

# Avoiding Environmental Cracking in Amine Units

API RECOMMENDED PRACTICE 945  
FOURTH EDITION, SEPTEMBER 2022



## Special Notes

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed. The use of API publications is voluntary. In some cases, third parties or authorities having jurisdiction may choose to incorporate API standards by reference and may mandate compliance.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to ensure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be used. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

All rights reserved. No part of this work may be reproduced, translated, stored in a retrieval system, or transmitted by any means, electronic, mechanical, photocopying, recording, or otherwise, without prior written permission from the publisher. Contact the Publisher, API Publishing Services, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001-5571.

## Foreword

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

The verbal forms used to express the provisions in this document are as follows.

Shall: As used in a standard, “shall” denotes a minimum requirement to conform to the standard.

Should: As used in a standard, “should” denotes a recommendation or that which is advised but not required to conform to the standard.

May: As used in a standard, “may” denotes a course of action permissible within the limits of a standard.

Can: As used in a standard, “can” denotes a statement of possibility or capability.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001.

Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001, [standards@api.org](mailto:standards@api.org).



## Contents

|                                                                                                                        | Page |
|------------------------------------------------------------------------------------------------------------------------|------|
| <b>1</b> Scope .....                                                                                                   | 1    |
| <b>2</b> Normative References .....                                                                                    | 1    |
| <b>3</b> Terms and Definitions .....                                                                                   | 2    |
| <b>4</b> Background on Amine Units .....                                                                               | 2    |
| <b>4.1</b> Amine Units Process Description .....                                                                       | 2    |
| <b>4.2</b> Amine Solution Types .....                                                                                  | 3    |
| <b>4.3</b> Problems in Amine Units .....                                                                               | 4    |
| <b>5</b> Guidelines for Construction Materials and Fabrication of New Equipment and Piping .....                       | 6    |
| <b>5.1</b> Construction Materials .....                                                                                | 6    |
| <b>5.2</b> Fabrication .....                                                                                           | 7    |
| <b>6</b> Inspection and Repair of Existing Equipment .....                                                             | 11   |
| <b>6.1</b> General .....                                                                                               | 11   |
| <b>6.2</b> Inspection .....                                                                                            | 11   |
| <b>6.3</b> Examination Procedures and Methods .....                                                                    | 12   |
| <b>6.4</b> Repair of Damaged Equipment .....                                                                           | 14   |
| <b>6.5</b> Postweld Heat Treatment of Undamaged or Repaired Equipment .....                                            | 15   |
| ANNEX A (informative) Cracking Mechanisms .....                                                                        | 16   |
| ANNEX B (normative) Considerations for Corrosion Control .....                                                         | 27   |
| ANNEX C (normative) Historical Guidelines for PWHT for Various Amine Types .....                                       | 32   |
| ANNEX D (informative) Request for New Information Concerning Problems with Environmental Cracking in Amine Units ..... | 34   |
| Bibliography .....                                                                                                     | 37   |

## Figures

|                                                                                                                  |    |
|------------------------------------------------------------------------------------------------------------------|----|
| <b>1</b> Simplified Process Flow Diagram of a Representative Amine Unit .....                                    | 3  |
| <b>A.1</b> Sulfide Stress Cracking in an Existing Hardened Heat-Affected Zone of a Weld .....                    | 17 |
| <b>A.2</b> Hydrogen Blisters Near the ID Surface of a Carbon Steel Flange .....                                  | 18 |
| <b>A.3</b> Stepwise Hydrogen-Induced Cracking (HIC) in a Carbon Steel Specimen .....                             | 18 |
| <b>A.4</b> Stress-Oriented Hydrogen-Induced Cracking .....                                                       | 20 |
| <b>A.5</b> Alkaline Stress Corrosion Cracking in the Vicinity of a Weld .....                                    | 22 |
| <b>A.6</b> Alkaline Stress Corrosion Cracking in a Pipe Weld in MEA Service .....                                | 23 |
| <b>A.7</b> Alkaline Stress Corrosion Cracking in an Elbow in DEA Service .....                                   | 24 |
| <b>A.8</b> Intergranular Alkaline Stress Corrosion Cracking in DEA Service .....                                 | 25 |
| <b>D.1a</b> Report Form for New Information Concerning Problems with Environmental Cracking in Amine Units ..... | 35 |
| <b>D.1b</b> Report Form for New Information Concerning Problems with Environmental Cracking in Amine Units ..... | 36 |



# Avoiding Environmental Cracking in Amine Units

## 1 Scope

This recommended practice (RP) discusses environmentally assisted cracking of carbon steel equipment in amine treating units. Amine stress corrosion cracking and sulfide stress cracking of stainless steels in amine units is beyond the scope of this document, although there have been isolated reports of such problems. This RP provides guidelines for carbon steel construction materials including their fabrication, inspection, and repair to help assure safe and reliable operation. The carbon steels referred to in this document are defined by the ASTM designation system, or are equivalent materials contained in other recognized codes or standards. Welded construction is considered the primary method of fabricating and joining amine unit equipment. See terms 3.6 and 3.7 for the definitions of weld and weldment.

This document is based on current engineering practices and insights from industry experience. Older amine units may not conform exactly to the information contained in this RP, but this does not imply that such units are operating in an unsafe or unreliable manner. No two amine units are alike, and the specific strategies to avoid cracking in a unit will be customized to that unit. Each user company is responsible for safe and reliable unit operation.

Rotating equipment is specifically excluded from the API 945 scope. However, API 610 on centrifugal pumps does have a table that recommends PWHT of all welds in amine services.

## 2 Normative References

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) applies.

API 510, *Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration*

API 570, *Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems*

API Recommended Practice 572, *Inspection of Pressure Vessels*

API Recommended Practice 579-1/ASME FFS-1, *Fitness-for-Service*

API Recommended Practice 582, *Welding Guidelines for the Chemical, Oil, and Gas Industries*

API Standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction*

API Recommended Practice 583, *Corrosion Under Insulation and Fireproofing*

API Technical Report 938-C, *Use of Duplex Stainless Steels in the Oil Refining Industry*

API Recommended Practice 956, *Hydrogen-Assisted Crack Growth in 2-1/4 Cr-1 Mo Steel*

American Welding Society (AWS), AWS D.10.10

NACE SP0472<sup>1</sup>, *Methods and Controls to Prevent In-Service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments*

NACE No. 2/Near-White Metal Blast Cleaning SSPC-SP 10

---

<sup>1</sup> Association for Materials Protection and Performance (AMPP), formerly NACE International.

NACE SP0296, *Detection, Repair, and Mitigation of Cracking in Refinery Equipment in Wet H<sub>2</sub>S Environments*

NACE MR0103/ISO 17945, *Materials Resistant to Sulfide Stress Cracking in Corrosive Petroleum Refining Environments*

NACE Publication 8X194, *Materials and Fabrication Practices for New Pressure Vessels Used in Wet H<sub>2</sub>S Refinery Service*

Welding Research Council (WRC), WRC 452

### 3 Terms and Definitions

The following terms and definitions apply to this document.

#### 3.1

##### **amine service**

Minimum concentration of 2 weight percent amine in water-based solution.

#### 3.2

##### **fresh amine**

An amine-water solution containing no H<sub>2</sub>S and/or CO<sub>2</sub> (i.e. solution which has not been used in the unit and therefore not exposed to acid gas). Less commonly referred to as pure amine or virgin amine.

#### 3.3

##### **lean amine**

An amine-water solution which has been regenerated to remove most of the H<sub>2</sub>S and/or CO<sub>2</sub> but typically contains some trace levels of H<sub>2</sub>S and/or CO<sub>2</sub>.

#### 3.4

##### **postweld heat treatment (PWHT)**

A thermal treatment performed on a weldment, typically to reduce hardness and/or residual stresses.

#### 3.5

##### **rich amine**

An amine-water solution which has been exposed to H<sub>2</sub>S or CO<sub>2</sub> in a contactor containing a significant amount of H<sub>2</sub>S and/or CO<sub>2</sub> and has not been regenerated to remove H<sub>2</sub>S or CO<sub>2</sub>.

#### 3.6

##### **weld**

The weld deposit.

#### 3.7

##### **weldment**

The weld deposit, heat-affected zones (HAZ), and adjacent base metal zones subject to residual stresses from welding.

### 4 Background on Amine Units

#### 4.1 Amine Units Process Description

In refineries and petrochemical plants, gas and liquid hydrocarbon streams can contain acidic components such as hydrogen sulfide (H<sub>2</sub>S) and carbon dioxide (CO<sub>2</sub>). Amine units operating at low and high pressures are used to remove such acidic components from process streams through contact with, and adsorption by, an aqueous amine solution.

Figure 1 is a simplified process flow diagram for a representative unit. The gas or liquid streams containing one or both the acidic components are fed to the bottom of a gas absorber tower or liquid contactor vessel, respectively. The lean (regenerated low acid) amine solution flows downward, counter to the acid laden hydrocarbon streams in the tower and absorbs the acidic components during the process. The purified gas or liquid stream flows upward and passes to the overhead system. The rich amine solution goes out of the bottom of the absorber (contactor) and is fed to a regenerator (stripper) tower, where the acidic components are removed by pressure reduction and by the heat supplied from a reboiler. The acidic components are removed overhead and sent to an incinerator, thermal oxidizer, or sulfur removal plant (usually called “sulfur recovery unit”), or another processing operation. The lean amine solution that leaves the bottom of the regenerator is cooled in a heat exchanger, then returned to the absorber or contactor to be used again for purification of the hydrocarbon streams. Since the amine is recycled back to the absorber (contactor), various salts and reaction products can accumulate and concentrate.

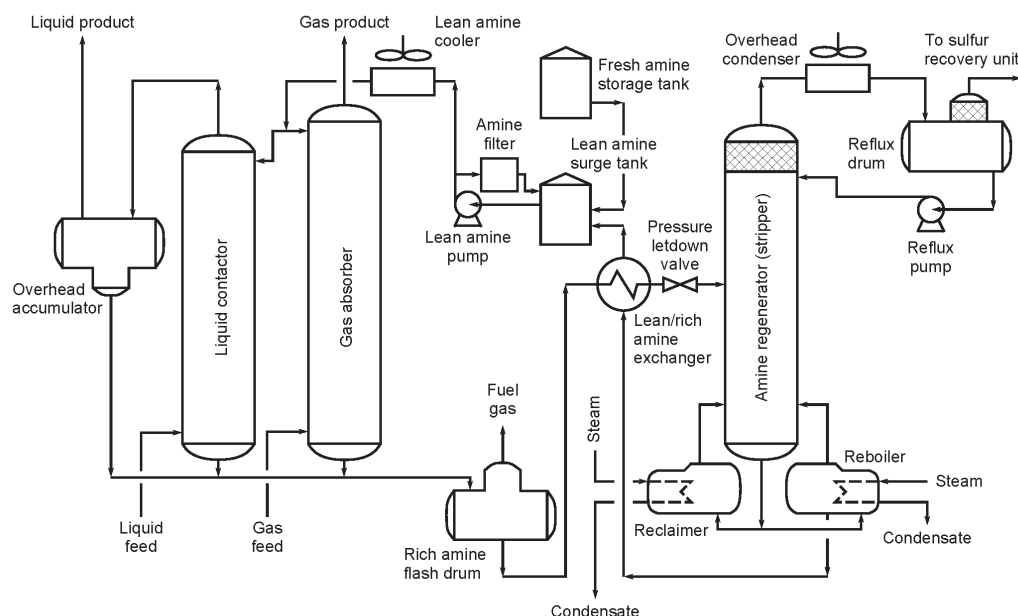


**Figure 1—Simplified Process Flow Diagram of a Representative Amine Unit**

## 4.2 Amine Solution Types

Various types of water-soluble amines have been developed for the purification of process streams. The most commonly used amines are aqueous solutions of:

- Monoethanolamine (MEA),
- Diethanolamine (DEA),
- Methyldiethanolamine (MDEA),
- Diisopropanolamine (DIPA),
- Diglycolamine (DGA).

## 4.3 Problems in Amine Units

### 4.3.1 General

Metallurgical and corrosion problems in amine units can usually be traced to design, material selection or fabrication, operating practices, or solution deterioration. The problems fall into two major categories—environmental cracking and wall loss corrosion.

### 4.3.2 Environmental Cracking

Fresh amine solutions (solutions of amine and water, without  $H_2S$  or  $CO_2$ ) have shown not to produce environmental cracking.

Conversely, both “lean” amine and “rich” amine can cause cracking of carbon steel equipment, due to four different mechanisms.

- 1) Sulfide stress cracking (SSC).
- 2) Hydrogen-induced cracking (HIC) associated with hydrogen blistering.
- 3) Stress-oriented hydrogen-induced cracking (SOHIC).
- 4) Alkaline stress corrosion cracking (ASCC). Note that amine stress corrosion cracking is termed amine SCC, not ASCC. However, amine SCC is one of several forms of ASCC.

The first three mechanisms (SSC, HIC, and SOHIC) are most prevalent in carbon steels that have been exposed to rich amine solutions containing wet  $H_2S$ , and more commonly associated with the lower sections of absorber or contactor towers. In contrast, ASCC is more common in carbon steel components that have been exposed to lean amine service, especially in high residual stress areas. Cracking can occur both with and without significant metal loss. Definitions of these cracking mechanisms and photomicrographs are presented in Annex A.

In rich amine services, cracking can occur due to sulfide stress cracking (SSC) in areas of high hardness and, to a lesser degree, residual tensile stresses. Cracks have also been reported in areas where high hardness levels were not detectable with standard field hardness measurement equipment. Weld-repaired areas can be particularly susceptible to cracking when excessively hard zones or regions of high residual stresses have not been effectively eliminated by the repair procedure. In addition, cracking has also been known to occur in base metal where arc strikes have occurred on the wetted internal surfaces.

In lean amine service, alkaline stress corrosion cracking (ASCC) can occur in carbon steels at slightly elevated temperatures in regions of high stress. This cracking is more often associated in areas of significant residual stress including the heat affected zone in weldments or opposite external welds for attachments, such as piping shoes, ladders, and lifting lugs. High residual stress is the major driver for cracking in lean amine, not high hardness.

Several serious cracking problems have been reported since the early 1950s. Some have been due to ASCC and some due to SSC. ASCC of carbon steel by amine solutions was first mentioned in a report published in 1951 by the NACE Technical Practices Committee 5C on Sub-Surface Corrosion by Alkaline Solutions <sup>[1]</sup>. The report noted that piping, regenerators (strippers), absorbers, and heat exchanger shells and heads made from carbon steel had cracked after six months to 10 years of exposure to 15 weight percent MEA in water at temperatures up to 300 °F (149 °C). The MEA contained unspecified amounts of both hydrogen sulfide and carbon dioxide. Complete stress relieving via PWHT was recommended as a solution to the problem.

In 1953, ASCC was reported in MEA solutions in gas treatment plants <sup>[2]</sup>. Requirements for cracking included the presence of both a high stress and a particular corrosive amine solution. The elimination of either factor was found to prevent cracking. Recommended preventive measures included maintaining the reboiler temperature and the regenerator pressure at the lowest practical levels, using reclaimers, and preventing air contact to minimize the

corrosiveness of the amine solutions. Frequently, such process changes cannot be readily implemented, so stress relieving was recommended as an effective alternative.

Other instances of ASCC were reported in non-stress-relieved equipment operating in 20 weight percent MEA [3]. Affected equipment included two amine storage tanks, four absorber towers, one rich amine flash drum, one lean amine treater, and various piping locations. Cracking was found primarily at welds exposed to amine solutions where temperatures ranged from 127 °F to 200 °F (53 °C to 93 °C). The cracking was intergranular, and the crack surfaces were covered by a thin film of magnetite ( $\text{Fe}_3\text{O}_4$ ). No cracking was found in postweld heat treated (PWHT) piping that operated at temperatures as high as 310 °F (154 °C). Although the exact reason for the extensive cracking was not clear, it was concluded that PWHT could be used to prevent the problem.

A major problem occurred in 1984, when an MEA absorber tower ruptured at a U.S. refinery. This failure initiated as SSC in the hardened area of the heat-affected zone of a rewelded shell seam and propagated by SOHIC through the base metal [4]. The weld repair had been performed 10 years earlier as part of a procedure to replace a shell course which had hydrogen blisters.

In 1986, extensive leaking of piping welds was reported in lean MEA service [5]. The leaking was attributed to ASCC. Most leaks occurred at piping welds that had been in lean amine service for 4 to 8 years. Cracks were found in the weld deposits, heat-affected zones, and areas of the base metal adjacent to heat-affected zones. Typically, the cracks propagated parallel to the weld. Shear-wave ultrasonic inspection confirmed the presence of cracks at many other welds in lean amine piping. None of the cracked piping welds had received PWHT.

As a result of these occurrences, in 1985 the NACE Group Committee T-8 on Refining Industry Corrosion, in cooperation with the API Subcommittee on Corrosion and Materials, sponsored an industry-wide survey of cracking problems in amine services [6]. The results of this survey indicated that cracking was most prevalent in MEA service, and that it occurred in all types of equipment at temperatures as low as ambient. PWHT of welds was identified as the single most effective means of preventing cracking. Additional data on stress corrosion cracking of carbon steel in DEA and DIPA services were reported in 1991 [7] and in DEA, DIPA, and MDEA service in 1993 [8].

Industry experience has shown that piping and equipment in rich amine service with  $\text{H}_2\text{S}$  do not typically experience ASCC. An exception has been ASCC in rich amine services due to steamouts of rich amine equipment without first doing a thorough water wash to remove all residual amine. Steamouts strip  $\text{H}_2\text{S}$  from the rich amine and provide the heat to drive ASCC.

In theory, carbon steel equipment and piping cannot be subject to both SSC and Amine SCC in one solution, because the two mechanisms are driven by the opposite electrochemical processes. SSC is a cathodic reaction (hydrogen reduction) cracking mechanism when the steel is in active state. Amine SCC is an anodic reaction (iron dissolution at grain boundaries) cracking mechanism when the steel is in active-passive state or passive breakdown state [14]. Generally, the higher the bisulfide content (from high  $\text{H}_2\text{S}$  loading) of the rich amine stream, the lower the solution pH, so that the carbon steel is more likely in the active state and subject to SSC. On the other hand, the lower the  $\text{H}_2\text{S}$  loading is, the higher the solution pH, so that the carbon steel is more likely in passive state and subject to amine SCC. In general, however, wet  $\text{H}_2\text{S}$  cracking and ASCC are somewhat mutually exclusive. In the regenerator tower where the rich amine is flashed and heated to strip adsorbed acid gases to produce lean amine, it is difficult to define where the transition occurs between wet  $\text{H}_2\text{S}$  dominated cracking versus ASCC dominated cracking.

### 4.3.3 Corrosion

Corrosion (metal loss) of carbon steel components in amine units is not caused by the amines themselves. Fresh amine is considered non-corrosive because 1) it is a weak filming inhibitor on its own merit, and 2) there is no corrodent such as bisulfide, heat stable salts (HSS), and it has not yet been introduced into the circulating solution. Metal loss usually results from dissolved acid gases, including hydrogen sulfide and carbon dioxide. Corrosion can also be caused by a variety of amine degradation products including heat stable salts, such as bicine.

In rich amine, typically the corrosion rate is higher than that of lean amine because of high conductivity and/or low pH, and the rate increases with increasing temperature. For example, rich amine with temperatures greater than 220 °F (104 °C) can result in acid gas flashing and increased localized corrosion when the pressure drop is high enough to cause flashing (such as downstream of a pressure letdown valve). Normally a high corrosion allowance is required for carbon steel or an upgrade to austenitic stainless steel under these conditions.

In lean amine, the corrosion rate is generally lower than that in rich amine, but an excess of heat stable salts above 2 weight percent may significantly increase corrosion rates on carbon steel.

Overstripping of lean amine (i.e. having too low of an H<sub>2</sub>S content in H<sub>2</sub>S removal units) has led to severe corrosion problems especially in the hot sections of the lean amine circuit. These case histories probably had additional factors contributing to the corrosion risks, such as somewhat high HSS contents, but to reduce the risk, many operators apply a minimum H<sub>2</sub>S limit in addition to the maximum limits. The typical recommended minimum limits have ranged from ~100 to 800 ppmw H<sub>2</sub>S. Other refiners have used values between 0.001 to 0.02 mol H<sub>2</sub>S per mol amine as a minimum recommended limit. This is dependent on the refiner's experience and particular operation parameters and is also dependent on amine type/strength, HSS, velocity, and total dissolved solids. These limits vary considerably due to operational differences from refiner to refiner. In Tail Gas Treating units there are often environmental restrictions which require better stripping, resulting in lower H<sub>2</sub>S contents than the 100 ppmw to 800 ppmw minimum recommended. Since it would be impossible in these units to produce H<sub>2</sub>S contents above these minima and still meet environmental regulations, these limits are not applied to Tail Gas lean amine systems. Therefore, in these low H<sub>2</sub>S Tail Gas Treating units, other corrosion control steps are necessary.

The cracking of carbon steel components in amine service is often related to the general corrosivity of amine solutions. This is because corrosion reactions are the source of atomic hydrogen, which causes hydrogen blistering and cracking by mechanisms such as SSC, HIC, and SOHIC, primarily of components in rich amine service (see Annex A). Similarly, corrosion reactions contribute to ASCC, primarily of equipment in lean amine service. It is not possible, however, to quantitatively relate cracking severity to corrosion severity. Nevertheless, efforts aimed at improving corrosion control may also reduce hydrogen-related cracking. (See Annex B for more information regarding corrosion in amine units.)

## 5 Guidelines for Construction Materials and Fabrication of New Equipment and Piping

### 5.1 Construction Materials

Carbon steel, with a nominal corrosion allowance, has been used for most equipment in amine units that remove hydrogen sulfide or mixtures of hydrogen sulfide and carbon dioxide containing at least 5 % hydrogen sulfide. Some problems have been experienced with erosion-corrosion (see B.3 and B.6.2) associated with circumferential welds in rich amine piping made of carbon steel. The problems are usually solved by reducing fluid velocity to less than 6 ft/sec (1.8 m/sec). However, when rich amine loading is above design limits (see Annex B for examples), even reducing the velocity may not reduce the corrosion rate.

Typically, the corrosion rate of carbon steel in rich amines is much more affected by service velocity compared with that in lean amine. Normally a maximum of 6 ft/sec (1.8 m/sec) for rich amine and maximum 20 ft/sec (6.0 m/sec) for lean amine may be applied for carbon steel piping and pressure vessels (inlet and outlet nozzle sections). However, these are initial guidelines and corrosion rates will also depend on amine loading, heat stable salts content, and temperature. Sometimes increasing the line diameter may be needed to reduce fluid velocity and the corrosion rate. The velocity limits should be decided by the purchaser or owner-operator. The selection of material is a tradeoff. In some cases, upgrading to austenitic stainless steel can allow the owner-operator to specify smaller diameter pipe which is often less expensive than larger diameter PWHT carbon steel, even though velocities are higher in the smaller diameter stainless pipe.

Austenitic stainless steels have been used in locations where the corrosion rate of carbon steel is excessive, or the PWHT of carbon steel is to be avoided. Such locations include those that contact hot/rich solutions with high acid gas loading, areas of high velocity, turbulence, impingement, vapor flashing, or two-phase flow, and most heat transfer surfaces operating above ~175 °F (80 °C). Austenitic stainless steels are usually employed extensively

in amine units to remove carbon dioxide from hydrocarbon streams that contain very little or no hydrogen sulfide. For vessels and other fixed equipment, clad plate is preferred over solid stainless steel construction to avoid possible through-wall chloride stress corrosion cracking, although there are numerous cases where solid stainless has served reliably. Some owner-operators have specified solid stainless steel pressure vessels where control of external chloride stress corrosion cracking was achieved by external coatings such as organic paint coatings or thermally sprayed aluminum coatings. API Recommended Practice 583 gives additional guidance on prevention of corrosion under insulation, including SCC. For piping, solid austenitic stainless is generally used. Stainless alloys, such as Types 304L and 316L, have been used for regenerator reboiler tubes. In addition to these austenitic stainless steels, duplex stainless steels have been used for reboiler and reclaimer tubes. Duplex stainless steels have been used specifically in streams containing significant chloride levels which promote a chloride stress corrosion cracking and pitting risk in austenitic 300 series stainless steels.

Even higher alloys such as titanium tubes have been used in units handling CO<sub>2</sub>, but they may embrittle due to hydride formation in service. This is especially true at tube-to-baffle interfaces when a carbon steel baffle is used with titanium tubes.

For pressure vessel plate or rolled and seam-welded pipe, carbon steels with a low level of inclusions, inclusion shape control, or both may provide improved resistance to hydrogen blistering, HIC, and SOHIC. These steels should be evaluated for potential use in equipment that handles rich amine solutions, and in the regenerator overhead, especially if cyanides are present. In some units, operating conditions in the bottom of amine absorbers or contactors are conducive to hydrogen blistering, HIC, or SOHIC despite relatively low temperatures. Carbon steels with a low level of inclusions or inclusion shape control may also be useful in these locations. However, it should be noted that these steels are not immune to blistering and cracking, so their potential use should be carefully considered. It should also be noted that continuous cast steels may be low in inclusion content, but impurities that are present might segregate at the plate mid-wall, which can cause high hardness or laminations at that location. For vessels and other fixed equipment, austenitic stainless steel cladding, lining, or weld overlay are more reliable methods of protection in areas where corrosion, cracking, or hydrogen blistering occurs.

For carbon steel piping, seamless manufacturing methods have reduced the amount of inclusions in the product compared with rolled and seam-welded product made from plate. In addition, the inclusions in seamless carbon steel piping are not elongated as much as in rolled plate product. Therefore, seamless carbon steel pipe can offer improved resistance to hydrogen blistering, HIC, and SOHIC. For new construction, seamless ASTM A106 Grade B carbon steel piping is generally preferred. For large diameter piping where seamless is not available, ASTM A671 or ASTM A672 is preferred.

One operator found ASCC in a high pressure lean amine circuit on thick, seamless CS pipe at multiple locations remote from welds. It is believed that the pipe mill cold bent the pipe by running it through straightening rolls after hot forming resulting in high residual stress fields. Attention should be given to any cold bending practices that results in excessive plastic deformation during the manufacturing or fabrication process for piping components. See A.6 for more details on this failure.

## 5.2 Fabrication

### 5.2.1 General

Certain fabrication practices can help reduce the likelihood of cracking in carbon steels in amine units. These practices include controlling weldment hardness levels and applying PWHT. Attention should be given to proper base metal and weld composition to assure satisfactory response to heat treatment. To control cracking problems effectively, proper consideration should be given to each of these factors. Refer to API Recommended Practice 582 and NACE SP0472 for guidance on weld fabrication. Some owner-users also require materials and fabrication for lean or rich amine service comply with NACE MR0103/ISO 17945 and NACE Publication 8X194.

### 5.2.2 Weldment Hardness Control

Proper control of weldment hardness in fabricated carbon steel equipment and piping can provide resistance to SSC in rich amine. NACE SP0472 defines practical and economical means of protection against this type of

cracking, and outlines necessary controls on base metal, weld composition, and welding parameters to achieve weldments of acceptable hardness for the intended service.

As stated in NACE SP0472, the weld hardness of carbon steel equipment, including piping, should not exceed a Brinell hardness of 200, unless the purchaser has agreed to a higher allowable hardness.

However, it should be noted that a maximum Brinell hardness of 200 in the weld deposit provides no assurance of preventing SSC in the weld's heat-affected zone, or in base plate material where temporary attachments have been made or arc strikes have occurred. Other measures outlined in SP0472, including PWHT, should therefore be considered as a means of providing added cracking resistance to carbon steel weldments.

In the case of amine systems handling CO<sub>2</sub> only, there does not appear to be any benefit to limiting weldment hardness to 200 HB since amine containing carbonic acid produced by wet CO<sub>2</sub> does not cause environmental cracking. Hardness limits for such systems should be evaluated by each user based on past experience.

As noted in A.5, controlling weldment hardness has no known effect on the prevention of amine SCC. However, PWHT at sufficiently long duration and sufficiently high temperature reduces residual stress in carbon steel weldments, thereby greatly reducing the risk of amine SCC. Guidelines for PWHT requirements are outlined in NACE SP0472. Controlled deposition welding (CDW) processes such as temper bead, half-bead, and multi-bead welding are not effective for ASCC mitigation since residual stresses are not reduced by controlled deposition welding.

Dissimilar metal welds between carbon steel and stainless steel should be avoided to alleviate potential hard zones and the inability of PWHT to relieve residual stresses at the bimetallic joint.

### 5.2.3 Postweld Heat Treatment (PWHT)

PWHT, as described in NACE SP0472, should be applied to new carbon steel equipment, including piping operating continuously or intermittently in lean or rich amine services. For stainless clad carbon steel plate and stainless weld overlay onto carbon steel where the amine will not contact the underlying carbon steel, there is no need for PWHT for cracking avoidance.

There is no need for PWHT of carbon steel in fresh amine service. However, some owner-users perform PWHT on carbon steel equipment in fresh amine service as an added caution and to simplify their specifications so that PWHT is performed for all amine services regardless of amine type or loading.

In the past editions of this RP, different amine types were believed to have threshold temperatures for when PWHT is recommended. These threshold temperatures versus amine type are included in Annex C. While these may still be technically correct, there is enough evidence to caution the owner-operator that ASCC may still occur below the previously stated threshold temperatures. Therefore, this Edition does not differentiate among amine type, concentration, or operating temperature and has no minimum threshold temperature. PWHT is now recommended for any amine service except fresh amine. Refer to 5.2.3.3 for correct PWHT parameters.

Industry experience has shown that infrequent exposure to amines from amine contamination of hydrocarbon streams has resulted in ASCC. Most commonly, absorber overhead systems can be subjected to amine carryover and stress corrosion cracking due to inadequate amine de-entrainment in the tower caused by irregular operation, such as foaming upsets. Some operators have chosen to PWHT carbon steel piping up to the first overhead drum, and the drum itself.

Although PWHT is now recommended, historically, some users did not specify PWHT of seamless piping in rich amine services with H<sub>2</sub>S, based solely on the fact that ASCC did not typically occur in H<sub>2</sub>S-rich systems without CO<sub>2</sub>. In refining, most amine treating systems do not have significant amounts of CO<sub>2</sub> (except for steam methane reformers, fluidized catalytic crackers, and some cokers). In rich amine services without CO<sub>2</sub>, the governing mechanism is wet H<sub>2</sub>S cracking (e. g. sulfide stress cracking), not ASCC. Hence this requires controlling hardness in the weldment to acceptable levels. Multi-pass welding and thermal control per NACE SP0472 is one approach, but this requires minimizing residual elements (e. g. niobium and vanadium) to ensure the weld HAZ remains acceptably soft. The issue which stems from this approach relates to the definition of lean versus rich amine