Field-Testing Corrosion Inhibitors in Oil and Gas-Gathering Systems

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It is often desirable to test different inhibitors in the field to determine their efficacy. This article addresses a practical approach for conducting field tests of corrosion inhibitor products. Topics include chemical injection, corrosion monitoring, establishing baseline conditions, interpreting results, and determining cost performance for the products.

With many competing inhibitor products on the market today, it is important to be able to test different products under field conditions. This can be done easily and effectively once monitoring probes are in place at appropriate locations in the piping.

An earlier *MP* article discusses monitoring techniques and coupon/probe installations.[1] This article recommends monitoring locations and techniques for field testing of inhibitor effectiveness. Figure 1 shows a typical installation of a monitoring probe.

Conducting Field Tests

SELECTING LINES FOR TESTING

Many factors must be considered when conducting a field test or performance demonstration of corrosion inhibitors. The line selected for testing must have process conditions, which are representative of or slightly more severe than field averages. On crude oil production lines, the water cuts (percentage of water) should be roughly equivalent to those of the field. The fluid velocities and concentrations of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) should also be equivalent to field averages. Corrosion inhibitor injection and corrosion monitoring instrumentation must be installed such that valid results can be obtained.

SINGLE TEST LINES

Figure 2 illustrates an ideal test pipeline—the produced fluids flow from the producing wells to the gathering center, where the oil, water, and gas are separated. Ideally, corrosion-monitoring systems should be installed at both ends of the test line. The location upstream of the chemical injection point will confirm that there are no changes in the corrosivity of the produced fluids during the testing. The small portion of the pipeline, which is upstream of the chemical treatments, will need to be inspected periodically to ensure that the system integrity is maintained. It is most critical to install monitoring at or near the end of the pipeline because this documents that the entire line is receiving adequate corrosion inhibitor treatments.

TESTING ON A TRUNK LINE—ADDITIONAL INJECTION AND MONITORING POINTS

Sometimes it is impossible to conduct a corrosion inhibitor test using a single test line. Figure 3 illustrates one such gathering system used for testing corrosion inhibitors. Three drill sites or production areas were feeding product into a common trunk line. To conduct the field tests, corrosion inhibitor injection points were established for each of the production areas. Additionally, corrosion monitoring was established at the end of each line, before it entered the common trunk line. This test arrangement worked well because it was representative of the entire field. Having chemical injection at three different injection points required careful coordination, particularly when making changes to the chemical injection rates during the field test.

OBTAINING BASELINE DATA BEFORE STARTING CHEMICAL INHIBITION

When conducting corrosion inhibitor field tests, the baseline corrosion rate must be established before applying any corrosion inhibitor. This provides a basis for quantifying the relative efficiency of the chemical product in inhibiting (reducing) corrosion.

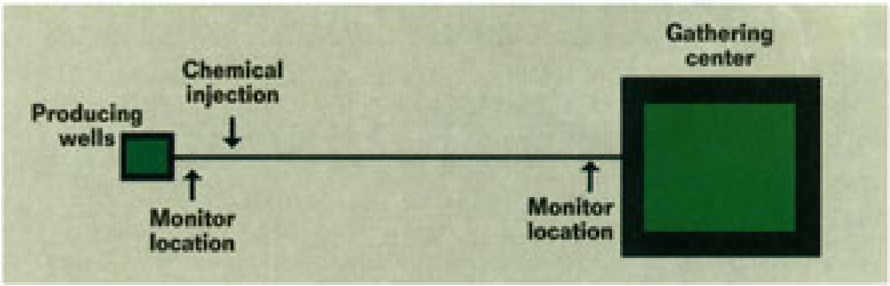
New corrosion probes should be installed inside the test line prior to the start of chemical inhibition. After establishing a uniform, baseline corrosion rate (which typically takes a few days), the chemical injection can begin. Comparing the corrosion rate after the initiation of inhibitor treatments to the corrosion rate before treatments allows one to calculate the relative efficiency of any corrosion inhibitor. The efficiency calculations should be associated with a specific treatment rate (e.g., parts per million [ppm]).

There are expenses associated with any change of chemical products, such as cleaning the chemical tanks, pumps, and injection lines (unless the old and new products are compatible) and placing new chemical labels on the tanks. As a consequence, a 10% improvement of the cost performance is typically desired to offset the ancillary expenses.

FIGURE 1

Corrosion probe connected to a remote data collector. The data are being transferred to a hand-held data logger.

FIGURE 2

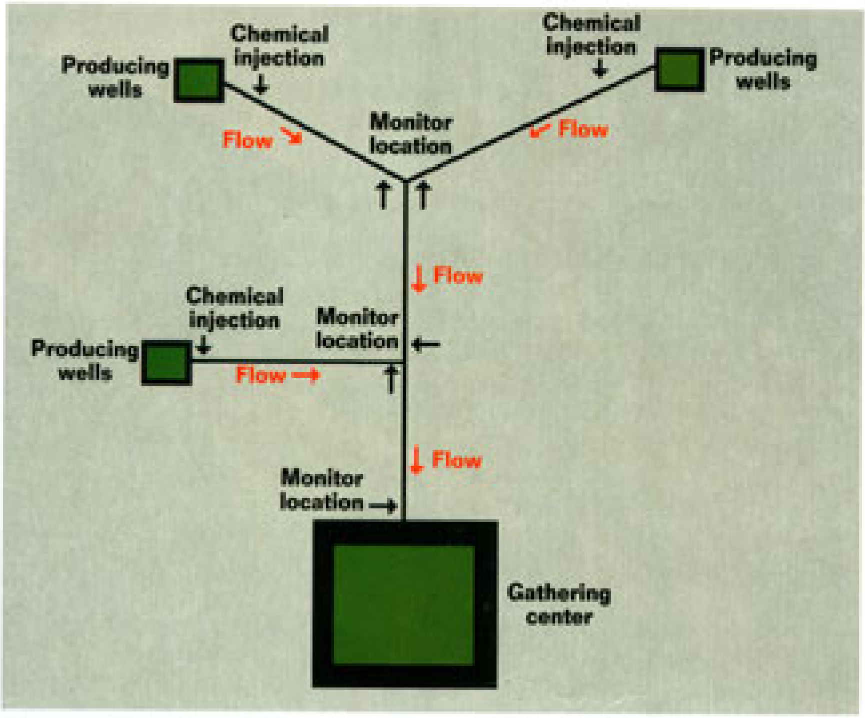


An ideal test line. Flow is from the producing wells to the gathering center. There is only one pipeline and one chemical injection point to simplify testing and reduce the number of variables. The most critical monitoring point is at the end of the pipeline at the gathering center.

CHEMICAL INJECTION THROUGH QUILLS AND NOZZLES

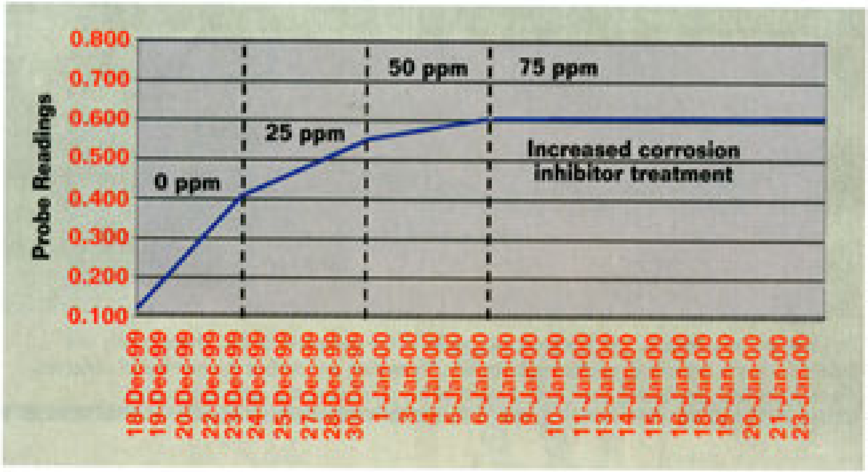
The corrosion inhibition should be introduced at the start of the pipeline, ideally using an injection quill. The quill disperses the corrosion inhibitor midstream in the pipeline. The concern is that concentrated corrosion or scale inhibitors by themselves can be corrosive until properly diluted by the produced fluids. Therefore, the inhibitors are delivered in stainless steel containers or plastic-coated steel drums. Pipeline failures have occurred immediately downstream of top-of-the-line weld-o-lets, which are used as chemical injection ports. Such failures have been attributed to general corrosion attack of the concentrated product, which attacked the pipe wall prior to

FIGURE 3



Field test and monitoring locations on a trunk-and-lateral gathering system that requires multiple chemical injection and monitoring points. The downstream monitoring locations are illustrated. It is ideal to have additional monitoring upstream of the chemical-injection points.

FIGURE 4



Ideal corrosion inhibition graph. This illustrates a reduction in corrosion rates with increased inhibitor treatment.

the product being diluted by the produced fluids. Consequently, the use of quills, which direct the product into the process fluids, is strongly recommended. If that is not possible, chemicals should be injected at turbulent areas, where mixing is greatest.

Chemical injection nozzles, which generate a fine spray, are most efficient for inhibiting gas pipelines. These specialty nozzles should be positioned midstream.

STEP INCREASES IN THE CHEMICAL INHIBITOR INJECTION RATES

Once the baseline, uninhibited corrosion rate has been established, the corrosion inhibitor injection should be started at a rate lower than that anticipated for the pipeline. When the corrosion inhibitor application begins, a thin inhibition film will be established. If the initial applications are too great, a thick film will quickly form; additional time will be necessary to allow the film to dissipate before being able to measure the minimum concentration of corrosion inhibitor needed to protect the pipeline adequately. The corrosion inhibitor must be given time to adsorb onto the pipe walls and reach a steady-state condition. Adsorption usually takes a few days and depends in part upon the length and surface condition of the pipeline and the quantity of debris—typically sand—within the pipeline. Sand will consume a significant portion of the corrosion inhibitor.

Next, the corrosion rate achieved with the initial treatment must be measured and compared to the ideal or acceptable corrosion rate. (This is typically 0 to 2 mpy [0 to 51 µm/y], depending on the particular system and the designed corrosion allowance.) If an acceptable corrosion rate has been obtained, then the minimum corrosion inhibition treatment level has been determined. If, however, the desired corrosion rate has not been obtained, then the corrosion inhibitor injection rate should be increased to the next rate step—such as from 24 to 36 or 48 ppm. Again, time should be allowed for the inhibitor to develop a uniform protective film throughout the pipeline before measuring the corrosion rates for each incremental step. Figure 4 illustrates an ideal corrosion inhibitor field test. Through these incremental steps, the minimum corrosion inhibition treatments can be defined for each pipeline.

The minimum concentration of corrosion inhibitor needed to achieve a certain level of performance (corrosion rate) can be used in cost-performance analysis for competing products. Actual treatments for any pipeline should be slightly above the minimum treatments, however, to provide a "buffer" for process upsets or changes in the production rates.

REESTABLISHING BASELINE CONDITIONS

Baseline conditions should be reestablished before testing other products. If the system returns to the same baseline rate, then the reduction in corrosion rate achieved by the first product can be attributed only to the performance of that product rather than to a change in production characteristics. Second, the time taken to return to the baseline corrosion rate is an indication of film persistency. Although corrosion inhibitors are designed for continuous injection, film persistency is desirable to ensure temporary protection to the pipelines and facilities during brief interruptions in the chemical injection.

FIELD TESTING BEFORE CONVERTING FACILITIES

Crude oil production is the top priority for any producing facility; it is essential for the facility's revenue generation. The corrosion engineer should therefore design field tests on production lines, which represent field conditions but are not absolutely crucial for field operations. The test plans should require only minimal manpower from production personnel. The field tests should include monitoring of the facilities' performance—this is an attempt to identify any process upsets directly related to the chemicals in the field test. The surfactant package in corrosion inhibitors can "scour" the pipelines and cause the formation fines to be transported to the process vessels, where crude oil, water, and gas separation problems could occur. Accordingly, it is advisable to stage emulsion breakers at the production facilities so that process upsets can be treated quickly.

The test procedure should start with specific plans for flushing the chemical injection pumps and quills if there are any incompatibilities between any incumbent product and the new test product. One simple test consists of mixing a small volume of the incumbent product with a small volume of the test product. (The ratios would typically be 2:1, 1:1, and 1:2.) If sediment or precipitate is observed, then a solvent rinse/flush step is necessary. Common flushes use diesel, water, or methanol (CH_3OH).

COST PERFORMANCE EVALUATIONS

Whenever a facility considers adopting a new corrosion inhibitor or any other product, the most important requirement is that the product performs as expected. The second most important requirement is that the product is cost-effective and reduces overall costs—whether direct price or other savings, such as a reduction in maintenance service costs. Using steps described earlier in this article, one can determine the minimum product concentration. Cost performance would then be determined based on the minimum concentration and the cost of the product adjusted for any savings.

The cost should be based on quotations, assuming bulk purchases of the product, as opposed to laboratory or small test volumes. In addition, the costs should include incidentals, such as transportation and any container rental fees. If the corrosion inhibitor contains additional components that reduce other chemical consumption—such as emulsion breakers—then that cost saving should be factored into the product's cost structure. If the product yields other savings that can be quantified—such as reduced maintenance expenses—then the savings should also be factored into the cost performance.

Conclusions

Chemical testing of corrosion inhibitors or other products should be considered a continuing process throughout the lifetime of each producing field. Water production typically increases, particularly if waterflood is a part of the secondary recovery efforts. System corrosivity also changes as the reservoir sours. Thus, the best corrosion inhibitor at the start of field life will not necessarily be the product of choice later in field life.

Corrosion inhibitor technology is continually advancing as new products are being developed throughout the world. Some of these products may prove to be more cost-effective than existing products.

By viewing corrosion monitoring and inhibitor testing as a continuing process, the integrity of crude oil and gas-gathering systems can be maintained. Such maintenance ensures continued production and revenue generation without compromising the system integrity or the environment.

Reference

1. D.E. Powell, D.I. Ma'Ruf, I.Y. Rahman, "Practical Considerations in Establishing Monitoring for Upstream Oil and Gas Gathering Systems," MP 40, 8 (2001): p. 50.

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