Amine Corrosion: Critical Parameters, Monitoring, and Integrity Considerations

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Key words*: amine unit, amine corrosion, risk, process parameters, flow, corrosion model*

Introduction

The removal of acidic compounds (H_2S, CO_2, etc.) from hydrocarbon streams, both liquid and gaseous, is a critical process in refinery and gas plant operations. This is typically achieved through an absorption–desorption process using a range of alkanolamine-based solvents.

While pure alkanolamines are not inherently corrosive, their corrosivity arises from the absorption of acid gases, solvent decomposition products, and variability of process parameters. It is well documented that primary amines (e.g., MEA) are generally more corrosive than secondary (e.g., DEA) or tertiary amines (e.g., MDEA). However, the final corrosiveness of an amine system is a superposition of several additional factors, such as amine concentration, acid gas loading, temperature, flow characteristics, or the presence of impurities.

Therefore, corrosion risk analysis in amine systems requires a detailed understanding of process parameter interactions, which can be effectively supported by modelling tools that generate insights to enhance inspection strategies, optimize corrosion monitoring programs, and guide process modifications such as material selection and the establishment of Integrity Operating Windows (IOWs).

Process parameters and amine corrosion

Temperature and acid gas loading

Corrosion reactions in alkanolamine solutions follow the general temperature-reaction rate relationship described by the Arrhenius equation. Since the absorption process is exothermic, the temperature inside the contactor/absorber will locally increase, leading to the formation of hot spots (>90°C) conducive to corrosion activities. The rich amine stream exiting the absorber typically maintains a temperature range of 70-80°C, thus exhibiting relatively lower corrosiveness up to the flash-tank. However, this condition may vary with the increase in amine strength and acid gas loading. Typical acid gas loading values for common solvents and other relevant information are available in our ***Knowledge Library*** – register now for free access.

Contaminants/Heat Stable Amine Salts

The corrosiveness of amine systems can be influenced by the presence of contaminants such as oxygen, carbon monoxide (CO), and carbonyl sulfide (COS). The basic mechanism of HSAS (Heat Stable Amine Salts) formation is relatively simple: strong organic acid anions formed during decomposition replace weaker acid anions HS^- and HCO_3^- in the respective amine-acid gas reactions.

Additionally, lighter acids such as formic and acetic may evolve inside the reboiler due to temperature, accelerating corrosion not only of carbon steel but also of popular austenitic steels (304L/316L). Other compounds formed from the decomposition of amine solvents, such as thiosulfates, amine-acids like bicine or glycine, will also affect the solvent's corrosiveness.

One of the key aspects of amine unit integrity management is controlling the HSAS concentration. However, there is no clearly defined or universally accepted “safe” limit for HSAS. Some consensus suggests that HSAS levels below 2–3wt% (as amine) generally result in relatively low solvent corrosiveness. This threshold should nevertheless be treated with caution, as the

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concentration of individual contaminants can significantly influence the overall corrosivity. For more details, please refer to the ***Knowledge Library***.

There are several methods available for reducing HSAS, including traditional low-pressure thermal reclaiming, vacuum distillation, ion exchange, and electrodialysis. For units operating at low to moderate HSAS levels, the most used technique for reducing heat-stable amine salts is side-stream thermal reclaiming (typically treating about 0.5-5% of the total amine inventory). This method has been successfully applied in MEA and DGA units.

Flow/wall shear stress

Flow-accelerated corrosion can occur even in seemingly 'non-corrosive' solvent streams, where parameters such as acid gas loading, HSAS, or temperature are within safe boundaries. This issue is often overlooked by designers who may be misled by various 'industry-accepted' rules of thumb, sometimes endorsed by standards like API RP 571, API RP 581, or API RP 945. Additionally, operators managing specific amine unit configurations may lack full control over the flow in certain areas of the unit.

Expectedly, there is no clear consensus on amine velocity limits; however, most authors seem to accept the range of 1.5-1.8 m/s (5-6 fps) for the rich amine stream. The boundary for lean amine flow velocity is even less clear. It appears that 6 m/s (20 fps) for lean solvent is too high, and a more reliable or conservative level would be in the same range as for rich amine (1.5-1.8 m/s).

It is important to emphasize that maintaining low velocity does not always equate to minimizing flow-accelerated corrosion. Flow restrictors such as tee, elbow, or weld protrusion may create localized turbulence zones, resulting in accelerated corrosion. Therefore, it is crucial for designers and plant engineers to consider not only flow velocity but also Wall Shear Stress (WSS) as a parameter that can better assess adequate flow boundaries. Hence, corrosion models developed for amine systems should be coupled with advanced flow modeling to ensure accurate prediction of corrosion behavior. This integrated approach is broadly applicable to all corrosive systems in which flow conditions play a role in governing corrosion processes.

Our newly launched amine corrosion prediction model, ***Amine-Corrology®***, is now integrated with advanced flow modeling tools. An example demonstrating how our latest ***Amine-Corrology®*** model compares against published corrosion–flow data is provided at the end of this paper.

Corrosion monitoring and inspection in Amine Units

Understanding amine solvent properties and process conditions is essential for targeting corrosion monitoring and inspection efforts at the most susceptible area.

The importance of corrosion monitoring in amine units appears to have diminished over the last two decades. Several factors contribute to this trend. First, there has been a general shift toward upgrading metallurgy from carbon steel to stainless steel or higher alloys in the most critical areas, such as the hot lean outlet from the regenerator and the lean/rich exchanger. Second, the increased use of proprietary solvent mixtures with enhanced anti-corrosion properties and improved resistance to decomposition has played a significant role. Still, localized corrosion phenomena such as flow-accelerated corrosion represent a serious threat to the unit's integrity. One of the most common areas of flow-accelerated corrosion are tee-joints at rich amine pump discharge piping (see Figure 1).

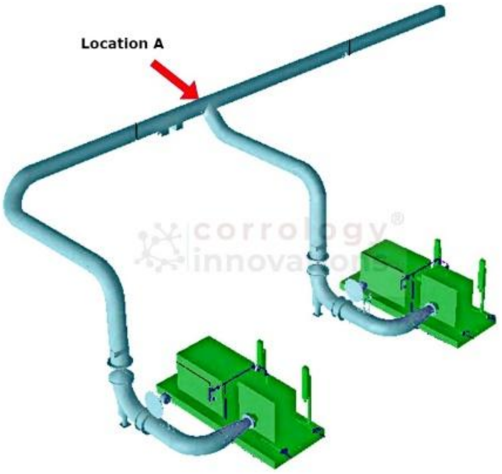


Figure 1 Example of UT Monitoring Locations for Amine Unit - Rich Amine Pump Outlet.

The next commonly corrosion-affected section of the Amine Unit is regenerator-reboiler system, mainly due to the higher operating temperature (in the range of 100–140°C), low H_2S concentration (lean amine), which prevents the formation of a protective iron sulfide layer and the presence of multiphase flow at the reboiler outlet.

The outlet from the regenerator reboiler often experiences accelerated corrosion due to the multiphase flow (resulting in high wall shear stress) and potential instabilities in reboiler operations - usually caused by poor control of the heating steam flow and the likelihood of periodic overheating.

Corrosion monitoring and also inspection prioritization should focus on areas with the highest turbulence - primarily the extrados of elbows in the hot amine return line to the regenerator, as shown in Figure 2 (location A).

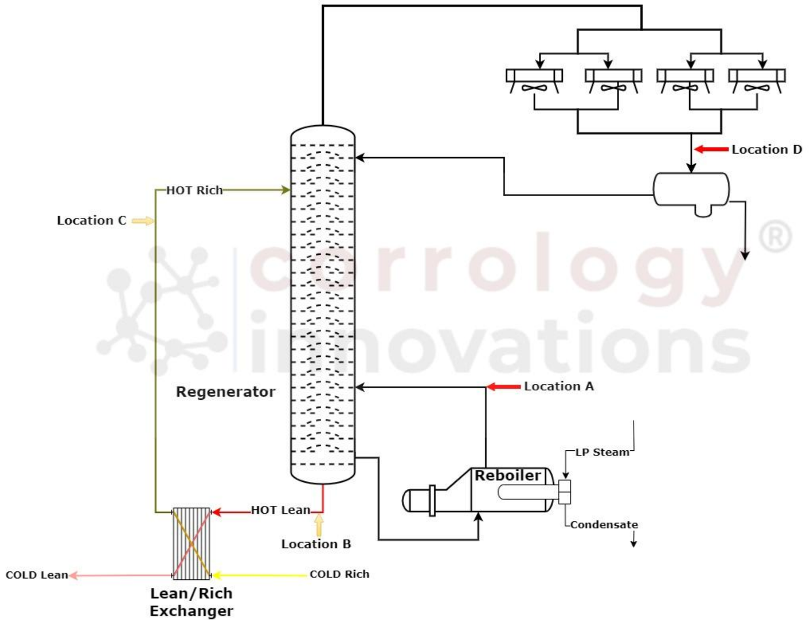


Figure 2 Amine unit – Amine regenerator section with typical corrosion monitoring locations.

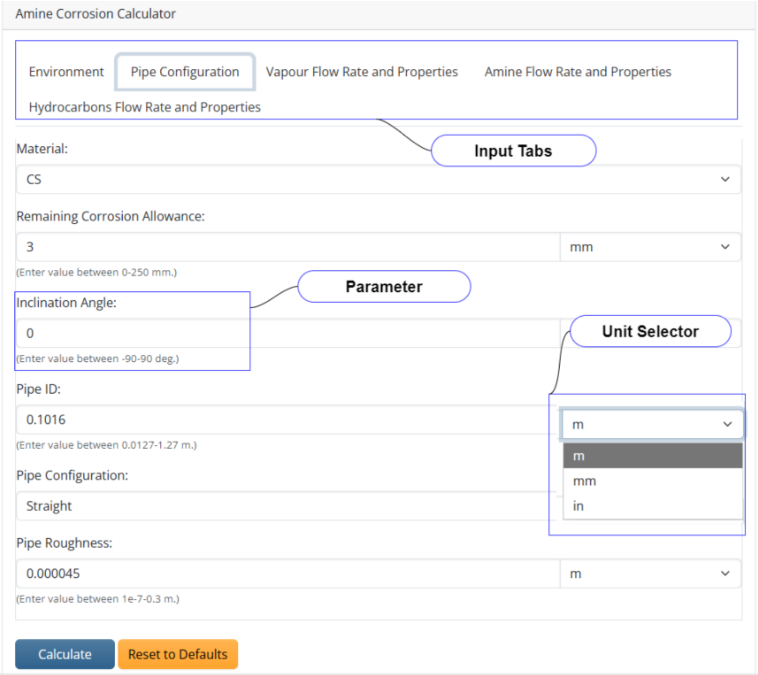
If the hot lean amine piping from the regenerator bottom to the Lean/Rich exchanger is made of carbon steel, corrosion monitoring may be needed in this area. This is especially important when the unit has high HSAS levels or experiences amine over-stripping (see Figure 2, Location B). Similar to the reboiler outlet, the user should identify areas with high wall shear stress for monitoring location and inspection activities.

It is therefore clear that corrosion risk assessment, a key element in developing Integrity Operating Windows, Corrosion Control Documents, and Inspection Strategies, must be supported by accurate and comprehensive flow characterization. For more details, please refer to the ***Knowledge Library*** — register now for free access.

Amine-Corrology®

The Amine-Corrology® model provides a structured framework in which flow modeling is integrated with key process parameters to evaluate corrosion behavior in an amine system. By integrating these parameters with flow characteristics, the model enables more accurate evaluation of areas susceptible to increased corrosion. The predictions from the model have been compared with published case studies to confirm their relevance and accuracy.

Figure 3 shows a screenshot of the input tab for Pipe Configuration. By selecting the dedicated input tabs, the user can enter all relevant data for the operating environment as well as liquid and vapour properties. In the Unit Selector, the user can choose the appropriate engineering unit.



Material:
CS

Remaining Corrosion Allowance:
3 mm
(Enter value between 0-250 mm.)

Inclination Angle:
0
(Enter value between -90-90 deg.)

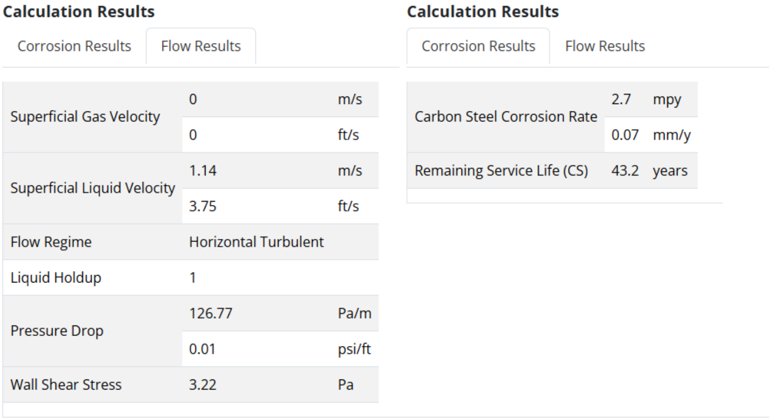
Pipe ID:
0.1016 m
m
mm
in
(Enter value between 0.0127-1.27 m.)

Pipe Configuration:
Straight

Pipe Roughness:
0.000045 m
(Enter value between 1e-7-0.3 m.)

Figure 3 Example of Amine-Corrology® – Pipe Configuration data input screen.

After completing all input fields across the tabs, clicking the **Calculate** button will display the Results screen, showing corrosion and flow parameters as illustrated in Figure 4.



Superficial Gas Velocity	0	m/s
	0	ft/s
Superficial Liquid Velocity	1.14	m/s
	3.75	ft/s
Flow Regime	Horizontal Turbulent	
Liquid Holdup	1	
Pressure Drop	126.77	Pa/m
	0.01	psi/ft
Wall Shear Stress	3.22	Pa

Carbon Steel Corrosion Rate	2.7	mpy
	0.07	mm/y
Remaining Service Life (CS)	43.2	years

Figure 4 Example of Corrosion and Flow results.

Table 1 presents a model verification, benchmarking predicted amine corrosion rates against published corrosion data to evaluate accuracy under representative conditions.

Table 1 – Model verification: predicted corrosion rates benchmarked against published data.

Case	Material	Solvent type	Measured CR, mm/y	Predicted CR, mm/y
A	Carbon steel	MEA 30% Rich[2]	>1.4	>1.4
B	Carbon steel	MEA 30% Lean[3]	>1.4	1.2
C	Carbon steel	MEA 17% Lean[4]	0.025	0.07
D	Carbon steel	MEA 18% Rich[5]	0.025-0.15	0.04-0.07
E	Carbon steel	MEA 18% Rich[6]	<0.2	0.06
F	Stainless steel (316L)	MEA 30% Rich	<0.1	0.04
G	Stainless steel (316L)	MEA 30% Lean	<0.1	0.02

Case A: MEA 30% Rich, Acid Gas Loading: 0.5 mol/mol, T: 110°C, Flow: ~2100m^3/d, HSAS: <2wt%
Case B: MEA 30% Lean, Acid Gas Loading: 0.25 mol/mol, T: 120°C, Flow: ~2100m^3/d, HSAS: <2wt%
Case C: MEA 17% Lean, Acid Gas Loading: 0.09 mol/mol, T: 126°C, Flow: Low, HSAS: NA
Case D: MEA 18% Rich, Acid Gas Loading: 0.53 mol/mol, T: 55°C, Flow: >3000m^3/d, HSAS: Low
Case E: MEA 18% Rich, Acid Gas Loading: 0.57 mol/mol, T: 57°C, Flow: >9000m^3/d, HSAS: Low
Case F: MEA 30% Rich, Acid Gas Loading: 0.5 mol/mol $_{(aver)}$, T: 110°C, Flow: ~2100m^3/d, HSAS: <2wt%
Case G: MEA 30% Lean, Acid Gas Loading: 0.25 mol/mol, T: 120°C, Flow: ~2100m^3/d, HSAS: <2wt%