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Effect of Injection Method Towards Volatile Corrosion Inhibitor Efficacy in Wet Gas Pipelines

(Kesan Kaedah Suntikan terhadap Keberkesanan Perencat Kakisan Meruap dalam Saluran Paip Gas Basah)

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ABSTRACT

Pigging is performed before the injection of Volatile Corrosion Inhibitors (VCIs) to remove corrosion products and other residues from the internal surface of the pipeline. This process results in pre-corroded surface conditions, which raises concerns regarding the effectiveness of VCIs under such circumstances. Additionally, optimal dosage and injection method are critical for VCI to serve a dual role in mitigating top-of-line corrosion and bottom-of-line corrosion in wet gas pipelines. In this study, 1000 ppm VCI was injected using batch and continuous methods under non-corroded and pre-corroded conditions to evaluate the performance of API 5L X65 carbon steel using a TLC setup following the weight loss method (ASTM G1-03). Experimental results demonstrate that the VCI significantly reduces uniform corrosion rates (UCR) particularly at the bottom-of-line, achieving a maximum of 98% inhibition efficiency. However, with the overall pitting rates (PR) were reduced, localized attacks became the dominant. The VCI continuous injection method proved more effective in reducing the general corrosion severity but remained insufficient for controlling localized pitting case. On the other hand, pre-corrosion conditions facilitate VCI effectiveness in reducing severity at the top-of-line; however, this effect is not observed at the bottom-of-line. Lifespan predictions correlated closely with both UCR and PR, showing that high-dosage VCI application via either batch or continuous injection alone does not provide adequate long-term protection, regardless of the initial surface condition. These findings suggest that a hybrid approach combining multiple injection methods may be necessary to further mitigate corrosion severity and extend the operational lifespan of the pipeline.

Keywords: Batch injection method; bottom-of-line corrosion; continuous injection method; pre-corroded condition; top-of-line corrosion; volatile corrosion inhibitor

ABSTRAK

Pigging dilakukan sebelum suntikan Perencat Kakisan Meruap (VCI) untuk membuang produk kakisan dan sisa lain dari permukaan dalaman saluran paip. Proses ini mengakibatkan keadaan permukaan pra-karat yang menimbulkan kebimbangan mengenai keberkesanan VCI dalam keadaan sedemikian. Di samping itu, dos optimum dan kaedah suntikan adalah penting untuk VCI memainkan peranan ganda dalam mengurangkan kakisan atas dan kakisan bawah dalam saluran paip gas basah. Dalam kajian ini, 1000 ppm VCI telah disuntik menggunakan kaedah kelompok dan berterusan di bawah keadaan tidak berkarat dan pra-karat untuk menilai prestasi keluli karbon API 5L X65 menggunakan persediaan TLC mengikut kaedah penurunan berat (ASTM G1-03). Keputusan uji kaji menunjukkan bahawa VCI mengurangkan kadar kakisan seragam (UCR) dengan ketara terutamanya di bahagian bawah, mencapai kecekapan perencatan maksimum 98%. Walau bagaimanapun, dengan kadar lubang keseluruhan (PR) dikurangkan, serangan setempat menjadi dominan. Kaedah suntikan berterusan VCI terbukti lebih berkesan dalam mengurangkan tahap keterukan kakisan umum tetapi masih tidak mencukupi untuk mengawal kes bopeng setempat. Sebaliknya, keadaan pra-karat memudahkan keberkesanan VCI dalam mengurangkan tahap keterukan di bahagian atas talian; walau bagaimanapun, kesan ini tidak diperhatikan di bahagian bawah talian. Ramalan jangka hayat berkait rapat dengan UCR dan PR, mendedahkan bahawa aplikasi VCI dos tinggi melalui suntikan kelompok atau berterusan sahaja tidak memberikan perlindungan jangka panjang yang mencukupi, tanpa mengira keadaan permukaan awal. Penemuan ini menunjukkan bahawa pendekatan hibrid yang menggabungkan pelbagai kaedah suntikan mungkin diperlukan untuk mengurangkan tahap keterukan kakisan dan memanjangkan jangka hayat operasi saluran paip.

Kata kunci: Kaedah suntikan berterusan; kaedah suntikan kelompok; kakisan bahagian atas talian; kakisan bahagian bawah talian; keadaan pra-karat; perencat kakisan meruap

INTRODUCTION

Pipelines remain the preferred method for transporting oil and gas because they enable efficient and continuous movement of fluids over long distances with relatively low operational cost. In 2025 alone, the global oil and gas pipeline market size was valued at USD 155.28 billion (Fortune Business Insights 2026). Meanwhile, carbon steel remains the primary material for pipelines worldwide due to its strength and low cost, with market growth driven by rising demand and emphasis on pipeline safety and integrity (Askari, Aliofkhazraei & Afroukhteh 2019; HTF Market Intelligence 2025).

However, looking at 20 years of trend between 2006 and 2025, Pipeline and Hazardous Materials Safety Administration (PHMSA) under the U.S. Department of Transportation has recorded 2387 incidents caused by corrosion with a cost damage of USD 1.3 billion, and the internal corrosion accounting for approximately 60%. Another record in 2013-2017 alone, approximately 12% of incidents on gas transmission, gas gathering, and hazardous liquid pipelines and less than half of 1% of incidents on natural gas distribution pipelines were caused by internal corrosion (Pipeline and Hazardous Materials Safety Administration 2025). This phenomenon has been documented as a key driver of material loss and structural degradation in operating oil and gas pipelines (Farh, Ben Seghier & Zayed 2023). This internal pipeline deterioration due to corrosion occurs, because of electrochemical reactions between the pipeline material and the transported fluids. Oil and gas pipelines typically operate under multiphase flow conditions containing brine or water, hydrocarbons, acidic gases and frequently entrained solids, all of which contribute to corrosion processes (Abdu, Khalifa & Abdelrahman 2023; NACE International 2024; Zhao et al. 2018).

In wet gas pipelines, two common internal corrosion mechanism are bottom-of-line corrosion (BLC) and top-of-line corrosion (TLC) (Figure 1). Bottom-of-line corrosion occurs in the lower section of the pipeline where water accumulates due to gravity, creating a corrosive aqueous phase that directly contacts the steel surface (Chanda 2013). In contrast, top-of line corrosion occurs at the upper internal wall of the pipeline due to the condensation of the water vapour containing dissolved corrosive gases such as CO_2 or H_2S (Singer 2017). This condensed water forms an acidic electrolyte that attacks the pipeline surface even in an environment where bulk liquid water is absent (Larrey & Gunaltun 2000; Nyborg & Dugstad 2007). These types of internal corrosion are increasingly recognized in the industry (NACE International 2024) as one of the causes of failure in incidents involving several wet gas pipelines worldwide (Al-Moubaraki & Obot 2021; Askari, Aliofkhazraei & Afroukhteh 2019).

To mitigate internal corrosion, corrosion inhibitors are widely implemented, as the most cost-effective method for protecting internal pipeline surfaces by adsorbing onto the steel surface and forming a protective film that slow down metal dissolution reaction (Shwetha, Praveen & Devendra 2024). A particular type of corrosion inhibitor known as volatile corrosion inhibitors (VCIs) has been studied for mitigating TLC (Bastidas, Cano & Mora 2005; Eslami & Singer 2022; Punpruk 2010). These compounds possess sufficient vapour pressure to distribute through the gas phase and condense onto the pipeline surface, where a condensed film forms; they also form adsorbed molecular films that can serve dual functions - protecting both the top-of-line and bottom-of-line regions under simulated pipeline conditions.

Corrosion inhibitor delivery methods significantly influence the inhibition efficiency, and two common approaches are batch or continuous injection methods (NACE International Standard Practice SP21469 Corrosion Inhibition Selection and Management for Oil and Gas Production, 2021). In batch injection method, the VCI is

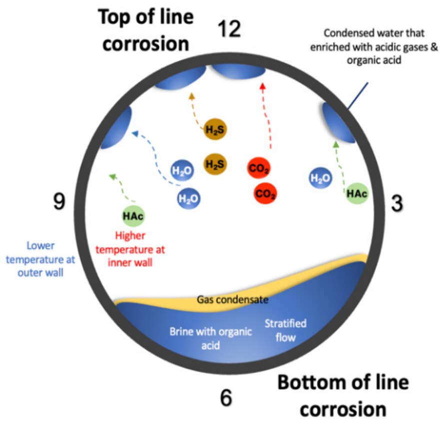

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FIGURE 1. Cross section of pipeline showing the top-of-line corrosion and bottom-of-line corrosion

injected periodically based on operational needs (Bahadori et al. 2024; Eslami & Singer 2023; Gunaltun & Belghazi 2001) and typically at a relatively high concentration (Pacheco, Ibrahim & Franco 2010). In contrast, continuous injection method offers the advantage of maintaining a steady VCI flow throughout production without affecting productivity, typically at a lower concentration (Bahadori et al. 2024; Sonke & Grimes 2017).

With either method, pigging is performed before VCI injection to remove corrosion buildup that could reduce inhibitor effectiveness (Laycock et al. 2024; Simon Thomas 2000; Sonke & Grimes 2017). However, pigging may not be fully effective, leaving residual deposits, especially in older pipelines that have accumulated significant corrosion products and scale (Adaze, Badr & Al-Sarkhi 2023; Mand, Longwell & Enning 2019; Mosher, Lam & Tsaprailis 2016). Additionally, pigging duration depends on pipeline length, resulting in extended exposure of the unprotected internal surface and allowing new corrosion products to form prior to corrosion inhibitor injection. These situations that occur to this 'pre-corroded surface' raise concerns about the efficacy of VCI to mitigate further corrosion attacks.

Therefore, this study evaluates VCI efficiency using batch and continuous injection on non-corroded and pre-corroded API X56 5L specimens, based on uniform and pitting corrosion rates, to predict pipeline lifespan. Fixed steel and gas temperatures are maintained to promote high water condensation, enabling comparison of inhibition performance between the injection methods.

METHODOLOGY

MATERIALS

A commercial volatile corrosion inhibitor (VCI) was employed in this study, and the test specimens consisted of API 5L X65 carbon steel. The bottom solution, with a total volume of 1600 mL, was prepared using distilled water containing 1000 ppm sodium chloride, 500 ppm acetic acid, and 1.25% (v/v) gas condensate. Following the experimental procedure, the specimens were cleaned using Clarke's solution, composed of 93% concentrated hydrochloric acid, 2% antimony trioxide, and 5% stannous chloride. Additional chemicals utilized in the experimental setup included 12,500 ppm sodium hydroxide for gas discharge filtration and neutralization and activated carbon, which were applied in the filtration unit.

METHODS

All tests were conducted following three experimental stages: pre-experiment, during experiment, and post-experiment. Experimental setups and operating parameters remained consistent across all runs, with variations limited to VCI concentration and the condition of the metal specimens. The control test was conducted using non-corroded specimens without VCI. Batch injection tests at 1000 ppm VCI were carried out under two conditions: non-corroded specimens and pre-corroded specimens. Meanwhile, the continuous injection test at 1000 ppm VCI was performed only with non-corroded specimens.

The VCI was introduced at the beginning of the experiment for both the batch injection tests with non-corroded specimens and the continuous injection tests. For the batch injection tests involving pre-corroded specimens, VCI was introduced only after 48 h to allow the specimens to develop a pre-corroded surface. All experiments were conducted over a period of five days, except for the continuous injection test, which extended to seven days as the bottom solution required replenishment on the third day of operation, together with an additional dose of 1000 ppm VCI. The test matrix is summarized in Table 1 while the overall configuration of the TLC unit is illustrated in Figure 2(a).

Pre-experiment method

Three main components were prepared prior to each experimental run. First, four metal specimens, as illustrated in Figure 2(b), were mechanically polished using silicon carbide abrasive papers of progressively finer grades to obtain a uniform surface condition. Second, a brine solution containing gas condensate was prepared to simulate the corrosive test environment. Third, the experimental arrangement consisted of the complete TLC glass apparatus together with an integrated series of filtration and neutralization units connected to the main TLC equipment to ensure safe handling and treatment of the effluent stream.

To simulate the top section of the pipeline interior, two metal specimens were mounted on holders with their uncoated surfaces exposed to the inner glass cell environment, while two additional specimens were suspended by strings and immersed in the bottom solution to represent the lower pipeline region. The lid was designed with dedicated openings that allowed flush mounting of the specimen holders and provided access for a temperature probe to measure the steel surface temperature. A condensation environment was established by circulating cold water around the specimen holders while simultaneously heating the bottom solution with a hot plate. Condensed water was collected using two funnels positioned directly beneath the top specimens. The setup also included a thermocouple to monitor gas temperature, a liquid injector for VCI dosing, and a sparger to introduce gas into the system. The outlet gas stream passed through a condenser to reduce vapor losses and limit depletion of the bottom solution. Except for the control test, VCI was introduced only after the bottom solution had been pre-purged with nitrogen to minimize dissolved oxygen. The overall flow of these tests is illustrated as in Figure 3.

TABLE 1. Test matrix for control, batch injection (non-corroded and pre-corroded conditions) and continuous injection tests

Parameter	Control 0 ppm VCI (Non-corroded)	Batch Injection 1000 ppm VCI (Non-corroded)	Batch Injection 1000 ppm VCI (Pre-corroded)	Continuous Injection 1000 ppm VCI (Non-corroded)
VCI concentration	N/A	1000 ppm		
Test material	API 5L X65 Carbon Steel			
Total pressure	1 bar			
CO_2 partial pressure	Saturated			
Liquid temperature	70±1 °C			
Gas temperature	55±1 °C			
Steel temperature	34±1 °C			
Water condensation rate	1.2 ± 0.1 mL/m^2.s			
Testing solution	1000 ppm NaCl with 500 ppm CH_3COOH and 1.25% (v/v) gas condensate			

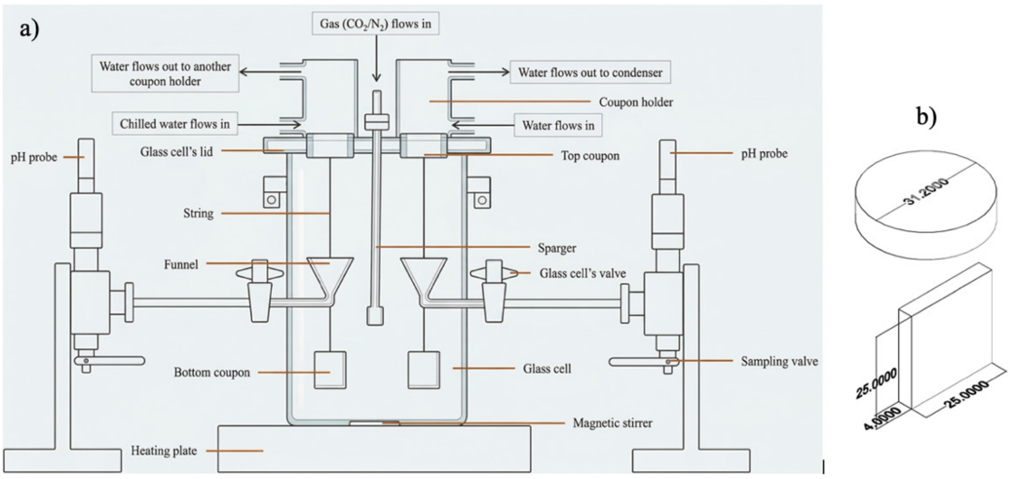


FIGURE 2. (a) Schematic diagram of the TLC testing unit and (b) Dimension of top and bottom specimens

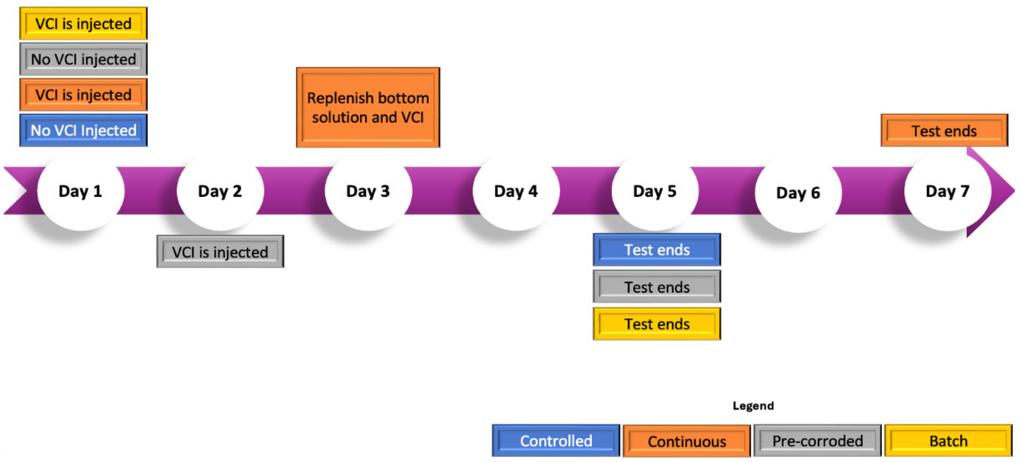


FIGURE 3. The overall flow of tests with respect to VCI injection time

During the experiment

System parameters, including liquid temperature, gas temperature, steel temperature, water condensate pH and brine solution changes were monitored during operation. The collected water condensate was used to determine the water condensation rate according to Equation (1).

$$\text{Water condensation rate}\left(\frac{\text{mL}}{\text{m}^2.\text{s}}\right) = \frac{\textit{volume of condensed water }(mL)}{\textit{Area of coupon }(m^2) \times \textit{Total duration of collected condensed water }(s)} \quad (1)$$

Post-experiment method

Uniform corrosion rates for the top and bottom specimens were calculated in accordance with ASTM G1-03 standards using Equation (2). The final uniform corrosion rate was reported as the average value derived from all specimens within each experimental set. Surface profilometry of the specimens was examined via an Infinite Focus Microscope (ASTM G21-96), where the pitting depth was defined by the maximum pit depth identified on each specimen. Pitting kinetics were quantified through Equations (3) and (4) provided the pitting ratio required for the characterization of localized corrosion. Finally, VCI performance was substantiated by determining the inhibition efficiency through the mathematical relationship established in Equation (5) (Kokalj 2023).

$$\text{Uniform Corrosion Rate}\left(\frac{\text{mm}}{\text{yr}}\right) = \frac{87600\ x\ \textit{Mass Loss }(g)}{\textit{Area }(cm^2)\ x\ \textit{Density}\left(\frac{\text{g}}{\text{cm}^2}\right) x\ \textit{Duration }(hr)} \quad (2)$$

$$\textit{Pitting Rate}\left(\frac{\text{mm}}{\text{yr}}\right) = \frac{\textit{Pit Depth }(mm)}{\textit{Duration }(yr)} \quad (3)$$

$$\textit{Pitting Ratio} = \frac{\textit{Pitting Rate}\left(\frac{\text{mm}}{\text{yr}}\right)}{\textit{Uniform Corrosion Rate}\left(\frac{\text{mm}}{\text{yr}}\right)} \quad (4)$$

$$\textit{Inhibition efficiency, } \eta\ (\%) = \frac{\textit{UCR inhibited} - \textit{UCR unhibited testing}}{\textit{UCR inhibited}}\ x\ 100\% \quad (5)$$

The uniform corrosion rates and pitting rate values can be classified in accordance with NACE SP0775 (NACE International 2023) (Table 2(a)), while the pitting ratio is classified based on the criteria for localized corrosion, as shown in Table 2(b) (Zhao et al. 2018).

RESULTS AND DISCUSSION

BOTTOM SOLUTION OBSERVATION

The comparison of the visual observations on the bottom solution at the beginning of the test and at the end of the test were recorded for the cluster of tests in Table 3. The brownish/blackish colour observed on the control and pre-corroded test indicated the formation of iron corrosion products. Based on the colour of the bottom solution and knowing that the system is oxygen-limited, there are a possibility these corrosion products are iron carbide and iron oxides (Kahyarian, Achour & Nesic 2017). Furthermore, with the intense dark colour appearance, it may indicate that the corrosion products exceeded the supersaturation value, as indicated by the thick black precipitates found in the bottom solution. This observation is contrary to the batch injection test on non-corroded specimens and the continuous injection test, due to the fact that VCI was injected as early as Day 0 of the test for both tests.

VISUAL OBSERVATION ON THE SPECIMENS AFTER TEST

Table 4(a) shows the top and bottom specimen observations for all tests, with the corrosion products were still attached to the specimens, while Table 4(b) shows the top and bottom specimens after the corrosion products had been removed. Referring to Table 4(a) for the top specimen, black layers/spots were observed on all specimens except for the control test's specimen (see red circles). This observation possibly indicates the formation of a corrosion product

TABLE 2. Classification of uniform corrosion rate and pitting rate and localized corrosion

a) Classification of uniform corrosion rate and pitting rate based on NACE SP0775			
Classification	Low	Moderate	High
Avg. General corrosion rate	< 0.05 mm/yr	0.05 – 0.2 mm/yr	>0.2 mm/yr
Maximum pitting rate	<0.13 mm/yr	0.13 – 0.3 mm/yr	>0.3 mm/yr
b) Classification of localized corrosion based on pitting ratio			
Classification	No localized corrosion	Possible localized corrosion	Localized corrosion
Value	Pitting Ratio < 3	3 < Pitting Ratio < 5	Pitting Ratio > 5
Condition	Only applicable when the measured pit depth > 10 um		

TABLE 3. Comparison on bottom solution for all tests on Day 0 vs. Day 5

Test	Control 0 ppm VCI (Non-corroded)	Batch injection 1000 ppm VCI (Non-corroded)	Batch injection 1000 ppm VCI (Pre-corroded)	Continuous injection 1000 ppm VCI (Non-corroded)
Day 0				
Day 5				

layer on the specimen surface, with higher coverage of black layers/spots on the pre-corroded specimen surface of the batch injection test. It was noticed that the non-corroded specimen from the batch injection test turned brownish once retrieved from the equipment which may be due to the oxidation process. Rough surfaces were clearly observed on the top specimen for the control test even without the corrosion product layer being removed (see yellow circle). These rough areas are suspected to have undergone ongoing corrosion until the end of the test, which can be verified later with the uniform corrosion rate value. Supposedly, in the system with the presence of both water and hydrocarbon (condensate), condensation of both liquids can be differentiated by surface roughness; a smooth surface indicated a hydrocarbon-wetted are whilst a rough surface indicated a water-wetted area (Jufri et al. 2023). Although there are obvious areas demonstrating that condensation occurred on the specimen surface (see blue circles), but there is no clear observation either the areas were water-wetted or hydrocarbon-wetted. Nevertheless, a corrosion product or a VCI layer is believed to occupy areas where water condensed, creating protective layers in those areas. Conversely, areas exposed to gas condensate may experience less corrosion, as the condensate can act as a protective barrier (Ramlan et al. 2024).

Black precipitates are also observed on the bottom specimens (Table 4(a)), predominantly near the edges, indicating downward accumulation of corrosion products over time due to gravity (Al Maawali, Maskery & Al Nabhani 2024; Zhang & Lan 2017). No noticeable observation can be made on the bottom specimens without corrosion products (Table 4(b) for bottom specimens).

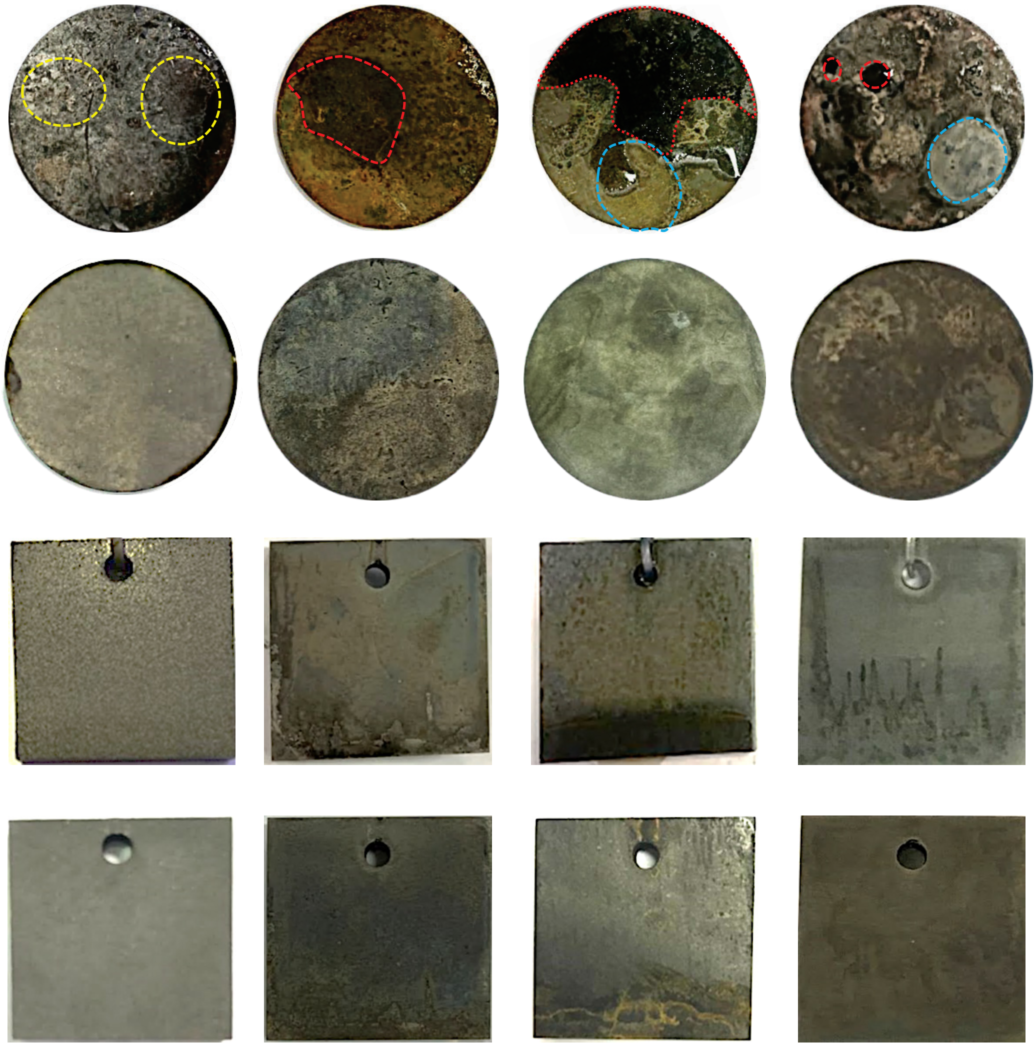
SURFACE PROFILOMETRY ANALYSIS

Surface profilometry on the metal specimens without a corrosion product layer was conducted in accordance with ASTM G46-21 (ASTM International 2021) using an Alicona Infinite Focus Microscope at 50× magnification. The results are presented in Table 5 for top-of-line (TOL) and bottom-of-line (BOL) specimens. The pitting rate and pitting ratio were determined using Equations (3) and (4) based on the measured pit depth values. Overall, the profilometry analysis showed that the batch injection test for the non-corroded specimen exhibited the highest pit density, with the deepest pit observed among all tests. For the bottom-of-line corrosion tests, only the control test exhibited high pit density along with the deepest pit. In general, these findings are related to the efficiency of the VCI in preventing top-of-line and bottom-of-line corrosion, which will be further discussed in the next section.

TOP-OF-LINE CORROSION (TLC) RATES

A compilation of results for top-of-line specimens, which consists of uniform corrosion rate, pitting rate, and pit ratio, is illustrated in Figure 4. In the absence of the VCI, the specimens experienced only general corrosion as

TABLE 4. Top and bottom specimen observations for all tests with and without corrosion products

Test	Control 0 ppm VCI (Non-corroded)	Batch Injection 1000 ppm VCI (Non-corroded)	Batch Injection 1000 ppm VCI (Pre-corroded)	Continuous Injection 1000 ppm VCI (Non-corroded)
Top specimen (a) With corrosion product layer				
Top specimen (b) Without corrosion product layer				
Bottom specimen (a) With corrosion product layer				
Bottom specimen (b) Without corrosion product layer				

the pitting ratio was less than 2 (Zhao et al. 2018). This observation corresponds to a high water condensation rate which promoted a high uniform corrosion rate (Al-Moubaraki & Obot 2021; Gunaltun & Larrey 2000). On the other hand, VCI injection managed to reduce the uniform corrosion rate across all cases relative to the control test, yielding uniform inhibitor efficacy (η) ranging between 65% and 76%. However, it failed to achieve a corrosion rate below than 0.1 mm/yr., the industrial acceptable limit (Al Maawali, Maskery & Al Nabhani 2024; Johnson et al. 2009; Pessu et al. 2022). Furthermore, according to NACE International (2023), the uniform top of line corrosion rate and pitting rate for all tests are classified as 'High'. Additionally, the pitting rates were notably higher in the batch injection test for non-corroded (4.16 mm/yr.) and pre-corroded cases (2.41 mm/yr.), with classification of localized corrosion; indicating insufficient VCI protection (Fazil et al. 2023; Ong et al. 2020). Nevertheless, a slight reduction of pitting rate observed in the pre-corroded case for the batch injection test, suggests that a semi-protective corrosion product layer had formed, which, through a synergistic effect with the VCI contributed to a further reduction in corrosion severity (Shamsa et al. 2021). Also, it was noted that, with a higher frequency of 1000 ppm VCI injection, the uniform inhibition efficacy achieved 76%. This improvement is attributed to the continuous replenishment of the inhibitor layer as studies show that the molecules desorb over time and require replenishment to maintain effective surface coverage (Qin et al. 2026). Additionally, the sustained presence of the inhibitor films helps to suppress further growth of pit depth as shown in the reduction in pit depth and therefore lowering the pitting risk of localized corrosion (Finšgar & Jackson 2014).

BOTTOM-OF-LINE CORROSION (BLC) RATE

The compilation of results for top-of-the-line specimens, which consists of uniform corrosion rate, pitting rate, and pit ratio, is illustrated in Figure 5. A similar observation was made for bottom-of-line corrosion for the control test; the specimens experienced only general corrosion as the pitting ratio remained below 2 (Zhao et al. 2018). A uniform inhibition efficiency of 98% was achieved in both batch and continuous injection tests, using non-corroded specimens, with 'Moderate' risk classification as per NACE International (2023). This result demonstrated that the VCI is not only active in the vapor phase but is also infused into the liquid phase enabling protection on the bottom specimens in the bulk solution subsequently reducing uniform corrosion rate and further improving the protection on the pitting corrosion (Al-Moubaraki & Obot 2021; Yotapan et al. 2024). On the other hand, the batch injection test using pre-corroded specimens recorded the highest uniform corrosion rate and pitting rate (1.63 mm/yr. and 6.50 mm/yr.), as the VCI inhibition efficiency is compromised most likely due to inability to form a protective layer on the metal surface with the presence of deposition of corrosion products (Liu et al. 2010; Paolinelli, Pérez & Simison 2008; Shamsa et al. 2021; Xiong et al. 2017; Zhang et al. 2015).

PREDICTION OF LIFESPAN OF PIPELINE BASED ON INJECTION METHOD

The lifespan predictions for each case when considering 3 mm as the corrosion allowance for the pipelines (Kapusta, Pots & Connell 1999) is illustrated in Figure 6 (following Equation (6)).

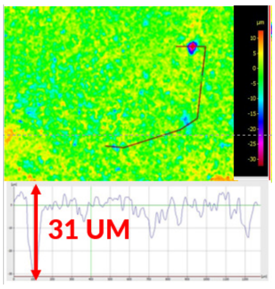
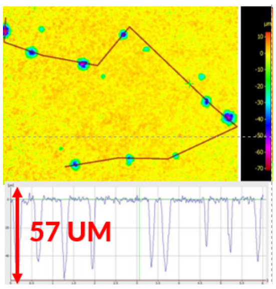
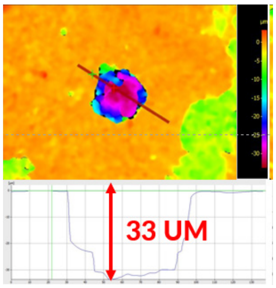
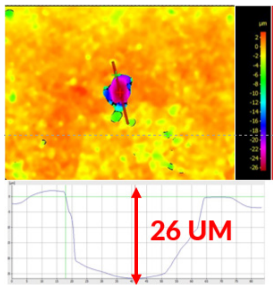
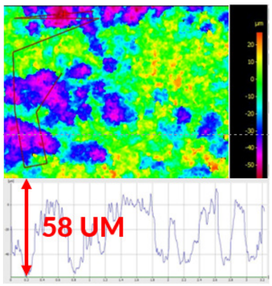
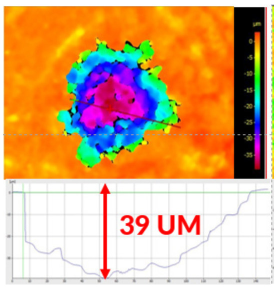
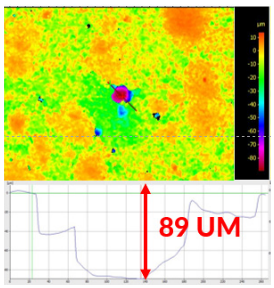
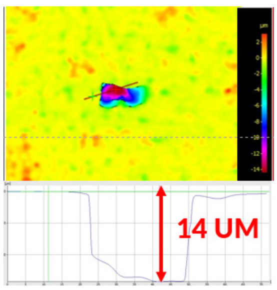
$$Pipeline\ lifespan,\ year = \frac{Corrosion\ allowance\ (mm)}{Corrosion\ Rate\ \left(\frac{mm}{yr}\right)} \quad (6)$$

None of the cases are predicted to exceed one year before corrosion penetrates the nominal pipeline thickness, except for the continuous VCI injection in non-corroded conditions. The pipeline integrity is compromised significantly at bottom-of the line, with corrosion severity due to the localized attack. Despite improvements observed with continuous injection of 1000 ppm for the non-corroded cases, the pipeline failures remain high due to uneven protection coverage on the top and bottom of the pipeline, therefore, even the mitigation via continuous VCI injection methods alone may not be sufficient.

CONCLUSIONS

Following the successful completion of the study on VCI batch and continuous injection methods for mitigating corrosion towards top-of-line corrosion (TLC) and bottom-of-line corrosion (BLC), a summary of the findings is presented in Table 6.

TABLE 5. Top and bottom specimens' surface profilometry analysis for all tests

Test	Control 0 ppm VCI (Non-corroded)	Batch injection 1000 ppm VCI (Non-corroded)	Batch injection 1000 ppm VCI (Pre-corroded)	Continuous injection 1000 ppm VCI (Non-corroded)
(a) Top specimen				
(b) Bottom specimen				

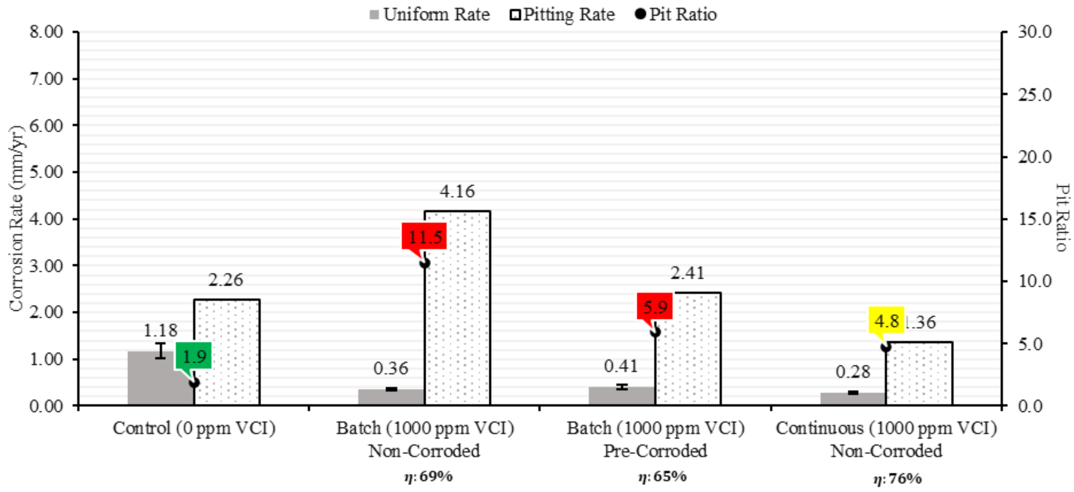


FIGURE 4. Performance of VCI for top-of-line corrosion based on uniform corrosion rate, pitting rate and pit ratio against control test

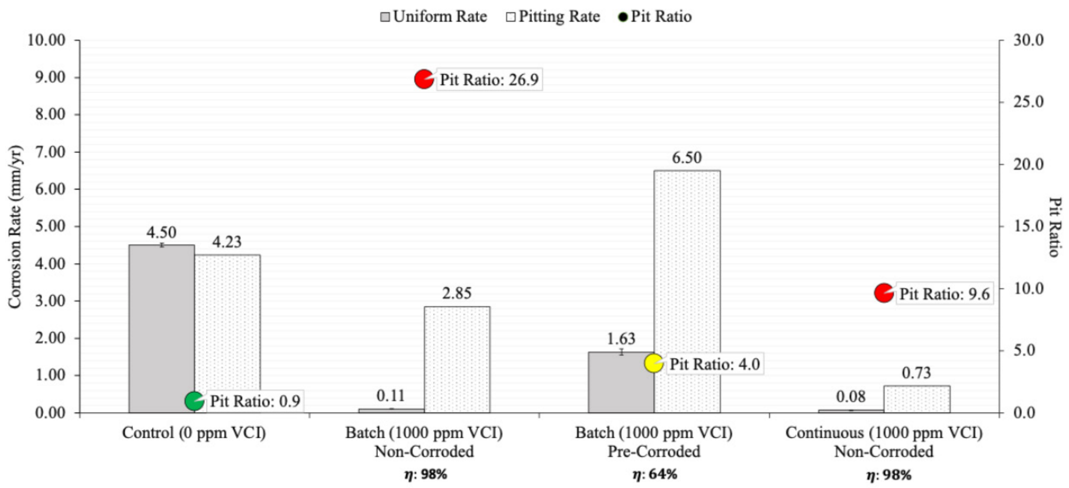


FIGURE 5. Performance of VCI for bottom-of-line corrosion based on uniform corrosion rate, pitting rate and pit ratio against control test

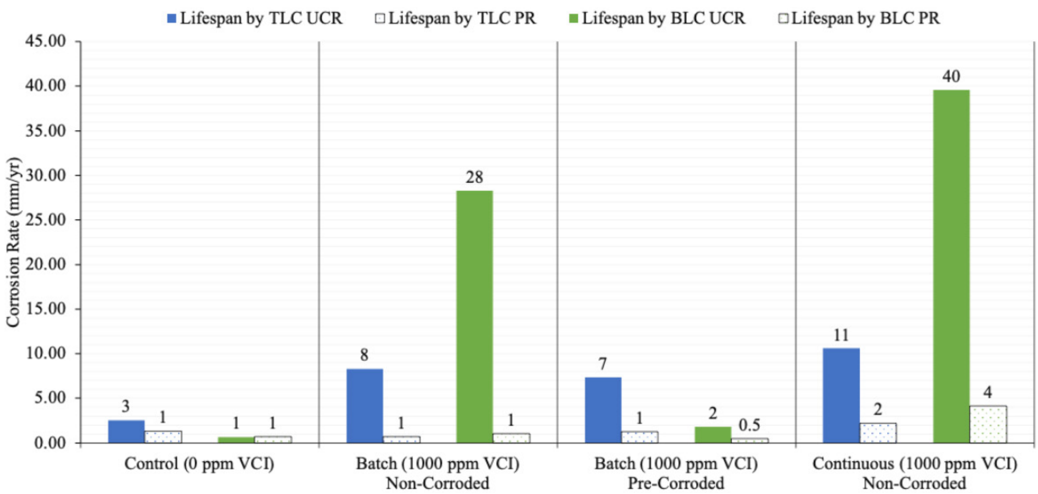


FIGURE 6. Uniform and pitting corrosion-based lifespan predictions for all cases

TABLE 6. Summary of VCI inhibition for every case based on uniform corrosion rate, pitting rate, pit ratio against control test and pipeline lifespan prediction

Test	Control 0 ppm VCI (Non-corroded)		Batch Injection 1000 ppm VCI (Non-corroded)		Batch Injection 1000 ppm VCI (Pre-corroded)		Continuous Injection 1000 ppm VCI (Non-corroded)	
	Value	Classification	Value	Classification	Value	Classification	Value	Classification
TLC UCR (mm/yr)	1.18	High	0.36	High	0.41	High	0.28	High
TLC Pitting Rate (mm/yr)	2.26	High	4.16	High	2.41	High	1.36	High
BLC UCR (mm/yr)	4.50	High	0.11	Moderate	1.63	High	0.08	Moderate
BLC Pitting Rate (mm/yr)	4.23	High	2.85	High	6.50	High	0.73	High
TLC Pitting Ratio	1.9	No localized corrosion	11.5	Localized Corrosion	5.9	Localized Corrosion	4.8	Possible localized corrosion
BLC Pitting Ratio	0.9	No localized corrosion	26.9	Localized Corrosion	4.0	Possible localized corrosion	9.6	Localized Corrosion
	Top	Bottom	Top	Bottom	Top	Bottom	Top	Bottom
Inhibition efficiency	-	-	69%	98%	65%	64%	76%	98%
Pipeline Lifespan Prediction based on UCR (year)	3	1	8	28	7	2	11	40
PR Pipeline Lifespan Prediction based on PR (year)	1	1	1	1	1	0.5	2	4

Uniform corrosion rate The uniform corrosion rate (UCR) reduced with the introduction of VCI, with a significant impact on the bottom of the line (BOL), achieving a maximum inhibition efficiency of 98%.

Pitting rate While the pitting rate (PR) decreased with the introduction of VCI, localized attacks became the dominant corrosion mechanism.

Injection method Continuous injection of VCI helped reduce overall corrosion severity, but it did not provide sufficient protection against localized corrosion.

Pre-corroded surface Interestingly, the VCI worked synergistically with corrosion products (pre-corroded) at the top-of-line (TOL), but not at the bottom-of-line (BOL).

Pipeline lifespan prediction Neither batch nor continuous injection of this VCI—even at high dosages—was sufficient to significantly extend the pipeline's lifespan, regardless of whether the surfaces were pre-corroded. Combining both methods (batch and continuous) might further reduce corrosion severity.

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