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Corrosion Inhibitors for Jet Pump Applications

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ABSTRACT

Jet pumps present unique challenges for corrosion inhibitors since they must perform in high temperatures, pressures, and shear conditions. These chemistries need to also be compatible with the power fluids and not cause any ancillary problems such as foaming or emulsions in the production system. These compatibility challenges are amplified with produced water with extremely high total dissolved solids (TDS) brines such as those encountered in the Bakken. Production from these wells often require the injection of fresh water to mitigate the formation of halite precipitates. Continuous corrosion inhibitor applications into systems where the produced high TDS water rates are low, can lead to emulsions, particularly if the power fluids are not heated. For Jet pumps with concentric string geometries set up to produce the fluids and gases separately, a batch treating corrosion inhibitor was developed to treat the outer gas annulus area. This paper describes laboratory testing results for various corrosion inhibitors used in jet pump applications, including products for continuous and batch treatment, and discusses the results obtained from field applications.

Key words: Jet Pump, Bakken, Corrosion Inhibitors, High TDS, Emulsions

INTRODUCTION

In the oilfield, selection of an artificial lift mechanism is dependent on various factors including cost, expected fluid volume, viscosities, sand/solids production and gas-oil ratio (GOR). In the Bakken, the vast majority of the artificial lift pumps are of the rod pump type. For higher fluid volume wells, electrical submersible (ESP) pumps are commonly used, however these pumps are susceptible to gas lock-up in systems with high levels of gas production and accelerated wear in wells with high sand/solids production.¹ For these wells, Jet pumps have been successfully used as means for artificial lift.²

For corrosion inhibitors, each artificial lift mechanism present different challenges in terms of shear, temperature, mixing dynamics, as well as the potential effects these products may have on the system, including potentially increasing emulsion tendencies. In the Bakken, many of the wells use freshwater injection to mitigate the formation of halite, including the wells that use jet pumps as an artificial lift mechanism. This results in fluctuations in both the final produced water salinities and in some cases the water oil ratios produced. For corrosion inhibitors, high salinities in the produced water present a solubility challenge, and low water cuts can lead to difficulties in water oil separation,³ especially if no heater treaters are available. This is especially true for jet pump applications due to the high shear that is generated by the jet pump itself. In addition, emulsions have been linked to reduced corrosion inhibitor performances in CO₂ systems.⁴

Corrosion inhibitor solubility in jet pump applications is particularly challenging since the typical method of application is to dose the product into the high-pressure discharge of the pump used to inject the lift fluids. This fluid is typically power oil but may be comprised of a water/oil mix when power oil is in short supply. As a result, the applied corrosion inhibitors must perform and remain soluble/dispersible in both the power fluids as well as in the produced fluids, which can cover a wide variety of salinities and water cuts. These variations in water cuts, coupled with high shear, can significantly impact emulsions by the presence of corrosion inhibitors.⁵

To address the dispersibility and emulsion challenges, various corrosion inhibitors were tested in the laboratory for continuous application into the power fluid using well established protocols for corrosion testing². Testing included Rotating Cylinder Electrode (RCE) and Autoclave tests. The top four performing products were field trialed and evaluated by monitoring various key performance indicators including Corrosion Rates via Electrical Resistance (ER) probes, Iron counts, Amine residuals, and the Basic Sediment and Water (BS&W) of the produced fluids.

Another corrosion challenge for jet pumps is the outer casing in jet pumps with concentric strings (figure 1). Traditional jet pumps inject the power oil through the tubing string and the production fluids and gas, along power oil is produced up the annulus. Concentric string jet pumps are constructed with dual casings that allow production of the power oil and produced liquids up an inner annulus, while the gasses are produced up an outer annulus. To protect this outer annulus, a periodic treatment with a batch corrosion inhibitor was determined to be the most effective method for providing corrosion protection in this area of the wells.

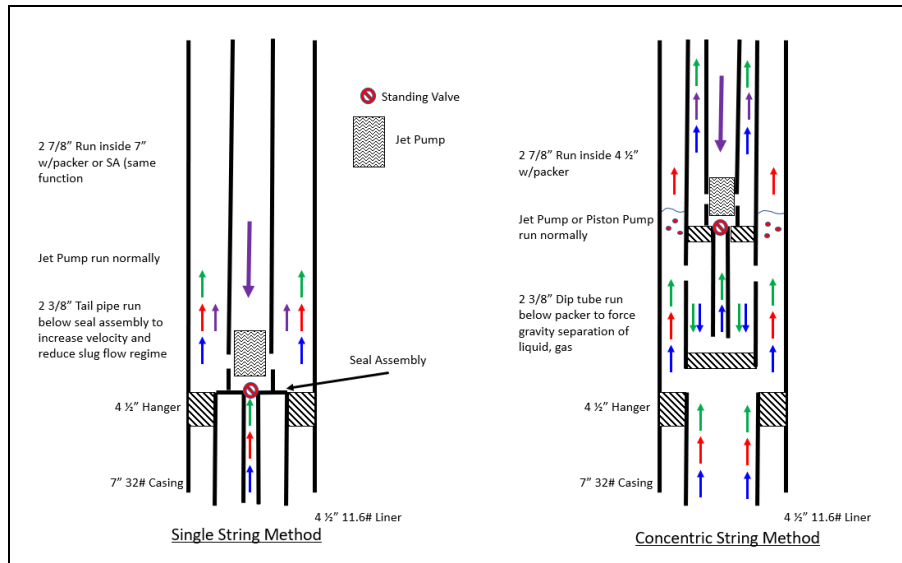


Figure 1: Traditional vs Concentric String Jet Pumps

To select the best product for this application, laboratory batch corrosion performance tests using a dip-and-drip technique were used to evaluate the inhibitor persistency. Due to the sour nature of the wells where concentric string jet pumps were installed, the corrosion inhibitors selected were also tested in the presence of H_2S . After implementation of the batch treatment program for the outer gaseous casings, pitting failures were drastically reduced from every 5 month to over a year without any failures.

EXPERIMENTAL PROCEDURE

Compatibility Testing

Compatibility tests were conducted to select the products for a field trial. Initial screening began by conducting synthetic field water compatibility testing with corrosion inhibitors from a test kit. Compatibility testing was conducted at 10 ppm, 100 ppm, 1000 ppm, and 1% concentrations and placed into an oven at 160°F (71°C) for 24 hours. The water composition used for testing is listed in table 1.

Table 1
Field water composition

Na^+	Mg^{2+}	Ca^{2+}	Sr^{2+}	Ba^{2+}	Fe^{2+}	HCO_3^-	SO_4^-	Cl^-
87090	1471	19520	2470	30.59	109.40	244	55.30	177550

Of the screened products, five products listed in table 2 were clear and showed no signs of incompatibility after 24 hours.

Table 2
Products compatible with synthetic brine

Product	Active Ingredients
A	Coco, Benzyl, and Pyridine Quat Blend (salted)
B	Fatty Alcohol, Benzyl, and Coco Quat Blend (salted)
C	Ethoxylated Tallow Alkyl Amine blend
D	Ethoxylated Amines
E	Benzyl Quat (salted) and Ethoxylated Tallow Alkyl Amine blend

Based on the compatibility results, performance tests were conducted on these products including RCE and Autoclave testing.

Performance Testing

RCE Testing

A standard RCE test was performed using an ACM Potentiometer to screen potential corrosion inhibitor chemistries under the typical surface flow conditions using linear polarization resistance (LPR). A summary of the test conditions is listed in table 3 and are designed to simulate conditions encountered on surface gathering lines.

Table 3
RCE Test Conditions

Test Products	A, B, C, D, and E
Concentration	20 ppm (total fluids)
Test Fluids	50% Synthetic brine / 50% Field crude
Shear	7.94 Pa (2.8 m/s)
Temperature	160°F (71°C)
Test Duration	18 Hours
Gas	100% CO ₂ Sparge
Initial pH	5.0
Coupon material	UNS G10180 polished to 600 grit finish

Results for RCE testing are provided in figure 2 and table 4. The results show the two best performers were products D and E, however all products provided > 97.8% protection at 50 ppm.

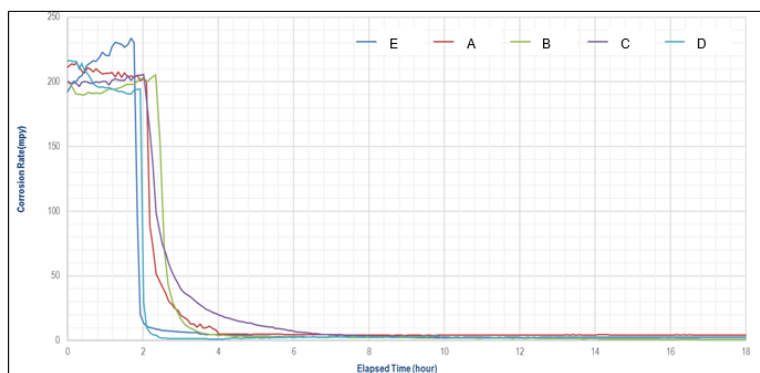


Figure 2: RCE LPR Results

Table 4
RCE Test Results Summary

Product	Avg Un-Inhibited Corrosion Rate	Inhibited Corrosion Rate	% Inhibition
A	207.18 mpy (5.26 mm/y)	4.52 mpy (0.11 mm/y)	97.82%
B	196.04 mpy (4.98 mm/y)	2.78 mpy (0.07 mm/y)	98.58%
C	200.84 mpy (5.10 mm/y)	2.72 mpy (0.07 mm/y)	98.56%
D	200.55 mpy (5.09 mm/y)	3.12 mpy (0.08 mm/y)	98.44%
E	216.82 mpy (5.51 mm/y)	2.43 mpy (0.06 mm/y)	98.88%

Autoclave Testing – Continuous Injection

Since no significant performance differences were observed between the RCE test results, all products were selected to move onto autoclave testing to evaluate the products by simulating high pressure and high temperatures typical of downhole conditions.

Tests were performed using a fluid matrix consisting of synthetic brine and field crude. Test fluids were sparged with CO₂ for 1 hour and treated with inhibitor (except blank) prior to transferring to the autoclave. Four carbon steel UNS G10180 coupons, polished to 600 grit finish, were mounted on the internal support spindle in a rotating cage arrangement and set to a height that ensures the coupons would be immersed in the aqueous phase. After assembling and sealing the autoclave, sparging with CO₂ was continued for 30 minutes through a dip tube, and the head space vented to displace any remaining oxygen. The headspace vent then sealed, and the system pressurized and heated to the planned test conditions (table 5). These conditions sealed and maintained over a three-day period.

Table 5
Autoclave Conditions for Continuous Injection

Test Products	A, B, C, D, and E
Concentration	150 ppm (total fluids)
Test Fluids	50% Synthetic brine / 50% Field crude
Shear	10 Pa
Temperature	260°F (127°C)
Gas Composition	40 psi (2.76 bar) CO ₂
Test Duration	72 Hours
Initial pH	5.0
Coupon material	UNS G10180 polished to 600 grit finish

At the end of the test, the autoclave cells were cooled, depressurized, and the coupons retrieved and cleaned with Super Clark's solution. The corrosion rate was then established by weight loss measurement.