Experimental evaluation of corrosion inhibitors for completion fluids in the petroleum production systems

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Abstract

Corrosion is the natural and continuous degradation of materials caused by either chemical, mechanical, or electrochemical reactions. Corrosion inhibitors may be added to the completion fluids to address corrosion problems efficiently. It is critical to add corrosion inhibitors in completion fluids, specifically under high-temperature conditions, since the corrosion rate is higher when the temperature is high. This corrosion process limits the life of the drill tools or the oil and gas well and causes formation damage. This research studied corrosion and corrosion inhibition treatments for five completion fluids, namely potassium chloride, sodium chloride, sodium bromide, calcium chloride, and calcium bromide. Phosphate and sulfite-based corrosion inhibitors were individually added to the completion fluids, and their corrosion properties were studied to tackle the corrosion issue. In addition, a mixture of phosphate-based and sulfite-based corrosion inhibitors in completion fluids was studied. Additionally, the experimental results recommend using divalent brines as they were identified as a better medium for lowering corrosion rate and conditions than the monovalent brines. A novel aspect of this study is that the materials leveraged for conducting experiments are also used in actual petroleum production field operations. The experiments demonstrate that the corrosion rate can be efficiently controlled at high temperatures in deeper wells.

Keywords Corrosion · Corrosion rate · Corrosion inhibitors · High temperature · Completion fluids

Introduction

Well completion process is one of the essential stages in oil and gas extraction. It refers to completing the well to become ready to produce oil and gas (NatGas 2013). In other words, it is transforming a petroleum well from being in the drilling phase to being in the production phase through the installation of production casing and other equipment (Iannuzzi 2011). Well completion can differ in its type based on specific conditions and restrictions. For instance, the selected well completion design should meet the descriptions of the type of hydrocarbon flowing into the wellbore, bottom hole assembly consideration, and tools to be used during the production stage (Repnu 2011). With that being said, well completions range in costs based on the formation type or environment and the location that it is placed (Zendehboudi and Bahadori 2015).

A completion fluid is a liquid free of solids that is fundamental to the completion process of an oil or gas well (Chandrasekaran 2017). These fluids are used for various purposes, including controlling the well pressure and preventing the well from a blowout or preventing the casing from collapsing under overpressure (Fink 2015). Another advantage that completion fluids have is enhancing the well's productivity by reducing damage to the producing zone and fixing and cleaning the wellbore during the completion phase. These completion fluids are most often brines that are nothing but a mixture of water and salt. The most used brine in the petroleum industry include chlorides, bromides, and formates. This fluid can be of any fluid density or have other flow characteristics used and chemically compatible with the reservoir formation and fluids within (Chandrasekaran 2010).

Completion fluid has several properties and characteristics that may affect its efficiency. Two of these properties are salinity and pH level. High salinity levels in a completion fluid containing inorganic salts like NaCl, KCl, and $CaCl_2$ will lead to the corrosion of drill tools and casing. This corrosion process is not just restricted to reducing the life of the

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drill tools or the oil and gas well; instead, it may also cause formation damage (Repnu 2011). Additionally, it is noted that the pH of these fluids falling in the range of 9–11 promotes corrosion avoidance. At the same time, fluids with very high pH must be avoided since they cause clotting of mud and deflocculating issues (Al-Hameedi et al. 2020). Research shows that high pH brines and incompatibility with formation can also cause formation damage (Amani et al. 2015; Al Moajil et al. 2017; Al-Yami and Nasr-El-Din 2009; Bennion et al. 1996; Retnanto and Yamin 1999; Retnanto et al. 2012). Hence, an ideal completion fluid should resist corrosion, operate well under different conditions, and ultimately prevent stress cracking in metals (Houchin et al. 1994).

Forming the completion fluid gets very challenging as they lack solids, but it also experiences more significant problems such as corrosion. By definition, corrosions are destructive material attacks by reacting with the environment, as illustrated in Fig. 1. In oil and gas wells, it is suspected that crude oil and natural gas carry various products that can be corrosive, such as CO_2, H_2S, and free water (Popoola 2013). Corrosions can also be affected by high pressure and temperature due to thermal expansion—and an increase in the temperature will cause a decrease in the brine's density. The density change will affect the well stability, especially if the brines cannot handle the formation pressure since high temperature and high pressure influence the corrosion rate (Chiriac 2014).

In order to recommend an inhibition treatment, a balance between cost and efficiency should be achieved. Combining both inhibitors will yield an efficiency of 62% at maximum concentrations. (Amani et al. 2016). Oxygen, water, and carbon dioxide play an important role in corrosion. The former is added in the present stage, whereas the latter is injected during the recovery operation, which can result in severe corrosion of the completing string. Under high-temperature high-pressure (HTHP) conditions, H_2S plays a fundamental role in corrosion dynamics.

To further comprehend the corrosion process, it is critical to understand the common elements that play a vital role in this process. The first element is dissolved oxygen. Since steel will be discussed, the reaction of iron with the oxygen dissolved in water results in the formation of rust called ferric hydroxide that does not dissolve in water. This process is described in the equation below:

$$2Fe^{++} + {}^1/_2 O_2 + H_2O = 2Fe^{+++} + 2OH^- \tag{1}$$
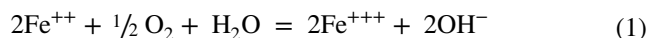
Corrosion continues in the case of an open system because of the presence of infinite oxygen. However, the rate of corrosion depends upon the concentration of oxygen. If the concentration is small, then the corrosion rate is greater, leading to rust-resistant to O_2 diffusion, and vice-versa if the concentration of O_2 is greater.

The second element is CO_2 dissolved in water, enhancing the corrosion rate. However, at equal quantities of both O_2 and CO_2, the reaction is weaker than that induced by the former. When CO_2 reacts with water, bicarbonate is formed, indicating the acidic behavior of CO_2 in water as depicted in the equation below:

$$2CO_2 + 2H_2O + 2e^- = 2HCO^{-3} + H_2 \tag{2}$$

This bicarbonate formed is prone to cause severe corrosion within the pipes due to its acidic nature, which lowers the pH of the aqueous phase. The increase in corrosive behavior of CO_2 should be bought to control as it leads to severe pitting attacks that are identified as one of the dominant causes of pipeline failures (Kalam et al. 2021).

Fig. 1 Corrosion as an electrochemical process (HyperPhysics)
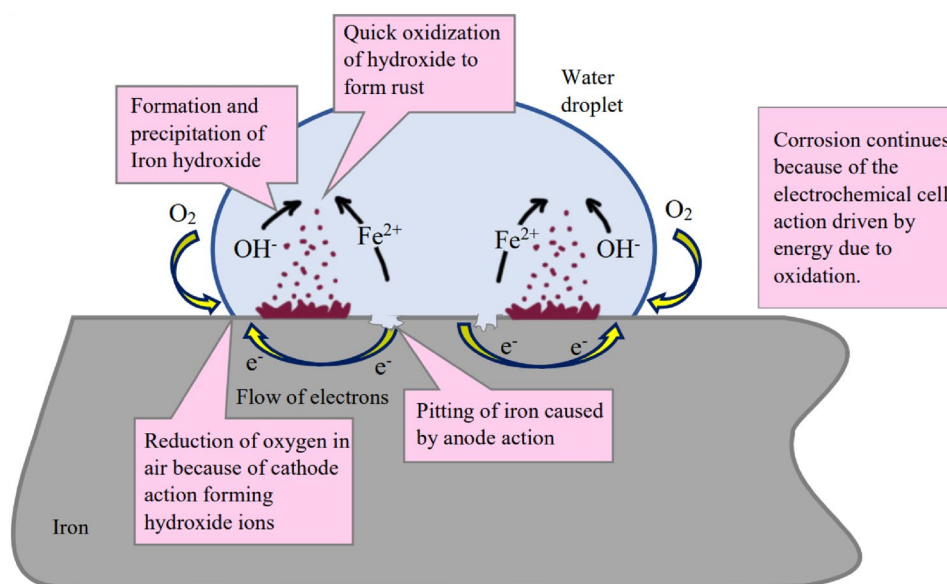
From the description of CO_2 and O_2, it is evident that their reaction with water will result in vigorous corrosion rates.

The third element is H_2S, which helps with corrosion if dampness exists. The chemistry reasoning behind the deterioration of iron in the presence of H_2S is that they are highly soluble in H_2O, which creates a weak dibasic acid in the presence of O_2. This reaction is represented as given in the following equation:

$$H_2S + \tfrac{1}{2} O_2 = H_2O + 2S \qquad (3)$$

This rate of corrosion depends strongly on the concentration of gas dissolved. The concentration of H_2S gas is inversely related to the corrosion process. If the amount of H_2S present is meager, the corrosion will be very severe. Still, if it is present in massive amounts, it will have a reverse effect, thereby inhibiting the corrosive reaction.

In the presence of both H_2S and CO_2, alongside having direct contact with O_2, the material will eventually crack and fail due to the severe localized corrosion damage formed (Al-Tammar et al. 2014). Sulfur compounds can show variation under different conditions within the reservoir, for instance, temperature, pressure, and pH. Based on these circumstances, they can provoke or inhibit bacterial growth and corrosion since it is known that sulfur compounds can impact the microbial communities by enhancing microbially dominated corrosion (Basafa and Hawboldt 2019).

Outside of the medium where the corrosion ring is present, an external factor that aggravates the corrosion process is the medium's temperature. The reaction rate increases with an increase in temperature, and the solubility of gases in water will decrease along with the viscosity. There are limitations to this as well. It is only possible if, for instance, in dissolved O_2, the corrosion rate will increase with rising temperature until it reaches the critical point and starts to decline again with O_2 solubility. However, in the case of an open system, the oxygen will escape, and in the opposing case, the trapped oxygen in the system will cause the corrosion rate to increase at high temperatures.

Corrosion inhibitors are chemical substances that are added to an environment suspected of potentially corroding materials, and it diminishes, delays, or even prohibits the occurrence of corrosion in that environment (Guo et al. 2017; Sherif 2014). Corrosion inhibitors encompass many conveniences as they eradicate corrosion-reducing chemicals that require significant alteration of pH values, eradicate hydrogen-sulfide and oxygen scavengers, and further eliminate aggressive species from the environment. Corrosion inhibitors are classified as cathodic, anodic, or mixed depending on whether they deal with a corrosion process based on cathodic or anodic reactions or a combination of both (Ramezanzadeh and Ramezanzadeh 2021).

Despite the excellent performance that corrosion inhibitors demonstrate concerning corrosion protection, it still introduces a high level of toxicity when utilized and is more expensive and economically inconvenient (Gece 2008). However, due to their previously mentioned attractive conveniences and future potential, extensive research is conducted to further enhance and extend their practicalities beyond their inconveniences. Some of the knowledge gaps of corrosion inhibitors include determining corrosion inhibitors suitable for multiple alloys. Also, the hydrodynamic influence on the functionality of corrosion inhibitors is not fully comprehended. Other pieces of knowledge are insufficient, such as the availability of corrosion inhibitors that deal with localized corrosion specifically, lack of understanding of mechanisms incorporated by corrosion inhibitors in acid cleaning, and preliminary assessment of the toxicity properties of corrosion inhibitors (Farahati et al. 2019).

Inhibitors are substances that can be added to a medium in small concentrations to reduce corrosion by either acting as a barrier by forming an adsorbed layer or retarding the cathodic, the anodic, or a combination of both processes (Palanisamy 2019). Research showed that halogen ions are well-known for inhibiting corrosions when dissolved in acid solutions. Their efficiency follows the order: I- > Br- > Cl- (Palanisamy 2019). Also, it was found that mixed inhibitors (anodic and cathodic) are less dangerous than pure anodic inhibitors, and they can decrease the corrosion intensity. They can control both anodic and cathodic corrosion. Some common inhibitors in this category are silicates and phosphates (Palanisamy 2019). Additionally, adding inhibitors when using low-density formate muds was recommended, as concluded from the metal-coupon-weight-loss method and CGF-II HTHP static corrosion tester (Xiangton et al. 2016).

Optimizing production is known to rely upon the use of completion brines. The completion fluid could either be monovalent brines or divalent brines. In an experiment performed by Aouda and his colleagues, they opted for monovalent brines like NaBr or NaCl because they have high chlorides, sulfates, and carbonates. However, divalent brines like $MgCl_2$ or $MgBr_2$ are avoided because they tend to cause severe formation damage due to the in situ precipitation of gypsum, limestone, and sodium chloride (Aouda et al. 2016). The complexity of how certain factors dynamically influence corrosion is presented in Table 1.

The ultimate objective of this research is to develop further the use of corrosion inhibiting materials in preventing and controlling the rate of degradation by enhancing the inhibition properties. In addition, a careful determination of the applicability of completion fluids is tackled along with their compatibility in petroleum production systems. The project examines different kinds of corrosion inhibitors currently available in the market and different types of completion fluids present in the actual petroleum field operation.

Table 1 Factors affecting corrosion

Factors	Definition
Electrochemical series	The reactivity of the metals decides the rate of corrosion
Impurities of metals	The presence of tiny electrochemical cells such as reactive metal and moisture starts the corrosion
Presence of electrolytes	Provide means of migration and continuous flow of electrons causing to speed up the corrosion process
Temperature gradient	The increase in temperature leads to the collision of particles due to energy gain, increasing the corrosion rate
Oxygen of concentration	An increasing supply of oxygen accelerates the rates of corrosion
pH	The acidity (H+) and/or alkalinity (OH–) of the environment contributes to the corrosion rates; as the pH increases, the lower the risk of corrosion
Salinity	Referred to Cl-ion content of the environment, especially when it reacts to other ions such as sulfates and oxides, to name a few
High pressure	At HTHP condition, records show that corrosion is high contrary to the ambient condition in its environment
Humidity	Moisture-saturated air reacts with oxygen and electrons on the surface of the metal. Therefore, the longer it is exposed, the faster it will corrode

Methodology

The corrosion rings are intended to measure the corrosive effect of completion or drilling fluid. The ring technique is specifically designed for the detection of corrosion types characterized by a metal loss, such as:

1. Placement of corrosion test plates in the pipeline to evaluate the corrosiveness of the environment
2. Installation and removal time of exposure downhole can be highly informative to corrosion rate determination
3. Understanding the type of corrosion and the causes behind it
4. Aid in choosing the proper remedial action

The corrosion test equipment must have the following condition to support the process of selection.

1. Ring Construction: machined to fit in the toolbox recess at the end of the pin
2. Ring Composition: steel should be identical to that of the pipe of the toll used

3. Ring Marking: the ring should be stenciled with a serial number for identification
4. Ring Preparation: the ring should be shipped to the field in a sealed plastic envelope to prevent initial metal degradation

The schematic illustrated in Fig. 2 below shows the flow process that accommodates the intents of this project.

Figure 3 shows the five completion fluids, i.e., calcium bromide, calcium chloride, sodium bromide, sodium chloride, and potassium chloride.

The HTHP corrosion tester shown in Fig. 4 is designed to perform corrosion tests under elevated temperature and pressure. The device can heat the sample to 400°F (204.4 °C) and apply up to 5000 PSI (34.5 MPa). Four samples can be tested simultaneously. All wetted components are made of corrosion-resistant stainless steel.

Operational Specification:

Maximum Pressure: 5000 PSI (34.5 MPa)

Maximum Temperature: 400 °F (200 °C)

Temperature Accuracy: ± 0.5 °C

Capacity: 4 sample bottles of 150 mL each
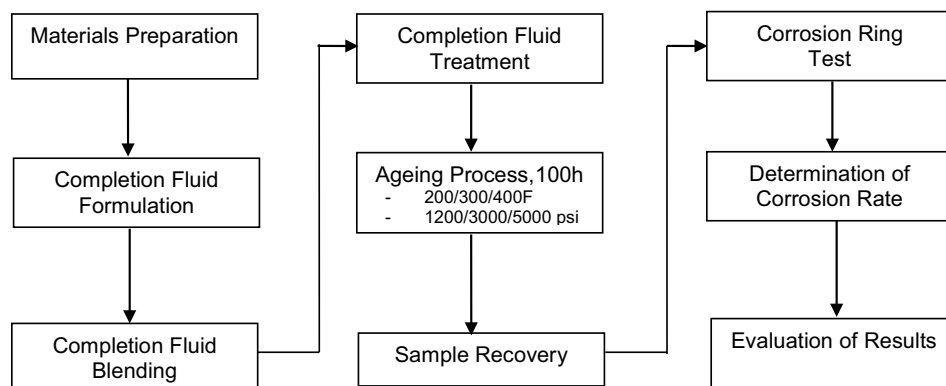
Agitator Speed Range: 0–100 RPM

Fig. 2 Flow process of the corrosion ring test

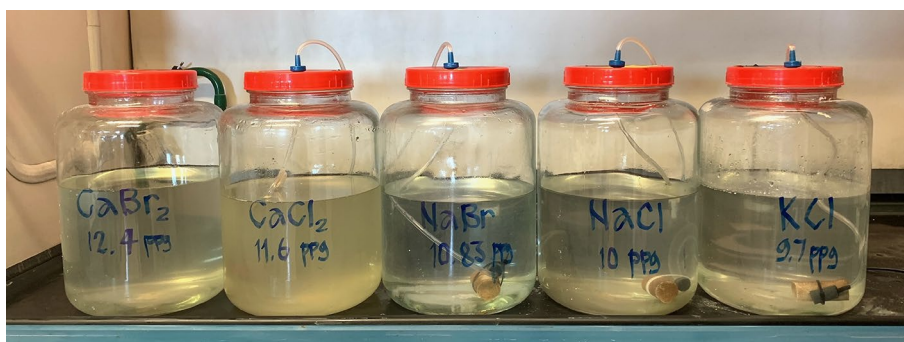**Fig. 3** Completion of fluids for the research project

Fig. 4 OFITE HTHP corrosion tester

After preparing the completion fluid, the treatment will simultaneously be tested during the test. Incubation of the corrosion ring as the sacrificial item will dictate if inhibition to corrosion is effective. It is projected that the corrosion rate will reduce upon incorporating a specific inhibitor concentration.

Initial actual test

Upon receiving the ring, a visual inspection should be done. If mechanical damage is observed, a "NO" test is required; otherwise, proceed with the test.

i. Oxygen Corrosion: scrape the scales formed on the ring's surface using the soft bristle brush. If the scales are attracted to the magnet, a confirmatory test is required, which is the acid test
ii. CO_2 Corrosion: 3–5 drops of iron sulfide detecting solution on the corroded area forms green discoloration, partially confirming the effect of CO_2
iii. H_2S Corrosion: 3–5 drops of iron sulfide detecting solution on the corroded area forms yellow discol-

oration and/or formation of miniature scrambled egg, partially confirming the effect of H_2S

Secondary actual test (cleaning)

Next, is a confirmatory test using 15% HCl acid, following the cleaning process using a soft bristle wire brush. The corrosion inhibitor can be used to minimize further corrosion.

After cleaning, the following are "confirmed if":

i. Oxygen Corrosion: pitted appearance was observed on the surface of the ring
ii. CO_2 corrosion: an effervescence was observed as the reaction of CO_2 gas to HCl and O_2, forming carbonic acid and a generalized/localized kind of corrosion
iii. H_2S corrosion: formation of yellow discoloration of the solution, evolution of rotten egg-like odor, and spatial cracking in the ring's surface

Completion fluid formulation and blending

Blending procedure

The weight based on the brine formulation being used is achieved using the table of formulations found in the handbook of different operating companies supplying in the chain. This calculation was done using the salt and water measured in pounds (lb). The concentration of salt in water (sol. Weight %) gives the maximum amount of solute (salt) in the solvent (water) and hence becomes a saturated solution as represented below:

$$\text{Sol, wt\%} = \frac{\text{salt(lb)}}{\text{salt (lb)} + \text{water(lb)}}$$

Table 2 shows the solution weight % and saturation point per weight of each completion fluid at ambient temperature.

Table 2 Maximum solubility of salt in water/bbl @ 25 °C

Salt name	Sol, wt.%	Salt, lb	Water, lb	Density, ppg	Sp.Gr.	pH
Sodium chloride, NaCl	26.00	109.00	311.00	10.00	1.20	9.9
Potassium chloride, KCl	24.00	98.00	309.00	9.70	1.16	9.9
Sodium bromide, NaBr	46.00	245.00	288.00	10.83	1.30	9.9
Calcium chloride, CaCl$_2$	40.00	198.00	298.00	11.6	1.39	9.9
Calcium bromide, CaBr$_2$	57.00	366.00	277.00	12.4	1.49	9.9

1. Measure the amount of salt to be used in grams equal to 1 lb/bbl. to the completion of water's volume in ml. (Note that water density is 1 g/ml)
2. Pour the water into a clean container, then turn the mixer on
3. Add the salt to the vortex of the solution and wait for 10 min or until all solute dissolves

Table 3 Corrosion rate conditions

Type	Range (lb/ft^2/year)	Range (milli-inch per year)
Low	0.0–2.0	0.0–50.0
Medium	2.1–4.0	50.1–100.0
High	4.1–6.0	100.1–150.0
Severe	6.1 and above	150.1 and above

Test procedures

1. Material preparation starts with completion fluid, selecting the appropriate sizes and coupons of corrosion plates, availability of salts, and calibrated equipment
2. Formulate the brines based on their maximum weight capacity and saturation
3. After setting the formulation matrix, separately blend all completion fluid variables. Store all samples in sealed and room temperature conditions to avoid brine crystallization
4. Properties such as weight, pH, viscosity, and other important factors will be analyzed
5. Each brine will be treated in six different batches based on percentage, type, and ratio
6. All samples of the corrosion ring with corresponding completion fluid will then undergo the aging process using the roller oven or directly to the HTHP corrosion tester, depending on the factors and restrictions at high-temperature and high-pressure conditions
7. After the test matures, corrosion plates will be recovered and tested right away to prevent further surface deterioration
8. The test procedure will follow the NACE SP0775-2013(2.3) and OFITE procedures

9. Lastly, after the corrosion rate has been determined, an evaluation of the effectivity of inhibitors will be concluded based on the tabulated results
10. Finally, a recommendation will be given if further options must be considered

Results and discussion

Determining the corrosion rate helps in knowing the corrosion category it will belong to, as shown in Table 3, where the corrosion rate will be low if the corrosion rate is in the range of 0.0–5.0 mpy. Table 3 addresses the four corrosion types alongside their corresponding corrosion rates.

The following equations were used to obtain the required data from experimental results obtained:

$$\text{Weight loss (grams)} = \text{Initial weight} - \text{Final weight} \quad (4)$$

$$\text{Exposure Time (hrs)} = \text{Date and Time out} - \text{Date and Time in} \quad (5)$$

$$\text{Corrosion Rate}\left(\text{lbs/ft}^2 - \text{year}\right) = \kappa \times \frac{\text{Weight loss}}{\text{Exposure Time}} \quad (6)$$

$$\text{Corrosion Rate(milli} - \text{inch per year)} = \kappa \times \frac{\text{Weight loss}}{\text{Exposure Time}} \times 24.62 \quad (7)$$

$$\text{Inhibitor Efficiency, } \% = \frac{\text{corrosion rate without inhibitor} - \text{corrosion rate with inhibitor}}{\text{corrosion rate without inhibitor}} \times 100 \quad (8)$$

a. Before   b. After

Fig. 5 Corrosion plates in potassium chloride (KCl)

Figure 5 displays the collected outcomes of corrosion plates before and after initial and secondary actual tests for potassium chloride (KCl) as an example.

The corrosion plates were inserted in the KCl brine samples with 1.5%, 3%, and 4.5% phosphate-based corrosion inhibitor for about 100 h at 280 °F. After this period, the plates were removed. Figure 5 shows the pictures of the weighed and recorded plates as the initial weight before the testing procedure using 15% HCl and steel wool. After the cleaning process, the plate was weighed and recorded as the final weight.

The duration of exposure, loss of weight, and the K-factor were used to determine the corrosion rates. The value obtained was classified as low, medium, high, or severe corrosion. As shown in Table 4, without any corrosion inhibitors, the corrosion was severe when the base used KCl and NaCl as they were more significant than 150.0 mpy. However, the severity lowered when the base was NaBr, where it was recorded as high, then further changed to divalent brines, i.e., CaCl$_2$ and CaBr$_2$. In the case of divalent brines, the former exhibited high corrosion, whereas the latter was of medium severity based on the range of corrosion rates as displayed in Table 3 above.

Equation (4) through Eq. (8) were used to compute the results, as shown in Table 5 through Table 7 below.

After the exposure, the cleanup of the corrosion plates was followed by weighing these, which allowed for determining the weight loss using Eq. (4) and the corrosion rates

Table 4 Corrosion rate for all the completion fluids

		Salts	Ref#	Weight (grams)			Exposure	K Factor	Corrosion rate (Ib/ft^2/year)	Corrosion rate (mpy)	Corrosion rate conditions
				Initial	Final	Loss	(hrs)				
A	Base	KCl	8011	20.10	18.00	2.10	100.0	440.6	9.26	227.99	Severe
B	Base	NaCl	7898	20.64	19.03	1.61	99.8	440.6	7.09	174.60	Severe
C	Base	NaBr	7900	21.30	20.11	1.19	99.6	440.6	5.27	129.77	High
D	Base	CaCl$_2$	8012	19.97	19.01	0.96	99.4	440.6	4.25	104.58	High
E	Base	CaBr$_2$	7950	20.25	19.35	0.90	97.5	440.6	4.07	100.29	Medium

Table 5 Corrosion rate for potassium chloride (KCl) with phosphate-based corrosion inhibitor and sulfite-based corrosion inhibitor

KCl	Based inhibitors,%		Ref #	Weight (grams)			Exposure	Corrosion rate (lb/ft^2/year)	Corrosion rate (mpy)	Inhibitor efficiency	Corrosion rate conditions
	Phosphate	Sulfite		Initial	Final	Loss	(hrs)				
A	–	–	8011	20.10	18.00	2.10	100.05	9.26	227.99	–	Severe
AC1.5	1.5	–	7746	19.93	18.19	1.75	96.2	8.01	197.18	13.5	Severe
AC3.0	3.0	–	8037	20.10	18.65	1.45	96.4	6.61	162.82	28.6	Severe
AC4.5	4.5	–	8038	20.09	19.00	1.09	96.5	4.96	122.23	46.4	High
HighAO1.5	–	1.5	8039	20.24	18.44	1.80	96.8	8.20	201.77	11.5	Severe
AO3.0	–	3.0	8040	20.36	18.79	1.56	97.1	7.10	174.74	23.4	Severe
AO4.5	–	4.5	8041	20.29	18.98	1.31	97.4	5.91	145.60	36.1	High

using Eqs. (6) and (7). As shown in Table 5, the corrosion conditions are the same using both inhibitors. However, the corrosion rate is lower when a sulfite-based corrosion inhibitor is used than a phosphate-based corrosion inhibitor. Phosphate-based corrosion inhibitor costs $800/drum, and sulfite-based corrosion inhibitor costs $250/drum. Since the corrosion condition is severe when low concentrations of the inhibitors are used, *i.e.*, 1.5% and 3%, it is better to use 4.5% of the inhibitor to achieve a lower corrosion rate. The phosphate-based corrosion inhibitor is costlier than the sulfite-based corrosion inhibitor. Hence, for this case, a sulfite-based corrosion inhibitor is a better inhibitor for KCl as the base sample.

The efficiency of the corrosion inhibitors, phosphate-based corrosion inhibitor, and sulfite-based corrosion inhibitor was compared by plotting the corrosion rates against the concentration of based inhibitors, as shown in Fig. 6. The corrosion rates were lower when a phosphate-based corrosion inhibitor was used as the inhibitor. High corrosion was obtained from the severe corrosion conditions when 4.5% of the inhibitors were used. Using a phosphate-based corrosion inhibitor is technically feasible since it lowers corrosion, but a sulfite-based corrosion inhibitor is a better option in this case.

Practically, the cost of a 1.5% of phosphate-based corrosion inhibitor will be the same as a 4.5% of sulfite-based corrosion inhibitor. Considering inhibitors' efficiency using Eq. (8), at 1.5%, the efficiency of the former is 12.5%, and that of the latter is 36%. Since the difference is enormous, then sulfite-based corrosion inhibitor at 4.5% should be a better option.

The same procedure is done with NaCl as the base sample. Corrosion conditions improve when phosphate-based corrosion inhibitor is used but remain high when it is at 1.5% concentration, and it goes to medium severity at both 3.0%
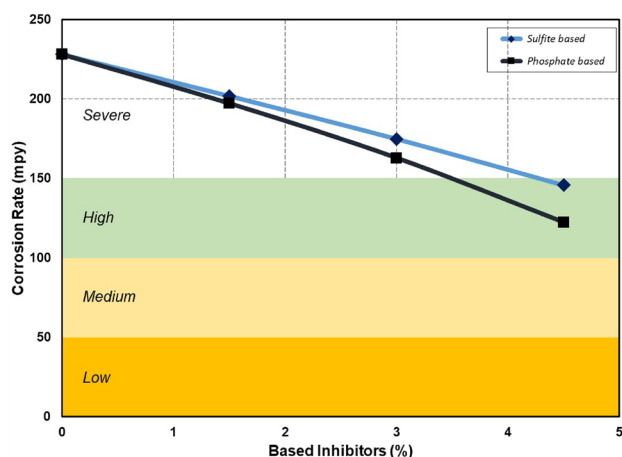
and 4.5% concentration. On the other hand, when sulfite-based corrosion inhibitor is used, the severity remains high throughout different concentrations. Nevertheless, a sulfite-based corrosion inhibitor may be used at a higher concentration to reduce severity conditions, and economically, it is also considered a better option.

When NaBr is used as the base sample, the corrosion conditions reduce from high to medium and low when 1.5%, 3%, and 4.5% phosphate-based corrosion inhibitors are used, respectively. However, in sulfite-based corrosion inhibitor, the corrosion condition is high when 1.5% is added to the sample but lowers to medium when 3% and 4.5% are added. Phosphate-based corrosion inhibitor is a better option since it significantly reduces corrosion rates and is technically feasible. Still, even though the corrosion rates are different, with the severity being the same, economically, a sulfite-based corrosion inhibitor at low concentration will be considered a better inhibitor for NaBr as the base.

The inhibitor efficiency can reach up to 61% using phosphate-based corrosion inhibitors at high concentrations. Economically, the sulfite-based corrosion inhibitor is three times less costly than the phosphate-based corrosion inhibitor. The efficiency of the former is 21% at 1.5% concentration, and that of the latter is 61% at 4.5% concentration. Since the difference is significant, a sulfite-based corrosion inhibitor at 4.5% is recommended.

When $CaCl_2$ is used as the base sample, corrosion conditions reduce from the medium when 1.5% and 3% of phosphate-based corrosion inhibitor are used but to lower requirements when 4.5% of it is added to the base. The same trend is observed in the case of sulfite-based corrosion inhibitors, as can be seen in Table 6. The corrosion rates are lower for phosphate-based corrosion inhibitors, but very little difference. The sulfite-based corrosion inhibitor will be regarded as a better inhibitor for $CaCl_2$ as the base sample because the corrosion conditions remain the same in both cases. For phosphate-based corrosion inhibitors, the inhibitor efficiency can reach up to 61%, whereas sulfite-based corrosion inhibitors can reach 52%. At 1.5%, the efficiency of the former is 17%, and that of the latter is 52%. Considering the vast difference, sulfite-based corrosion inhibitor at 4.5% should be a better option.

In Fig. 7, it can be analyzed that the trend observed between the two inhibitors is very close and similar to each other. The sulfite-based corrosion inhibitor is a better choice with this bit of difference because of its feasibility.

When $CaBr_2$ is used as the base sample, corrosion conditions reduce from the medium when 1.5% and 3% phosphate-based corrosion inhibitors are used to lower requirements when 4.5% of it is added to the base. The same trend is observed in the case of sulfite-based corrosion inhibitors. The corrosion rates are lower for phosphate-based corrosion inhibitors but with a minimal difference compared with

Fig. 6 Corrosion rate versus inhibitor's concentration for potassium chloride (KCl)

Table 6 Corrosion rate for calcium chloride (CaCl$_2$) with phosphate-based corrosion inhibitor and sulfite-based corrosion inhibitor

CaCl$_2$	Based inhibitors,%		Refs	Weight (grams)			Exposure (hrs)	Corrosion rate (lb/ft^2/year)	Corrosion rate (mpy)	Inhibitor efficiency (%)	Corrosion rate conditions
	Phosphate	Sulfite		Initial	Final	Loss					
D	–	–	8012	19.97	19.01	0.96	99.40	4.25	104.58	–	High
DC1.5	1.5	–	7935	21.35	20.57	0.78	98.1	3.52	86.63	17.2	Medium
DC3.0	3.0	–	7938	20.68	20.19	0.49	98.3	2.19	53.89	48.5	Medium
DC4.5	4.5	–	7899	20.14	19.77	0.37	98.4	1.66	40.83	61.0	Low
DO1.5	–	1.5	7870	21.24	20.40	0.84	98.5	3.77	92.91	11.2	Medium
DO3.0	–	3.0	7869	21.31	20.72	0.59	98.7	2.64	64.89	38.0	Medium
DO4.5	–	4.5	7930	21.28	20.83	0.45	98.8	2.01	49.42	52.7	Low
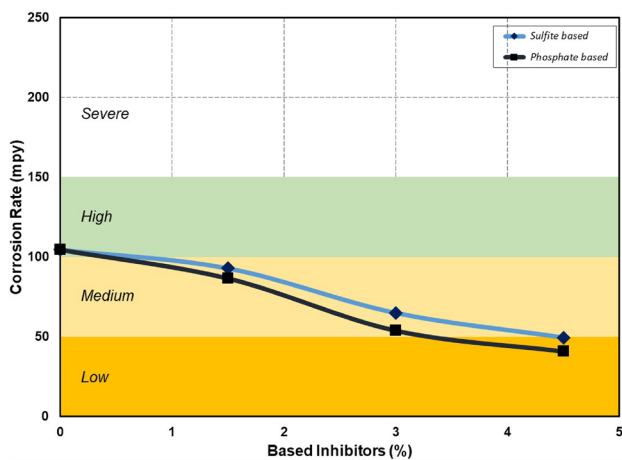
Fig. 7 Corrosion rate versus inhibitors concentration for calcium chloride (CaCl$_2$)

solutions where sulfite-based was added. Hence, a sulfite-based corrosion inhibitor will be considered a better inhibitor for CaBr$_2$ as the base sample because the corrosion conditions remain the same in both cases.

After the individual analysis of each brine sample with sulfite-based corrosion inhibitor and phosphate-based corrosion inhibitor, the next part of the testing involved an equal mixture of these two corrosion inhibitors. For instance, for a 1.5% concentration of the inhibitor, 0.75% of sulfite-based corrosion inhibitor and 0.75% of

phosphate-based corrosion inhibitor were added to the base sample. The same idea was used for adding 3% and 4.5% of corrosion inhibitors. For this study, only NaCl and CaCl$_2$ were used. When NaCl is used as the base sample, the corrosion rate conditions reduce from high to medium, as shown in Table 7 in the presence of inhibitors. Here, the corrosion condition was severe without any addition of an inhibitor. But as an equal mixture of 0.75% and 1.5% of each inhibitor were added, the corrosion rate dropped to 102–125 mpy, corresponding to high corrosion conditions. But when 2.25% of each inhibitor was added, the corrosion rate lowered to 94.7 mpy, which belonged to the medium corrosion type. The option was somewhat a more acceptable and feasible choice.

As shown in Fig. 8, the line corresponding to the 50:50 ratio lies between the pure phosphate-based corrosion inhibitor and pure sulfite-based corrosion inhibitor lines. The result is thus a better illustration of using each inhibitor in equal amounts, thereby enhancing lower corrosion conditions feasibly.

Figure 9 shows the corrosion inhibitor efficiency against the concentration of based inhibitors. This graph quickly illustrates the performance of each inhibitor and the 50:50 proportion in the mixture of phosphate-based corrosion inhibitor and sulfite-based corrosion inhibitor when the same amount of it is added to the NaCl brine. It is known that phosphate-based corrosion inhibitor is three times more expensive than sulfite-based corrosion inhibitor.

Table 7 Corrosion rate for sodium chloride (NaCl) with a mix of 50% phosphate-based corrosion inhibitor and 50% sulfite-based corrosion inhibitor

| NaCl	Based inhibitors,%		Refs	Weight (grams)			Exposure (hrs)	Corrosion rate (lb/ft^2/year)	Corrosion rate (mpy)	Inhibitor efficiency (%)	Corrosion rate conditions
	Phosphate	Sulfite		Initial	Final	Loss					
B	–	–	7898	20.64	19.03	1.61	99.83	7.09	174.60	–	Severe
B1.5–50:50	0.75	0.75	8019	20.03	18.91	1.12	99.0	4.99	122.83	29.7	High
B3.0–50:50	1.50	1.50	8020	20.35	19.41	0.94	99.1	4.17	102.56	41.3	High
B4.5–50:50	2.25	2.25	8021	20.02	19.15	0.87	99.1	3.85	94.70	45.8	Medium
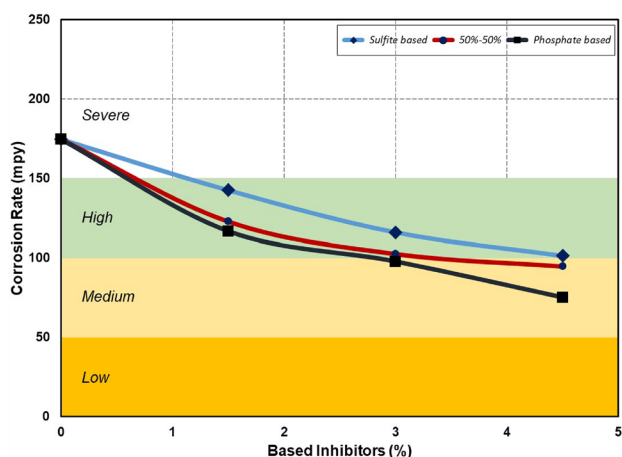
Fig. 8 Corrosion rate versus inhibitors concentration for NaCl with 50–50%
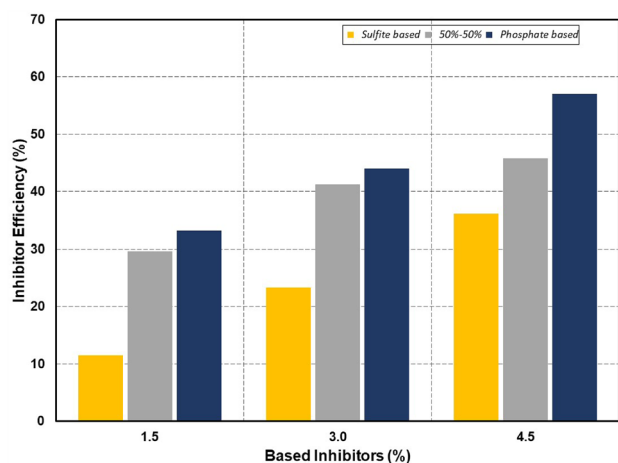

Fig. 9 Corrosion inhibitor efficiency versus inhibitors concentration for NaCl with 50–50%

Figure 9 shows that the efficiency of phosphate-based corrosion inhibitors is very similar to that of the mixture of the two inhibitors. In simpler words, the efficiency of the mixture of 0.75% of each is very close to 1.5% of phosphate-based corrosion inhibitors. Hence, a phosphate-based corrosion inhibitor could be a better option. The same trend is observed when 3% of inhibitor is added. For 4.5% of based inhibitors, the efficiency of phosphate-based corrosion inhibitors is 57%, and that of the mixed inhibitors is 46%. This difference is slightly more significant so that the mixed inhibitor would be more cost-effective and feasible in this case.

In the case of $CaCl_2$ used as the base sample, the corrosion rate conditions are better than the former, as the corrosion condition was high without adding an inhibitor. Nevertheless, as an equal mixture of 0.75% and 1.5% of each inhibitor were added, the corrosion rate dropped below

95 mpy, corresponding to medium corrosion conditions. However, when 2.25% of each inhibitor was added, the corrosion rate lowered to 43.52 mpy, which belonged to the low corrosion type. Instead, the outcome was a more acceptable and feasible choice of using inhibitors and a base sample.

The performance of this equal mixture of both corrosion inhibitors is very close to that of phosphate-based corrosion inhibitors. Only 2.25% of each inhibitor was required to obtain a lower corrosion condition. The finding is an excellent choice because using phosphate-based corrosion inhibitors alone was not economically feasible. However, it was highly efficient, as seen in this paper's earlier sections. The sulfite-based corrosion inhibitor is a better choice with slight differences because of its feasibility.

It was concluded that the efficiency of phosphate-based corrosion inhibitors is very similar to the mixture of two inhibitors, except in the case of 1.5%. For 4.5% of based inhibitors, the efficiency of phosphate-based corrosion inhibitor is 61%, and that of the mixed inhibitors is 58%. This difference is minor, so that the mixed inhibitor would be more cost-effective and feasible in this case. The same is applicable for 3%. However, if the 1.5% case is considered, then the difference in efficiency is approximately 5%. For phosphate-based corrosion inhibitor, it is 17%, and that of 50:50 is 12%, whereas for sulfite-based, it is 11%, all leading to medium corrosion conditions; hence, sulfite-based is economically a better option.

Regarding the uncertainties associated with the results mentioned above, some sources of error can lead to the rise of uncertainties. These can be limitations in the used devices. For instance, the weighing scale measures the weight with an accuracy of 0.01 g, and the temperature accuracy is ± 0.5 °C. Moreover, there might be systematic errors with the temperature at which the oven is set, which is an error related to how the oven is calibrated. And lastly, the conditions where the corrosion plates were put in might not be exactly the same as how they are in the petroleum production system, especially when it comes to other gases, humidity, and so on. Hence, the results obtained are considered accurate as it imitates some of the conditions and, most importantly, the HPHT conditions. Concerning the experiments' repeatability, each set of experiments was done twice. The results show a discrepancy of less than 2%.

Conclusions

This research concentrates on studying corrosion and its respective corrosion inhibition treatments for completion fluids such as potassium chloride, sodium chloride, sodium bromide, calcium chloride, and calcium bromide. Salinity and pH level are two properties identified as affecting the efficiency of the completion fluids. Various corrosion

inhibitors were examined for several completion fluids under HTHP conditions.

1. Based on the results of this testing, the phosphate-based corrosion inhibitor is the most effective inhibitor at the given concentrations to reduce corrosion
2. However, the selection factor in selecting the treatment is not dependent only on the efficiency, rather it is also inclusive of costs. Sulfite-based is less expensive than the phosphate-based inhibitor
3. Considering this, a mixture of phosphate-based corrosion inhibitors and sulfite-based corrosion inhibitors seems the most economical and efficient among the tested inhibitors for different completion fluids
4. This study involved the use of monovalent and divalent brines. The divalent brines were a better medium for lowering corrosion rate and conditions than the monovalent brines obtained from the corrosion rate and type results
5. In the future, corrosion rates under low (180 °F) and medium (230 °F) temperature and pressure conditions will be determined to evaluate the effect of temperature and pressure under varying conditions. The most effective corrosion inhibitor can be chosen based on the results obtained for these conditions

Declarations

Conflict of interest On behalf of all the co-authors, the corresponding author states that there is no conflict of interest.

Ethical approval The submitted work is original and has not been published elsewhere in any form or language.

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