CORROSION MITIGATION THROUGH AUTOMATED CHEMICAL MANAGEMENT AND DOWNHOLE DESIGN OPTIMIZATION IN TEXAS DELAWARE NORTH

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ABSTRACT

Occidental's (Oxy's) Texas Delaware North operations face significant corrosion-related challenges, specifically following the flowback period when low pressure annular flow gas lift (LPAGL) is installed for the first artificial lift installation (FLI). Over the past three years, hole in tubing (HIT) failures in LPAGL wells occurred an average of 53 times each year, resulting in approximately $18.6MM in workover expenditures and 198 MBOE of deferred production. The highly corrosive downhole environment, combined with high peak fluid production rates (6,000 – 10,000 total BFPD), creates conditions where LPAGL wells develop holes in tubing within one year after FLI.

This paper presents an integrated two-pillar approach to corrosion mitigation. The first, automated chemical injection controller systems, optimizes downhole treatment volume and the second involves downhole design options: externally coated tubing strings or internal chemical capillary string (capstring) installations. These design options eliminate clamps, bands, and external capstrings, components used in LPAGL that have historically been the main contributors to HIT failures in LPAGL wells in the Texas Delaware.

Field trials demonstrated significant performance improvements in the Texas Delaware. Automated chemical injection achieved 90% chemical optimization while providing a cumulative discounted cash flow of $457.5M/yr for the new well development program. Externally coated tubing trials and internal capstring trials have delivered runtimes exceeding 1.5 years and 1 year, respectively, with zero failures to date. This exceeds the typical ~1 year runtime for LPAGL installations with bare tubing, external capstrings, and bands/clamps. These integrated solutions are projected to reduce failure rates significantly across the asset for LPAGL wells.

This paper details the root cause analysis of corrosion failures, implementation methodologies, economic justification, and trial results of each of the corrosion mitigation solutions that have extended runtimes for LPAGL FLIs and reduced costly premature HIT failures.

INTRODUCTION

Corrosion-induced tubing failures represent one of the most significant operational and financial challenges in the Delaware Basin. The combination of high CO_2 content, elevated total dissolved solids (TDS) levels, and aggressive production rates creates an environment in which multiple corrosion mechanisms attack tubing simultaneously.

Historical data from 2022-2025 reveals 182 workovers were required due to corrosion, with total financial losses exceeding $98.2MM in the Texas Delaware from cumulative workover spend and deferred production over that time.

Wells in the Texas Delaware typically follow the lifecycle shown below, with the corrosion failures being most prominent during the LPAGL stage.

Table 1: Methods of production for gas lift wells in the Texas Delaware.

Operating Time (Months)	Method of Production	Total Fluid Production (BFPD)
0 – 1.5	Natural Flow up Casing	Up to 15,000
1.5 – 24	Low Pressure Annular Flow Gas Lift (LPAGL)	Up to 10,000
24+	Tubing Flow Gas Lift (TFGL)	Up to 1,200

Traditional LPAGL designs, as shown in the figure below, use external capstrings with clamps or bands and experience corrosive attacks at specific locations, leading to premature and sometimes repetitive HIT failures. On average, HITs develop after less than one year due to corrosion at capstrings, clamps, and bands that contact the tubing. The downhole equipment is subjected to highly corrosive reservoir fluids and high-velocity flow as the wells produce on LPAGL. Additionally, approximately 15% of these wells were consistently undertreated chemically through 2025, which directly correlates to increased corrosion failures.

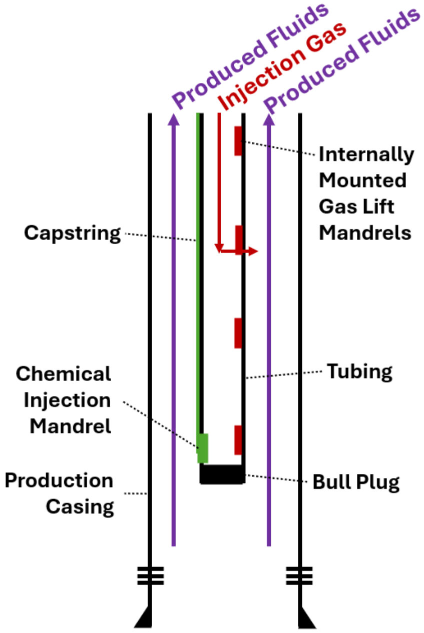


Figure 2: Example of standard LPAGL design.

The need for a comprehensive solution led to the development of an integrated approach, combining automated chemical management and optimized downhole equipment designs with externally coated tubing or internal capstrings. The objective of these trials is to yield tubing run times of approximately 2 to 3 years so that the tubing installed during FLI can last from FLI until LPAGL to TFGL conversion. This paper presents performance data from field trials, provides economic analysis supporting broader adoption, and documents the implementation of this strategy across regional operations.

<u>ROOT CAUSE ANALYSIS</u>

Corrosive Environment Characterization and Mechanisms

Premature HIT failures due to corrosion in the Texas Delaware are heavily concentrated where capstrings, clamps, or bands contact the OD of the tubing. These locations experience high shear turbulent flow and changes in cross-sectional flow area, which accelerate corrosion by stripping chemical treatment protection off these areas. Water analysis data from these wells also revealed an exceptionally challenging operating environment with TDS around 80,000 ppm, CO_2 around 2.00 mg/L, and high production flow rates. Several corrosion mechanisms attack the tubing simultaneously, with some more strongly linked to premature failures than others. The six corrosion mechanisms described below have been identified as primary challenges in this environment.

1. **Erosion Corrosion** – High-velocity flow removing protective films.

Figure 3: Erosion corrosion example.

2. **Crevice Corrosion** - Occurring under capstrings, clamps, and bands.

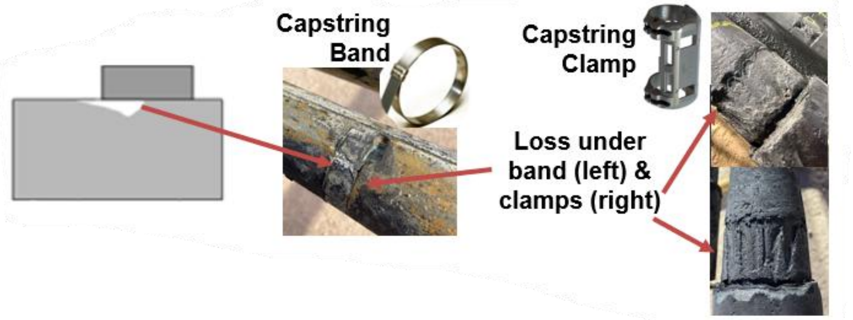


Figure 4: Crevice corrosion example.

3. **Galvanic Corrosion** - Dissimilar metal contact with the less noble metal experiencing loss.

Figure 5: Galvanic corrosion example.

4. **Fretting Corrosion** - Mechanical wear due to capstring movement.

Figure 6: Fretting corrosion example.

5. **Biological Corrosion** - Sulfate-reducing bacteria activity.

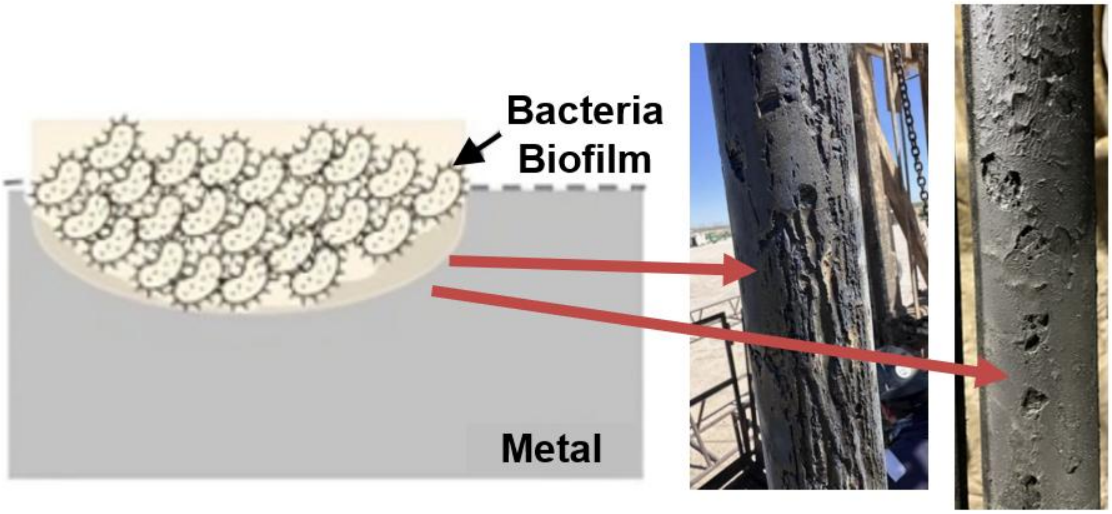


Figure 7: Biological corrosion example.

6. **CO_2 Corrosion** - Carbonic acid attack creating iron carbonate scales.

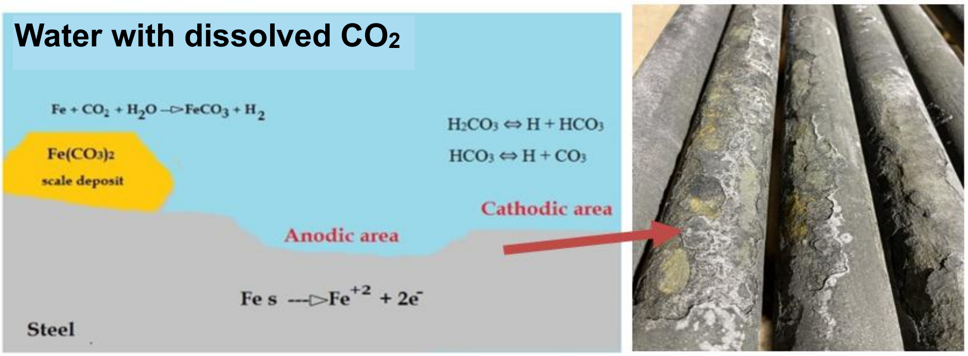


Figure 8: CO_2 corrosion example.

Case Study: LPAGL Well A

Well A is a Wolfcamp B well that has been producing on LPAGL since flowback. The well suffered from a premature corrosion-induced failure:

- FLI in September 2023.
- Corrosion-induced HIT failure in June 2024:
  - Runtime: 10 months.
- Chemical treatment trends revealed the well was undertreated for 30% of its operating period since FLI.
- Downhole failure resulted in an extensive fishing job:
  - Workover cost: $1.98MM.
  - Production deferred: 1,300 BOEPD for 116 days.

Figure 8: Well A’s HIT failure,corroded clamp, and tangled capstring.

Production declined to 0 BOEPD due to the inability of the well to surface fluid. After repair, production returned to previous trends. This demonstrates both the severity of corrosion-induced failures and the costly interventions that can result. Due to the high-cost workover resulting from Well A's severe corrosion, Well A was selected as the first candidate for externally coated tubing.

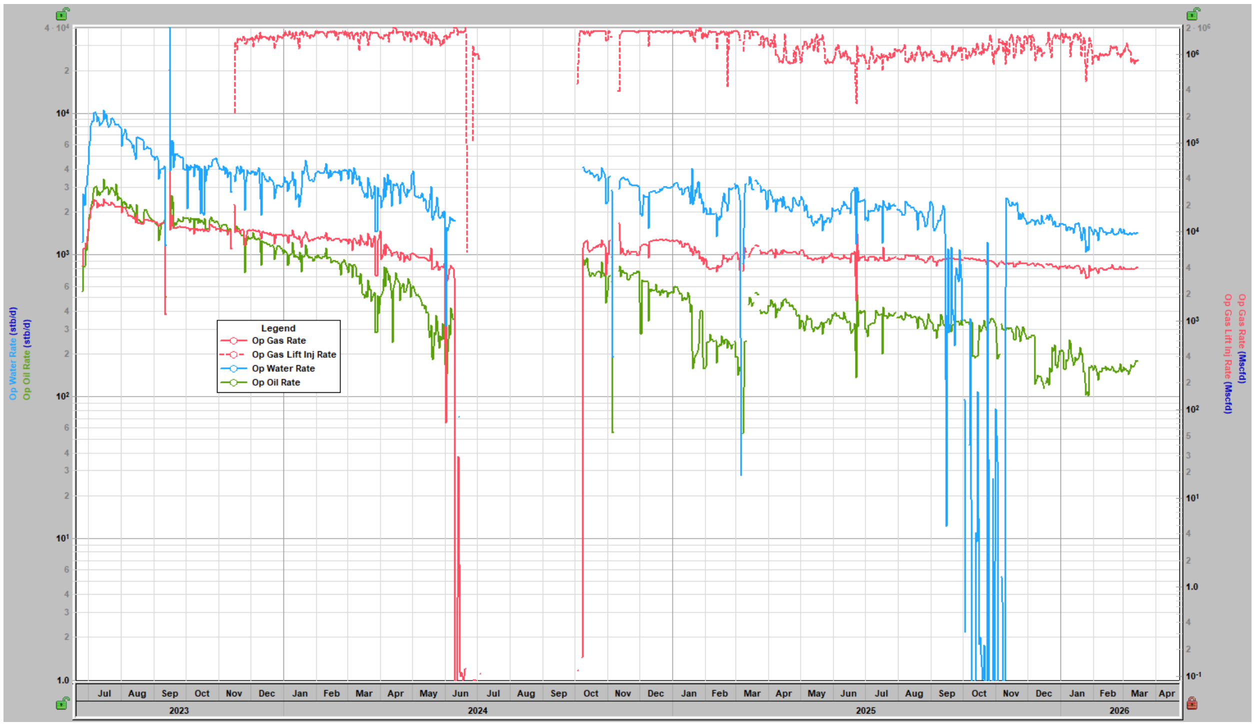


Figure 9: Well A's production trends pre- and post-failure.

PILLAR 1: AUTOMATED CHEMICAL INJECTION

Traditional chemical treatment rates are manually adjusted by the chemical vendor on either a weekly (for new development wells) or monthly basis (for legacy wells), based on weekly production data and known artificial lift design provided to the chemical vendor from the operator. With this information, treatment rates were expected to be manually adjusted and monitored accordingly, asset wide. Significant over- and under-treatment trends were realized across the area that did not correlate with well production data. Analysis revealed 23% of the wells in the asset were being overtreated, while 15% of the well count was being undertreated.

By trialing chemical controllers on various well pads, the chemical treatment efficiency was optimized, minimizing over- and under- treatment scenarios. The chemical controllers were programmed to receive well test data sent daily from the operator's production database and then use the well information to calculate the exact treatment volume necessary for each specific well. This removed the human intervention necessary when chemical treatment rates were manually updated and managed, providing a reliable, automated solution. The controller systems feature:

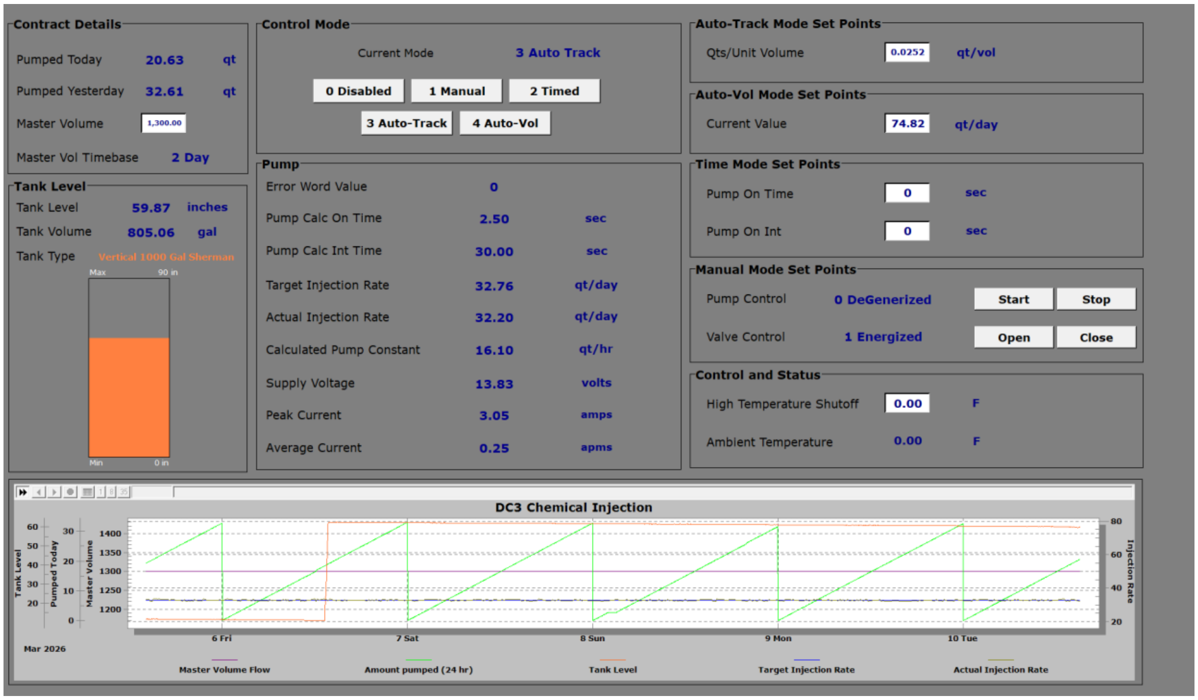
- Programmed treatment formula: GPD = 0.000042 × saturation (PPM) × BWPD (well test data):
    - Typical saturation: 150 ppm for new development wells.
- Rolling 5-day production average from production database well test data:
    - Daily automatic treatment rate adjustments based on updated test data.
    - Automatic injection shutdown during well shut-ins to prevent unnecessary treatment.
- Cygnet integration for real time data visibility and alarm escalation, vendor accountability, and surveillance for remote troubleshooting.

Integrating automated controllers resulted in “on target” treatments realized across the asset. This cascaded with OPEX savings from optimized $/BOE, as well as reducing downhole intervention costs from premature HITs with proper downhole chemical treatment protection.

Figure 10: Chemical treatment comparison between daily and monthly rate change frequencies.

Single-Point and Multi-Point System Implementation:

Two automated controller systems were trialed in the asset: single-point and multipoint. The single-point system refers to one dedicated system per well: single pump, single chemical tank, and a single controller system automating treatment for a single well. The multipoint system is a dedicated system for all the wells on a single pad: single tank, single pump, and one controller automating treatment for the entire pad. Both controller systems can monitor and control the chemical injection process based on programmed parameters and selected operation modes designated by the operator. Remote control capabilities, alarms and shutdowns, and Cygent and SCADA integration for surveillance monitoring are features provided by both systems for prudent operations.



Contract Details

Pumped Today	20.63	qt
Pumped Yesterday	32.61	qt
Master Volume	1,300.00	
Master Vol Timebase	2 Day	

Tank Level

Tank Level	59.87	inches
Tank Volume	805.06	gal
Tank Type	Vertical 1000 Gal Sherman	

Control Mode

Current Mode 3 Auto Track

Pump

Error Word Value	0	
Pump Calc On Time	2.50	sec
Pump Calc Int Time	30.00	sec
Target Injection Rate	32.76	qt/day
Actual Injection Rate	32.20	qt/day
Calculated Pump Constant	16.10	qt/hr
Supply Voltage	13.83	volts
Peak Current	3.05	amps
Average Current	0.25	apms

Auto-Track Mode Set Points

Qts/Unit Volume 0.0252 qt/vol

Auto-Vol Mode Set Points

Current Value 74.82 qt/day

Time Mode Set Points

Pump On Time	0	sec
Pump On Int	0	sec

Manual Mode Set Points

Pump Control	0 DeGenerized
Valve Control	1 Energized

Control and Status

High Temperature Shutoff	0.00	F
Ambient Temperature	0.00	F

Figure 11: Cygnet integration and surveillance of automated chemical controller.

The single-point system includes a single DC3 Mirador controller with various preprogrammed control modes for a single well. These modes include “disabled” (off), “manual” (on/off), “Auto-Time” (timed mode), “Auto-Volume” (set rate), and “Auto-Track” (calculated rates based on real time production data). The controller includes an integrated tank level monitor to measure chemical inventory. The automated smart sight glass and controller are installed with the existing chemical pump, providing automated pump calibrations ensuring chemical treatment is delivered on target for the designated well.

Figure 12: DC3 Mirador system including intelligent controller, automated sight glass.

The DC3 controllers' connectivity leverages 900 MHz radios, gateways installed at PLCs, and MODBUS TCP and RTU to create a mesh network backbone. This allows all controllers to communicate with each other and with neighboring gateways to the operator's SCADA network.

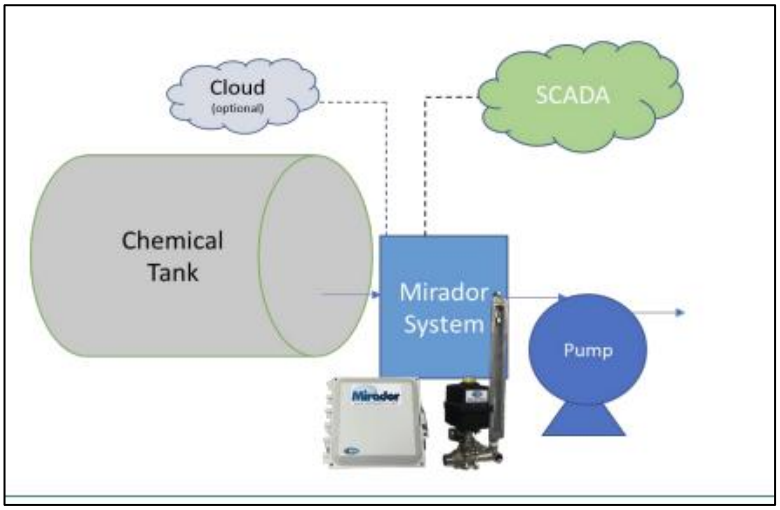


Figure 13: DC3 Mirador communication system.

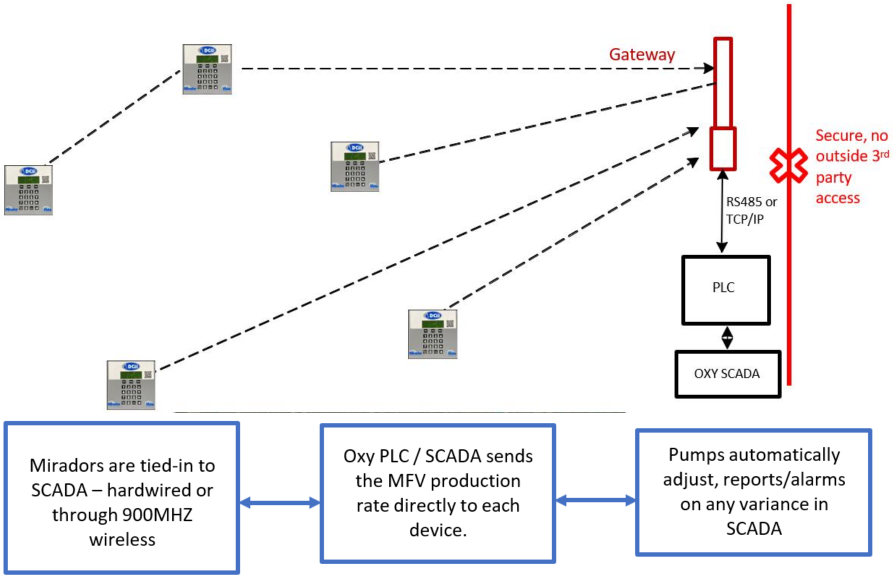


Figure 9: DC3 Mirador mesh network communications.

The multipoint system includes an ABB TotalFlow XRC controller and solenoid header that can accommodate up to eight wells. A magnetic flowmeter is used to measure the amount of chemicals being pumped for each well through the solenoid header. Depending on the chemical volumes needed to treat each well, multiple pumps can be retrofitted to the multipoint system to accommodate required volumes and various well injection pressures. A chemical tank radar level transmitter is placed on each chemical tank to measure chemical inventories.

Figure 15: ABB TotalFlow system with solenoid header and controller for well pad.

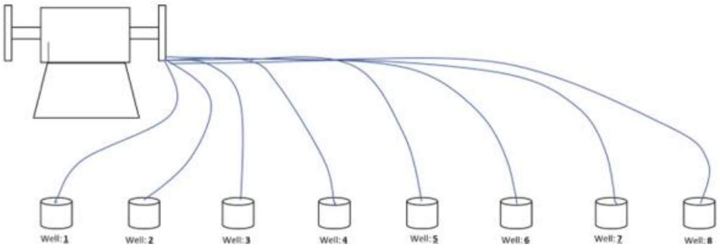


Figure 16: Simplified multipoint system schematic.

The multipoint controller modes include “disabled” (off), “manual” (on/off), “fixed-time” (timed mode), “batch”, “volume” (set rate), and “auto-adjust” (calculated rates based on real time production data). The TotalFlow controller communication options include remote protocol (Serial or TCP), MODBUS RTU (host or slave), or TCP (server to client).

Performance Results:

Single-point and multipoint control systems were trialed on various wells in the asset, both yielding positive results. The controller systems are being implemented asset wide on all existing and future development. By implementing single-point or multipoint automated controller systems that use daily rate change logic based off well test data, the following results were achieved:

- Financial results:
    - First-year discounted cash flow (DCF) of $3,730/well.
    - Total Cum DCF: $457.5M/yr.
- Treatment accuracy:
    - >90% wells within ±10% of target.
    - Chemical residuals (SICI): 100-300 ppm per trial well.
    - Undertreatment incidents: <5% wells/month.
    - Chemical OPEX reduction: >15% vs. baseline.

PILLAR 2: DOWNHOLE DESIGN SOLUTIONS WITH EXTERNALLY COATED TUBING AND INTERNAL CAP STRING INSTALLATIONS

After the flowback period for new wells, the majority of wells go on LPAGL to allow produced fluids to flow up the larger annular space between the casing and tubing due to their high production rates. Historically, when running LPAGL, stainless steel capstrings were run externally and either banded or clamped to the tubing string, to allow for chemical injection to reach the end of tubing (EOT). This had been the traditional installation design until LPAGL wells were averaging <1 year runtime before failure. The failures on these wells all revealed the same trends: concentrated corrosive attacks at the specific locations of the bands, clamps, and capstring. With highly corrosive reservoir fluids and high velocity flow that will always be present in Texas Delaware development, alternative designs had to be explored to increase the longevity of the downhole equipment.

EXTERNALLY COATED TUBING

The first design solution trialed included adding an external coating on the entire tubing string to provide a physical barrier between the tubing and the highly corrosive, high shear environment present in LPAGL operations. This barrier prevents fluid contact with the tubing body and collars, therefore eliminating the possibility of corrosion-induced failures to occur in the downhole equipment. The chemical treatment for the well can then be switched from the traditional external capstring/clamp injection application to using an atomizer in its place. When the chemical is atomized, it is converted to a gaseous state and injected with the compressed lift gas inside the production tubing. It then exits with the gas lift gas through the gas lift valves to enter the annulus to the production fluid. The chemical can then liquify and saturate the production fluid and provide protection to the production casing – as the tubing is protected by the external coating.

The externally coated tubing that has been trialed is an epoxy resin created by Bond-Coat that is applied tip-to-tip of each tubing joint at a thickness of 30-40 mil. The gas lift mandrels are also coated for additional protection of the gas lift assembly. Though the coating adds an additional thickness to the tubing, no specialized equipment or handling tools are required by workover rigs to run the coated tubing in the wells. The coating is also rated for temperatures up to 300°F and pressure-rated to the yield strength of the tubing. The coating is applied to the tubing joints and mandrels as follows:

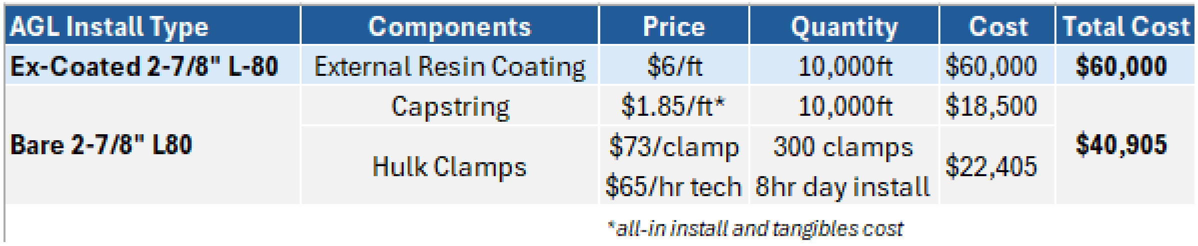
1. Automated grit blasting to NACE No. 1/SSPC-SP 5 standard for surface preparation.
2. First layer of epoxy resin applied to the tubing string, followed by a curing period.
3. Second layer of epoxy resin applied at achieve uniform thickness of 35-40 mil throughout.
4. A 100% holiday detection is performed at 10KV.
5. The coated joints are stored and marked for customer pickup. Touch-up kits are provided with each shipment for field repairs.

Figure 107: Grit blasting, curing process, and final product of epoxy resin coating.

Economic Analysis

Table below compares the tangible and labor costs associated with installing externally coated tubing versus the traditional LPAGL design of external capstring with clamps and bands. For example, for a 10,000 ft string of 2-7/8-in. tubing, an incremental cost of ~$20K would be incurred to run the external coating of epoxy resin.

Table 2: Incremental cost analysis of traditional AGL vs. externally coated tubing.



AGL Install Type	Components	Price	Quantity	Cost	Total Cost
Ex-Coated 2-7/8" L-80	External Resin Coating	$6/ft	10,000ft	$60,000	**$60,000**
Bare 2-7/8" L80	Capstring	$1.85/ft*	10,000ft	$18,500	**$40,905**
	Hulk Clamps	$73/clamp $65/hr tech	300 clamps 8hr day install	$22,405	

**all-in install and tangibles cost*

Trial Results

The epoxy resin coating has been trialing on a total of 13 wells in Texas Delaware Basin, nine wells for FLI applications, and four LPAGL wells that had prematurely failed with the traditional design. All wells with the external coated tubing are still producing, with no HIT failures or had any negative production impacts to date. The longest runtime for the trial subset is 15 months. Complete water analysis on the trial subset has revealed no increase in iron or manganese that would indicate metal loss from the downhole equipment from coating failure. Because no wells with the externally coated tubing have required to be pulled yet, the trial wells will continue to be monitored until such a situation arises. The goal is to eliminate premature corrosion-induced failures on LPAGL wells and remove the coated tubing only when production rates have declined enough to justify converting to tubing flow.

INTERNAL CAPSTRING INSTALLATION

Realizing that nearly all premature HIT failures occur in high-rate (i.e. wells peaking around 6,000 – 10,000 BFPD after FLI) LPAGL wells near the external capstring, clamps, or bands, Oxy began partnering with Flowco Inc. in 2023 to develop an internal capstring tool. The internal capstring eliminates the need for bands or clamps and removes the capstring from the production flow path. Gas lift is still injected down the tubing and the well produces up the tubing-casing annulus, but produced fluids do not contact the capstring. Flowco developed a prototype and Oxy began running the tool in November 2024. To date, Oxy has completed 15 installations (including five FLIs), with the longest runtime exceeding 12 months. There have been no tubing failures in the trial wells and the install count continues to grow as the tool is used regularly in the asset.

Internal Capstring Tools

The internal capstring tools include four main components: lower assembly, upper assembly, hanger, and hanger extension. Figure 17 through Figure 21 below show pictures of each component and an example installation. Flowco offers tools sized for 2-3/8-in., 2-7/8-in., and 3-1/2-in. tubing. This operator has successfully run all these sizes.

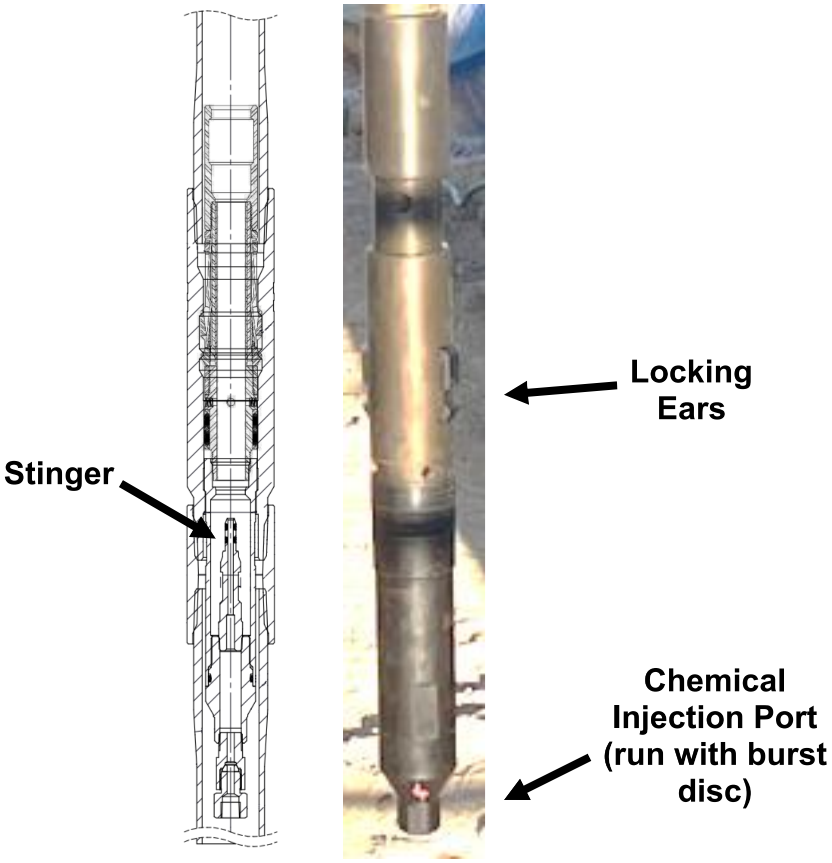


Figure 18: Lower assembly, run on slickline. The tool sets in an XN nipple in the tubing.

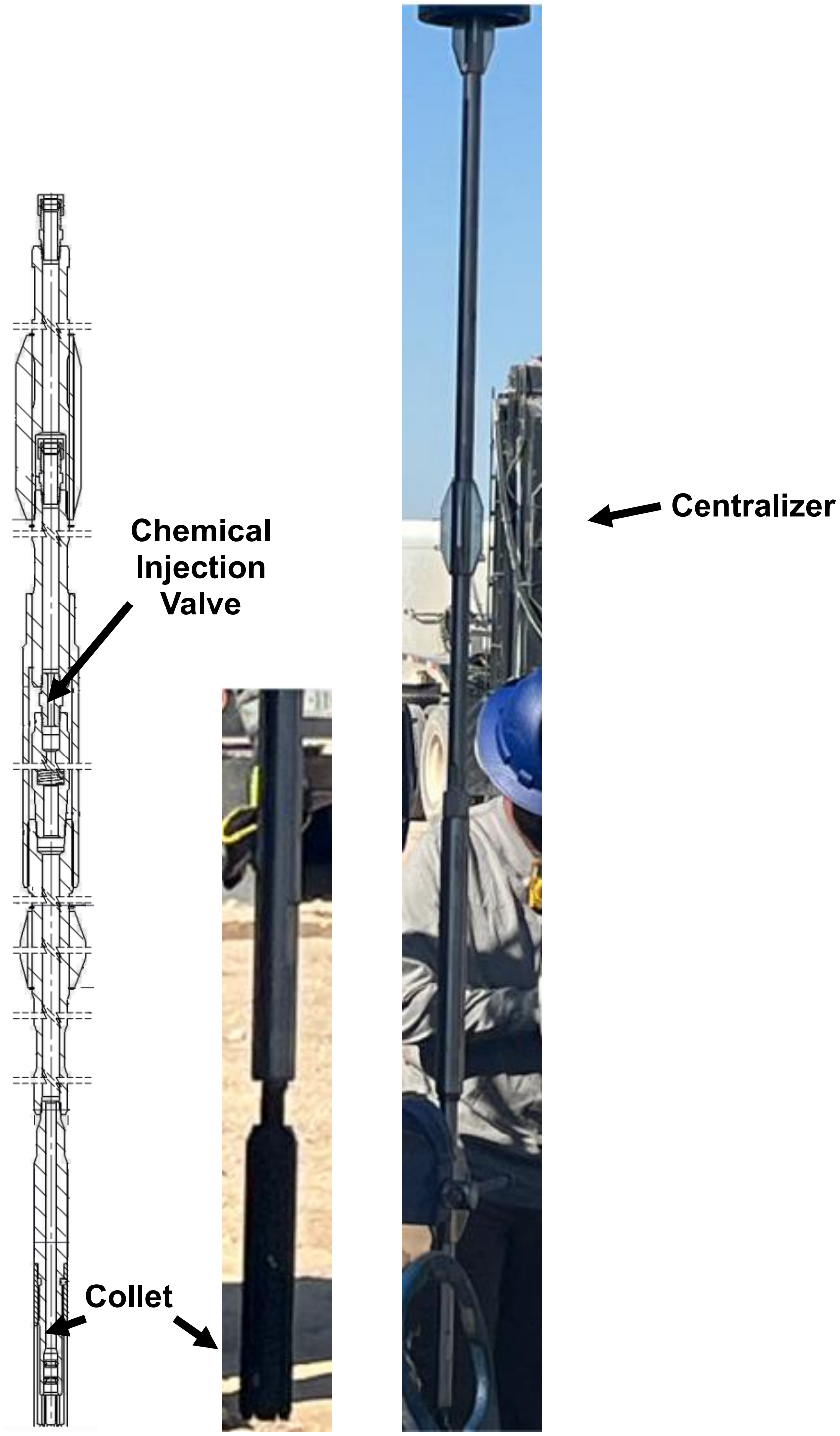


Figure 11: Upper assembly, run with capillary unit. The centralizers help align the tool so the collet can enter the lower assembly. The collet latches onto the stinger in the lower assembly and provides a seal.

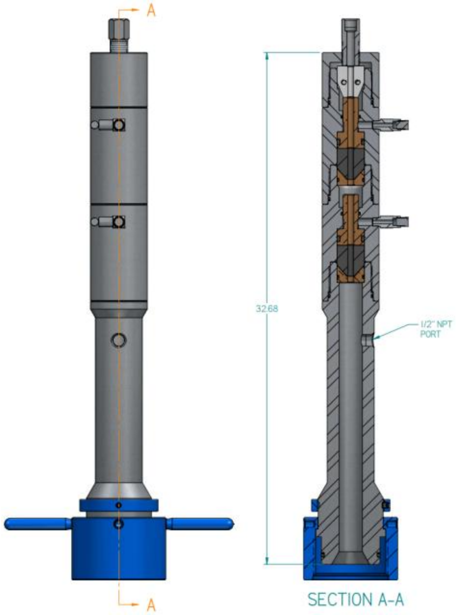


Figure 20: The hanger supports the capstring and provides a seal.

Figure 21: Hanger extensions can vary in length, depending on the tree configuration. Sufficient height must be available to make up the hanger while a master valve(s) is closed for well control.

Installation Process

Though the internal capstring could be installed at almost any time, whether the well has been in production or was recently worked over, installation is recommended immediately following a workover. This reduces the probability of solids building up in the tubing ID, which can cause the capstring tool to stick during installation, or solids in the produced fluids building up, which can plug the capstring tools.

Below is a summary of the installation steps:

1. Pump Truck: Pump a flush down the tubing to ensure the tubing is clean.
2. Slickline: Make a drift gauge ring run down to the XN nipple to ensure the tubing is clear.
3. Slickline: Set the lower assembly in the XN nipple.
4. Capillary Unit: Run the 3/8-in. capstring with the upper assembly. Stab into the lower assembly and hang off the capstring in the capstring hanger.
    a. Use appropriate hanger extension based on the tree configuration.
5. Chemical Pump: Pump on the capstring to rupture the burst disc in the lower assembly. Return the well to production with the chemical pump on.
    a. If desired, capture a water sample to test for residuals.
6. Production Tree: Install chains and/or signs signaling that the master valves and swab valves can no longer be used.

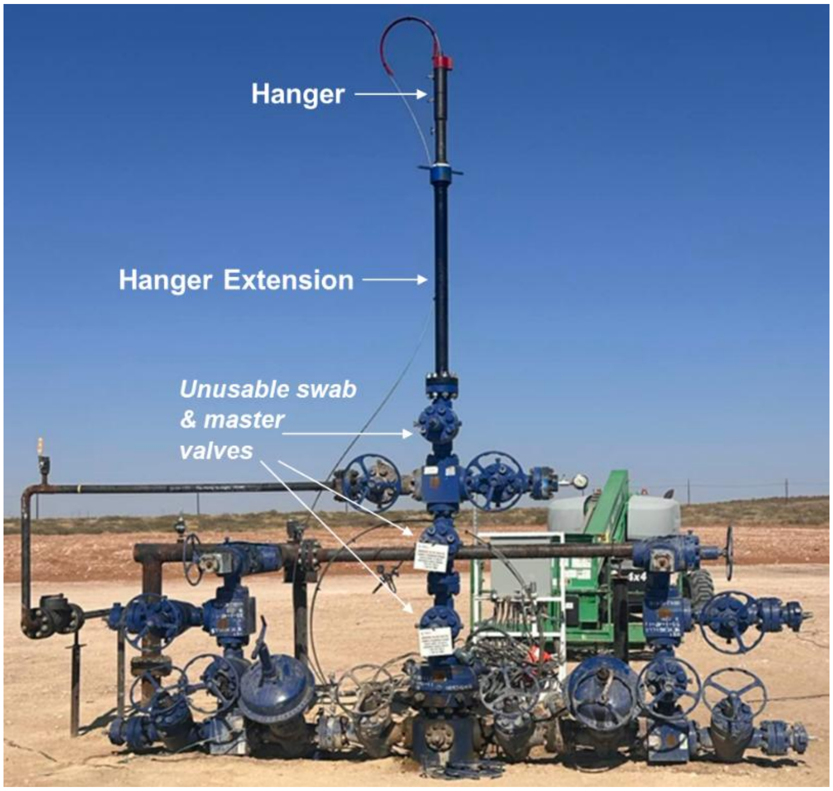


Figure 22: Example installation showing tree configuration with internal capstring system.

Gas Lift & BHA Design Considerations

Some design modifications were required to accommodate the internal capstring system. These changes must be made when the tubing and gas lift design are run, prior to installing the internal capstring.

- Gas Lift Mandrels: Internally mounted (IM) mandrels were traditionally used for LPAGL applications. However, IM mandrels create a restriction in the tubing ID that prevents the internal capstring tools from being run. Thus, conventional fluid mandrels were used to provide an unobstructed tubing ID and protect the Gas Lift Valves (GLVs) from produced fluids in the annulus.
- Bottom Hole Assembly: Past LPAGL designs included a bull plug at the end of tubing (EOT), with no profile nipples run. To accommodate the internal capstring tools, the tubing was run open ended and an XN nipple was added for setting the lower assembly. The open EOT enables the chemical to be injected through the lower assembly and around the EOT.
- Capstring Size: For past LPAGL installs, ¼-in. external capstrings were the most common size. To add weight and increase rigidity during installation, 3/8-in. capstrings were used for internal capstring installations.

Economic Analysis

The objective of the internal capstring was to extend the run life of the tubing installed during FLIs with LPAGL. Most tubing strings develop HITs long before the wells are ready to convert from LPAGL to Tubing Flow Gas Lift (TFGL), which adds an additional workover. Running the internal capstring adds approximately $13K over the traditional external capstring cost but is expected to eliminate a high-dollar workover. With the internal capstring, the expectation is that the tubing will last from FLI (with LPAGL) to its TFGL conversion without requiring a HIT failure workover in between.

CONCLUSIONS

The integrated two-pillar approach to corrosion mitigation in the Texas Delaware Basin demonstrates significant performance improvements and economic benefits:

1. Automated chemical injection systems provide superior accountability and reliability compared to manual rate change programs in highly corrosive environments.
2. Externally coated tubing and internal capstrings extend runtimes beyond one year (current trials >15 months with zero failures), eliminate high-risk failure points (capstrings, clamps, bands), and provide net cost savings when eliminating associated components for LPAGL wells at an economic investment and ease of install.

This integrated approach is enabling the operator’s Texas Delaware asset to significantly reduce corrosion-related failures while improving operational efficiency and economic performance. Trials have shown no failures or negative production impacts to date. This approach is currently being scaled up through the asset. The methodology presented is applicable to other Delaware Basin operations facing similar corrosion challenges.

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