

# Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries

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## Introduction

Sulfidation corrosion, also often referred to as “sulfidic corrosion,” continues to be a significant cause of leaks in piping and equipment within the refining industry. The objective of this recommended practice (RP) is to provide a better understanding of sulfidation corrosion characteristics and give practical guidance to inspectors and maintenance, reliability, project, operations, and corrosion personnel on how to address sulfidation corrosion in petroleum refining operations. Examples of failures are discussed to highlight the common causes. The methods used to control and inspect for sulfidation corrosion are summarized. The data herein are a compilation of information extracted from published technical papers, industry information exchanges (NACE and API), and contributions from several owner/operators. Some refining companies have developed proprietary methods to predict sulfidation corrosion, and these were not made available as part of this effort.

There are two separate and distinct mechanisms of sulfidation corrosion. One occurs where  $H_2$  is present in addition to the sulfidation-causing sulfur species, as is common in many refining processes, such as hydrotreating and hydrocracking. The other occurs in the absence of  $H_2$  (hydrogen free) in processing units that do not employ  $H_2$  as a component of the process. They both are non-aqueous, diffusion-based corrosion mechanisms that occur at elevated temperature. There is considerable debate in the industry as to the correct threshold temperature for hydrogen-free sulfidation, and in a change in this edition, the API 571 threshold of 500 °F (260 °C) for hydrogen-free services is adopted herein. Experience has shown that little significant corrosion will occur at operating temperatures below 500 °F for hydrogen-free sulfidation services without the influence of naphthenic acid corrosion.

Common refinery units in which essentially  $H_2$ -free sulfidation corrosion can occur are the crude/vacuum, fluid catalytic cracker, coker, and visbreaker units. Hydroprocessing and hydrocracking units can experience  $H_2$ -free sulfidation corrosion in their feed sections before the hydrogen is introduced, and in their distillation sections downstream of where the hydrogen is removed. They experience sulfidation in the presence of hydrogen in their reaction sections. This sulfidation in the presence of  $H_2$  is typically referred to as “ $H_2/H_2S$  corrosion” and the minimum temperature is 450 °F (230 °C).

Included in this RP are:

- background to damage mechanisms,
- the most common types of damage observed,
- root causes of sulfidation corrosion,
- methods to predict and monitor the corrosivity of systems,
- materials selection for new and revamped processes, and
- inspection and nondestructive examination (NDE) methods used for detecting sulfidation corrosion.

Materials and corrosion specialists should be consulted for additional unit-specific interpretation and application of this recommended practice.

# Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries

## 1 Scope

This recommended practice (RP) is applicable to hydrocarbon process streams with sulfur-containing compounds, without the presence of hydrogen ( $H_2$ ), which operate at temperatures above approximately 500 °F (260 °C) up to about 1000 °F (540 °C). There is considerable debate in the industry as to the correct threshold temperature for  $H_2$ -free sulfidation, and in a change in this edition, the API 571 threshold of 500 °F (260 °C) is adopted herein. Experience has shown that little significant corrosion will occur at operating temperatures below 500 °F (260 °C) for  $H_2$ -free sulfidation services without the influence of naphthenic acid corrosion. Mercaptan corrosion, particularly in condensate service, has been reported below this temperature but is not explicitly covered in the Second Edition of API 939-C. For  $H_2$ -containing services, the threshold temperature is set at 450 °F (230 °C).

A lower threshold limit for sulfur content is not provided because significant corrosion has occurred in the reboiler/fractionator sections of some hydroprocessing units (which do not contain  $H_2$ ) at measured sulfur or hydrogen sulfide ( $H_2S$ ) levels as low as 1 ppm.

Corrosion of nickel (Ni) base alloys in hot  $H_2S$  environments is excluded from the scope of this document. In addition, while sulfidation can be a problem in some sulfur recovery units, sulfur plant combustion sections and external corrosion of heater tubes due to firing sulfur-containing fuels in heaters are specifically excluded from the scope of this document.

## 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 570, *Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems*

API Recommended Practice 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*

API Recommended Practice 578, *Guidelines for a Material Verification Program (MVP) for New and Existing Assets*

API 579-1/ASME <sup>1</sup> FFS-1, *Fitness-For-Service*, June 2007, Second Edition

API Recommended Practice 584, *Integrity Operating Windows*

ASME SA-516, *Specification for Pressure Vessel Plates, Carbon Steel, for Moderate- and Lower-Temperature Service*

ASTM A106/A106M <sup>2</sup>, *Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service*

## 3 Terms, Definitions, Abbreviations, and Acronyms

### 3.1 Terms and Definitions

For the purpose of this document, the following terms and definitions apply.

---

<sup>1</sup> ASME International, 2 Park Avenue, New York, New York, 10016, [www.asme.org](http://www.asme.org).

<sup>2</sup> ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, [www.astm.org](http://www.astm.org).

### 3.1.1

#### **common corrosion system and circuits**

Typically, the piping and equipment that is organized into corrosion systems, sometimes referred to as loops, that have similar expected damage mechanisms. A system may be the overhead system of a tower. A circuit is a subset of a system, and the term “common corrosion circuit” indicates that corrosion rates and other damage would be expected to have similar likelihood and would have similar process conditions.

### 3.1.2

#### **hydrogen free**

#### **H<sub>2</sub> free**

Processes where H<sub>2</sub> is not intentionally added. There may be trace amounts of H<sub>2</sub> present but are in services such as crude/vacuum units, fluidized catalytic cracking (FCC), cokers, etc.

### 3.1.3

#### **integrity operating window**

#### **IOW**

Established limits for process variables (parameters) that can affect the integrity of the equipment if the process operation deviates from the established limits for a predetermined amount of time. This documentation describes limits related to unit- and equipment-specific process parameters for the given materials of construction. Operation within the limits should not adversely affect the mechanical integrity of the equipment and piping. An IOW can also define process monitoring tasks to ensure that operating conditions are maintained within the established parameters.

NOTE Guidance on setting and using IOWs is given in API 584.

### 3.1.4

#### **killed steel**

Steel that has been completely deoxidized by the addition of an agent, such as Si or aluminum (or other methods such as vacuum treatment), before casting, so that there is practically no evolution of gas during solidification. Killed steels are characterized by a high degree of chemical homogeneity and freedom from porosity.

### 3.1.5

#### **low-alloy (Cr-Mo) steels**

Steels that contain 1 % to 9 % chromium (Cr) and 0.5 % to 1 % Mo (molybdenum).

### 3.1.6

#### **low-silicon (Si) carbon steels**

Carbon steels that contain less than 0.10 weight (wt) % Si.

### 3.1.7

#### **material spec break or specification break**

A change in metallurgy where carbon steel or alloys with lower alloy content are joined or mated up to a higher alloy content.

### 3.1.8

#### **mils/yr or mpy**

Corrosion rate expressed as thickness loss over a period of time. 1 mil/yr = 0.001 in./yr (40 mils = 1 mm). Often expressed as “mpy.”

### 3.1.9

#### **reactive sulfur**

Crude oil and fractions contain various sulfur compounds. Some are reactive and can cause corrosion, whereas others are not very reactive and do not cause corrosion. It is not the total sulfur content that is most critical in predicting corrosion, but the amount of reactive sulfur present.

**3.1.10****sulfidation**

Corrosion of metal resulting from reaction with  $\text{H}_2\text{S}$ , sulfur compounds, and/or sulfur-containing hydrocarbon molecules in high-temperature environments such that a surface sulfide scale forms. The term “sulfidic corrosion” is consistent with this definition.

**3.2 Abbreviations and Acronyms**

For the purposes of this document, the following abbreviations and acronyms apply.

|                      |                                                                                         |
|----------------------|-----------------------------------------------------------------------------------------|
| AUT                  | automated ultrasonic testing                                                            |
| CDU                  | crude distillation unit                                                                 |
| $\text{Cl}^-$ SCC    | chloride stress corrosion cracking                                                      |
| CML                  | corrosion monitoring location; formerly known as “TML” (thickness measurement location) |
| Cr                   | chromium                                                                                |
| ERW                  | electric resistance welded                                                              |
| FCC                  | fluidized catalytic cracking                                                            |
| FCCU                 | fluid catalytic cracking unit                                                           |
| GWUT                 | guided wave ultrasonic testing                                                          |
| $\text{H}_2$         | hydrogen                                                                                |
| $\text{H}_2\text{S}$ | hydrogen sulfide                                                                        |
| IOW                  | integrity operating window                                                              |
| Mo                   | molybdenum                                                                              |
| NDE                  | nondestructive examination                                                              |
| Ni                   | nickel                                                                                  |
| PMI                  | positive material identification                                                        |
| PTASCC               | polythionic acid stress corrosion cracking                                              |
| RT                   | radiographic testing (inspection), a.k.a. gamma ray or X-ray inspection                 |
| Si                   | silicon                                                                                 |
| SS                   | stainless steel                                                                         |
| UT                   | ultrasonic testing (inspection)                                                         |
| VDU                  | vacuum distillation unit                                                                |
| XRF                  | X-ray fluorescence                                                                      |

## 4 Basics of Sulfidation Corrosion

Sulfidation corrosion, also often referred to as “sulfidic corrosion,” is not a new phenomenon but was first observed in the late 1800s in a pipe still (crude separation) unit, due to the naturally occurring sulfur-containing organic compounds found in crude oil. When heated for separation, the various fractions separated from the crude were found to cause corrosion of the steel equipment as a result of reaction with the sulfur-containing compounds. With the advent of FCC and coking processes, sulfidation corrosion was also experienced in these units <sup>[1] [2]</sup>.

When hydroprocessing was introduced in the 1950s, changes in the corrosion behavior of construction materials were noted. This led to the recognition that a different sulfidation corrosion behavior resulted under hydroprocessing conditions that typically involve the presence of  $H_2$ .

Empirical industry data as well as laboratory research indicate that the sulfidation corrosion rate is a function of a variety of factors, including temperature, the total sulfur concentration, the types of sulfur-containing compounds present, the type of process stream (e.g. light gas or heavy oil), the velocity, heat transfer conditions, the presence or absence of  $H_2$ , and the material of construction.

In the absence of  $H_2$ , corrosion due to sulfur-containing compounds typically is thought to occur at temperatures above 500 °F (260 °C). As discussed below, a set of curves called the “modified McCconomy curves” <sup>[3]</sup> can be used to help predict corrosion rates in the absence of  $H_2$ . These curves show that at a given temperature and total sulfur level, steels with increasing Cr content [from carbon steel to 5Cr-0.5Mo to 9Cr-1Mo to stainless steel (SS)] will experience lower corrosion rates.

In the presence of  $H_2$ , i.e.  $H_2/H_2S$  corrosion, corrosion rate starts to increase above about 450 °F (230 °C). A different set of curves, known as “the Couper-Gorman curves,” <sup>[4]</sup> can be used to help predict the corrosion rate in this environment. These curves relate the amount of  $H_2S$  present with temperature to estimate the corrosion rate. While in  $H_2$ -free sulfidation, 5Cr-0.5Mo and 9Cr-1Mo have useful resistance, in  $H_2/H_2S$  sulfidation, there is little improvement in alloy performance until the Cr level reaches 12 wt %. In addition, materials such as 18Cr-8Ni stainless achieve a significant improvement in corrosion resistance over and above 12Cr wt % SS. Each crude oil or crude blend has its own characteristic chemistry, sulfur-containing organic compounds, and effect on sulfidation corrosion. Despite the industry’s best efforts, the accurate prediction of the resulting  $H_2$ -free sulfidation corrosion rate for a specific crude oil and its fractions is an elusive technical challenge. Oil refineries that processed a consistent diet of a particular crude oil or crude blend could often base future predictions on past experience. However, over the past 20+ years, global economics have resulted in many refineries processing tens of different crudes in any given year, thus minimizing the accuracy, or even feasibility, of predictions based on historical data. Additionally, the verification of the actual sulfidation corrosion rate experienced while processing a specific crude oil is very difficult.

In both  $H_2$ -free sulfidation and  $H_2/H_2S$  corrosion, the metal surface will form sulfide scales. These metal sulfide scales tend to slow down the sulfidation corrosion rate, since their formation tends to protect the underlying metal surface. In plain carbon steel, these will be iron sulfides, and in Cr-Mo steels, these will be chromium-iron sulfides. The Cr-based sulfides are more robust and protective than the plain iron sulfides, and the Cr sulfides will maintain their protection to higher temperatures and fluid velocities than iron sulfides.

Sulfidation results in wastage of steel, resulting in loss of wall thickness of piping and components, heater tubes, and pressure vessels. Most industry sulfidation incidents have occurred in piping components, due to their thinner overall wall thicknesses and their higher population density vs other equipment types. Although sulfidation corrosion under certain circumstances can be isolated or localized, the majority of sulfidation corrosion damage is general or uniform in nature, i.e. present over a fairly large surface area of a given component and not dependent on differences between local conditions and bulk conditions. As a result, because the nature of the corrosion is commonly general thinning, ruptures are possible instead of a pinhole leak. Ruptures can lead to the potential release of large quantities of hydrocarbons. Figure 1 to Figure 4 depict piping components that experienced  $H_2$ -free sulfidation corrosion.



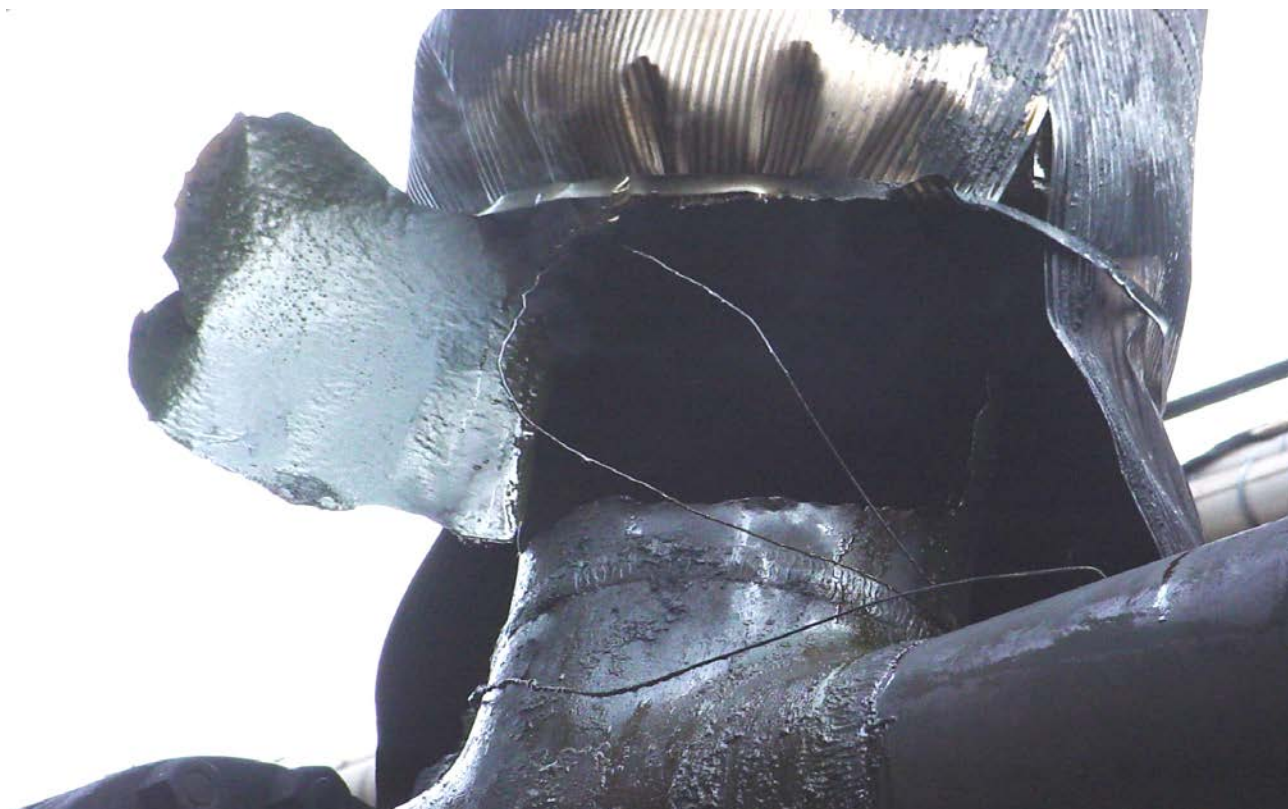
NOTE There is relatively uniform thinning, which resulted in a sizeable rupture.

**Figure 1—NPS 8 Carbon Steel Piping Failed Due to Sulfidation Corrosion ( $H_2$  Free)**



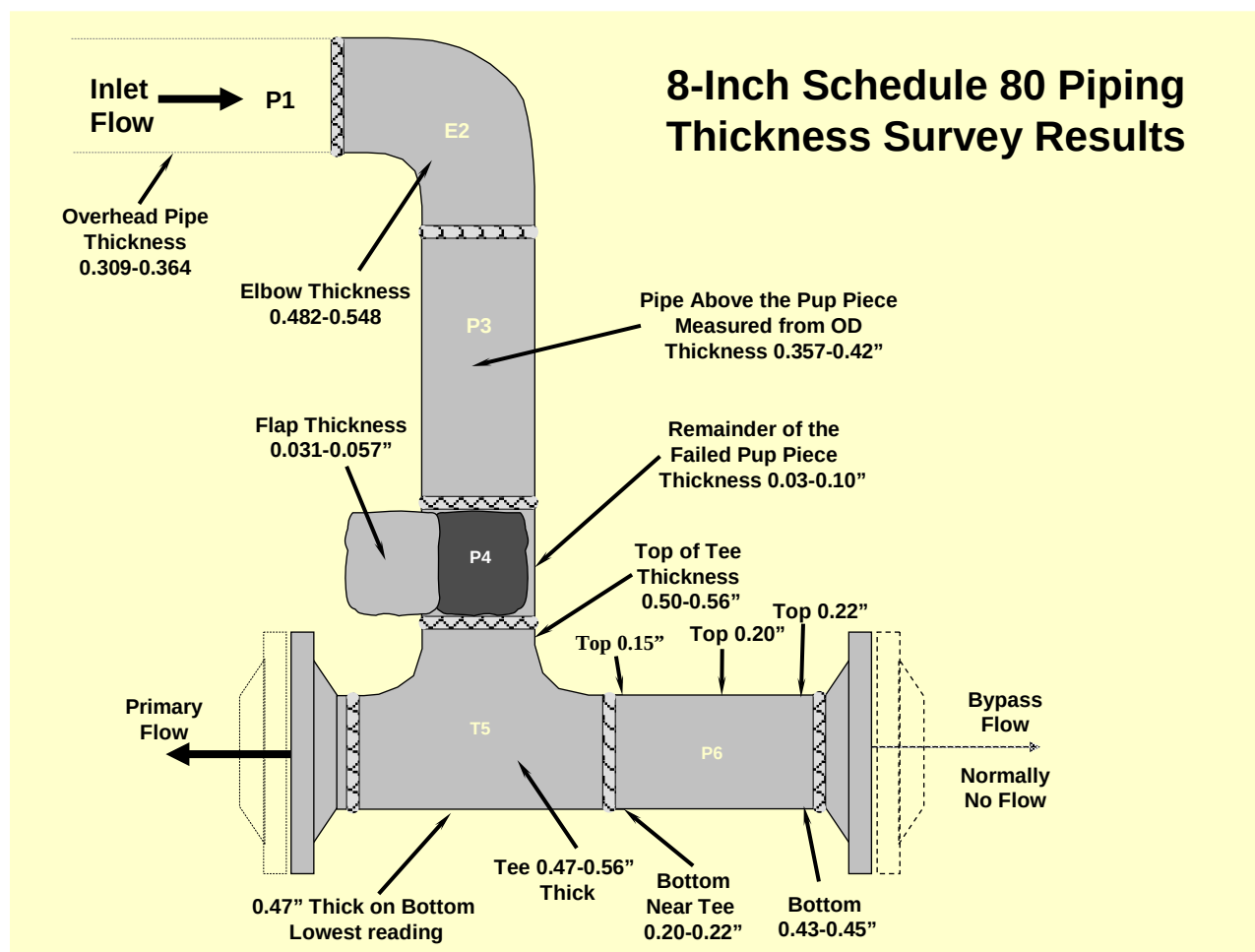
NOTE The carbon steel nipple (on right) corroded severely in 2 years in a crude unit (original thickness on left). It was specified as 9Cr-1Mo.

**Figure 2—Corroded Carbon Steel Sight Glass Nipple**



NOTE Also see the sketch in Figure 4.

**Figure 3—FCC Fractionator Bottoms Carbon Steel Piping Operating at 150 psig (1 MPa) and 650 °F to 700 °F (340 °C to 370 °C)**



NOTE 1 1 in. = 25.4 mm.

NOTE 2 There may be a flow regime effect.

**Figure 4—FCC Fractionator Bottoms Carbon Steel Piping Shown in Figure 3 Operating at 150 psig (1 MPa) and 650 °F to 700 °F (340 °C to 370 °C)**

## 5 Location of Sulfidation Corrosion

Sulfidation corrosion can occur wherever sulfur-containing compounds are present in a hydrocarbon stream and the temperature exceeds approximately 500 °F (260 °C).  $H_2/H_2S$  corrosion can occur above 450 °F (230 °C) in the absence of hydrocarbon. API 571 contains generic process flow diagrams for typical refinery units and identifies where  $H_2$ -free sulfidation corrosion and  $H_2/H_2S$  corrosion typically occur.

$H_2$ -free sulfidation most frequently occurs in the hotter areas of the following types of units: crude, vacuum, coker, visbreaker, and hydroprocessing feed and distillation sections.  $H_2/H_2S$  corrosion most commonly occurs in hydroprocessing units such as desulfurizers, hydrotreaters, and hydrocrackers downstream of the  $H_2$  injection point through the reaction section to the separation section.

## 6 Effects of Process and Material Variables on Corrosion Rates

### 6.1 Introduction

For the purpose of discussion, sulfidation is presented at several degrees of complexity in this section. First, the fundamentals are covered. Then the basic variables to consider in estimating corrosion rates and complicating factors that can, at times, cause high variability in corrosion rates are covered.

Crude oils also contain other corrosive constituents that can cause corrosion in H<sub>2</sub>-free elevated temperature service. Some crude oils contain organic acids that are often collectively referred to as “naphthenic acids.” It is often difficult to isolate the individual effects of naphthenic acids and sulfidation. A detailed discussion of the effects of naphthenic acids is outside the scope of this document, but it is important to note that naphthenic acids can dissolve the iron sulfide scale or at the very least render it less protective. Generally, corrosion due to sulfur compounds results in an iron sulfide scale that partially protects the metal from naphthenic acid corrosion. Naphthenic acid generally accelerates corrosion rates.

### 6.2 H<sub>2</sub>-free Sulfidation

#### 6.2.1 Fundamentals

The fundamentals of H<sub>2</sub>-free sulfidation corrosion are covered in Section 4 and Section 5. Sulfidation predominately occurs by direct reaction of sulfur-containing species with the metal surface. H<sub>2</sub>-free services are defined as those in which H<sub>2</sub> is not intentionally added as part of the process.

Carbon steels and some low-alloy steels can corrode in H<sub>2</sub>-free process streams in the presence of reactive sulfur-containing hydrocarbon compounds above about 500 °F (260 °C). Corrosion rates can be highly variable and difficult to predict. The basic and complicating variables below affect the ability to predict corrosion rates.

#### 6.2.2 Basic Variables

##### 6.2.2.1 Temperature and Alloy Content

Carbon steels and low-alloy steels up to and including 9Cr-1Mo can be susceptible to H<sub>2</sub>-free sulfidation corrosion. Below 450 °F (230 °C), the corrosion rate is essentially nil. Between 450 °F (230 °C) and 500 °F (260 °C), experience has shown that sulfidation rates are extremely low (<1 mpy). The corrosion rate increases with temperature from 500 °F (260 °C) to about 800 °F (425 °C). The increase is more exponential than linear. The corrosion rate is believed to peak around 800 °F (425 °C), and at higher temperatures, the rate decreases [5]. There are several theories as to why there is a peak, ranging from coke formation, destruction of reactive sulfur species, and formation of more stable iron sulfide scales. (See 7.3 regarding materials selection and this peak.)

In 1961, McConomy [6] developed corrosion rate vs temperature plots for several alloys. These curves represented average corrosion rates from industry data collected in the 1960s from non-desulfurizing and desulfurizing processes before H<sub>2</sub> addition, including fired heater tubes. In subsequent years, these curves were modified (lowered) by a factor of 2.5 because it was found that they were, in most cases, too conservative [3]. These newer curves are referred to as the “modified McConomy curves,” which are reproduced in Figure B.1 and Figure B.2. These curves have an adjustment for sulfur content. There is significant scatter in the data and other variables influence rates; thus, these curves should be used with the knowledge that much higher or lower rates are possible (possibly by a factor of 10).

The curves illustrate the beneficial effect of Cr as an alloying element; the higher the Cr content of the steel, the lower the sulfidation rate, i.e. 9Cr-1Mo will corrode less than 5Cr-0.5Mo, which corrodes less than carbon steel. The exact reason for the beneficial effect of Cr is not clear, but it is believed to be related to the stability and protective nature of the iron-chromium-sulfide corrosion product scales formed on the surface of the metal.

While the McConomy curves cannot precisely predict corrosion rates, the curves are often successfully used to compare and predict the relative rates of corrosion for different steels, using the ratio of the rates predicted by the curves at a given temperature and sulfur content for the alloys of interest.

### 6.2.2.2 Sulfur Content and Speciation

The modified McConomy curves are based on a 0.6 % total sulfur content in the crude or fraction and are accompanied by a corrosion rate multiplier for lower and higher sulfur contents. In general, the higher the sulfur content of the stream, the more corrosive the stream will be. This effect is less pronounced than the temperature effect. However, as discussed in Annex B, the situation is more complex. Most crude oils contain a range of sulfur-containing species, including  $\text{H}_2\text{S}$ , mercaptans, polysulfides, thiophenes, aliphatic sulfides, and aliphatic disulfides, as well as elemental sulfur,<sup>[7][8]</sup> and each has a different reactivity or effect on corrosion rate. Some companies have performed analyses of crude oil and its fractions for various sulfur compounds and have developed predictive models based on a combination of laboratory and field experience. Nonetheless, it is very difficult for a refinery to accurately assess a crude oil (unknown to them) for corrosivity based on total sulfur content alone or a breakdown of the sulfur species.

### 6.2.3 Complicating Variables

#### 6.2.3.1 Nature of the Hydrocarbon Phase

Sulfur compounds tend to concentrate in heavier liquid fractions, but given the same sulfur content and temperature, light gaseous hydrocarbons appear to be more aggressive. This may be due to different sulfur species or could be a function of the heavier hydrocarbon wetting the surface and retarding the sulfidation corrosion reaction.

#### 6.2.3.2 Si Content

Carbon steel components and welds with low Si (<0.10 %) content can corrode at an accelerated rate when exposed to high-temperature sulfidation corrosion conditions. Refer to Annex C for data showing the relative corrosion rates of high- and low-Si-content steels. In some applications, carbon steel will appear to be adequate based on measured corrosion rates until failure occurs at some undocumented or unidentified low-Si component. Figure 3 and Figure 4 relate to a failure where there were differences in Si content among the various components and welds. The lower-Si-content steel components corroded at a greater rate.

Commonly used grades of carbon steel seamless pipe and fittings used today (including ASTM A106 pipe, ASTM A234 fittings, and ASTM A105 forgings) all have a minimum required Si content of 0.10 wt %. Older forging specifications including ASTM A105 and ASTM A181 had no such requirements until 1995, and ASTM A53 piping still has no minimum Si requirement. In addition, ASTM A234 fittings do not require a minimum Si content if they are made from forgings. Since the advent of dual certification in the mid-1980s, most seamless carbon steel piping has been dual stamped "A53/A106," meaning that it has 0.10 wt % Si required to meet the ASTM A106 specification. ASTM A53 piping that is longitudinally welded [electric resistance welded (ERW)] pipe is never dual certified, and even today it may be low Si.

There have been reports of accelerated corrosion of low-Si weld metal. These cases are rare and, with a few exceptions, have occurred mostly in non-U.S. refineries. This could be due to different welding practices and electrodes used in other countries. However, none of the 45 incidents reported in Section 9 were attributed to this phenomenon.

Although the case histories and test data to date on the effect of low Si content on carbon steel corrosion rates have been only in  $\text{H}_2$ -free environments, some users are including  $\text{H}_2/\text{H}_2\text{S}$  services in their special inspection programs, as discussed in 7.2.6. This is based on the theories on the corrosion reactions and protective scales, showing a possibility that the two mechanisms could be similarly affected by the Si content.

#### 6.2.3.3 Velocity

Carbon and low-alloy steels form a sulfide scale in high-temperature sulfur-containing streams, which can retard the sulfidation rate. Under high shear stress conditions, the scale can be removed (particularly if naphthenic acid is present), or the scale that is formed will be thinner and less protective, causing accelerated corrosion. One example of high velocity (high shear stress) effects was the severe sulfidation corrosion of

carbon steel balance lines connected to atmospheric bottoms feed pumps. At a flow velocity reported to be at least 180 ft/s (60 m/s), the sulfide protective scale is immediately eroded away, resulting in bare metal, which then encourages more scale to re-form and erode away further, thus resulting in severe metal loss. Components in the same system exposed to lower flow rates did not corrode severely.

No flow or very low flow can also be detrimental. This can contribute to stratification of corrosive species and cause preferential attack. In some cases, such as in column bottoms, low velocity or long residence time can allow more H<sub>2</sub>S to evolve. Long chain sulfur species could thermally crack to create H<sub>2</sub>S that can increase the corrosivity of the bulk fluid. In relatively long, normally blocked-in lines, such as recirculation lines or start-up lines, thermal syphons can also occur, which can raise the temperature locally and exacerbate the corrosion. In addition to the long residence time possibly allowing more H<sub>2</sub>S to evolve, the thermal syphon creates flow off the main line that can replenish the corrosive sulfur species in the thermal syphon zone, leading to higher-than-expected corrosion rates, particularly along the top of horizontal runs.

Another key factor appears to be whether the surface is liquid wetted or not, with higher rates expected if the surface is in contact with a vapor phase rather than a liquid phase (perhaps six times higher, see 6.3.3.1).

On typical liquid-filled lines with flow velocities of about 3 fps to 10 fps (1m/s to 3 m/s), corrosion rates will be somewhat higher at elbows, but corrosion will also be found on the straight runs.

#### 6.2.3.4 Coking

Coke forming on the walls of piping and other equipment in general will reduce the rate of corrosion in non-heat-transfer components by isolating the steel or alloy surface from the sulfur compounds in the hydrocarbon fluid stream. An example of this is found in coke drums where in lower sections 12Cr cladding has cracked and or spalled off, but the shell did not corrode as severely as expected due to coke formation on the surface. Another example is in FCC reactor cyclones where corrosion is minimal in areas covered with coke. Under heat transfer conditions, such as those in fired heater tubes, the presence of a coke layer can increase the metal temperature, resulting in an increase in corrosion rate.

#### 6.2.3.5 Stripping Steam/Reboiling

The degree of stripping in sidestream strippers in the crude unit and in the FCC main fractionator can affect the buildup of H<sub>2</sub>S. If columns are not adequately stripped, the associated bottoms systems can experience higher corrosion rates. One refiner reported that when the stripping steam rate was reduced for energy savings, severe corrosion occurred in a carbon steel area of the FCC main fractionator vessel. The degree of reboiling can also affect the H<sub>2</sub>S content, with lesser amounts of steam leading to less effective stripping and concentration of higher levels of H<sub>2</sub>S in the bottoms of towers.

#### 6.2.3.6 Pressure

The total system pressure does not appear to be a major variable for H<sub>2</sub>-free sulfidation corrosion.

#### 6.2.3.7 “H<sub>2</sub>-free, Low-sulfur Streams” in Hydroprocessing Distillation Sections

##### 6.2.3.7.1 General

This mechanism can occur with as low as 1 ppm H<sub>2</sub>S and is not well understood. NACE Publication 34103 <sup>[9]</sup>, published in 2002 and updated in 2014, summarizes the available information. It is treated here as a special case of H<sub>2</sub>-free sulfidation although the observed corrosion rates often are more in line with those expected with H<sub>2</sub>/H<sub>2</sub>S corrosion. Corrosion has been found to be particularly severe in the hotter fractionator reboiler circuits (see 6.3.3).

##### 6.2.3.7.2 Temperature and Alloy Content

The higher the temperature, the more corrosive the stream will be subject to a peak discussed in 6.2.2.1. NACE Publication 34103 <sup>[9]</sup> shows corrosion rates have approached or exceeded those found in H<sub>2</sub>-containing