# Internal Corrosion Inhibition of Gas Gathering Lines

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Accelerated internal failures of gas gathering lines due to corrosion are an economic concern to operators. The initial cost of laying a pipeline has increased 28 per cent over the past 10 years due to higher costs of steel and labor. Another factor is higher pressure gas wells requiring the use of thicker-walled pipe to handle the pressure. Operators seeking methods to prevent internal gas gathering line failures are finding that organic corrosion inhibitors are successful in treating both old and new lines.

## DESCRIPTION OF CORROSION

(1) Sweet corrosion occurs in the presence of carbon dioxide. The mole per cent of carbon dioxide in gas multiplied by the line pressure is an indication of the corrosiveness of the aqueous phase. When moisture is present, carbon dioxide dissolves and forms carbonic acid.

(2) Sour corrosion occurs as a result of the presence of hydrogen sulfide. Several different forms of corrosion result from hydrogen sulfide:

- (a) Weight loss in aqueous solution, where the main concern is conversion of iron into iron sulfide and the loss of metal and strength.
- (b) Pitting, where small pits progress through the wall at a high rate.
- (c) Sulfide cracking which can occur in low temperature aqueous environments.

(3) Oxygen corrosion, which occurs in an aqueous solution.

(4) Electro-chemical corrosion, which occurs as the result of measurable electrical current flow due to a potential difference between two or more areas on a metal in the presence of an electrilyte.

Others have described the mechanism of these forms of corrosion in detail. However, it can be pointed out that a combination of these corrosive conditions is found in most gas gathering systems, and under these conditions the corrosion rate is usually accelerated. This is especially true when oxygen is mixed with either carbon dioxide or hydrogen sulfide.

Recently improved methods of detecting oxygen in gas gathering lines reveal oxygen presence even when hydrogen sulfide is present. In fact, an oxygen content of 240 ppm was found in one gathering system. Some of the means by which oxygen is thought to enter a system include:

(1) Wells pumping off.

(2) Pulling a vacuum in order to obtain gas.

(3) Venturi effect in small leaks, both high and low pressure.

(4) Suction side of a compressor.

(5) Vapor recovery units.

## EVALUATING THE CORROSION PROBLEM

It is apparent that monitoring a gas gathering system to determine the kind, severity and cause of corroson can be a profitable venture.

An analysis of the gas to determine the carbon dioxide, hydrogen sulfide, and oxygen content is essential. There is no exact correlation of corrosion rate with the amount of $H_2S$, and $CO_2$ present. However, even traces of $H_2S$ or oxygen can cause severe corrosive attack.

Another important step is to run laboratory analyses of the produced water. The presence of chlorides, calcium, and magnesium can increase electrochemical-type corrosion. Other qualitative indications of corrosion are test coupons and iron content tests performed on the water involved.

Hydrogen probes placed in a line can be utilized to evaluate the hydrogen gas pressure which occurs when hydrogen sulfide is present. If gas analysis, coupon and iron analysis, indicate evidence of corrosion, an inspection should be made. Inspection can be made with an instrument which records both the location of the pitting and the approximate depth of the pits.

When internal failures are occurring in a lateral or trunk line, accurate records as to frequency of failures are valuable. It is also beneficial to record whether the failure occurred in the bottom, middle, or upper quadrant of the line. Visual inspection as to the type of corrosion attack would provide information pertaining to the corrosion environment and the severity of the corrosion rate. This data can be correlated with coupon and iron analysis results. Evaluation of a corrosion mitigation program can then be made.

## INHIBITOR SELECTION

Corrosion inhibitors have been used extensively in both oil and gas wells to reduce corrosion damage to subsurface equipment. Most of the inhibitors used are the polar organic film forming amines. When properly selected and applied, these chemicals have been found to be the least expensive and most effective for use in gas gathering lines. They are available in a wide variety of formulations and solubility characteristics.

The basic types are oil-soluble, oil-soluble and water-dispersible, water-dispersible, and dual-phase. Dual-phase formulations consist of oil-soluble, water dispersible and a vapor phase, or a water-dispersible and vapor-phase inhibitor.

Before selection of an inhibitor, the corrosion problem must be defined. For instance, when water collects at several points in a line, the oil-soluble, highly water-dispersible inhibitor may work effectively. Internal corrosion existing at the lower and upper quadrants of the pipe calls for a dual-phase type inhibitor. The inhibitor selected should not create emulsion or foaming problems.

## INHIBITOR APPLICATION

There is no rule of thumb yet devised for applying inhibitors. However, two methods are widely used; (1) atomizing with a diesel fuel nozzle, and (2) slugging between pigs. The atomizing method is usually continuous. Figure 1 shows a field installation incorporating the continuous atomizing technique. Slugging, however, can be accomplished by mixing a high concentration of inhibitor with some type of hydrocarbon liquid and running it into the line ahead of a pig or between pigs. Both methods can be used on any given pipeline. Some applications are with chemical pumps and no atomizing, or with periodic slugs of inhibitor lubricated in without the use of pigs.

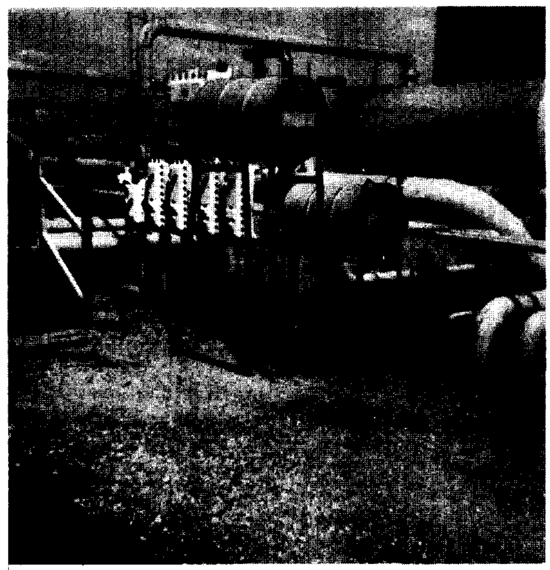

FIGURE 1

Chemical Injection Pump Installation Utilizing Atomizing System.

## AMOUNT OF CHEMICAL

After defining the cause of the problem and its severity and the selection of an inhibitor, the initial treatment is begun. A high concentration of inhibitor is used to build a film of organic amine on the metal surface within a short time. This amount will vary according to the size of pipe, length of system, and condition of pipe—whether new, or old and corroded.

A chemical pump can be used to slug or inject the chemical at a high rate (1 to 2 quarts per mmcf) over a predetermined test period. During this period, monitoring devices can be used to evaluate the effectiveness of the initial treatment. Most operators gradually reduce the high initial treatment and use monitoring methods to determine how much the inhibitor concentration can be reduced. After a few months of treatment, a visual inspection should be correlated with data gathered from other evaluation methods.

## CASE HISTORIES

It is apparent that most gas gathering systems will have their own unique corrosion and treating problems. Therefore, extensive corrosion evaluation procedure is necessary. Case histories exemplify this.

### Gas Gathering System—West Texas Area

1. Length of line—8 miles.
2. Diameter of line—12 inches.
3. Number of years in service—7.
4. Gas volume carried in line—25 mmcf gas per day.
5. Water volume per day 3 to 12 bbl.
6. Gas analysis—0.78 mole per cent $CO_2$, 4 to 125 ppm oxygen originating at vapor recovery units.
7. 600 psi on line.
8. Failure occurred downstream from the discharge side of the compressor.
9. Treatment initiated with one quart of an oil-soluble, water-dispersible inhibitor per mmcf (25 qts/day).
10. Another failure downstream from the first.
11. Changed to a dual phase inhibitor because corrosion was evident over entire inside surface of the pipe.
12. Treatment rate was reduced to two quarts per day.
13. No further failures in three-year period.
14. Present cost of treatment .072 cents per mmcf.

### Gas Gathering Line—Permian Basin Area—No. 1

1. Length of line—1/4 mile.
2. Diameter of line—26 inches, wall thickness 1/2 inch.
3. Number of years in service—new line.
4. Old 1/2 inch thick line in service two years before being replaced. Severe corrosion over all quadrants of the pipe.
5. Volume gas carried in line—58 mmcf gas per day.
6. Water volume per day—three to five barrels.
7. Gas analysis—5 grains hydrogen sulfide, 40 to 240 ppm oxygen (originating at vapor recovery units and leaks in lines). Subsequently, oxygen concentration was reduced to present 0.5 to 40 ppm. Trace of $CO_2$.
8. pH of water—5.8.
9. 700 psi on line.
10. Coupon probe showed a base line corrosion rate of 68 mpy.
11. Test spool pits showed maximum penetration rate of 130 mpy.
12. Treatment initiated with dual phase inhibitor at the rate of one pint per mmcf.
13. Coupon probe reading showed zero corrosion rate in two days.
14. Treatment was reduced to 3/4 pint/mmcf and was maintained at this rate for six months. At the end of six months, coupon probe readings showed zero to 0.5 mpy. Visual inspection of test spool showed the small pits to have a penetration rate of approximately 2 to 3 mpy.
15. Treatment was reduced to 1/2 pint/mmcf, coupon probe readings varied from 0.8 to 1.5 mpy.
16. Cost of treatment at present, .0135 cents per mmcf.

### Gas Gathering Line—Permian Basin Area—No. 2

1. Length of line—9 miles.
2. Diameter of line—4 miles of 4-inch, 5 miles of 6-inch.
3. Number of years in service—10.
4. Six internal failures in one year. Bottom quadrant of pipe.
5. Volume gas carried in line—3.5 mmcf/day.
6. Water volume per day—6 to 8 barrels.
7. Gas analysis—20 grains hydrogen sulfide.
8. 300 to 400 psi on line.
9. Baseline iron counts of water—172 ppm.
10. Baseline coupon corrosion rate—8.2 mpy.
11. Initiated daily treatment with oil-soluble, water-dispersible inhibitor using 4 gallon slugs for five days.

12. Treatment was reduced to a 5 gallon slug once monthly.
13. Three months later, iron counts were 15 to 25 and mpy loss 0.2 to 0.5.
14. Treatment was reduced to 4-gallon slug once monthly.
15. Iron counts on water 6 months later—5 to 15 ppm, coupon mpy loss of 0.2 to 0.5.
16. Two failures in two years after treatment started.
17. Cost of present treatment—.071 cents per mmcf.

## CONCLUSION

Operators now monitoring their gas gathering lines to arrest internal corrosion before failures occur find that selection of the proper corrosion inhibitor is essential to an effective program. Failures in both old and new gas gathering lines can be economically treated thus achieving great profits.