USING HIGH PERFORMANCE INTERNAL PLASTIC COATINGS TO PREVENT CORROSION IN GAS LIFT WELLS

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Abstract

As companies move to lower their operating and maintenance costs, gas lift use has seen a dramatic increase in unconventional production patterns in the Permian Basin[1]. Due to the corrosivity of acid gasses and the corrosive nature of produced water in these wells, asset protection is crucial to provide long term production and minimize costly workovers. In this study, we will review a gas lift well in the Permian basin that utilized internal plastic coatings as their primary source of corrosion mitigation versus chemical inhibition methods.

The results of this study show the ability of a properly selected internal plastic coating in protecting the tubing string and gas lift mandrels from corrosion and scale buildup. By providing a durable barrier between the steel and the corrosive environment, the coating offers a robust and cost-effective solution for maintaining asset integrity. This study highlights the benefits of internal plastic coatings in optimizing production efficiency and reducing operational costs in both the Permian Basin and other unconventional oil and gas regions.

Introduction

Gas lift is a commonly used artificial lift method to produce oil and gas in the Permian Basin. Many operators are utilizing this method to maximize early production and minimize costs versus electrical submersible pumps (ESPs) and other artificial lift methods, but the tubing can still be susceptible to corrosion from the production environment[1].

NOV Tuboscope partnered with a Permian Basin operator that was experiencing multiple hole in tubing (HIT) failures a year despite using a combination corrosion/scale inhibitor on continuous injection. These failures have resulted in costly workovers several times a year, per well, to replace the corroded tubing. After a thorough review of the well conditions, intervention types, and history in this field (Table 1), a modified novolac internal plastic coating system was recommended to protect the tubing string from corrosion. The operator's plan was to abandon the current chemical treatment program and rely solely on internal coatings to prevent corrosion and scale buildup on the tubing string and mandrels. The operator defined a successful trial with the internal coating, as a 12-month run life. The savings from ceasing the corrosion inhibitor continuous injection more than offset the application cost of the internal coating without even considering the workover and tubing replacement costs.

The internal coating system was selected due to its best-in-class chemical and abrasion resistance. Industry practices have dictated the need for internal coating systems to offer greater levels of abrasion resistance to better handle mechanical interventions downhole. The coatings enhanced wear performance enables it to perform well with wireline runs while still maintaining its superior resistance to corrosive species downhole. The thick-film powder coating is based on modified novolac chemistry with a high degree of flexibility and impact resistance. The propriety coating system is designed to extend tubing life as well as provide an increase in hydraulic efficiency due to the coatings low surface roughness (Rz = 1.52 microns).

In addition to corrosion protection, the operator was also looking to prevent scale deposits from adhering to the tubing ID and reducing flow rates. An internal plastic coating aids in mitigating scale from binding to the surface in two ways, mechanical and chemical. The smooth surface of the internal coating helps prevent mechanical binding and the low surface energy reduces the sticking tendency of scale to the coating surface. Figure 1 shows the surface energy results of various polymers, internal plastic coatings and metals.[2]

<u>Data and Results</u>
A 14-month trial was performed where the entire tubing string was internally coated, and the chemical inhibition program was abandoned. The internally coated tubing was installed on 10/28/20 and pulled on 12/21/21 to install an ESP. During the tubing pull, a wellhead inspection service was selected. The use of wellhead inspection allows for sequential tubing condition results that provided vital information for evaluating the condition and effectiveness of our coatings. The scanning process shows wall loss in the tubing due to rod wear and erosion, along with pitting due to corrosive fluids and agents. The technology used during tubing scanning is important to determine these flaws effectively and accurately in the pipe. An NOV Tuboscope Wellchek™ unit was onsite to perform the wellhead scan of the tubing as it was being pulled out of hole. This specific unit has a modified contact EMI (pitting/corrosion) sensor, Isolog Gamma Ray (rod cut/wall loss) detector, and an Eddy Current split detector all providing a more accurate scan when compared to a standard noncontact EMI only. It was determined that contact EMI yields better detection of anomalies in the tubing because the signal is strongest at the surface of the joint. This same contact EMI will provide you with a stronger flux detection while the Gamma portion is the only true measurement of wall loss (rod cut/erosion) which can prevent mirroring commonly seen in EMI only reports.

The tubing scan chart for this gas lift well shows pitting on the left side of the log while Rod wear or erosion is displayed on the right side of the log. All 10,000 ft of tubing pulled scanned yellow band and no pitting was detected throughout the tubing string in this example as seen in Figure 2. Two joints, at 3,000 ft and 9,000 ft were set aside for further coating investigation at NOV Tuboscope's R&D laboratory in Houston, TX. The remaining tubing was run back downhole.

The two joints returned to the lab were sectioned off into pin, center, box and visually examined. A visual evaluation was performed looking for blistering characterized (size, density) as per ASTM D714, swelling, discoloration and chemical attack. No visual signs of blistering, swelling, discoloration or chemical attack were observed. Sample photos in Table 2 also show no scale deposit buildup on the ID of the coating before the samples were cleaned.

Further coating investigation was performed to test the coatings adhesion to the substrate. A modified ASTM standard D6677-01 Knife Adhesion Test was used to evaluate coating adhesion. The knife adhesion test involves the formation of a V shaped groove in the coating that extends to the metal surface (Table 3). With the aid of a 10X magnification, a knife edge is inserted into the groove and operated as a lever with one side of the groove as the fulcrum. This produces a direct upward force lifting the coating from the substrate. The test produces a range of responses that are indicative of the adhesion to the substrate and graded as follows:

- A - No metal exposed. Coating breaks within itself (cohesive failure).
- B - Some metal exposed. More coating showing than metal.
- C - Mostly metal exposed. Some coating remains.
- D - Little or no coating remains on the surface of the metal. Relatively large flakes of coating can be removed with a low amount of effort.
- F - Coating is removed without the use of the knife.

All samples tested for the 3,000ft and 9,000ft joints showed very good to excellent adhesion to the steel, receiving an “A” grade. This indicates that the coating has formed and maintained a strong and durable bond with the steel. The images in Table 3 provide visual evidence of the coating's exceptional adhesion. The red phenolic primer, which serves as the foundation for the topcoat, remains unaffected and intact beneath the surface, demonstrating the coating's ability to adhere without compromising the underlying layers. Furthermore, the adhesion test revealed no signs of softening or weakening of the coating during the downhole trial, confirming its resilience to the harsh conditions encountered in the well environment.

Conclusion

The modified novolac internal coating system successfully passed the 12-month trial period downhole. Laboratory testing proved the coating samples were found to be within Tuboscope’s as applied specifications. In addition to being properly adhered to the substrate, the internal coating system showed no signs of blistering, softening or chemical attack during the 14-month period downhole. After being pulled for inspection, the string of internally coated tubing was run back downhole with an electric submersible pump (ESP) and has continued production.

The tubing scan results and laboratory testing confirm the internal coating recommended is suitable for this well and should continue to be successful in preventing corrosion and mitigate scale buildup in the specified downhole environment, regardless of the production method used. The operator has since standardized on this coating technology for highly corrosive wells in the region that are experiencing several HIT failures.

As of 10/7/24, the well is still producing and has yet to record a hole in tubing failure since introduction of the internal plastic coating.

Tables and Figures

Table 1: Gas Lift Well Conditions

Location:	Pecos, TX
Coating Type:	Modified Novolac
Tubing Design:	2 7/8”, L-80, 6.5#
Environment **BHT:** **BHP:** **CO_2 Concentration:**	 165 °F 4,000 psi 450 ppm

H_2S Concentration: **pH:**	68.4 ppm 6.1 – 7.3
Production **Oil:** **Gas** **Water:**	 200 bbl/day 1.5 mmscf/day 800 bbl/day
Well Depth:	10,000 ft

Figure 1: Surface Energy for Polymers and Metals

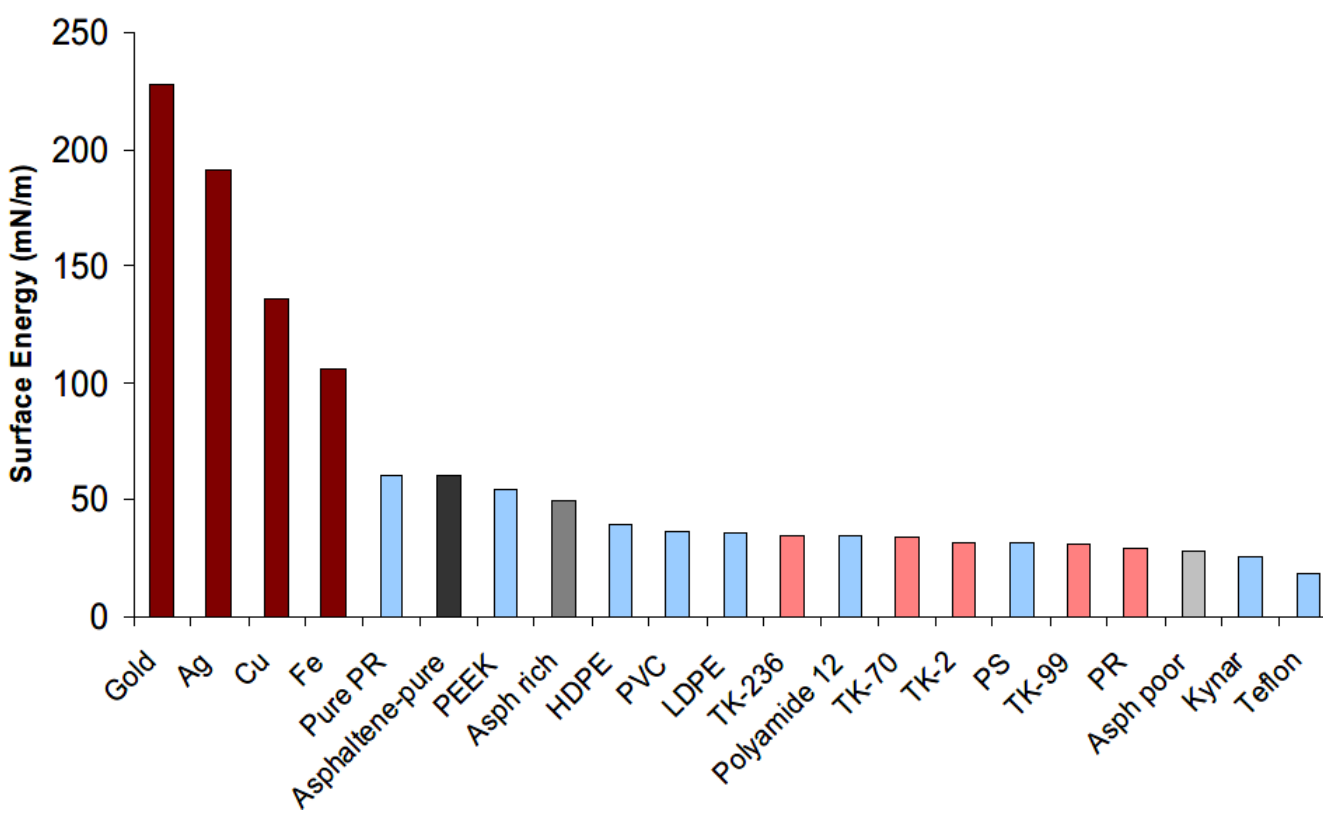


Figure 2: Tubing Scan Results

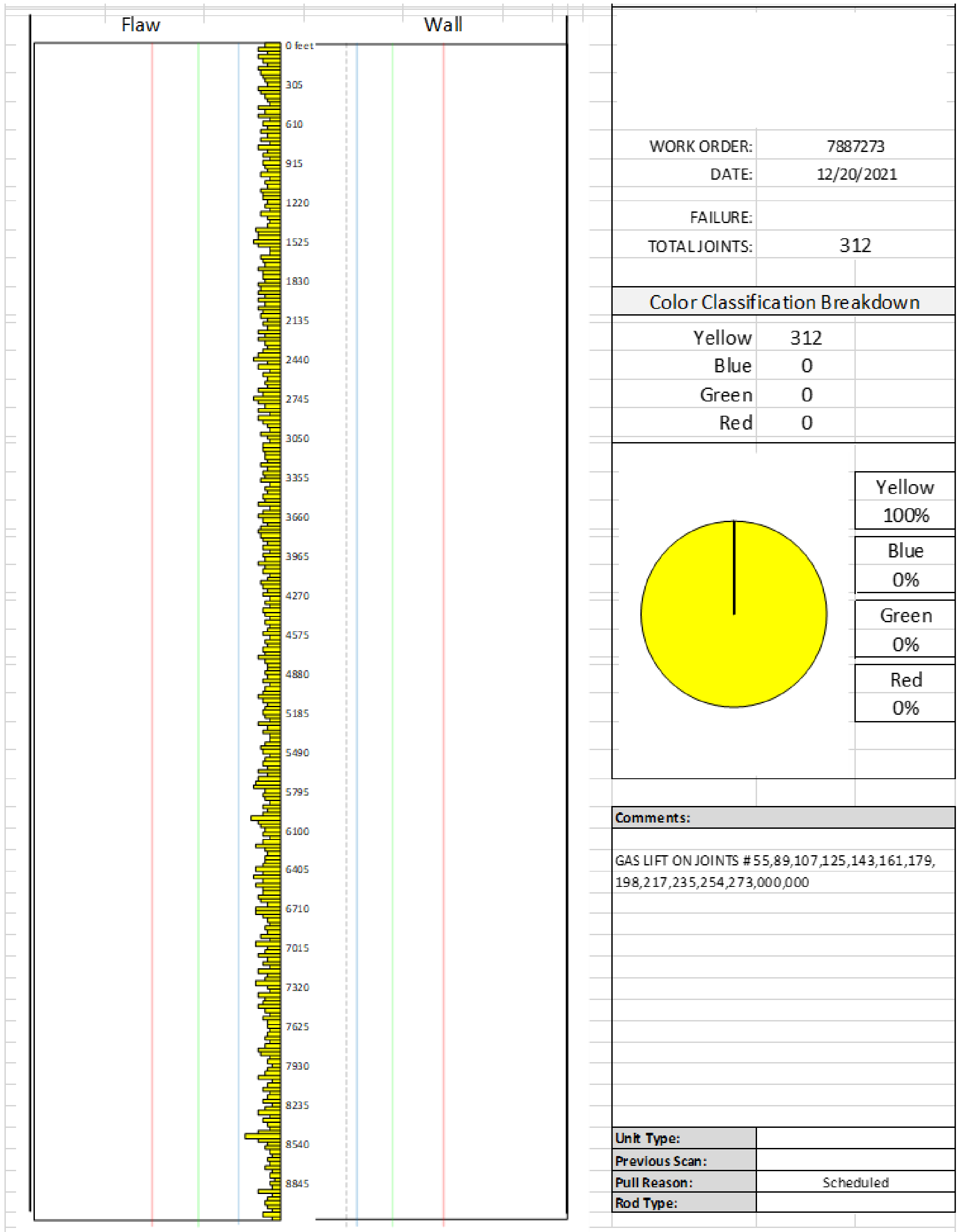
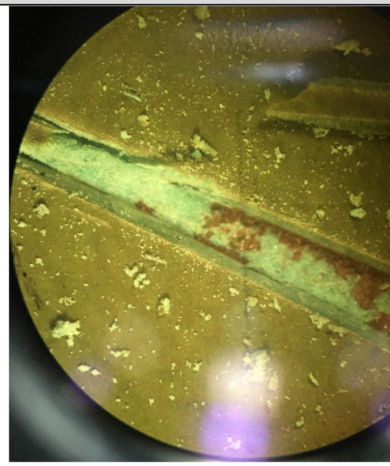
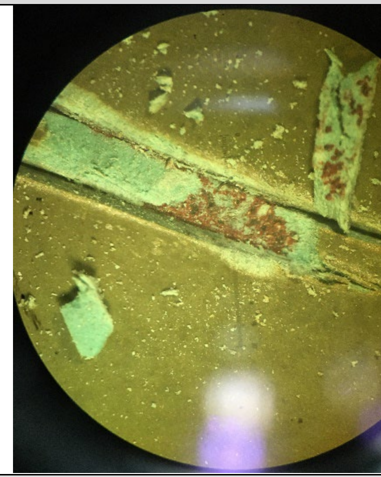
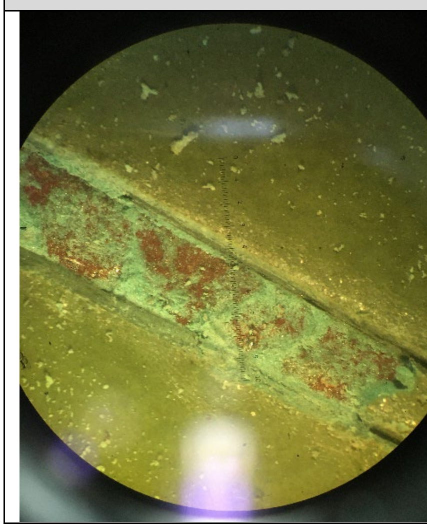
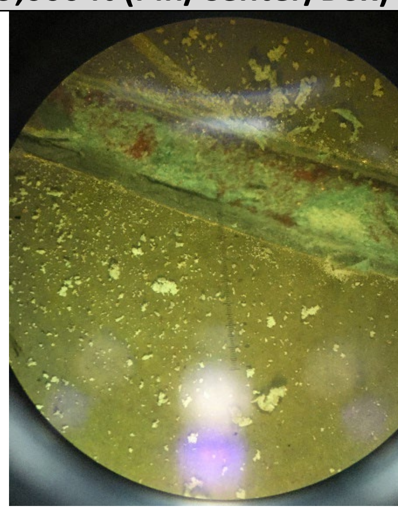


Table 2: Visual Examination of Pipe Samples

3,000 ft	
	
9,000 ft	
	

Table 3: Knife Adhesion Test Images

3,000 ft (Pin/Center/Box)		
		
9,000 ft (Pin/Center/Box)		
		

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