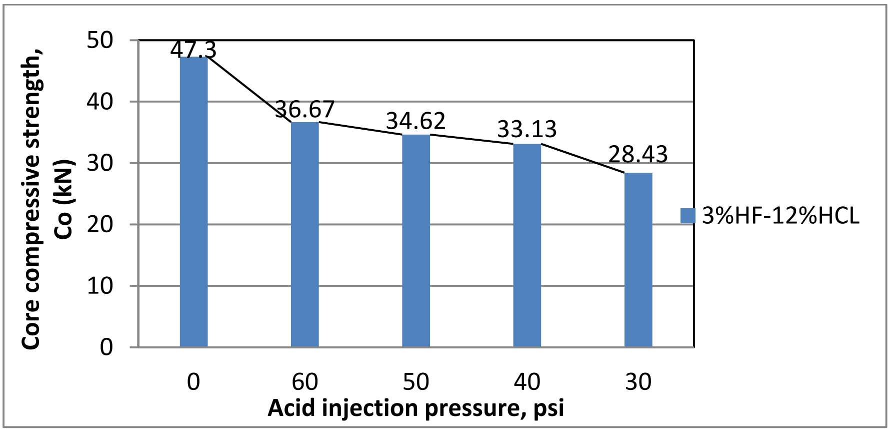

Figure 8 Effect of injection pressure on compressive strength at acid concentration of 3% HF-12% HCl

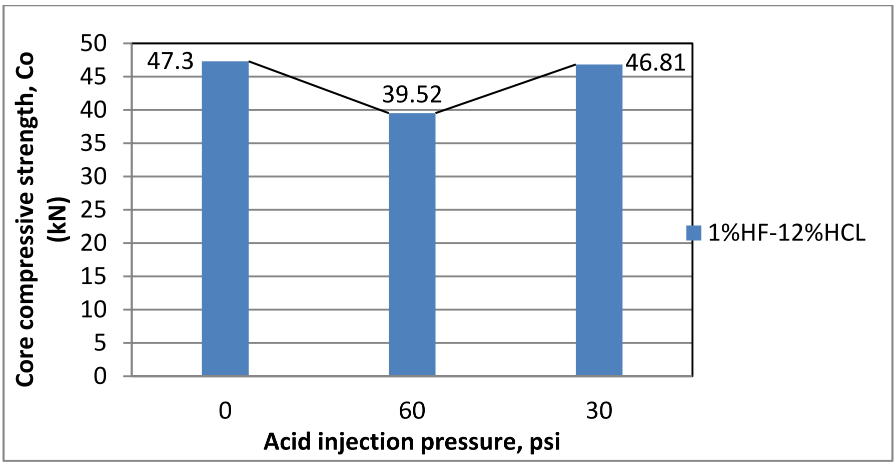

Figure 9 Effect of injection pressure on compressive strength at acid concentration of 1% HF-12% HCl

4.0 CONCLUSIONS

Based on the research works of matrix acidizing on sandstone's compressive strength, there were several conclusions could be framed out accordingly:

(1) Matrix acidizing affects the compressive strength of a sandstone formation.

(2) Mud acid of 9% HF-12% HCl concentration is found to have significantly reduced the compressive strength as compared to lower concentration of HF.

(3) Volume of mud acid required to achieve ARC 1.0 reduces when injection pressure increases. Injection pressure should be greater than 30 psi (206 KN/m^2) in order to achieve ARC greater than 1.0. It is important to note that higher injection pressure would reduce the overall effectiveness of the acid treatment due to insufficient reaction time.

(4) Acidizing process can increase the permeability of a damaged formation due to invasion of drilling mud particles into the formation's pore throat. This phenomenon has been proved that with the injection of mud acid into the core samples, it does successfully increase the ARC value.

(5) The increase of ARC or rock's permeability from the acidizing process is found to totally depend on acid concentration and injection pressure.

(6) Acidizing process can improve well productivity by increasing the pores and channels for the oil to flow. But if an acidizing process is not properly designed and applied, it may cause the formation to collapse and totally block all the channels and pores.

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APPENDIX A
Improved permeability ratio

Acid concentration	Injection pressure (psi)	Initial permeability, K_i (md)	Damaged core permeability, K_d (md)	Damaged percentage (%)	Final core permeability, K_f (md)	Treatment ratio (%)	Ratio K_f/K_d
9%HF - 12%HCL	60	222.91	63.12	71.56	123.69	48.98	1.96
	30	228.57	68.82	69.89	141.55	51.38	2.06
6%HF - 12%HCL	60	236.89	66.04	72.12	115.21	42.68	1.74
	50	231.14	62.32	73.04	131.18	51.73	2.1
	40	216.46	63.13	70.84	145.59	56.64	2.31
	30	222.94	62.24	72.08	122.3	48.11	1.96
3%HF - 12%HCL	60	225.46	69.27	73.71	104.36	43.21	1.76
	50	216.88	61.06	71.85	123.37	50.51	2.02
	40	208.46	60.32	71.06	152.07	60.33	2.52
	30	220.76	63.63	71.18	142.75	56.64	2.31
1%HF - 12%HCL	60	234.32	68.6	70.72	91.91	25.36	1.34
	30	227.02	60.03	71.72	104.38	42.49	1.74

Note: Temperature, T = 80°F, top load pressure, P = 200 psi, and volume of acid, V = 1500 ml were kept constant throughout the experimental works

APPENDIX B
Compressive strength of treated core sample

Acid concentration	Injection pressure (psi)	Initial permeability, K_i (md)	Damaged core permeability, K_d (md)	Final core permeability, K_f (md)	Treatment ratio (%)	Core's compressive strength, C_o (kN)
				Initial compressive strength		47.3
9%HF - 12%HCL	60	222.91	63.12	123.69	1.96	24.25
	30	228.57	68.82	141.55	2.06	23.9
6%HF - 12%HCL	60	236.89	66.04	115.21	1.74	36.88
	50	231.14	62.32	131.18	2.1	36.52
	40	216.46	63.13	145.59	2.31	30.2
	30	222.94	62.24	122.3	1.96	28.54
3%HF - 12%HCL	60	225.46	69.27	104.36	1.76	36.67
	50	216.88	61.06	123.37	2.02	34.62
	40	208.46	60.32	152.07	2.52	33.13
	30	220.76	63.63	142.75	2.31	28.43
1%HF - 12%HCL	60	234.32	68.6	91.91	1.34	39.52
	30	227.02	60.03	104.38	1.74	46.81

Note: Temperature, T = 80°F, top load pressure, P = 200 psi, and volume of acid, V = 1500 ml were kept constant throughout the experimental works