Development of a Unique Organic Acid Solution for Removing Composite Field Scales

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ABSTRACT: Removal of oil field scales commonly requires low pH acid, which may cause many issues under downhole conditions. Because of the deposition of different scale types and the economic effect, there is a need to develop a remedial descaling fluid that can be effectively used to remove different types of scales at a different position in the well. This paper provides a new scale dissolver that is noncorrosive and has high scale dissolution performance for composite scales. This study shows a series of comprehensive experimental lab tests as scale characterization, equilibrium brine compositional analysis, fluid compatibility and stability, solubility test, precipitation tendency for the dissolved solids, corrosion test, and core flooding. The scale samples contain magnetite, kaolinite, calcium carbonate, and sulfate scales. The results showed that the dissolution rate was higher than 74% for composite field scale samples after 6 h at 70 °C, while the new dissolver completely dissolved the two samples at 100 °C after 5 h. The new dissolver outperformed the common commercial dissolver used in the oil and gas industry. The new dissolver has a pH of 9 and showed safe use regarding the precipitation of dissolved solids that can be produced during the scale treatment and a low corrosion rate of 0.063 kg/m² at 6.9 MPa and 100 °C for 6 h. Also, the new dissolver was tested through core flooding for Indiana limestone and showed core permeability enhancement; the treatment with the new dissolver enhanced the core permeability from an initial value of 0.67 milliDarcy (mD) to record 1.29 mD.

INTRODUCTION

Field operational problems that occurred due to scale precipitations are very common in oil and gas fields. These problems lead to a decrease in the oil and gas field production and can even cause well shut down and stop the production due to the precipitation of the scales along the production system, starting from the reservoir rock pore system, perforation, downhole well equipment, especially the artificial left systems, production tubing, wellhead, pipelines, and surface facilities.1−4 Scale precipitation in these locations will cause a decrease in the porosity system in the reservoir, wettability alteration,5 and partially or fully plugged the production flow, injection system, and disposal wells.5

The petroleum system includes the oil and gas stream, associated formation water, and in some cases, injected water for reservoir enhanced recovery. Many different minerals and brines are existing among these streams, and therefore, they formed different scales of precipitation. Reservoir formation water, produced water, and seawater are usually utilized after treatment as water sources for reservoir flooding and injection operations to increase the petroleum reservoir recovery. These water sources contain different brines and minerals as formation water is rich with high concentrations of barium and calcium minerals and low concentration of sulfate ions; on the other side, seawater has a high concentration of sulfate ions and low concentration of barium and calcium minerals. Scale
precipitation is a result of the incompatibility between different water sources as injected water and reservoir formation water.8 A common source for the sulfide scales is the hydrogen sulfide (H₂S) gas, and sulfide scales precipitated when H₂S chemically reacts with existing minerals such as zinc, lead, and iron. Iron sulfide is considered the common sulfide scale in the oil field. Sulfate scales are common scale types in the petroleum industry as barium sulfate/barite (BaSO₄), calcium sulfate (CaSO₄), strontium sulfate/celadonite (SrSO₄), and gypsum (CaSO₄·2H₂O), in addition to other scale types such as carbonates (CaCO₃, MgCO₃, and FeCO₃), oxides, and hydroxides of Fe and Mg.8,9 Scale precipitation is controlled by the pressure and temperature condition, pH, chemical equilibria of the reaction, ionic strength, and the interaction exposure time.10 Due to these controlling conditions for the scale precipitation, the location of scale is different based on the existing source and operation condition as the sulfate scales precipitated with the seawater injection system because of incompatibility of water sources and this is considered as a hard scale type due to its low solubility with acid.11 Commonly, zinc and lead sulfides precipitated in downhole completion tools as control valves.12,13 The drilling operations utilized barite (barium sulfate) as a weighting material for the drilling fluids, and during drilling operations, the mud invades the drilled formation with barite solids, and therefore, barium sulfate scale precipitated and damaged the drilled formation by reducing the rock porosity and permeability.14 Strontium-based sulfate is a common scale with the production surface facilities and processing units.15 The precipitation of calcium sulfate scales is commonly related to the reservoir zone and artificial lift systems as electrical submersible pumps.16,17

■ SCALE REMOVAL
Removing the scale precipitations from the production systems is a very hard and complicated job due to the different scale types and operating conditions. The two approaches for scale removal are mechanical removal and chemical solutions, and commonly, they might be used together for descaling jobs. Many factors control the descale job design as technical features and economics. The technical aspects should consider the dissolution efficiency under the operating conditions of temperature and pressure, thermal stability, H₂S gas generation after dissolution, corrosion rate that affects the integrity of downhole and surface equipment, tubing, and pipeline network, and damaging effect for the reservoir rock. On the other hand, economics should consider the chemical and/or mechanical job cost and solution volume to scale mass ratio.18,19

Olajire20 mentioned that scale management technology is very critical as the scale deposition can stop oil and gas production. The descaling operation requires high cost, and therefore, utilizing chemical inhibition might provide efficient results to prevent the scale depositions.21,22 The field application for scale inhibitors showed successful case studies for different scale types based on the technical design for inhibitors in terms of chemical composition and dose.23

Preparing the chemical dissolver is considered a complex and hard task as many scale types coexist due to the variety of minerals in the flow streams that provide sources for scale buildup; therefore, various chemical reactions occurred between the chemical dissolver and the different scale ions and minerals. Scale solubility is different from one type to another based on the chemical composition of scale, i.e., sodium chloride (halite) is highly soluble in water; however, another scale types are soluble in acids, i.e., iron oxides and some sulfides scales and carbonate scales as calcium types.8

pH is another challenge for the chemical design of the descaling operation. Calcium sulfate is a scale type that was found to have low solubility with high pH dissolvers.24 Also, dissolvers that have low pH will increase the tubular corrosion and therefore damage the facilities’ integrity.25,26 Recent research studies27–30 are directed to provide chemical dissolvers with high pH to sustain the well downhole and surface equipment, processing units, and facilities; also, this will save the corrosion inhibitor and intensifier cost that is commonly added to the treatment operations for low pH dissolvers.31,32 Ahmed et al.28 added tetrakis hydroxymethyl phosphonium salts (THPS) to ethylenediaminetetraacetic acid (EDTA) to formulate a slightly alkaline chemical solution with about pH value of 8. Another recent research was executed and provided a chemical dissolver with a 12.5 pH value for composite sulfate/sulfide scale removal at low temperatures, and the results showed scale solubility efficiencies of 91.8% at 45 °C and 79% at 35 °C.30

The chemical removal for scale precipitations is a common method for descaling operations in the oil and gas industry that utilized various organic and inorganic solutions that depends mainly on the scale chemical composition for the chemical design of the dissolver.33 Surfactants can be used to remove the hydrocarbon layer that covered the scale precipitations, and therefore, the dissolver solubility increased as there is more contact with the scale body after removing this layer of hydrocarbon. Among the chemical dissolvers that are used in the oil industry, hydrochloric acid (HCl) is considered one of the common acids as a scale dissolver.34 However, many types of scales were found not soluble in HCl; also, HCl has a corrosion effect and produces H₂S, which is a toxic gas. Therefore, additional chemical additives are usually added to HCl for controlling the chemical reactions to overcome the cons of using HCl in the chemical descale jobs.35,36–38 HCl performed well for removing scales as zinc sulfides and limited types of iron sulfides as pyrrhotite and troilite; however, HCl did not perform well in solubility with marcasite and pyrite scales.37 HCl showed low solubility efficiency with sulfate scales as strontium, calcium, and barium sulfates (barite).20,21

Other chemical solutions for descale operations are organic acids like citric acid, maleic acid, formic acid, and acetic acid. Organic acids are mainly utilized for removing scales in high-pressure high-temperature reservoirs.39–41 The organic acids showed a low corrosive effect and provided chemical reactions for a long time; however, the solubility efficiency of organic acids is lower than that of HCl.40

The alternative solution in the industry for organic and inorganic acids is utilizing chelating agents as scale dissolvers as they have a low corrosion effect and are safe to handle and environment-friendly.42 Ethylenediaminetetraacetic acid (EDTA), hydroxethyl ethylene diamine tricarboxylic acid (HEDTA), hydroxyethyl iminodiacetic acid (HIDA), glutamic acid di-acetic acid (GLDA), diethylenetriamine pentaacetic acid (DTPA), nitrilotriacetic acid (NTA), and methylglycine-diacetic acid (MGDA) are considered common examples for the chelating agents in field descale operations.43 A study was performed to evaluate the dissolution efficiency for DTPA (20 wt %) with a catalyst (9 wt % potassium carbonate) to dissolve the pyrite (FeS₂) scale precipitation, and results showed that
85% of the scale was dissolved at 70 °C and a time of 48 h. \(^{44,45}\) Nitritoltriacetic acid (NTA) is an additional example of the chelating agents that provides a high biodegradability. \(^{46}\) However, using the chelating agents in the descale treatment is not considered the optimum solution as they are expensive chemicals and further experimental work is needed to determine the optimum pH, solution concentration, treatment time, and thermal stability. \(^{29,43}\)

The new contributions of this paper are providing a new organic scale dissolver for composite scale removal with a high pH of 9.0 and a low corrosion rate. Also, core flooding experimental work was performed to simulate the field application of the new dissolver. The experimental lab work in this study covered a wide-ranging evaluation for the new dissolver to evaluate its scale dissolution performance at 70 and 100 °C, the new scale dissolver compatibility, stability, precipitation tendency for the dissolved solids after solubility, corrosion rate, and core flooding. The study utilized two real field scale samples that contain different compositions of magnetite, kaolinite, calcium carbonate, and sulfate scales. Comprehensive characterization was executed for the brine analysis, and scale elemental and compositional analysis was performed to help for the chemical design of the new scale dissolver. The novelty in this study is to provide a new organic dissolver with overcoming the previous problems associated with the chemical solutions for descale treatment as clearly stated in the discussion section.

### MATERIALS AND EXPERIMENTAL WORK

**Material Description.** Two composite scale samples were collected from surface production facilities of two different fields to be used in this study for evaluating the dissolution rate of the new scale dissolver. Scale sample 1 was collected from a gas well that produces from a carbonate formation reservoir at 31.854 MPa pressure and 104 °C and the water cut was 15% with a water production rate of 793 barrels per day, as shown in Table 1. Scale sample 2 was collected from an oil well that produces from a sandstone reservoir with 26.5 MPa pressure and 102 °C and a water cut of 28% with a water production rate of 6717 barrels per day. Figure 1a shows scale sample 1 and Figure 1b shows scale sample 2, and it is clear from visual inspection of the samples that they are different in their physical features in terms of size and color. Scale sample 1 had a size smaller than sample 2, and it had a darker color than sample 2.

![Image](image1)

**Figure 1a:** Scale sample 1 from a gas well. 
**Figure 1b:** Scale sample 2 from an oil well.

| formation type | well type | water cut, % | reservoir pressure, MPa | reservoir temperature, °C | water production, bbl./day |
|---------------|-----------|--------------|-------------------------|--------------------------|---------------------------|
| carbonate     | gas producer | 15          | 31.9                    | 104                      | 793                       |
| sandstone     | oil producer | 28          | 26.5                    | 102                      | 6717                      |

Table 1: Field Data for the Collected Two Samples

Brine analysis is very important for scale analysis, and hence, equilibrium brine composition analysis was performed for the two sources for the water from the two fields, as shown in Table 2. Brine analysis showed that there is a variation in the cation and anion concentration in terms of milligrams per liter (mg/L) for two water samples from the two fields: the analysis showed that ferrous (Fe(II)) cations had the highest concentration for sample 1 with 36,333 mg/L followed by sodium cations (Na+) with 19,353 mg/L, while sample 2 had a high concentration of Na+ with 36,133 mg/L and 18,153 mg/L Fe(II). The most dominant anion concentration was the chloride ion (Cl−) for the two samples with 33,033 and 77,676 mg/L for water samples 1 and 2, respectively.

X-ray diffraction (XRD) was utilized as per the standards of American Society for Testing and Materials \(^{17}\) to determine the mineralogical composition for the field scale samples, and the scale elemental composition was determined with X-ray fluorescence (XRF). The mineralogical composition of the two scale samples is shown in Table 3. XRD is presented in weight percentage of each compound; sample 1 had 46.3 wt % magnetite (Fe₃O₄), 25.2 wt % calcium carbonate (CaCO₃), 12.2 wt % strontrium sulfate (SrSO₄), 8.8 wt % halite (NaCl), and 7.5 wt % barium sulfate (BaSO₄). Sample 2 contained calcium carbonate with 28 wt %, calcium sulfate with 24 wt %, kaolinite with 17.7 wt %, barium sulfate with 13 wt %, magnetite with 12 wt %, and halite with 5.3 wt %. It is clear from compositional analysis that the two samples are different and that is because of the location of scale deposition and the operational conditions of temperature and pressure.

Table 4 lists the elemental composition (XRF) of the field scale samples. Scale samples 1 and 2 contained high slightly similar percentages of iron (Fe), calcium (Ca), sulfur (S), chloride (Cl), barium (Ba), sodium (Na), and aluminum (Al). Iron represents the highest elemental composition for sample 1 with 46.485 wt %, while calcium is the highest weight percentage for sample 2 with 43.22 wt %. Sample 1 had an extra amount of strontrium (Sr), while sample 2 had additional weight percent of silicon (Si) and magnesium (Mg).

The proposed scale dissolver in this study was prepared with a chemical composition of acrylic acid (15–30 wt %), lactic acid (5–15 wt %), nonionic surfactant (1–3 wt %), ethylene oxide (<1 wt %), and water (70 wt %), as shown in Table 5. Regarding the functions of the new dissolver additives, acrylic acid was used for inhibition of scale types as calcium sulfate-, calcium carbonate-, calcium phosphate-, barium sulfate-, and magnesium-containing scales. \(^{58}\) Lactic acid is one of the most common descaling agents due to its acidity for removing the hard deposits. Ethylene oxide, which is an iron reduction system, was added for iron control in sour environments; the new design fluid has a multicomponent iron reduction system that helped to eliminate the precipitation problems by efficiently reducing ferric iron to ferrous iron at all acid concentrations.

The new dissolver fluid had a specific gravity of 1.15 and a pH of 9.0 with an amine-like odor. These properties were measured under ambient conditions.

**Experimental Lab Work.** This section discussed in detail the lab tests that were performed for the evaluation and characterization of the new scale dissolver. Extensive laboratory tests were executed to assess the new dissolver performance in terms of fluid compatibility and stability, solubility efficiency, precipitation tendency for dissolved solids, and core flooding with carbonate core samples to confirm the new scale dissolver compatibility.

**Fluid Stability and Compatibility.** Fluid stability and compatibility tests are usually performed to evaluate the fluid stability against the change in conditions as temperature and time. Fluid stability is a function of its resistance to breakdown, while fluid compatibility measures the fluid propensity to
produce deposits while mixing. The stability test procedures are as follows:

- Fifty milliliters (mL) of the fluid was taken into a flask and stirred for 10 min in a hot plate without any heat.
- The flask was covered and put on a hot plate at 125 and 150 °C for 24 h.
- The fluid was examined for any color changes and/or precipitations.

Compatibility test procedures were performed as two experiments: the first test by mixing the developed dissolver and formation water with a 50:50% ratio and the second test by mixing the dissolver with crude oil with the same ratio. Then, the solution was kept in a static oven at 150 °C for 24 h and color changes, precipitation, sludge, separation, and any physical changes were observed.

### Solubility Test

The fluid solubility test is performed to determine the solubility efficiency of the fluid for the scale sample. The test determines the fluid dissolution rate in terms of a mass unit of scale per volume unit of the fluid under the required temperature, pressure, operation condition if static or dynamic. The scale mass to removal solution liquid ratio is considered a critical parameter for the technical and economic design for the field descale job. The scale precipitations mass was calculated from the diameter dimension reduction because of the scale and its density. The main objective of the descaling operation is to achieve a higher dissolution rate with less dissolver amount for cost-saving.

1. A quantity of 100 mL of the fluid was put in a flask to be heated to 70 °C for 1 h with the hot plate as in Figure 2.
2. A mass of 10 g from the scale sample (W1) was obtained.


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**Table 2. Equilibrium Brine Composition Related to Water Samples from the Two Fields**

| cations | well 1 mg/L | well 2 mg/L | anions | well 1 mg/L | well 2 mg/L |
|---------|-------------|-------------|--------|-------------|-------------|
| Ba^{2+} | 36          | 72          | OH^{-} | 0.014       | 0.005       |
| Ca^{2+} | 1710        | 10,051      | Cl^{-} | 33,033      | 77,676      |
| CaOH^{+} | 0.010     | 0.030       | CO_{3}^{2-} | 0.083       | 0.021       |
| H^{+}   | 0.002       | 0.004       | HCO_{3}^{-} | 131         | 47          |
| Sr^{2+} | 42          | 0.0         | HSO_{4}^{-} | 0.234       | 0.593       |
| CaHCO_{3}^{+} | 0.0 | 38         | Na_{2}CO_{3}^{-} | 0.009      | 0.004       |
| Mg^{2+} | 1009        | 1415        | NaSO_{4}^{-} | 0.177      | 0.0         |
| MgOH^{+} | 0.110     | 0.080       | SO_{4}^{2-} | 1196       | 410         |
| Fe^{2+} | 36,333      | 18,153      |        |             |             |
| CaCl^{2-} | 4         | 56          |        |             |             |
| Na^{+}  | 19,353      | 36,133      |        |             |             |

**Table 3. Mineralogical Composition of the Field Scale Samples (XRD)**

| compound          | chemical formula | sample 1, wt % | sample 2, wt % |
|-------------------|------------------|----------------|----------------|
| magnetite         | Fe_{2}O_{3}      | 46.3          | 12.0           |
| calcium carbonate | CaCO_{3}         | 25.2          | 28.0           |
| strontium sulfate | SrSO_{4}         | 12.2          | 0.0            |
| halite            | NaCl             | 8.8           | 5.3            |
| barium sulfate    | BaSO_{4}         | 7.5           | 13.0           |
| calcium sulfate   | CaSO_{4}         | 0.0           | 24.0           |
| kaolinite         | (Al_{2}O_{3}-nSiO_{2}-mH_{2}O) | 0.0 | 17.7 |

**Table 4. Elemental Composition of the Field Scale Samples**

| element | sample 1 (wt %) | sample 2 (wt %) |
|---------|-----------------|-----------------|
| Fe      | 32.4            | 9.0             |
| Ca      | 10.1            | 25.5            |
| S       | 6.0             | 4.0             |
| Sr      | 5.8             | <0.1            |
| Cl      | 5.4             | 3.2             |
| Ba      | 4.4             | 7.6             |
| Na      | 3.1             | 2.1             |
| Al      | 1.7             | 1.2             |
| Mn      | 0.3             | 0.0             |
| K       | 0.2             | 0.2             |
| Zn      | 0.2             | 0.0             |
| Br      | 0.1             | 0.0             |
| Si      | <0.1            | 0.0             |
| Mg      | 0.0             | 5.0             |
| Cu      | 0.0             | <0.1            |

**Table 5. Chemical Composition of the New Scale Dissolver**

| component          | wt % |
|--------------------|------|
| acrylic acid       | 15–30|
| lactic acid        | 5–15 |
| nonionic surfactant | 1–3  |
| ethylene oxide     | <1   |
| water              | 60–70|
Figure 2. Multiple-position hot plate.

3 The scale mass was then added to the dissolver fluid in the flask.
4 The test was continued for 6 h under 70 °C and atmospheric pressure.
5 After the test period, the solution was left to cool down.
6 After cooling down, a filter paper with a vacuum pump setup was used to separate the nondissolved scale solids from the solution.
7 The weight of the dry filter paper (W2) was determined.
8 The filter paper with the nondissolved scale solids was dried in an oven (70 °C) for 2 h.
9 The weight of the filter paper with the scale solids after drying (W3) was measured.
10 The weight of the nondissolved scale solids = W3 − W2 = W4 was determined.
11 The dissolution efficiency of the scale dissolver = [(W1 − W4)/W1] × 100 was determined.

Precipitation Tendency for Dissolved Solids. After the solubility test, the dissolver is saturated with the dissolved solids. These dissolved solids might be precipitated, and that will lead to initiate scale problems again after the treatment. Therefore, the precipitation tendency test should be conducted to assess how much from the dissolved solids within the dissolver solution will precipitate. Precipitation tendency for the dissolved solids was applied for 24 h at 100 °C. The test was performed for the new dissolver and compared with the most common acid in the petroleum industry descale application HCl (15 wt %).

Corrosion Test. The field descale applications required using low-corrosive fluids to not damage the pipelines and the downhole equipment. Commonly, the corrosion test is performed for new dissolvers to determine the corrosion rate that could occur by using that new fluid for any field curing job. In this study, the corrosion rate was performed under high-pressure high-temperature (HPHT) conditions using an autoclave cell at 6.9 MPa and 100 °C for 6 h. The corrosion test was carried out without adding corrosion inhibitors to the solution, and the test was executed using an actual casing coupon (T95 casing grade).

The corrosion test was performed by exposing the steel coupon to the fluid solution in the autoclave cell under the designed condition of pressure, temperature, and time. The weight of the coupon was determined before and after the test to get the steel weight loss due to exposing the coupon surface area to the fluid for some time as per the following equation:

$$CR = \frac{W_f}{A \times T}$$

where CR is the corrosion rate [mg/(cm² h)], W_f is the weight loss (mg), A is the initial surface area of the coupon (cm²), and T is the exposure time (h).

Commonly, the corrosion test is performed for 6 h as this time is sufficient for the descale jobs in the field. The coupon and solution should be extremely observed by the end of the test to get the indications about the precipitations and color change in the solution and that will help for further analysis.

Core Flooding Experiment. For further evaluation of the new dissolver, a core flooding experiment was conducted to evaluate the compatibility of the new scale dissolver with carbonate cores. The experiments were conducted using an Indiana limestone core sample (3 inches length by 1.5 inches diameter) with 15% porosity. Core flooding experiments were conducted with the new dissolver at a pH of 9. The core flooding was performed as follows:

1 The core was heated up to 100 °C, the outlet pressure was set at 7.58 MPa, and the overburden was 3.45 MPa more than the injection pressure (around 13.78 MPa).
2 The initial core permeability was determined by injecting fresh water at room temperature with four different flow rates, and then the flow rate versus pressure was plotted.
3 The core flooding was conducted by injecting the new dissolver.
4 After that, the core sample was back flushed by fresh water and then the core permeability was measured at room temperature at the same different rates as mentioned in step 2 to obtain the final permeability.

The permeability ratio is determined as per eq 2 to estimate the permeability enhancement

$$K \text{ ratio } = \frac{k_f}{k_i}$$

where K ratio is the permeability ratio (%); k_f is the final permeability (mD); and k_i is the initial permeability (mD).

RESULTS AND DISCUSSION

Fluid Stability and Compatibility. The new dissolver showed good stability and compatibility performance at 125 °C and 150 °C, no precipitation was found, and the fluid was still clear. Figure 3 shows the solution pictures for the stages of the stability test for the initial solution, after 24 h at 125 °C, and after 24 h at 150 °C.
Solubility Results. The new dissolver showed high dissolution efficiency for the two scale samples that were collected from the field. Figure 4 represents the dissolution efficiency for the new dissolver versus commercial dissolvers that are commonly used for field chemical descale operations. The scale solubility was determined for the chemical dissolvers under 70 °C for 6 h except for EDTA (20 wt %) and DTPA (20 wt %) where the experiment time was extended to 24 h due to their low dissolution efficiency. As shown from Figure 4, the new dissolver completely dissolved scale sample 2 within 6 h, while it dissolved 74.6% from sample 1. The dissolution efficiency was compared with other dissolvers as HCl acid (15 wt %), EDTA (20 wt %), and DTPA (20 wt %). The results presented a low dissolution rate for both EDTA (20 wt %) and DTPA (20 wt %) especially for sample 1 as the efficiencies of dissolution for DTPA (20 wt %) were 47.9% for sample 2 and 27.4% for sample 1, while EDTA (20 wt %) dissolved 25.1% and 41.3% from samples 1 and 2, respectively. HCl (15 wt %) dissolved 85.1% from sample 1 and 37.2% from scale sample 2. It is clear that even HCl (15 wt %) performed well with sample 1; the new dissolver presented high balanced performance for both scale samples, and also, the new solution overcame the HCl disadvantages such as the corrosion effect and the precipitation tendency.

Additionally, the new dissolver was tested for solubility at a high temperature of 100 °C for 5 h, as shown in Figure 5. The results showed that by increasing the temperature from 70 to 100 °C, the dissolution efficiency of the new dissolver for sample 1 increased from 74.6 to 78.2%, while the new dissolver completely dissolved sample 2 after 5 h, which proved the high dissolution performance at high temperature. The overall dissolution performance is acceptable for the two scale types, which enhances the field descale application as more than one type of scale is existing and this needs a special curing solution to dissolve different scale types. The two scale samples showed different compositions, and this is the reason behind the difference in their dissolution rates; also, sample 1 had a higher content of strontium sulfate and magnetite, which might be the reason for sample 1 to be hard and to have a lower dissolution rate than sample 2.

Precipitation Tendency for Dissolved Solids. The dissolved solids tendency for precipitation was tested, and the results as presented in Figure 6 showed that the dissolved solids precipitation tendency with the new dissolver is very low as it recorded 3.1% for sample 1 and 2.3% for sample 2. Also, the comparison results with HCl acid (15 wt %) showed that the precipitation tendency with HCl was higher than that of the new dissolver with 3.6 and 4 times for samples 1 and 2, respectively. The results confirmed the safe use of the new dissolver regarding the dissolved solids precipitation problem.

Corrosion Test. The corrosion test was conducted, and the results showed that the new dissolver performed in a safe way as the low corrosion test, which showed 0.063 kg/m² at 6.9 MPa and 100 °C for 6 h. The low corrosion rate for the new dissolver will help to protect the integrity of the pipelines, surface facilities, well equipment, and downhole tools. This corrosion rate was achieved without the need for any corrosion inhibitors or intensifiers that are commonly used with the curing solution, and hence, extra cost will be saved by this new solution. Figure 7 shows the steel coupon and the fluid solution after the corrosion test. Slightly, minor changes were observed on the steel coupon (Figure 7a), while the new
dissolver solution after the test is shown in Figure 7b, and that visual inspection confirmed the good results of the corrosion test.

**Core Flooding.** The core flooding experiment was performed, and the results showed that the new scale dissolver was able to enhance the core permeability. Figure 8 shows the differential pressure versus the injected pore volumes during the core flooding experiment using the new dissolver. The results showed that the differential pressure was increased from 296 kPa until 579 kPa was reached due to the injection forcing effect of the new dissolver into the rock pores until about 1.5 pore volumes of the new scale dissolver was reached, and during that, the chemical reaction between the core sample and the new scale dissolver started to initiate the wormholes within the rock sample. The wormholes initiated at 579 kPa (1.5 pore volumes injected) and started to propagate with a low rate and then the propagation rate increased after injecting 2.5 pore volumes of the new dissolver. The new dissolver was able to break through the core sample after injecting 4.6 pore volumes of the new dissolver. Figure 9b shows the wormholes that were created by new dissolver flooding. Furthermore, the new dissolver enhanced the core permeability from an initial permeability of 0.67 mD to record 1.29 mD after the treatment to achieve a permeability ratio of 1.93.

The results of the experimental lab work that was performed to assess the new dissolver performance demonstrated the high performance of the new dissolver in terms of fluid stability and compatibility, dissolution rate for the two field-scale samples at 70 and 100 °C, low corrosion rate, and core permeability enhancement. Also, the precipitation tendency of the dissolved solids showed that the new dissolver is outperforming HCl performance with 3.6 and 4 times for samples 1 and 2, respectively, and this point is very critical for the treatment success as the precipitation of the dissolved solids might initiate other types of scales that are uncontrollable and will need further descale chemical treatment.

**Reaction Mechanism.** The chemical treatment provided an efficient mechanism to solve major associated problems with sulphide and carbonate. Proper acid treatment volume and placement techniques are critical to the success of a scale removal treatment. The fluid design must avoid unexpected
adverse fluid reactions that may decline the benefits of chemical treatment.

**Reaction Mechanism of Inorganic Acids.** Inorganic acids as HCl cause the most severe adverse fluid reactions on HCl−oil interactions. Some of the byproducts will be organic and inorganic deposits.

\[
2\text{HCl} + \text{CaCO}_3 \rightarrow \text{CaCl}_2 + \text{CO}_2 \uparrow + \text{H}_2\text{O} \quad (3)
\]

\[
2\text{HCl} + \text{FeS} \rightarrow \text{FeCl}_2 + \text{H}_2\text{S}\uparrow \quad (4)
\]

Surfactants are used in acidizing to reduce surface and/or interfacial tension, modify wettability, speed cleanup, disperse additives, break emulsions, and prevent the formation of sludge. Careful selection of appropriate surfactants requires intensive analysis in the design of well treatments, and incorrect surfactant selection can eliminate the performance of the treatment to which it is intended and/or detrimental.

Iron precipitation:

\[
2\text{Fe}^{3+} (\text{ferric}) + \text{H}_2\text{S} \rightarrow \text{S}^{2-} + 2\text{Fe}^{2+} + 2\text{H}^+ \quad (5)
\]

\[
\text{Fe}^{2+} (\text{ferrous}) + \text{H}_2\text{S} \rightarrow \text{FeS} \downarrow + 2\text{H}^+ \quad \text{pH} > 2 \quad (6)
\]

\[
\text{Fe}^{3+} (\text{ferric}) + 3\text{OH}^- \rightarrow \text{Fe(OH)}_3 \downarrow \quad \text{pH} > 2 \quad (7)
\]

\[
\text{Fe}^{2+} (\text{ferrous}) + 2\text{OH}^- \rightarrow \text{Fe(OH)}_2 \quad \text{pH} > 5 \text{ to } 7 \quad (8)
\]

When Fe³⁺ (ferric ions) are dissolved by the acid, iron precipitation and permeability reductions can occur after acidizing. The oxidation state of the iron controls precipitation. Ferric iron precipitates at a pH of about 2, while ferrous iron (Fe²⁺) precipitates at a pH of about 7. The actual values will depend on the concentrations of the ferrous and ferric ions. Because spent acid solutions rarely rise to a pH above 6, precipitation of ferrous iron is a little problem. Most spent acid at sour wells when pH < 2 and, in the presence of hydrogen sulfide, Fe³⁺ ions have to be controlled.

Iron sulfide:

\[
\text{Fe}^{2+} + \text{H}_2\text{S} \rightarrow \text{FeS} + 2\text{H}^+ \quad (9)
\]

Sulfur:

\[
\text{H}_2\text{S} + 2\text{Fe}^{3+} \rightarrow \text{S} + 2\text{Fe}^{2+} + 2\text{H}^+ \quad (10)
\]

\[
2\text{Fe}^{3+} + \text{S}^{2-} \rightarrow 2\text{Fe}^{2+} \quad (11)
\]

Sequestrering agents do not prevent sulfur precipitation in a sour environment.

**Reaction Mechanism of Sodium EDTA.**

\[
\text{C}_{10}\text{H}_{13}\text{Na}_2\text{O}_8 + \text{CaCO}_3 \rightarrow \text{C}_{10}\text{H}_{13}\text{CaNa}_2\text{O}_8 + \text{CO}_2
\]

\[
+ \text{H}_2\text{O} \quad (12)
\]

\[
\text{C}_{10}\text{H}_{13}\text{Na}_2\text{O}_8 + \text{FeS} \rightarrow \text{C}_{10}\text{H}_{13}\text{FeNa}_2\text{O}_8 + \text{S}^{2-} + 2\text{H}^+ \quad (13)
\]

\[
\text{Fe} + 2 + \text{S}^{2-} \rightarrow \text{FeS} \downarrow \quad \text{pH} > 2 \quad (14)
\]

Sulfur precipitates in this reaction. If the iron is reduced from +3 to +2, at a pH of about 2, ferrous sulfide will form. In this case, an iron control agent needs to be added, besides a sequestering agent that needs to control the ferrous iron so iron sulfide will not precipitate.

The treatment of sour wells, therefore, presents an entirely different type of precipitation problem. In addition to sulfur precipitation, by the reaction of Fe³⁺ with H₂S, the dissolved Fe²⁺ will precipitate also as ferrous sulfide upon spending of the acid. FeS will precipitate at a pH of an average of 1.9–2.

**Reaction Mechanism of Sodium Acetate.**

\[
\text{CH}_3\text{COOH} + \text{NaOH} \rightarrow \text{CH}_3\text{COONa} + \text{H}_2\text{O} \quad (15)
\]

\[
2\text{CH}_3\text{COONa} + \text{CaCO}_3 \rightarrow (\text{CH}_3\text{COO})_2\text{Ca} + \text{Na}_2\text{CO}_3 \quad (16)
\]

\[
2\text{CH}_3\text{COONa} + \text{FeS} \rightarrow (\text{CH}_3\text{COO})_2\text{Fe}^+ + \text{S}^{2-} + 2\text{H}^+ \quad (17)
\]

**Reaction Mechanism of Sodium Lactate.**

\[
\text{CH}_3\text{CH(OH)}\text{COOH} + \text{NaOH}
\]

\[
\rightarrow \text{CH}_3\text{CH(OH)}\text{COONa} + \text{H}_2\text{O} \quad (18)
\]

\[
2\text{CH}_3\text{CH(OH)}\text{COONa} + \text{CaCO}_3
\]

\[
\rightarrow (\text{CH}_3\text{CH(OH)}\text{COO})_2\text{Ca} + \text{Na}_2\text{CO}_3 \quad (19)
\]

\[
2\text{CH}_3\text{CH(OH)}\text{COONa} + \text{FeS}
\]

\[
\rightarrow (\text{CH}_3\text{CH(OH)}\text{COO})_2\text{Fe} + \text{Na}_2\text{CO}_3 \quad (20)
\]

The right combination of carboxylic acids contains many hydrogen ions in its solution, which is similar to a strong acid at the same concentration. Also, the new organic acid’s pH is similar to inorganic acid’s pH at the same concentration [pH was 0.6 for the new dissolver before adding the surfactant and 0.9 after adding the surfactant]. In a solution of the strong organic acid, the molecules are fully ionized. The byproduct of bicarbonates will increase the pH moderately while maintaining long time retardation to allow for a long time reaction lasting with carbonate and sulfide inorganic scales.

For sensitivity analysis of the new dissolver to determine the effect of each component in the composition, it was found that the first component (acrylic acid) was able to achieve 25.4% solubility ratio, while adding the second additive (lactic acid) increased the dissolution rate to record 78.6%, the third component enhanced the solubility efficiency to record 94.1%, and all the composition additives were able to achieve the high dissolution efficiency under the tested conditions of temperature and time.

### CONCLUSIONS

A new scale dissolver was presented with a high pH of 9.0 that showed a high dissolution performance for two types of field scales. The scale samples were collected from different fields and showed different compositions of magnetite, calcium carbonate, calcium sulfate, strontium sulfate, halite, barium sulfate, and kaolinite scales. Extensive laboratory work was executed to assess the new dissolver characterization and dissolution performance. The findings from the study can be drawn as follows:

- The dissolution efficiency of the new dissolver showed good results as the new solution dissolved sample 2 completely, where it dissolved 74.6% from sample 1 after 6 h at 70 °C, and the solubility was tested at 100 °C for 5 h and showed a dissolution rate of 78.2% for sample 1 and complete dissolution of scale sample 2.
- The new dissolver showed high overall performance for the two scale types over HCl (15 wt %), EDTA (20 wt %), and DTPA (20 wt %).
The results confirmed the safe use of the new dissolver regarding the dissolved solids precipitation problem and a low corrosion rate of 0.063 kg/m² at 6.9 MPa and 100 °C for 6 h.

Core flooding results showed enhancement in the core permeability from an initial value of 0.67 mD to 1.29 mD after the treatment to achieve a permeability ratio of 1.93.

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