

**Development of a New Corrosion Inhibitor for
Corrosion Under Insulation at Elevated Temperatures**

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ABSTRACT

Explosions, fires, plant shutdowns, injuries and destruction, the majority of these failures, are related to corrosion under insulation (CUI). CUI is often difficult to inspect and detect prior to failure in many industries with vast piping (refining, petrochemical, marine environments, power plants). Despite advances in materials and inspection technologies, CUI remains a serious and costly industry problem. In this investigation, API 5L X65 steel pipes were thermally insulated to evaluate the effectiveness of a new vapor phase corrosion inhibitor against CUI. Corrosion behavior was monitored under isothermal and cyclic wet/dry test conditions at 77 °C and 177 °C. Test results demonstrated that this corrosion inhibitor can successfully reduce corrosion attack under insulation even in a chronic wet environment. When this inhibitor was added to a 200 ppm salt solution and tested at boiling temperature, the corrosion rate was reduced by a factor of 15. The chemical analysis of the samples after corrosion testing revealed the formation of a protective Mo-rich inhibition compound on the pipe surfaces. To prolong pipe integrity and lower inspection and maintenance cost, the application of a protective coating system under the insulation is critical. The new vapor corrosion inhibitor when added to the thermal insulation provided highly effective corrosion resistance.

Key words: corrosion under insulation, corrosion inhibitor, pipeline steel, localized corrosion

INTRODUCTION

Corrosion Under Insulation (CUI) is the corrosion of piping, tanks and equipment under insulation that can occur when moisture penetrates the interface between insulation and the pipe or equipment and helps to create a corrosion cell. CUI is one of the costliest problems shared by refining, petrochemical, power, industrial, onshore and offshore industries. The inspection process is labor intensive and requires removing the insulation to detect CUI. CUI is a huge concern and needs specific attention and investment. Explosions, fires, plant shutdowns, injuries and destruction are corrosion related failures often due to CUI. More specifically, for refining, petrochemical, marine environments and power plants, industries with vast amounts of piping, the cause of production delay is corrosion damage under insulation that makes it difficult to inspect and detect prior to failure [1-5]. For corrosion under insulation, there are further complications from having to inspect the structures to ascertain the existence and extent of corrosion. Maintenance and plant inspection become labor and time intensive when large quantities of insulation must be removed. Despite advances in materials and inspection technologies, CUI remains a serious and costly industry problem. CUI can have detrimental effects on production volumes, can cause long-period plant shutdowns and can result in sudden and hazardous material leakage. A study done by Exxon Mobil Chemical in 2003 indicated that: The highest incidence of leakage in the refining and chemical industries is due to CUI. Between 60 and 80 percent of piping maintenance costs are related to CUI [6]. These numbers indicate that CUI is the major concern and with suitable preventive measures, millions of dollars can be saved annually [7].

The root cause of CUI is the presence of moisture and corrosive species at either the insulation-pipe interface or the equipment surface under insulation where there is a temperature differential. This difference in the temperature at the interface (between the insulation and the pipe) is below the dew point and results in condensation when the air is cooling down. Condensation creates moisture at the interface. Moisture combined with oxygen can lead to corrosion. The restricted geometry of the insulation material over the pipe, tank or other equipment, accumulates moisture that can develop into an electrochemical cell resulting in corrosion attack. The insulation promotes severe crevice corrosion attack that is exacerbated where degree of wetness and duration are high [7-10].

Three major factors that are essential to initiate CUI are: 1) presence of water/moisture in the insulation system and specifically at pipe/insulation interface; 2) temperature of the system and surrounding atmosphere; 3) corrosive contaminants in water [10].

Water or moisture must be present on the substrate for an electrochemical reaction to occur. Water can enter the system in various ways such as: during installation of the insulation, if there are punctures, leakages, slipped jackets, seal deterioration, temperature differentials or condensation. The water may remain depending on the absorption properties of the insulation material and the operating temperature. Depending upon process conditions, water saturated insulation may not dry out completely.

CUI occurs in a temperature range from -4 to 175 °C (25-347°F) where water is liquid. Systems with fluctuating temperatures are more susceptible to CUI, especially in pipelines with repetitive cooling and warming. In general, the metal temperature will be approximately the same as the process operating temperature (for insulated equipment). However, if the insulation is damaged

and/or highly humid conditions commonly exist, a process temperature significantly above 121 °C (250 °F) can result in metal temperatures low enough to cause CUI; therefore, the CUI range is extended to 175 °C (347 °F).

Chloride and sulfide are the primary contaminants and generally increase the corrosivity of the water. Contaminants can come from the environment, such as marine environments (e.g., offshore), or windborne salts from cooling tower drift, or from periodic testing of firewater deluge systems. These contaminants can cause problems for carbon-manganese steels, low-alloy steels and austenitic stainless steels. Contaminants can also be produced by leaching from the insulation material. In the presence of an applied or residual stress and temperatures exceeding 60 °C, water with high chloride content can contribute to stress corrosion cracking [4-7].

Piping systems may have specific locations that are more susceptible to CUI. These include the following areas: dead legs (vents, drains, etc.), pipe hangers and other supports, valves and fittings (irregular insulation surfaces), bolted-on pipe shoes, steam and electric tracer tubing penetrations, termination of insulation at flanges and other piping components, damaged or missing insulation jacketing, insulation jacketing seams located on the top of horizontal piping or improperly lapped or sealed insulation jacketing, termination of insulation in a vertical pipe, caulking which has hardened and separated or is missing, and low points in piping systems that have a known breach in the insulation system, including low points (normally referred to as “six o clock” position) in long unsupported piping runs.

CUI is a silent phenomenon, detection of the damage without removing insulation is costly and time consuming. Managing CUI can be done by detection of CUI and then prevention of CUI. There are several methods that can be used for detection of CUI. CUI detection methods include: monitoring of CUI by acoustic emission & humidity measurement [10], using pulsed eddy current technique [3], CUI by Pipe-CUI-Profiler [9], and using Risk-Based Inspection (RBI) to design CUI inspection plans [2].

This paper focuses on CUI mitigation and recommendation of a prevention method. The best way to minimize CUI is to avoid insulation, though this is not always practical [1]. Insulation is necessary for many reasons such as process requirements, heat conservation, fire protection, noise, preventing freezing or condensation, and personal protection. Conventional CUI prevention methods that are widely used in oil, gas and petrochemical industry consist of the following practices: design and install the insulation system to exclude water ingress, application of a suitable organic protective coating to resist corrosion, or vapor phase corrosion inhibitors.

In this investigation the effectiveness of a new vapor corrosion inhibitor (VCI) against CUI on the API 5L X65 steel pipes was studied. Corrosion behavior was monitored under isothermal and cyclic wet/dry test conditions at 77 °C and 177 °C (170-350 °F). Test results have demonstrated that this new corrosion inhibitor can successfully reduce corrosion attack under insulation even in a chronic wet environment. When this new VCI was added to a 200 ppm salt solution and tested at boiling temperature, the corrosion rate was reduced by a factor of 15. The chemical analysis on the samples post corrosion tests revealed formation of a protective molybdenum rich compound on the pipe surfaces. The results showed that an effective protective coating system under the insulation is critical and requires the inclusion of corrosion inhibitor to prolong the pipe integrity and lower inspection and maintenance cost.

EXPERIMENTAL PROCEDURE

The corrosion behavior of API 5L X65 steel pipe (ISO 3183 L450) was investigated. Samples of this material (2.5 cm (1 inch) length x 2.5 cm (1 inch) diameter pipe) were used for the total immersion tests in boiling water consistent with the ASTM G123 test practice (Erlenmeyer flask and condenser, hot plate to maintain boiling temperature, Figure 1). Tests were conducted in a control solution of 200 ppm Cl⁻, no inhibitor, or in a solutions containing 1.0% VCI or 5.0% VCI added to the control solution. The test duration was 240 hours with surface condition of exposed samples documented after 120 hours and 240 hours.

CUI tests were conducted on API 5L X65 pipes. These pipe samples (40.6 cm (16 inches) length x 5 cm (2 inches) diameter) were insulated with (2.0 cm or ~0.8 inch thick) thermal insulation and sealed with aluminum sheet. All pipes were sand blasted, machined and polished to 600 grit using silica carbide abrasive papers and rinsed with alcohol prior to use. Three samples were assembled, one sample was used as a control (no inhibitor applied), and two samples were wrapped with thermal insulation that was impregnated with inhibitor. The effectiveness of this inhibitor was evaluated at 77 °C (isothermal). Two other pipe samples were placed in in a cyclic corrosion test chamber for 240 hours; one test cycle was equal to 24 hours at 77 °C, followed by 24 hours at 177 °C. An aliquot of 20 ml of 200 ppm sodium chloride solution was injected by an Inconel tube into the pipe/insulation interfaces every 24 hours [11-12]. The samples were disassembled every 96 hours for visual inspection and evaluation. SEM/EDS analysis was conducted on all surface discoloration after CUI corrosion tests.



Figure 1: Corrosion set up for testing steel pipe in 200 ppm Cl⁻ solution at boiling temperature (100 °C) with and without inhibitor.

RESULTS

The corrosion behavior of API 5L X65 steel pipe was investigated using immersion corrosion and CUI tests at different elevated temperatures. Segments of steel pipe were subjected to total immersion in boiling water with inhibitor and without inhibitor (control sample) using similar apparatus recommended in ASTM G123 (Figure 1). These tests were conducted in a control solution (200 ppm Cl⁻ solution, no inhibitor), and solutions with 1.0% and 5.0% VCI addition. Test duration was 240 hours. Figure 2 shows a comparison of samples tested with and without inhibitor for 120 and 240 hours in the elevated temperature in total immersion conditions. The

inhibitor successfully protected the pipe samples against corrosion attack, the control samples were heavily corroded. In Figure 3, the graph shows the corrosion behavior of the steel pipes in the boiling water solutions. The control sample with no inhibitor shows a significantly higher corrosion rate and an increasing trend with time. The corrosion rate was ~5.3 mpy (mils per year) for the control samples, the 1.0% VCI treated solution corrosion rate was ~0.42 mpy, and 5.0% VCI treated solution showed a 0.36 mpy.

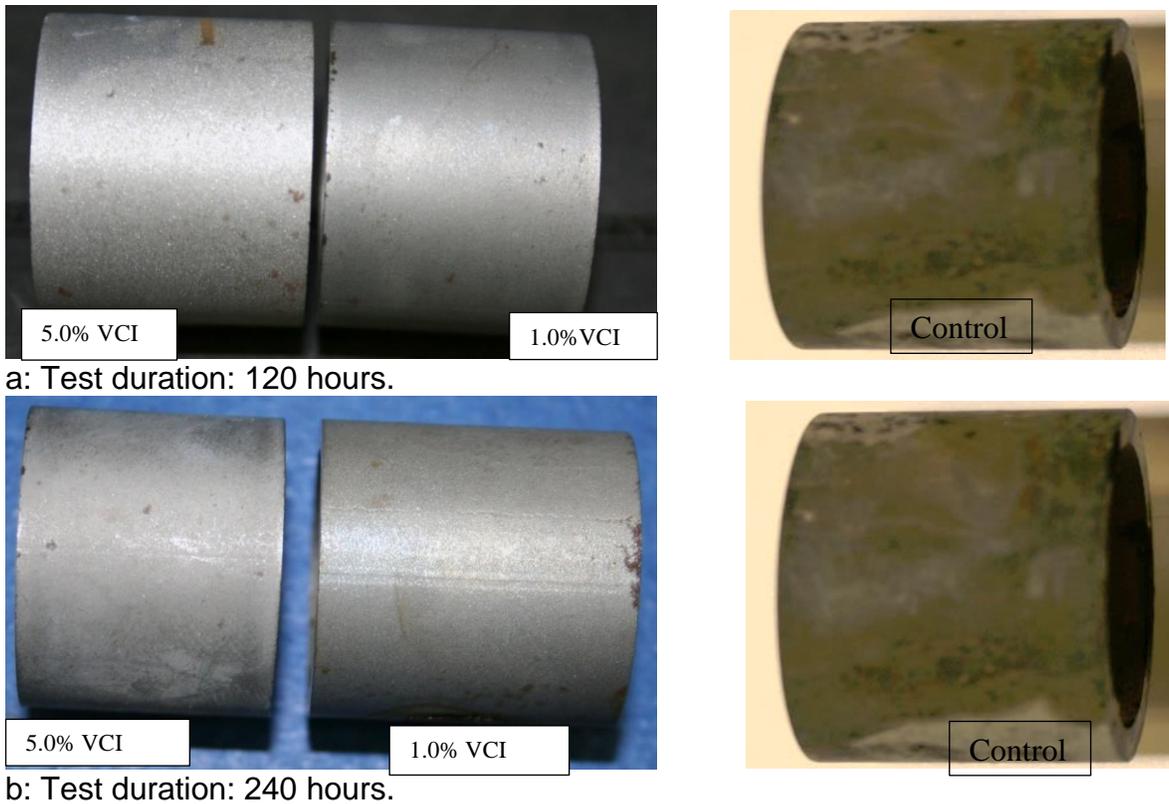


Figure 2: Corrosion behavior of steel pipe with addition of 1.0% or 5.0% VCI compared to control sample in 200 ppm Cl⁻ solution in boiling temperature (100 °C) for 120 and 240 hours.

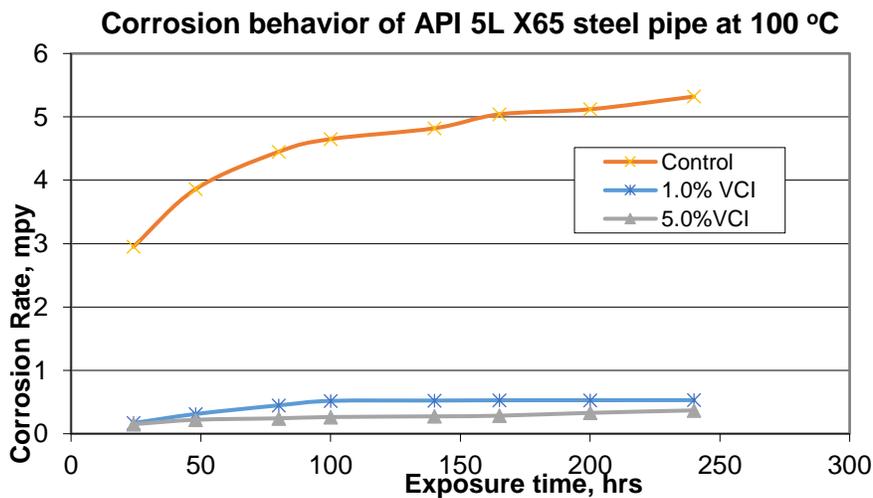


Figure 3: Corrosion behavior of steel pipes in boiling water solution at 100 °C. Control sample (with no inhibitor) shows highest corrosion rate.

Corrosion rates for both VCI treated solutions were very satisfactory and sample surfaces were corrosion free. The scanning electron microscope (SEM) images show corrosion free surfaces for the samples protected with inhibitor in Figure 4. The SEM/EDS analysis on the steel pipe in 1.0% and 5.0% VCI in 200 ppm Cl⁻ solution in boiling temperature for 240 hours, shows formation of Molybdenum -rich protective film on the surface (Figure 5).

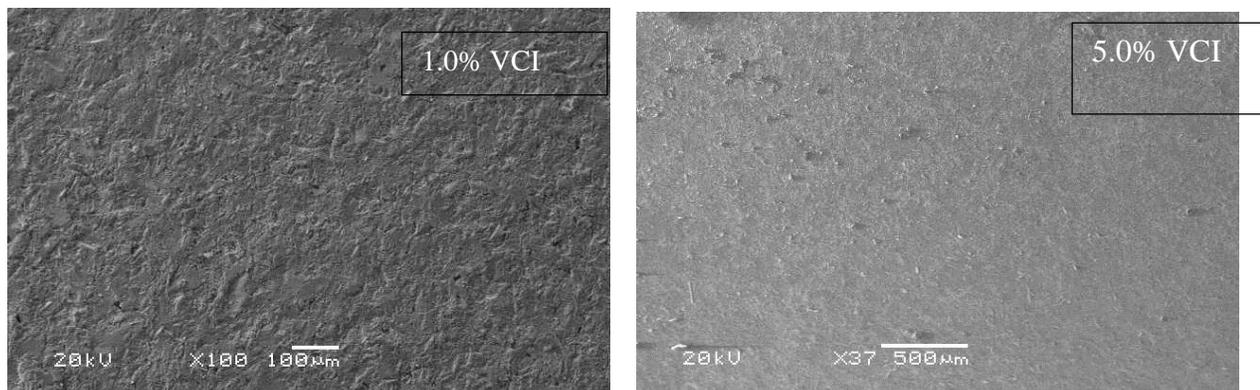
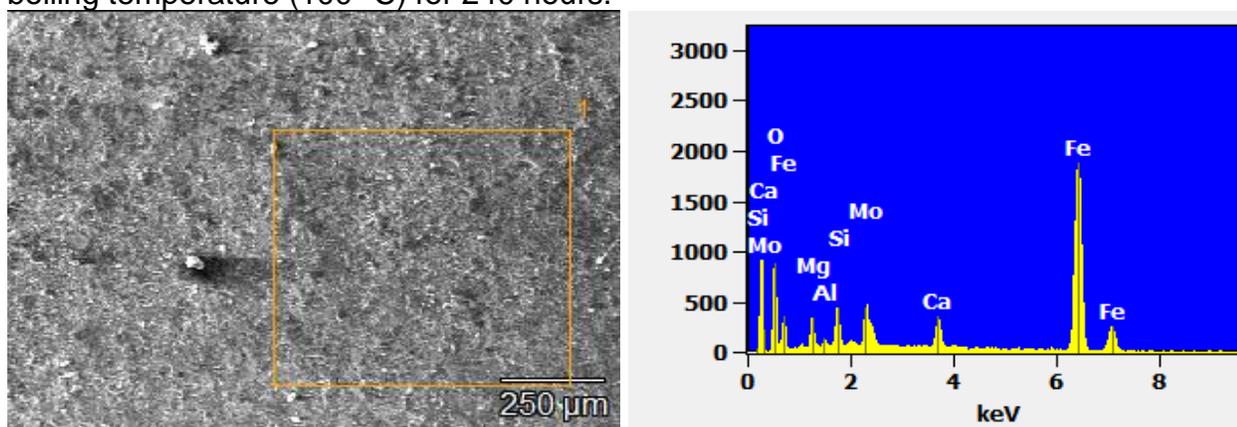


Figure 4: SEM micrographs of steel pipe with 1.0% and 5.0% VCI in 200 ppm Cl⁻ solution in boiling temperature (100 °C) for 240 hours.



Weight %	O	Mg	Al	Si	Ca	Fe	Mo
VCI 1_pt1	13.13	3.07	0.83	3.59	3.54	67.73	8.11

Figure 5: SEM/EDS analysis on the steel pipe in 1.0% and 5.0% VCI in 200 ppm Cl⁻ solution in boiling temperature (100 °C) for 240 hours, shows formation of Mo-rich protective film on the surface

Figures 6 and 7 show localized corrosion attack and red rust formation on the non-protected API 5L X65 steel pipe after 240 hours in cyclic corrosion tester. The inhibitor coated pipe showed no corrosion. Figure 8 shows the surface condition after CUI testing in thermal cycling conditions. Surface discolorations were observed on the tested pipe samples (Figure 8). Chemical analysis on surface deposits showed no corrosion species, but instead formation of the protective Mo-compound (the inhibitor is a molybdate base). The inhibitor treated pipes were relatively clean and free of corrosion. Figures 9 through 11, SEM/EDS analysis, showed formation of a molybdenum rich protective film on the tested pipe surfaces and no iron oxide formation was

detected The results verified that the VCI inhibitor formed a dry, hydrophobic film on the pipe and protected the pipe surface.

CONCLUSIONS

The effectiveness of vapor corrosion inhibitor against CUI was investigated. CUI and corrosion tests in isothermal and cyclic conditions showed significant improvement in corrosion performance of steel pipes. Results have demonstrated that this new inhibitor can successfully reduce corrosion attack under insulation despite pipe surfaces being in continuously wet/dry cyclic conditions. The corrosion rate measurement using immersion tests in boiling solution showed corrosion rate decreased from ~5.3 mpy (for the control samples) to less than 0.36 mpy (for the VCI treated samples). This is a reduction in the corrosion rate by a factor of 15 for the pipes protected with corrosion inhibitor. Both concentrations of 1.0% and 5.0% VCI showed a high degree of effectiveness in reducing corrosion. Therefore, application of 1.0% VCI is economically feasible compared with the Risk-Based Inspection (RBI) to design CUI inspection plans and costs.

Isothermal CUI tests at 77 °C, showed corrosion free surfaces for the VCI treated steel pipes, however, non-treated steel pipe surfaces suffered corrosion. Thermally cycled CUI tests of steel pipes showed some surface discoloration but were corrosion free. Chemical analysis showed the formation of a molybdenum rich protective film on the pipe surfaces and no iron oxide formation.

This investigation demonstrated that an effective protective coating system under the insulation is critical. Application of this new inhibitor can prolong the pipe integrity and reduce inspection and maintenance cost at elevated temperature

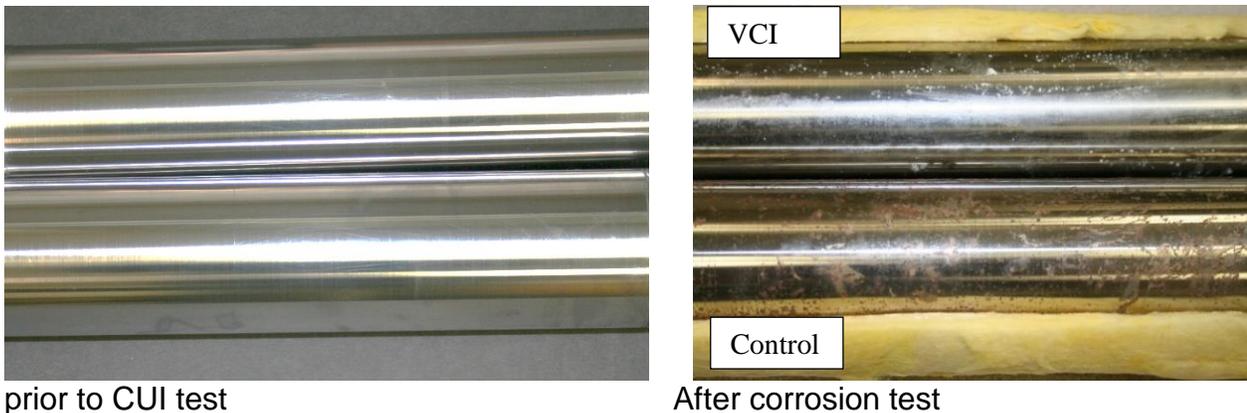


Figure 6: Surface condition of the pipe subjected to CUI tests after 240 hours at isothermal 77 °C and 20 ml of Cl- containing solution injected into pipe/insulation interface. Control sample showed localized corrosion and red rust formation.

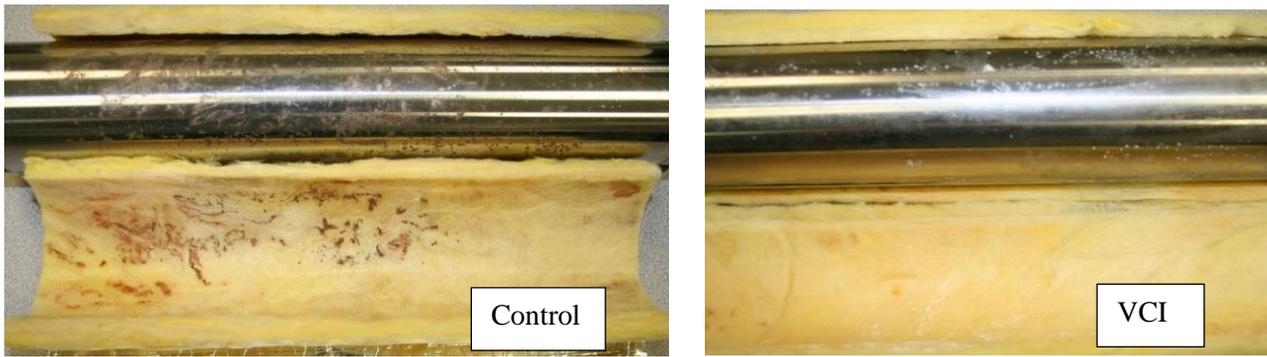


Figure 7: Surface conditions of the pipe and insulation subjected to CUI tests after 240 hours at isothermal 77 °C. Control sample showed localized corrosion and red rust formation. No sign of corrosion attack was observed on VCI treated sample.

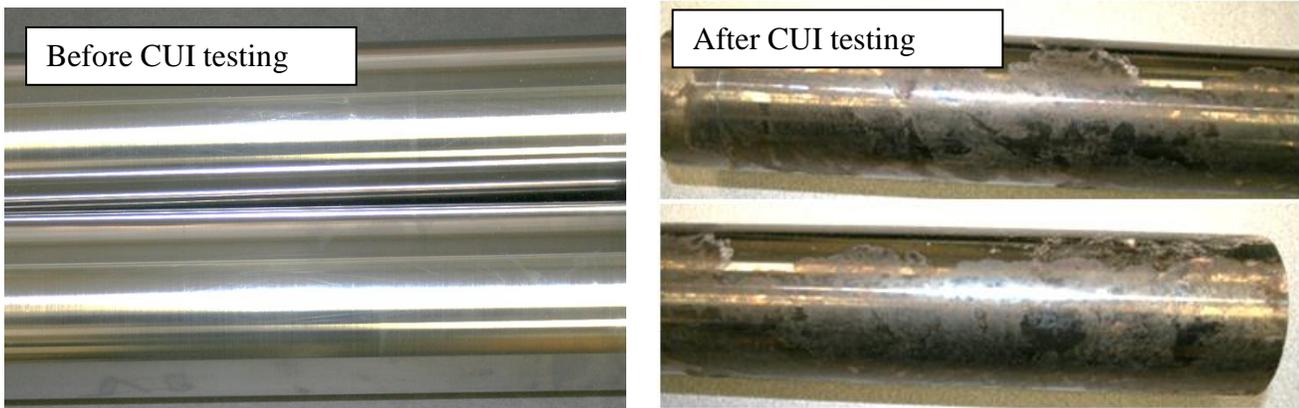


Figure 8: CUI tests on VCI coated pipe at thermal cycling between 77 and 177°C after 5 cycles with salt injection (240 hours), show outer surface discoloration, but no corrosion on pipe surface.



Figure 9: Pipe surface condition after CUI tests of the VCI coated pipe after five cycles of thermal cycling at 77 and 177°C, show morphology of surface deposits.

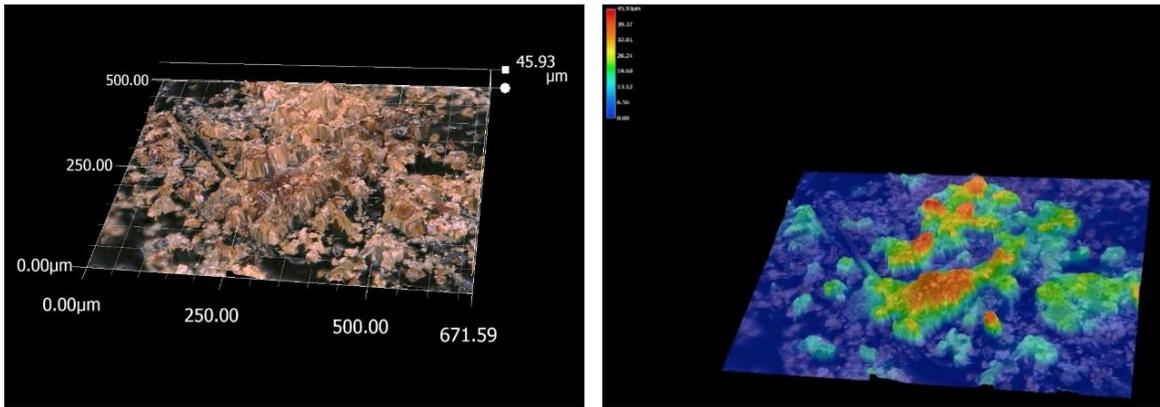
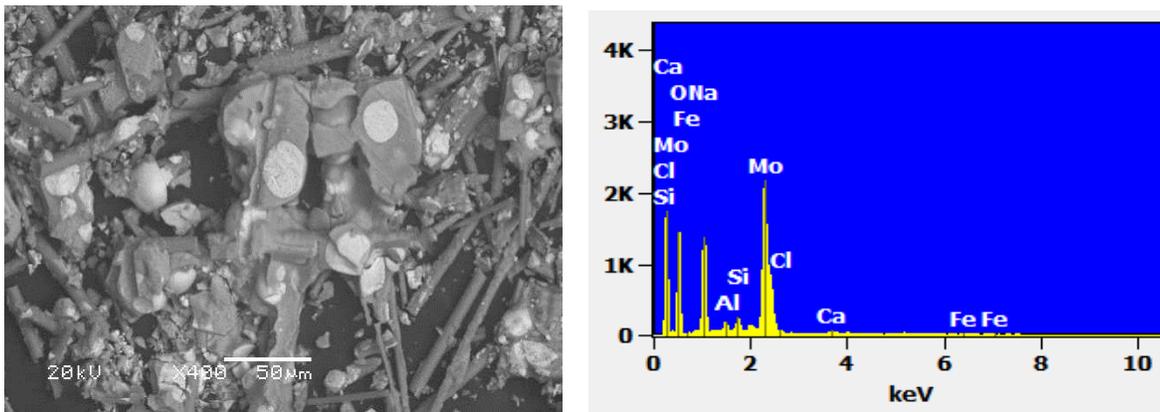


Figure 10: Surface condition of after CUI tests on VCI coated pipe at after five cycles of thermal cycling at 77 and 177°C. SEM/EDS analysis showed that there are Mo-rich deposits. No steel corrosion was detected in these deposits.



Weight %	O	Na	Al	Si	Cl	Ca	Fe	Mo
VCI_2_pt1	41.84	14.94	0.87	1.16	0.18	0.56	0.13	40.33

Figure 11: SEM/EDS analysis showed they are Mo-rich deposits (inhibitor compound) after CUI tests on VCI coated pipes five cycles of thermal cycling at 77 and 177°C. The detected iron level is very low indicating no corrosion of the pipe.

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