Case study: Southwestern United States

CGO49 inhibitor reduced corrosion rates and pipeline failures in a CO_2 gas gathering system

The operator of a major CO_2 gas gathering system in the Southwestern US began experiencing leaks in the lateral and main lines about two years after starting operations. The failures occurred mostly in the lower quadrant of the lines.

The system was being treated with a water soluble corrosion inhibitor that was continuously injected at each wellhead at a rate of 200 ppm based on the brine production. Weight loss coupons indicated a general corrosion rate of about 4.0 mpy in the lateral lines and 2.5 mpy in the main lines. However, most of the coupons showed significant localized pitting. Liquid traps along the lateral lines were used to minimize liquid hold-up and back pressure. It was not possible to pig the lines to remove stagnant brine.

In close cooperation with the customer, Baker Hughes conducted a complete system survey to fully understand key factors contributing to the problem and help identify treatment options. The survey revealed that the lateral lines operated in a highly stratified gas/liquid flow regime, while the main lines operated in a periodic stratified flow. Gas flow rates were determined to be great enough that a large amount of liquid hold-up was not anticipated.

Corrosion testing was conducted to aid in identifying an inhibitor package best suited for this application. Baker Hughes CGO49 corrosion inhibitor, a product with unique water partitioning qualities, emerged as the product of choice for this aggressively corrosive system.

The Baker Hughes CGO49 inhibitor was batch treated at the wellhead on a biweekly or monthly basis, depending on the brine production volumes, to protect the laterals. The main lines were protected by continuous injection of CGO49 inhibitor. The total amount of inhibitor was 200 ppm based on brine volume and one pint per mmscfd of gas production.

With the Baker Hughes CGO49 inhibitor program in place, corrosion rates quickly dropped to 0.1 to 0.3 mpy in the lower quadrant of the pipeline. Product residual tests verified inhibitor transport throughout the system. Pipeline failure rates were immediately reduced from 40 per year in the combined lateral and main lines system to just two failures in the year following start-up of the Baker Hughes CGO49 inhibitor program.

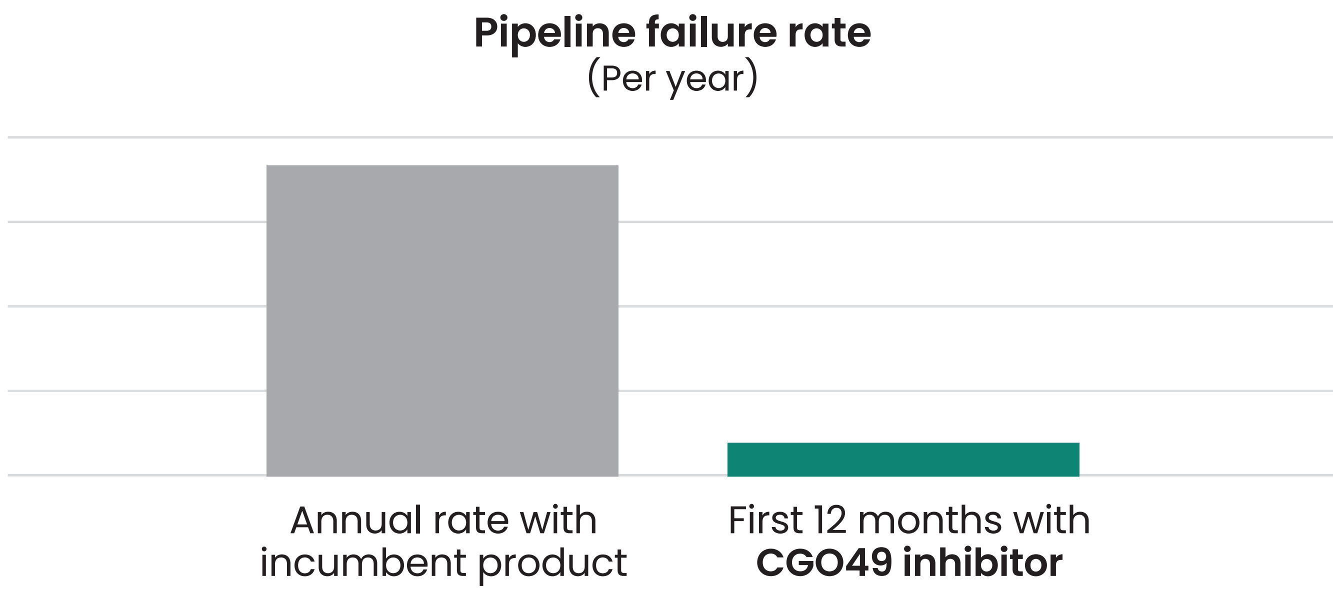
Once system corrosion was fully under control, Baker Hughes representatives worked to optimize the treatment program. Chemical injection rates were ultimately lowered to a mean residual level of 100 ppm in the main and lateral lines. At this lower inhibitor rate, both weight loss coupons and the absence of pipeline failures indicated maintenance of good corrosion control and the prevention of localized pitting.

Challenges

- Major CO_2 gas gathering system in the Southwestern US
- Leaks in the lateral and main lines

Results

- 95% reduction in pipeline failure rate
- Lower maintenance costs
- Lower chemical dosage and simplified treatment
- Improved production
- Reduced pipeline failure rates from 40 per year to 2 per year
- Optimized ongoing corrosion program to lower costs



Pipeline operating conditions	
Gas production	100 to 500 mmscfd
Gas velocity	3 to 16 ft (0.9 to 4.87m)/second
Carbon dioxide	99.9%
Hydrogen sulfide	None
Hydrocarbon	None
Brine TDS	30,000
pH	4 to 7
Pressure	60 to 100 psi
Temperature	40 to 100°F (4 to 38°C)

Baker Hughes