



Article New Environmentally Friendly Acid System for Iron Sulfide Scale Removal

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Abstract: Iron sulfide scale is a common problem in the oil and gas industry. The precipitation of the iron sulfide scale on the well completion tools or inside surface flow lines restricts the flow of the produced fluids and might affect the integrity of the pipelines or the surface and subsurface tools. Failure of the downhole completions tools will not only reduce the production rates but it might require workover and remedial operations that will add extra cost. The main objective of this paper is to evaluate a new environmentally friendly acid system (NEFAS) for iron sulfide scale removal using an actual field sample. The scale sample collected from a natural gas well is dominated by pyrrhotite (55%) in addition to calcite (21%), pyrite (8%), and torilite (6%) with minor traces of hibbingite, siderite, geothite, akaganeite, and mackinawite. High-temperature solubility tests were performed by soaking 2 g of the scale field sample with 20 cm³ of the NEFAS under static condition at 125 °C for different time periods (2, 6, 12, 18, and 24 h). The solubility results were compared with commercial solutions for iron sulfide scale removal such as hydrochloric acid (15 wt.%), glutamic acid diacetic acid (GLDA, 20 wt.%), and high density converters (HDC-3) under the same conditions. The corrosion test was performed at 125 °C for the developed solution after mixing with 2 wt.% corrosion inhibitor (CI) and 2 wt.% corrosion intensifier (CIN). The results were compared with HCl (15 wt.%) under the same conditions. NEFAS consists of 75 wt.% biodegradable acid at pH of 0.04. NEFAS achieved 83 g/L solubility of iron sulfide scale after 6 h at 125 °C under static conditions. The solubility efficiency was very close to 15 wt.% HCl after 24 h where the solubility was 82 and 83 g/L for NEFAS and HCl, respectability. HDC-3 and GLDA (20 wt.%) achieved a lower scale solubility; 18 g/L and 65 g/L respectively, after 24 h. NEFAS achieved a corrosion rate of 0.211 kg/m² after adding the CI and and CIN compared to 0.808 kg/m² for HCl. The new environmentally friendly biodegradable acid system provides efficient performance for the scale removal without harming the environment and causing any side effects to the operation.

Keywords: iron sulfide; scale removal; biodegradable acid; environmentally friendly; corrosion rate

1. Introduction

Iron sulfide scale is one of the major problems of flow assurance in the oil and gas industry. Iron sulfide scale is formed because of the presence of iron and hydrogen sulfide in sour oil and gas production wells. Iron sulfide scale usually causes many operational problems in the oil and gas industry as it accumulates in perforations, downhole tubing equipment, surface flow lines, and even inside the pore space of the reservoir rock itself [1–3]. The formation of iron sulfide scale can affect the performance of downhole tools such as artificial lift equipment. In addition, iron sulfide scale usually interferes with the safe operation of pipeline valving systems and rapidly erodes surface chokes because of the high erosion rate when it flows with the produced gas stream [4–6].

Iron sulfide depositions have an adverse influence on production and injection operations. The precipitation of the iron sulfide scale in the near-wellbore can diminish the productivity of the production wells [4], and also can cause loss of the injectivity in water injection wells [6–8].

Iron sulfide scale exists in several forms with troilite (FeS) and pyrite (FeS₂) as the most common types based on how rich the scales are in sulfur and ferric ions [5,9]. Iron sulfide scale type depends on the range of temperatures and the scale age. The scale materializes in a crystalline form having different ratios of sulfur to iron. The different forms of iron sulfide scale are: pyrrhotite (Fe₇S₈), troilite (FeS), marcasite (FeS₂), pyrite (FeS₂), greigite (Fe₂S₄), and mackinawite (Fe₉S₈) [5,9]. Several types of iron sulfide scale might exist in the same well. Usually hard or insoluble scales exist at shallower depths compared to the soft or soluble scales [10]. Using HCl cannot remove all the existing forms of iron sulfide in the same well because it can remove FeS, but it cannot remove the FeS₂ [11]. Therefore, both chemical and mechanical treatments are used in such cases.

Various sources deliver hydrogen sulfide and iron during different operational processes. Commonly in sour gas wells, hydrogen sulfide can be produced as free gas. Hydrogen sulfide is also produced due to water injection containing high sulfate content. The source of hydrogen sulfide might be sulfate-reducing bacteria (SRB), sulfur reduction by thermo-chemical interactions, thermal degradation of the organic sulfur compound, and using acid treatment of deep sour well [1,12]. The other component of iron sulfide scale is the iron that is produced either from the formation brine or by the corrosion of the tubing which is controlled by using effective corrosion inhibitors [6]. Iron can be introduced into the formation during acidizing with iron from the corroded tank surfaces or from the corroded well tubular. This will cause iron scale deposits in the formation or in the wellbore. Well stimulation acids can dissolve rust of storage tanks which contains a mixture of iron (II) and iron (III) [13]. Iron-containing minerals in the formation represent other iron sources such as chlorite clay mineral, iron carbonate compounds, etc. Iron compounds that precipitate during well stimulation can badly decrease the permeability of the reservoir [9].

Iron sulfide scale materializes in a crystalline form having different ratios of sulfur to iron. The sulfur to iron ration is one of the unique properties which distinguish different forms of iron sulfide. This disparity encourages experts for deep investigation and understating of these properties to develop proper treatments to remove or mitigate this kind of scale. The physical state of iron sulfide scale may vary from viscous black fluid to dry black powder. The physical and chemical properties of iron sulfide scale are function of many factors as temperature, pressure, scale age, and pH. Iron is usually present in a +2 or +3 oxidation state. At equilibrium conditions, all the iron is present in +3 oxidation state and it happens usually in the surface facilities. At normal reservoir conditions, iron is present in a +2 oxidation state. Based on the analysis of different field samples, it was observed that the ratio of iron (II) to iron (III) is 5:1 [9,14,15]. However, that ratio can vary in different wells and formations. A typical iron sulfide scales deposit is shown in Figure 1. Black powders are known in the industry as admixture of iron sulfide and other iron scales including iron oxide and iron carbonate chemically or mechanically mixed with salts, sand, liquid hydrocarbons, or metal debris [16].



Figure 1. Typical iron sulfide scales in pipelines [6].

Iron Sulfide Scale Removal

There are several chemicals that are being used to remove iron sulfide scales. Such chemicals include hydrochloric and organic acids, acrolein, tetrakis (hydroxymethyl) phosphonium salts (THPS), and chelating agents (sequestrants). Generally, the iron sulfide scale is soluble in hydrochloric acid and organic acids as formic acid (HCOOH) [6]. When the iron scale depositions contain low sulfur content, it would have a higher degree of solubility in HCl acid [17]. Leal et al. [18] reported that pyrite and marcasite iron sulfides are acid-insoluble, pyrrhotite showed a slow pace solubility, while mackinawite and trolite are highly soluble in low pH DPTA with 5 wt.% HCl. Lawson [19] showed that maleic acid was supposed to be one of the ferrous sulfide dissolvers with minimal production of H₂S.

Wang et al. [10] concluded that HCl can be used to remove the soft type of iron sulfide scale (FeS). The major problem of using HCl to remove soft scale is the high corrosion rate, especially at high temperatures. In addition, acid dissolution reaction generates a large amount of H₂S gas which can be a serious issue for well integrity and can increase the operational risk at surface facilities [3]. HCl also has a corrosion effect and, therefore, the removal formulation should include a corrosion inhibitor. On the other hand, using corrosion inhibitors resulted in decreasing the dissolution rate of iron sulfide while using the surfactants increasing the dissolution rate [20]. Mutual solvents such as monobutyl glycol ether were useful as it removed the hydrocarbons exist on the surface of the iron sulfide scale [21]. The reaction of hydrochloric acid HCl with iron sulfide produces the toxic H₂S gas as indicated by Equation (1), therefore, H₂S scavenger has to be added to the removal formulation to remove the H₂S [22]:

$$FeS + 2HCl \rightarrow Fe^{+2} + 2Cl^{-1} + H_2S.$$

$$\tag{1}$$

Sulfide scavengers which are aldehyde-based cause a reduction in the dissolution rate of iron sulfide because of the polymer deposition on the scale surface. However, triazine scavengers could be used as an alternative. A possibility for forming insoluble iron salts as a result of the increase in pH due to getting the HCl acid spends. Therefore, to prevent that, an iron control agent as citric acid or any chelating agent should be added [23]. Conversely, adding the citric acid to HCl reduces the dissolution of iron sulfide scale in HCl [2]. Using other chelates such as ethylenediaminetetraacetic acid (EDTA) will possibly have the same reduction effect for the iron sulfide dissolution rate. Mahmoud et al. [24,25] introduced a new formulation that can be used to remove pyrite iron sulfide scale from oil and gas wells. The tested scale contained more than 80% pyrite and they used 20 wt.% diethylenetriamine pentaacetic acid (DTPA) chelating agent at pH 11 with 9 wt.% potassium carbonate as a catalyst. The DTPA formulation dissolved 85% of the scale at 70 °C for 48 h. They suggested several catalysts that can enhance the dissolution rate of the pyrite scale such as potassium carbonate, cesium formate, and cesium carbonate. Abou Baker et al. [26] used a novel product that combines the effectiveness of chelating agent and dissolver of iron sulphide in actual field application (sandstone reservoir with a temperature of 149 °C). They concluded that the well production was returned with an increment of 50% above its original rate and the well was producing natural flow without using the jet pump.

Using less corrosive acids such as formic acid, thioglycolic acid, glyoxylic acid, or maleic acid can help in dissolving iron sulfide scales at high temperatures [19,27]. Acrolein (2-propenal) was claimed to be an iron sulfide scales dissolver and also acted as an H₂S scavenger and biocide [28,29]. However, acrolein should be carefully handled due to its high acute toxicity and also it is supposed to be a carcinogen [30]. Tetrakis (hydroxymethyl) phosphonium salts (THPS) as sulfate THPS showed a good dissolution performance for iron sulfide scale when it was injected with a small amount of alkylamine or it was preferred to use an ammonium salt [3,31]. During the removal of the iron sulfide scale, the iron was chelated to a nitrogen–phosphorus ligand and that made the water a red color. THPS was used successfully in a field application with a surfactant to kill sulfate-reducing bacteria SRB and dissolve iron sulfide scales, which led to 300% increase in the production rate in several wells [32]. Wang et al. [33] used THPS with different concentrations and additives to remove different iron sulfide scales consisting of pyrrhotite Fe₇S₈, mackinawite FeS, pyrite FeS₂, marcasite FeS₂, calcite, siderite,

and anhydrite. They used different concentrations of THPS (from 15 to 75 wt.%) and soaked it for time periods from 1–24 h. They also investigated the effect of ammonium chloride salt on the dissolution rate of scale and found that 50 wt.% THPS yielded the highest removal efficiency. The addition of ammonium chloride enhanced the scale solubility because it produced HCl but it increased the corrosion rate at 85 °C. However, THPS formulation with ammonium salts was found to be corrosive particularly at high-temperature conditions which makes it highly requiring a corrosion inhibitor [34].

Using THPS with EDTA as a chelating agent for removal of iron sulfide scale from a real field sample resulted in 70% solubility. The THPS and EDTA solution made had a neutral pH that would reduce the corrosion rate and consequently reduce the adding of corrosion inhibitors [35]. Hafiz et al. [36] reported a procedure to produce a synthetic iron sulfide scale with a multi-mineralogical composition similar to the scales commonly found in Khuff sour wells (26% pyrite, 11% goethite, 29% elemental sulfur, 19% halite, 13% iron hydroxide sulfate, and 2% alpha iron sulfate). Three dissolver were tested to dissolve the synthetic iron sulfide scale sample; dissolver (A) containing functionalized polymers, dissolver (B) containing a blend of THPS, and dissolver (C) containing a 50:50 mixture of A and B. The three dissolver A, B, and C achieved a dissolving capacity of 8.12 g/L, 3.5 g/L, and 38.8 gm/L respectively, which indicates a synergetic action of dissolvers A and B.

Another approach to remove iron sulfide scales is by the conversion of the insoluble Fe(II) to soluble Fe(III) using oxidizing agents such as chlorites/chlorine dioxide or permanganates, but using oxidizing agents could cause corrosion [37,38]. Reducing the particle size of the scale will increase the surface area of scale particles, and therefore, increase the interactions between the scale and the dissolver. However, it was found that there was a limited effect on the dissolution rate by increasing volume ratio of the dissolver with the scale mass and increasing agitation under the test conditions [39]. Recent studies were performed to find an effective chemical solution for removing the precipitated iron sulfide scales, and improving the scale dissolution [40–42].

The understanding of the origin of iron, formation of the iron sulfides, and sulfidation processes for iron surfaces is very important for the chemical surface interactions and provides a key role for designing the removal of iron sulfide scale [43]. Recently, a work by Onawole et al. [44] provided a new way for designing green chelating agents for the chemical removal of iron sulfide scale. Another recent study was performed to determine the optimum treatment time and pH control for the chelating agent as a chemical dissolution for the iron sulfide [45]. Ahmed et al. [46] studied the combination of THPS with EDTA to provide a basic pH that would help to reduce the tubular corrosion rate and reduce the use of corrosion inhibitors. The experimental and computational analysis showed that using THPS with EDTA is effective in dissolving iron sulfide scales as pyrrhotite (Fe₇S₈) and troilite (FeS).

Based on the above literature, there is an urgent need for the development of an environmentally friendly stable chemical formulation for the removal of iron sulfide which can efficiently remove the iron sulfide scale while being non-corrosive to the equipment and not releasing H_2S gas after the reaction with iron sulfide scale. In this paper, a new environmentally friendly acid system for iron scale sulfide scale removal was evaluated using actual field samples.

2. Materials and Experimental

2.1. Materials

A real sample of iron sulfide scale from the field was obtained and the composition of the sample was determined using X-ray powder diffraction (XRD). The composition of the iron sulfide scale sample is listed in Table 1. The new environmentally friendly acid system used in this study is a green acid solution synthesized by a catalytic reagent combination added to HCl, creating a biodegradable, non-bioaccumulating alternative to HCl. The synthesis removes the exothermic reaction created when water is added to HCl and significantly increases the strength of the acid, simultaneously creating a cathodic stimulation reducing the corrosiveness by a factor of 50 at ambient temperature. The titration test was performed to determine the actual percentage of HCl existing in the developed system and it

was found that the 100 wt.% NEFAS (New Environmentally Friendly Acid System) contains 20 wt.% HCl in addition to other additives.

Component	Chemical Formula	Percentage, %	
Pyrrhotite	Fe ₇ S ₈	55	
Troilite	FeS	6	
Mackinawite	FeS	1	
Pyrite	FeS ₂	8	
Hibbingite	Fe (OH) ₃ Cl	2	
Siderite	FeCO ₃	3	
Geothite	a-FeOOH	1	
Akaganeite	β-FeOOH	3	
Calcite	CaCO ₃	21	

Table 1. XRD analysis of the scale field sample.

Table 2 shows the fluid properties measured for the 100 wt.% and 75 wt.% NEFAS at room temperature. The 75 wt.% NEFAS had a density of 1.07 gm/cm³, a viscosity of 1.58 cP, the surface tension of 31.4 mN/m, and a pH of 0.04. Furthermore, commercial chemicals used in the real field application of iron sulfide scale removal were used also to compare their removal efficiency with NEFAS solution. The commercial chemicals used in the study were HDC-3, 20 wt.% GLDA, and 15 and 20 wt.% hydrochloric acid. GLDA was obtained from a service company at 40 wt.% stock concentration and pH 4, while HDC-3 was obtained at a pH of 14 from another service company. Corrosion inhibitor based on amino acids such as 3,5-diiodotyrosine and corrosion intensifiers such as tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione were used.

Table 2. NEFAS(New Environmentally Friendly Acid System) (75 wt.%) fluid properties at ambient temperature 25 °C.

Fluid Property	100 wt.% NEFAS	75 wt.% NEFAS
Density (gm/cm ³)	1.04	1.07
Viscosity (cP)	1.46	1.58
Surface Tension (mN/m)	42.95	31.56
pH	-1.29	0.04

2.2. Experimental Work

2.2.1. Solubility Test

The solubility tests were executed for the iron scale sample using the hot plate at a temperature of 125 °C and static condition. The solubility tests were conducted under a static condition to mimic the real field scale removal methodology during which the scale was soaked at static conditions for a certain soaking time to allow reaction between the acid and the scale in the well. The ratio of the scale weight to the removal fluid volume was decided as recommended by Bageri et al. [47,48] to design the solid to liquid ratio for the scale removal operation. That solid to liquid ratio depends on the amount of scale formed along the tubing internal diameter and so, the weight of the scale can be determined from the scale density and the accumulated scale volume that causes a decrease in the tubing internal diameter. Comparable work was performed by Elkatatny [49] to remove the iron sulfide scale using a new formulation and the author used a solid to liquid ratio (1:10) where 2 g of iron sulfide scale was soaked in 20 g of the removal fluid. He concluded that the acid mixture solubility was 78 g/L of iron sulfide scale at 100 °C after 24 h. In this study, the solid to liquid ratio used was 1:10. A solution of NEFAS fluid (20 mL) with concentration 75 wt.% was prepared and heated up to 125 °C using the hot plate connected to a liquid condenser to avoid any change in the liquid volume due to evaporation as shown in Figure 2. Then 2 g of the iron sulfide scale sample was added to the solution. The same

procedures were repeated for different soaking times as 2, 6, 12, 24 h at a static condition to evaluate the fluid removal efficiency as a function of time.



Figure 2. Multiple-position hot plate.

2.2.2. Corrosion Test

The corrosion test is usually performed to evaluate the corrosiveness of acids used in the oil and gas industry to ensure that it will not affect the integrity of the tubing and the downhole completion because of the high corrosion rate. It also ensures that the acid will not damage the surface equipment used to mix and inject the chemicals into wells or surface flowlines. The test measures the effect of the fluid on a steel coupon taken from coiled tubing material by calculating the corrosion rate after hanging the steel coupon in the fluid under 3.447 MPa and 125 °C, using the high-pressure high-temperature aging cell shown in Figure 3. The aging cell is isolated by teflon body to protect the steel body of the cell from the corrosive fluids.



Figure 3. High-pressure aging cell and teflon liner used for the corrosion test.

The test procedures as follow:

- 1. An acid volume of 350 mL was prepared.
- 2. The weight, thickness, and curvature radius of the steel coupon were measured.
- 3. The steel coupon was hanged in the high-pressure high-temperature aging cell.
- 4. A teflon liner that can be placed inside the aging cell was filled with the 350 mL acid volume.

- 5. The steel coupon was hanged in the teflon liner and ensured to be completely submerged in the fluid.
- 6. The teflon liner was placed inside the aging cell and the aging cell cap was closed.
- 7. A pressure of 3.447 MPa was applied from the top valve of the aging cell using nitrogen gas.
- 8. The aging cell was placed inside the oven for 6 h under a temperature of 125 °C.
- 9. After 6 h, the aging cell was taken out from the oven and waited until it cooled, then the pressure was vented and the cell was opened.
- 10. The measurements in step 2 were recorded again after the interaction with the fluid.
- 11. The corrosion rate was calculated.

The test was repeated following the same procedure to measure the corrosion rate for each acid system under the same conditions. For each test, a new coupon was used. The test was performed for the NEFAS fluid, 15 wt.% HCl with adding 2 wt.% corrosion inhibitor (N, N-diallyl-N-benzyl dodecyl ammonium) and 2 wt.% corrosion intensifier (formic acid). Adding the corrosion inhibitor to the acid will help to protect the tubular from the corrosion effect at high-temperature conditions while the intensifiers are usually added to the corrosion inhibitor to extend its performance under conditions such as higher acid concentration, high temperature, and long-time operations [50,51].

3. Results and Discussion

The solubility experiments were performed for different concentrations of NEFAS (100 wt.% and 75 wt.%) and HCl (15 wt.% and 20 wt.%) for 6 h for the initial comparison with HCl. Figure 4 shows that the solubilities of the four solutions are very close to each other and the 75 wt.% NEFAS achieved 83 g/L solubility of the iron sulfide while 100 wt.% NEFAS dissolved 82 g/L after 6 h. Therefore, The 75 wt.% NEFAS is more effective than the 100 wt.% NEFAS which will save 25% of the acid cost. Whenever the concentration of NEFAS was reduced below 75 wt.%, no considerable solubilities were achieved. The lower dissolving power for the 100 wt.% NEFAS compared to 75 wt.% NEFAS can be a result of the reduced fluid activity caused by the retarding effects of the dissolved reaction products and the increased NEFAS viscosity. Similar trends were reported for GLDA and HCl when used to dissolve carbonate rocks [52,53].



Figure 4. Static solubility of iron sulfide scale using different acid systems at 125 °C for 6 h.

The solubility of iron sulfide by 75% NEFAS under static conditions at different soaking times increased with soaking time for the first six hours as shown in Figure 5. The solubility of the iron sulfide after 2 h of soaking with NEFAS 75% was 77 g/L and increased to reach 83 g/L after 6 h. No

significant increase in the solubility can be noticed for soaking times of 12, 18, 20, and 24 h compared to 6 h. The obtained results confirmed that the NEFAS can be used with a concentration of 75 wt.% to remove the iron scale sample with high efficiency for only 6 h.



Figure 5. Static solubility of iron sulfide scale using 75 wt.% NEFAS at 125 °C.

Table 3 shows the solubility results of the iron sulfide scale using different acid systems commercially used in the oil field for scale dissolvers for 6 and 24 h at 125 °C. Figure 6 demonstrates that the solubility of HDC-3 was low (18 g/L) after 24 h. While 20 wt.% GLDA at pH 4 has a moderate solubility of 65 g/L after 24 h. The 15 wt.% HCl was able to remove the scale after 24 h with an efficiency of 84% while NEFAS was able to achieve the same solubility of 15 wt.% HCl after only 6 h. For further comparison, the corrosion tests were conducted for both NEFAS and HCl.

Table 3. Static solubility results of iron sulfide scale using different chemicals and concentrations after 6 and 24 h at 125 $^{\circ}$ C.

Removal Fluid	Time, (hr)	Solubility, (g/L)	Solubility, (%)	
HDC-3	24	18	18	
GLDA (20 wt.%)	24	65	65	
NEFAS (75 wt.%)	24	82	82	
HCl (15 wt.%)	24	84	84	
NEFAS (100 wt.%)	6	82	82	
NEFAS (75 wt.%)	6	83	83	
HCl (20 wt.%)	6	83	83	
HCl (15 wt.%)	6	84	84	

The corrosion tests were conducted using actual coiled tubing steel coupon soaked with 75 wt.% NEFAS and 15 wt.% HCl for 6 h at 125 °C. Table 4 represents the corrosion test results for the two removal fluid systems NEFAS (75 wt.%) and HCl (15 wt.%). Figure 7 shows that the corrosion rate of 15 wt.% HCl was 0.808 kg/m², which is higher than the acceptable range by the oil and gas industry (0.244 kg/m² at 125 °C). The corrosion rate of 75 wt.% NEFAS was 0.211 kg/m² after adding the corrosion inhibitor CI (2 wt.%) and corrosion intensifier CIN (2 wt.%). Based on these results, NEFAS will not affect the integrity of wellbore tubular compared to the commonly used HCl-based formulations in field applications.



Figure 6. Static solubility of iron sulfide scale using different chemicals at 125 °C for 24 h.

Acid	Coupon Weight, (g)		Coupon Thickness, (mm)		Corrosion
	Before	After	Before	After	Rate, (kg/m²)
75% NEFAS + 2% C.I. + 2% Int.	12.345	11.992	2.464	2.413	0.211
15% HCL + 2% C.I. + 2% Int.	12.373	11.000	2.464	2.261	0.808
15% HCL	12.118	2.697	2.464	1.245	0.244

Table 4. Corrosion test results at 125 °C and 3.447 MPa.



Figure 7. Corrosion rate comparison between NEFAS system (75 wt.% NEFAS + 2 wt.% CI + 2 wt.% CIN) compared to HCl system (5 wt.% HCl + with 2 wt.% CI + 2 wt.% CIN) at 125 °C and 3.447 MPa.

4. Conclusions

Extensive lab work was conducted to determine the removal efficiency of a new biodegradable acid system, NEFAS, for iron sulfide scale using actual field sample at 125 °C. Based on the obtained results, the following conclusions can be drawn:

- 1. NEFAS (75 wt.%) achieved iron sulfide solubility of (83 g/L) after 6 h.
- 2. NEFAS (75 wt.%) outperformed GLDA (20 wt.%), HDC-3, and HCl (15 wt.%) for iron sulfide scale removal.
- 3. The corrosion rate for the NEFAS (75 wt.%) was 0.211 kg/m² at 125 °C, which is lower than the corrosion rate accepted by the oil and gas industry after adding 2 wt.% corrosion inhibitor and 2 wt.% corrosion intensifier.

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