

Design, Materials, Fabrication, Operation, and Inspection Guidelines for Corrosion Control in Hydroprocessing Reactor Effluent Air Cooler (REAC) Systems

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Design, Materials, Fabrication, Operation, and Inspection Guidelines for Corrosion Control in Hydroprocessing Reactor Effluent Air Cooler (REAC) Systems

1 Scope

1.1 This recommended practice provides guidance to engineering and plant personnel on equipment and piping design, material selection, fabrication, operation, and inspection practices to manage corrosion and fouling in the wet sections of hydroprocessing reactor effluent systems. The reactor effluent system includes the equipment and piping subject to ammonium salting, NH_4HS corrosion, and associated fouling. This system usually begins at the last feed/effluent exchanger or first water injection point and continues through the cold high-pressure separator (1, 2, and 3 separator designs) or cold high- and low-pressure separators (4 and 5 separator designs). The reactor effluent system specifically excludes the stripper, fractionator, and final separation sections. However, guidance in this document may be applicable to ammonium salt corrosion mitigation in those areas, as well. The majority of these systems have an air cooler; however, some systems utilize only shell and tube heat exchangers. Reactor effluent systems are prone to fouling and corrosion by ammonium bisulfide (NH_4HS) and ammonium chloride (NH_4Cl) salts.

1.2 An understanding of all variables impacting corrosion and fouling in these systems is necessary to improve the reliability, safety, and environmental impact associated with them. Past attempts to define generic optimum equipment design and acceptable operating variables to minimize fouling and corrosion have had limited success due to the interdependence of the variables. Corrosion can occur at high rates and be extremely localized, making it difficult to inspect for deterioration and to accurately predict remaining life of equipment and piping. Within the refining industry, continuing equipment replacements, unplanned outages, and catastrophic incidents illustrate the current need to better understand the corrosion characteristics and provide guidance on all factors that can impact fouling and corrosion.

1.3 This recommended practice is applicable to process streams in which NH_4Cl and NH_4HS salts can form and deposit in equipment and piping or dissolve in water to form aqueous solutions of these salts. Included in this practice are:

- details of deterioration mechanisms;
- methods to assess and monitor the corrosivity of systems;
- details on materials selection, design, and fabrication of equipment for new and revamped processes;
- considerations in equipment repairs; and
- details of an inspection plan.

1.4 Table 1 lists factors affecting reactor effluent air cooler (REAC) system performance and section reference for more detail.

1.5 Materials and corrosion specialists should be consulted for additional unit-specific interpretation and application of this document. Each facility needs to establish its own safe operating envelope to ensure satisfactory service. This recommended practice helps to identify key variables necessary for monitoring and establishing the operating envelope.

1.6 Other equipment downstream of the REAC can also deteriorate from these ammonium salts. These include the recycle and sour gas systems and the H_2S stripper and product fractionator overhead systems. Although these are beyond the scope of this document, plant personnel should be alert to these other locations where ammonium salt fouling and corrosion can occur.

1.7 Since the first edition of API 932-B was published in July 2004, findings from several joint industry sponsored research programs have contributed important new data on NH_4HS corrosion relevant to these systems. While not all the data are in the public domain, recent publications have highlighted key data that are incorporated into this current edition of API 932-B.

Table 1—Factors Affecting REAC System Corrosion and Fouling

Key Issues		Section
NH_4HS concentration	Below 2%, solutions are not highly corrosive to carbon steel. Above 2%, solutions are increasingly corrosive. Materials of construction, piping configuration, H_2S partial pressure, and fluid velocity become important to corrosion.	6.1
Chlorides in process stream	Deposition and severe corrosion could result from NH_4Cl . Inject water to remove salts and scrub process gas.	6.6
H_2S partial pressure	Under the H_2S -dominated conditions typical of most hydroprocessing units, higher H_2S partial pressure increases the corrosion rate for a given NH_4HS concentration.	6.4
Wash water	Quantity of water injected to reduce NH_4HS concentration and to allow sufficient free water at injection point.	6.9.2
	Quality of wash water critical to prevent increased corrosion and deposition of inorganic materials.	6.9.1
	Adequate distribution through single or multiple injection points with quills to ensure REAC surfaces are washed.	8.6.3.2
Bulk fluid velocity	Increasing fluid velocity increases the corrosivity of the process. Velocities should be appropriate for the NH_4HS concentration and material of construction.	6.3
Materials of construction	Carbon steel performs acceptably under low NH_4HS concentration and velocities. Alloy 825 is more appropriate for more severe conditions.	7
REAC header box and tubes	Header box design should promote good flow distribution through tube rows.	8.1.2.1
	U-tubes should be avoided.	8.1.2.2
REAC inlet and outlet piping design	Piping design should minimize turbulence for NH_4HS solutions.	8.5.2
	Piping configuration should promote balanced flow through all REAC inlets to prevent salt deposition and to distribute wash water.	8.6.3.1
Process variables and monitoring	Establish an operating envelope and monitor key process variables to ensure they remain within acceptable ranges.	5.3 6.12
Inspection plan	Inspection plans should address all deterioration mechanisms possible in the equipment and piping system, including general and localized corrosion, HIC, SOHIC, and hydrogen blistering.	9

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 584, *Integrity Operating Windows*

API Standard 661, *Air-cooled Heat Exchangers for General Refinery Service*

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

API Recommended Practice 941, *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*

ASME B31.3¹, *Process Piping*

NACE SP0296², *Guidelines for Detection, Repair, and Mitigation of Cracking of Existing Petroleum Refinery Pressure Vessels in Wet H₂S Environments*

NACE SP0472, *Methods and Controls to Prevent In-service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments*

NACE MR0103, *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 H₂S Refinery Service*

NACE SP0114, *Refinery Injection and Process Mix Points*

3 Terms, Definitions, and Acronyms

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1

chloride stress corrosion cracking

Cracking of a metal under the combined action of tensile stress and corrosion in the presence of chlorides and an electrolyte (usually water).

NOTE Austenitic stainless steels are generally considered susceptible to this mode of cracking.

3.1.2

heat exchangers

Shell-and-tube designs, not including air coolers.

3.1.3

hydrogen-induced cracking

HIC

Stepwise internal cracks that connect adjacent hydrogen blisters on different planes in the metal or to the metal surface.

NOTE 1 No externally applied stress is needed for the formation of HIC.

NOTE 2 HIC is commonly found in steels with high levels of impurities, especially sulfur.

3.1.4

hydroprocessing unit

A hydrocracking, hydrotreating (also sometimes referred to as a desulfurizer or hydrosulfurizer), or similar unit producing ammonia (NH₃) and hydrogen sulfide (H₂S) in a reactor.

NOTE Some unit names are based on licensors' patented processes.

¹ ASME International, 3 Park Avenue, New York, New York 10016-5990. www.asme.org.

² NACE International, 1440 South Creek Drive, Houston, Texas 77084-4906. www.nace.org.



3.1.5

integrity operating windows

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 length of time (includes critical, standard, and informational IOWs).

3.1.6

IOW critical limit

An established IOW level that, if exceeded, could cause rapid deterioration to occur such that the operator must take immediate predetermined actions to return the process variable back within the IOW to prevent significant defined risks of potential equipment damage or hazardous fluid release that could occur in a fairly short timeframe.

NOTE Other terminology has been used in place of “critical limit,” such as “safe operating limit” or “safety critical limit.”

3.1.7

IOW standard limit

An established IOW level that, if exceeded over a specified period of time, could cause increased degradation rates or introduce new damage mechanisms beyond those anticipated. Since the timing of the impact from an exceedance of an IOW standard limit can vary significantly, the notification and response to an exceedance can also vary. For higher-risk exceedances, alarms or alerts are potentially needed and the operator may need to take predetermined actions. For lower risk exceedances, alerts may only be needed for eventual interaction with operating supervisors or appropriate technical personnel and subject matter experts (SMEs).

3.1.8

polythionic acid stress corrosion cracking

PTA SCC

Cracking of a sensitized austenitic stainless steel or other sensitized austenitic alloys under combined action of tensile stress and corrosion in the presence of polythionic acid that is usually formed from water, oxygen, and sulfide scales.

3.1.9

reactor effluent system

The reactor effluent system includes the equipment and piping subject to ammonium salting, NH_4HS corrosion, and associated fouling. This system usually begins at the last feed/effluent exchanger or first water injection point, and continues through the cold high-pressure separator (1, 2, and 3 separator designs) or cold high- and low-pressure separators (4 and 5 separator designs). The reactor effluent system specifically excludes the stripper, fractionator, and final separation sections. However, guidance in this document may be applicable to ammonium salt corrosion mitigation in those areas, as well.

3.1.10

sensitization

A condition of an alloy (usually an austenitic stainless steel or other austenitic alloy) created by the precipitation of constituents (usually carbides) at the grain boundaries, producing a chromium-depleted zone adjacent to the grain boundary. This precipitation can occur as a result of a heat treatment, whether accidental or intentional, such as from high-temperature service, or incidental (as during welding). It often causes the alloy to become susceptible to intergranular corrosion and stress corrosion cracking.

3.1.11

stress-oriented hydrogen-induced cracking

SOHIC

A stacked array of small blisters joined by hydrogen-induced cracking, aligned in the through-thickness direction of the steel as a result of high localized tensile stresses. SOHIC is a special form of HIC that usually occurs in the base metal, adjacent to the heat-affected zone of a weld, where there are high residual stresses from welding. It can also occur at other high-stress points, such as the tip of other environmental cracks (e.g. SSC) or geometric anomalies (e.g. at the toe of the weld).

3.1.12**sulfide stress cracking****SSC**

Cracking of a metal under the combined action of tensile stress and corrosion in the presence of water and H_2S . Ferritic and martensitic steels above a certain strength level or hardness threshold are considered most susceptible.

3.2 Acronyms

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

CHPS	cold, high-pressure separator (also referred to as HPLT, high-pressure low-temperature separator)
CLPS	cold, low-pressure separator (also referred to as LPLT, low-pressure low-temperature separator)
HHPS	hot, high-pressure separator (also referred to as HPHT, high-pressure high-temperature separator)
HLPS	hot, low-pressure separator (also referred to as LPHT, low-pressure high-temperature separator)
IOW	integrity operating window
PWHT	post-weld heat treatment
REAC	reactor effluent air cooler
SCC	stress corrosion cracking
CML	condition monitoring location

NOTE CML was formerly called "TML," thickness monitoring location.

4 Background of REAC Corrosion**4.1 History of Reactor Effluent System Corrosion Surveys**

4.1.1 Since widespread commercial use of hydroprocessing technology began in the early 1960s, significant equipment and piping failures have resulted from corrosion associated with the NH_3 , H_2S , and HCl in the reactor effluent stream. R.L. Piehl presented corrosion and failure data at the 1968 API Division of Refining meeting from an internal study of these units conducted by Standard Oil of California ^[1]. In 1975, NACE published data from a formal survey it conducted of refining corrosion engineers ^[2]. UOP and Unocal presented data in a NACE paper from a survey conducted in 1996 ^[3]. The last formal survey was conducted for API in 1998 in preparation for this recommended practice ^[6]. In addition to these surveys, numerous papers were written on individual experiences and research on the subject of REAC corrosion ^[7,8,9,10,11].

4.1.2 These surveys had common conclusions:

- Increasing NH_4HS concentration in the aqueous phase increases the corrosion of carbon steel and alloys.
- Increasing fluid velocity increases the corrosion rate. The recommended maximum velocities vary for carbon steels and alloys.
- The wash water injection rate and water distribution are critical to control NH_4HS deposition and aqueous solution concentrations.
- Wash water quality can influence the corrosivity of the system.
- NH_4Cl salt can cause fouling and corrosion in units with chloride present in the reactor effluent stream.

4.1.3 Surveys dealt with flow distribution through air cooler banks, inlet and outlet piping designs, determining and monitoring adequate wash water injection rates, material selection, flow velocities through tubes and piping, etc.

4.1.4 The survey results highlight industry-wide experience with corrosion in the reactor effluent system of hydroprocessing units. From the earliest studies to the most recent, corrosion continues to cause unscheduled unit outages, and in some instances, catastrophic events involving major fires and explosions. Although early studies proposed guidelines for operating, monitoring, and inspecting effluent systems, significant corrosion and leaks in these systems were still being reported on a regular basis at industry forums. Industry experience-sharing sessions, as well as the first and second editions of this recommended practice, have helped to reduce the frequency of these failures.

4.2 Typical Hydroprocessing Units

4.2.1 Hydroprocessing units use hydrogen at elevated temperatures and pressures along with a suitable catalyst to improve the quality of the feedstock. Common to all units is the production of H_2S and NH_3 from the reaction of hydrogen with sulfur and nitrogen present in the hydrocarbon feed.

4.2.2 Hydrotreating processes remove heteroatoms, such as sulfur and nitrogen, from the feedstock. The removal of sulfur can be necessary for either processing in downstream units where the sulfur can contaminate the catalyst or for product quality reasons. Feedstocks to the units can vary from light naphtha to heavy vacuum residuum. Generally, the “heavier” feedstocks require the most severe operation (i.e. higher temperature and pressure) and contain higher concentrations of sulfur and nitrogen that produce the highest concentrations of H_2S and NH_3 . Several other reactions can also occur, including the conversion of any chlorides in the feed to HCl . The formation of H_2S , NH_3 , and HCl are of primary importance to fouling and corrosion in the reactor effluent system. Generally, these three reactants will interact to form NH_4Cl and NH_4HS , but in units with minimal nitrogen in the feed, highly corrosive HCl may form. Figure 1 shows a typical process flow diagram.

4.2.3 Hydrocracking is a process whereby low-value hydrocarbon feedstocks are cracked or broken down into higher-value hydrocarbons. Typically, this takes heavy hydrocarbons and creates lighter hydrocarbons, such as cracking coker distillate, to make gasoline. Figure 2 shows a typical process flow diagram.

4.2.4 Hydrocracking and hydrotreating units have similar process characteristics, especially in the front-end processing, as illustrated in Figure 1 and Figure 2. The feed is preheated through a series of exchangers and a furnace to temperatures of $\sim 700^\circ\text{F}$ (370°C). Hydrogen is injected into the feed upstream of the reactor. The hydrogen and feedstock enter the reactor, where the catalyst promotes the reaction of hydrogen with sulfur and nitrogen to produce H_2S and NH_3 . The reactor effluent is a mixture that includes H_2S , NH_3 , hydrogen, hydrocarbons, and possibly HCl and H_2O . Again, these reactants will generally interact to form NH_4Cl and NH_4HS salts unless minimal nitrogen is present in the feed. Downstream of the reactor, the effluent is cooled through a series of shell-and-tube heat exchangers.

4.2.5 Downstream of the heat exchangers, the effluent is separated into hydrogen-rich vapor, water, and hydrocarbons. Units can have several different design schemes (described more fully in 4.3).

4.2.6 Continuous injection of wash water into the reactor effluent stream is commonly used to prevent fouling by NH_4HS and NH_4Cl salts, typically upstream of the REAC or shell-and-tube heat exchanger. For some hydroprocessing units (primarily low-severity naphtha hydrotreaters), good feed quality does not result in salt deposition, and therefore, the use of wash water is not required. Other units may produce a low volume of salts that may only require intermittent wash water.

4.2.7 In those units using wash water, the water-scrubbed effluent is routed into a separator vessel to separate the gas, liquid hydrocarbon, and sour water. The separator sour water at this point contains inorganic salts, such as NH_4HS and NH_4Cl . The gas phase is predominantly hydrogen, light hydrocarbons, and H_2S . It is recycled back to the reactor feed section, in some instances, after scrubbing the H_2S from the gas in an amine absorber. The liquid hydrocarbon streams may pass through additional separators or be sent to a H_2S stripper or product fractionator, where the hydrocarbon product streams are produced.

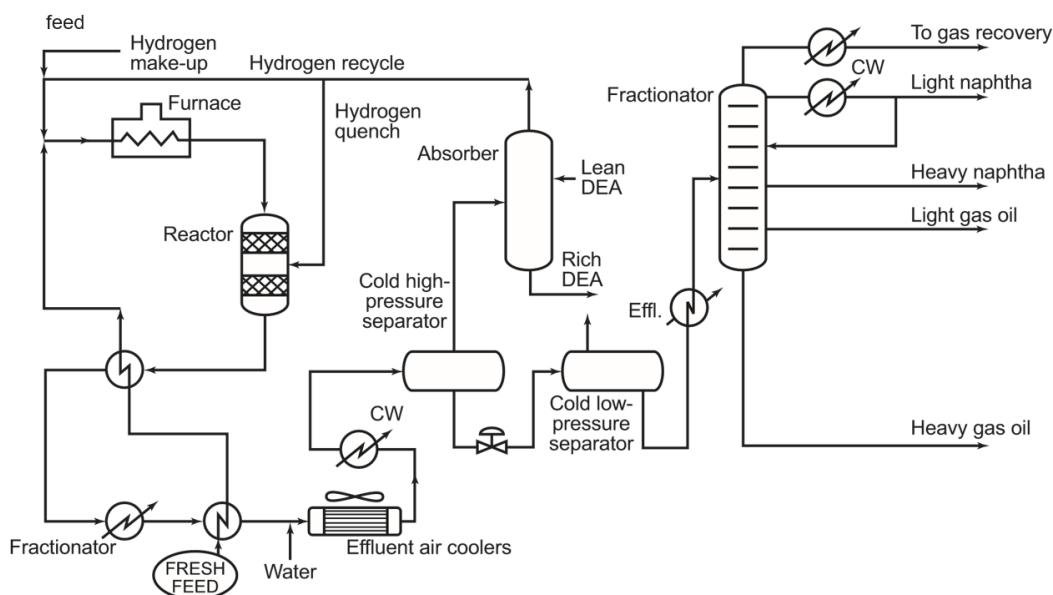


Figure 1—Example Hydrotreating Unit Process Flow Diagram

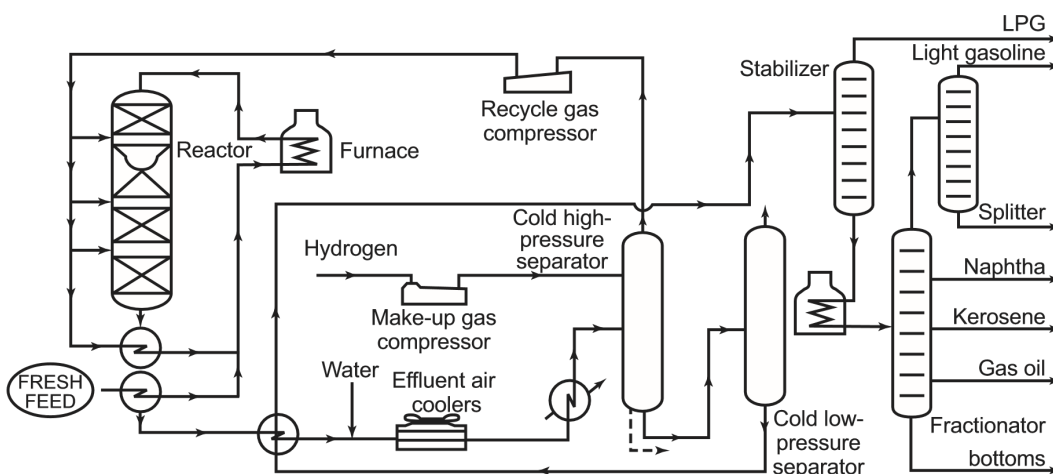


Figure 2—Example Hydrocracking Unit Process Flow Diagram

4.2.8 Makeup hydrogen to the unit can be supplied from either a hydrogen manufacturing unit, such as a steam methane reformer, or from a catalytic reformer unit where hydrogen is produced as a by-product of the reforming reaction. The source and upstream processing of hydrogen can have a significant impact on fouling and corrosion in hydroprocessing units since chlorides can be a contaminant in these hydrogen streams. Catalytic reformer hydrogen can contain HCl. If the hydrogen is not scrubbed of chlorides prior to injecting into the hydroprocessing unit feed stream, it may still contain hydrogen chloride. Additional sources of chloride may be organic and inorganic chlorides in the hydrocarbon feed stream. Organic chlorides, such as solvents and cleaners, may not break down in some processing units upstream of the hydrotreater. If organic chlorides are present in the feed stream to the hydrotreater, they will break down in the reactor to form HCl. Inorganic chlorides or salts would likely be stable through the reactor, but breakdown of these salts cannot be definitively ruled out.

4.2.9 In heavier hydroprocessing units, such as hydrocrackers, there is usually enough nitrogen in the feed and conversion of that nitrogen to ammonia to partially neutralize those chlorides. The salts or solutions formed, however, still result in unacceptably high corrosion rates to carbon steel. In light hydroprocessing units, such as naphtha hydrotreaters (NHTs), where minimal ammonia is formed, dew point solutions are even more acidic and highly corrosive. In cases where organic chlorides were present in NHT feeds, corrosion rates of over 1000 mils per year resulted in rapid piping failures (see 6.2 for additional details).

4.3 Effluent Separation Designs

4.3.1 Separation of the effluent stream can be accomplished through several different design schemes. Units are typically configured with one to four separators, although at least one unit is known to have a five-separator design. The process configuration of these separators can differ significantly between units, which uniquely changes the composition of the process streams and, therefore, the location of potential corrosion and fouling. Thus, it is critical to understand the influence of the separation design on the composition of the process streams.

4.3.2 Listed below are brief descriptions of some types of configurations to illustrate their function.

- a) CHPS or CHPS/CLPS system—The effluent stream is cooled through a series of feed/effluent exchangers and air coolers. Wash water is typically injected upstream of the air coolers. The cold effluent stream, generally 90 °F to 120 °F (32 °C to 49 °C), is separated in a cold, high-pressure separator (CHPS). Sour water is drawn off, containing most of the NH_3 from the effluent. The hydrocarbon liquid is drawn off and sent to the fractionation section (see Figure 3). In some units, this high-pressure hydrocarbon liquid and sour water are flashed into a cold, low-pressure separator (CLPS) before routing the liquid hydrocarbon to the fractionation section. See Figure 4.
- b) HHPS/CHPS system—The effluent stream enters a hot, high-pressure separator (HHPS) after being cooled to 400 °F to 550 °F (204 °C to 288 °C). The HHPS vapor is water washed upstream of the air coolers. Downstream of the air coolers, a CHPS removes the sour water. The HHPS liquid will contain dissolved NH_3 , H_2S , and possibly HCl , which can promote corrosion in the downstream fractionator overhead. See Figure 5.
- c) HHPS/CHPS/HLPS/CLPS system—The effluent stream enters a HHPS after being cooled to 400 °F to 550 °F (204 °C to 288 °C). The HHPS vapor may pass through a shell-and-tube heat exchanger before it is water washed upstream of the air coolers. Downstream of the air coolers, a CHPS removes the sour water. The HHPS liquid passes through a control valve where the pressure is let down. Gases in the liquid flash and are separated in a hot, low-pressure separator (HLPS). The HLPS vapor, which contains NH_3 , H_2S , and possibly HCl , is water washed upstream of the air coolers. A cold, low-pressure separator (CLPS) removes the sour water. The hydrocarbon liquid from the CHPS is often routed into a CLPS. See Figure 6.

4.4 REAC System Corrosion

4.4.1 The reactor effluent system is prone to deposition of NH_4HS and NH_4Cl salts. As the effluent is cooled, NH_4Cl salt can form below its salt deposition temperature and may deposit on cool metal surfaces. Upon further cooling, NH_4HS salt may form below its salt deposition temperature and may deposit on cool metal surfaces. However, in some cases, the NH_4HS deposition temperature is below the water dew point, so solid NH_4HS deposition will not be observed. The NH_4Cl deposition temperature is well above that for NH_4HS . The deposition temperatures for these salts can be estimated from the partial pressures of NH_3 , H_2S , and HCl in the effluent as detailed in Annex A.

4.4.2 NH_4Cl and NH_4HS salts can build up to cause a decrease in heat transfer efficiency. If uncorrected, the salt accumulations can restrict flow or completely plug heat exchanger and air cooler tubes, which increases the pressure drop and can promote flow maldistribution.

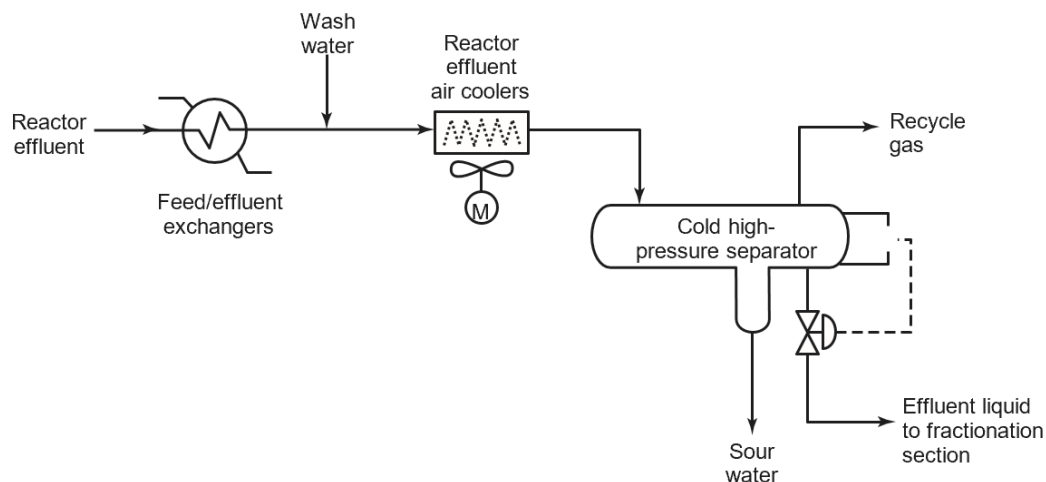


Figure 3—Example Process Scheme with a CHPS

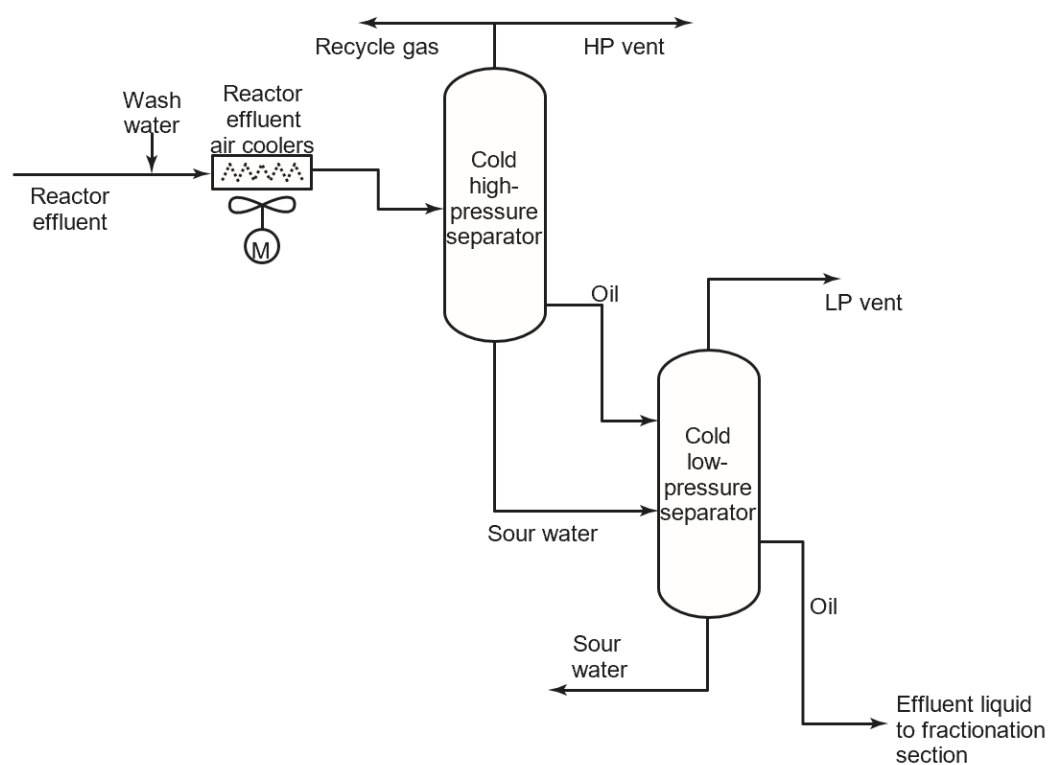


Figure 4—Example Process Scheme with a CHPS and CLPS

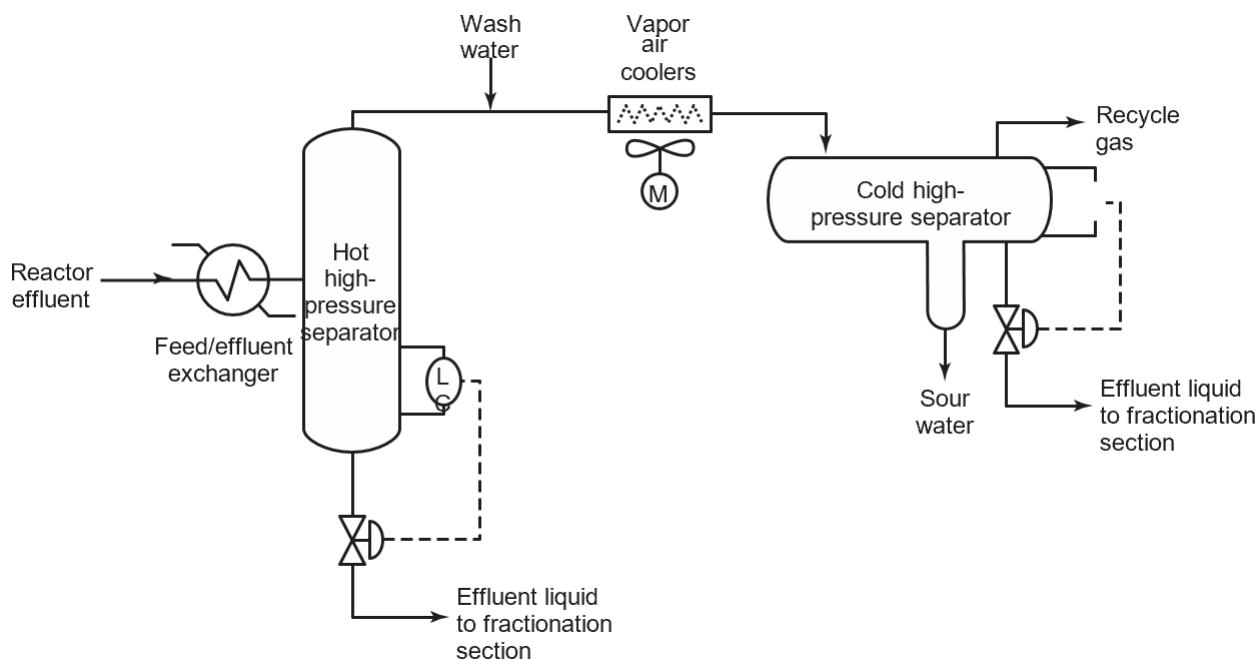


Figure 5—Example Process Scheme with Two Separators, a HHPS and CHPS

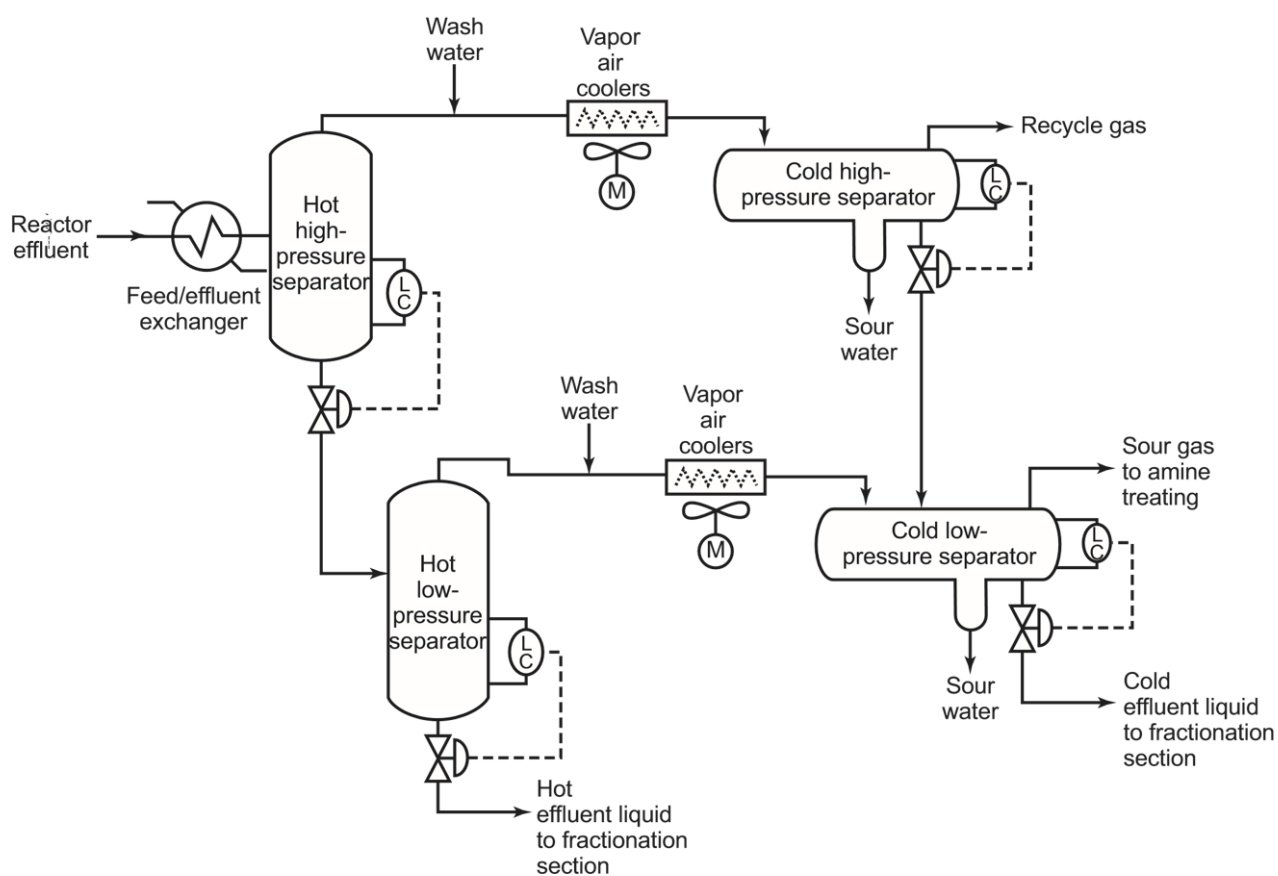


Figure 6—Example Process Scheme with Four Separators

4.4.3 The possible corrosion problems from these salts, both as deposits and aqueous solutions, are the following.

- a) Aqueous NH_4HS forms an alkaline, sour-water solution. These solutions can become a significant corrosion concern with increasing concentration, increasing partial pressure of H_2S , and with increasing velocity and turbulence. The predominant mechanism in these instances is erosion-corrosion. However, stagnant, concentrated salt solutions can also be corrosive.
- b) Solid NH_4Cl salt can form directly from NH_3 and HCl present in the vapor. Dry NH_4Cl salt at high temperature is not corrosive, but could foul equipment and plug heat exchanger tubes. NH_4Cl salt is hygroscopic (i.e. absorbs moisture from its surrounding environment) and can become wet due to trace amounts of free water in the reactor effluent stream. This can occur when the salt is at a temperature somewhat above the water dew point. A low pH condition can be created beneath the wet salt, producing localized corrosion. Thus, if NH_4Cl salts form upstream of the wash water injection, the salts can be corrosive if sufficient moisture is present in the vapor stream. With concentrated NH_4Cl solutions, the attack can be more general, typical of acidic solutions. Downstream of the injection location, if sufficient water is not present to dissolve and dilute the salt deposits, any wet deposits or concentrated salt solutions will be highly corrosive.
- c) Wet H_2S solutions can promote cracking; such as SSC, HIC, SOHIC, and hydrogen blistering; in susceptible materials.

4.4.4 Injection of wash water is typically used to prevent fouling and corrosion of heat exchanger and air cooler tubes. Both NH_4HS and NH_4Cl are highly soluble in water, so properly injected and distributed wash water effectively scrubs the vapor stream of salt-forming species and can remove salt deposits that form if they are contacted by the wash water. The wash water injection point(s) is (are) usually located upstream of the predicted location where salts will deposit. Corrosion by these aqueous salt solutions can occur if the injection system is not correctly designed and operated, and the quality, quantity, and distribution of wash water are inadequate. The flow regime downstream of the water wash can also play a large role in corrosion potential. This is discussed more in Section 6.5.

NOTE Section 6 contains detailed discussions on the impact of process variables and wash water on corrosion mechanisms.

5 Strategies to Promote System Reliability

5.1 General

5.1.1 A well-defined reliability program for the reactor effluent system is critical to maintaining the operability and mechanical integrity of equipment and piping. A program should be specific to individual units, as many design and operating characteristics can impact corrosion and fouling. The reliability of equipment and piping in these systems can be sensitive to small changes in process and design conditions, thus requiring careful thought in developing reliability programs. A reliability program should define three components:

- a) proper design and material selection;
- b) establishing and maintaining integrity operating windows; and
- c) developing effective inspection plans.

5.1.2 A reliability program does not necessarily require establishing a “zero corrosion rate” system, but rather establishing IOWs and monitoring and inspection plans to ensure that the system responds as expected. This program should allow the operator to manage system reliability and prevent unexpected incidents. Many refiners integrate these aspects of integrity management into a formal corrosion control document as described in API 970.

5.1.3 The reliability program is an ongoing process with regular measurements to be reviewed for possible modifications to the program. When inspection data indicate a change, it is necessary to understand the cause of the change so that the operating envelope can be modified or additional process-monitoring tasks can be

established as appropriate. The three parts to the reliability program complement each other and inspection programs alone cannot be relied on to provide reliability, especially since the corrosion can be localized.

5.2 Material Selection and Design

5.2.1 The design of and material selection for equipment and piping affect their performance in REAC systems. An understanding of how differences in these equipment and piping details change the dependence upon the scope and frequency of inspection and the range of the operating envelope is beneficial to promoting reliability. Section 7 and Section 8 detail these considerations.

5.2.2 Corrosion-resistant alloys are being used more today than in the past. Alloy metallurgy can broaden the range of acceptable operating limits, simplify future inspection and process monitoring, and reduce the need for periodic maintenance and replacement.

5.2.3 Existing unit equipment and piping should be reviewed to assess their susceptibility to deterioration and ensure that a proper IOW is established and that inspection plans are in place. This review may identify areas of vulnerability where replacement or upgrading may be appropriate, considering the needs for inspection and maintenance and the constraints imposed by the operating envelope.

5.3 Establishing an Integrity Operating Window

5.3.1 An integrity operating window (IOW) is the acceptable range for operating variables in the process where the deterioration rate is predictable and tolerable. Establishing and maintaining the IOW helps prevent process conditions from subtly creeping into undesirable ranges where more rapid deterioration could result. Any consideration for operating outside the IOW should be reviewed by the SME and, if significant, invoke the Management of Change (MOC) process.

5.3.2 The IOW can be difficult to establish, as several interrelated variables impact the corrosion potential. The effect of each variable and any synergistic effects on corrosion can be complex, but needs consideration. In some instances, experience within a particular unit allows a better understanding of corrosion characteristics for that unit and possibly increased flexibility in the IOW. This understanding, however, may not apply to other units.

5.3.3 For new units, the guidance given in this recommended practice is a starting point for developing an IOW (see API Recommended Practice 584). For existing units, the current operating variables provide a basis for establishing the IOW. However, they should be compared with the industry guidelines, and those variables operating outside industry guidelines should be reviewed to determine their significance to deterioration. The inspection history and deterioration rate data should be reviewed to identify evidence of deterioration and determine if the system has been properly inspected.

5.3.4 IOWs are typically classified into different levels, distinguished by risk, to set priorities on notifications (including alarms, alerts, and/or other notifications) and timing of actions to be implemented when IOWs are exceeded. In Recommended Practice 584, three primary levels of IOWs are proposed: “critical,” “standard,” and “informational.” These are established based on the predicted change in damage rate to equipment during an exceedance and the ability of the operator to take corrective action.

5.3.5 The specific REAC system design is key to establishing IOWs for the system and individual equipment items/components. Listed below are typical design factors and operating variables affecting corrosion that should be considered. These include the process variables given in 6.12 and the design factors listed below:

- a) water injection design, such as injection quills or spray nozzles, and single versus multiple points;
- b) air cooler inlet and outlet piping design—balanced, unbalanced, symmetrical, asymmetric;
- c) air cooler design—multiple inlets, multiple row passes, single inlet, single row passes;
- d) use of shell and tube heat exchangers instead of REAC;

- e) materials of construction for piping, air coolers, separator, heat exchanger components;
- f) piping configuration—short-radius versus long-radius elbows, tees, etc.;
- g) stream velocities and flow regime; and
- h) feedstock composition—sulfur, nitrogen, and chlorides.

NOTE Section 6 goes into more detail on process variables affecting corrosion, ending with a discussion on process monitoring and some specific IOWs to consider in 6.12.

5.3.6 Once an IOW is established, operating variables should be maintained within these ranges. All refiners should define actions to be taken if operating outside the range; for example, to correct the process or to implement the MOC procedure to redefine the acceptable range of the IOW. Multidiscipline teams, including operations, engineering, and inspection, have proven successful in both establishing IOW and defining appropriate actions if operations change outside the envelope.

5.3.7 Routine monitoring of the process variables as noted in Section 6.12 is critical to ensure that they remain within the envelope. Some variables, such as temperature and pressure, are easily monitored, while others are much more difficult to monitor. However, all process variables defined for the operating envelope should receive appropriate attention and priority.

5.4 Inspection Plans

Periodic inspection is an integral part of the reliability program that should be used to establish whether the rate of deterioration of the equipment and piping is as anticipated. A specific inspection plan should be developed for each unit. A generic plan is not recommended because too many variables influence deterioration. Section 9 provides detailed guidance on typical inspection activities and considerations for developing REAC system inspection plans.

6 Process Variables Affecting Corrosion

In this section, data are presented from laboratory studies of ammonium bisulfide corrosion and the parameters that affect it. The tests were run using a 0.15 in. (3.8 mm) tube to simulate pipe flow at velocities between 0 ft/s and 80 ft/s (0 m/s and 24 m/s). These velocities cannot be directly translated to full-size piping. Rather, WSS is the parameter used to translate the data from laboratory tubing to full-size pipe. At 20 ft/s (6 m/s), the WSS in the laboratory tubing is 2 times to 20 times that in full-size pipe depending on the pipe size [1 in. to 20 in. (23 mm to 508 mm)] nominal pipe sizes were evaluated) and flow regime. This causes laboratory corrosion rates to be higher than those in the field under the same conditions. For example, at 20 ft/s (6 m/s) with 2-phase flow, laboratory corrosion rates are 3 times to 4 times those predicted for pipe, and for liquid phase flow, the laboratory corrosion rates are 1.5 times to 2 times those for pipe.

6.1 Ammonium Bisulfide Concentration

6.1.1 The NH_4HS concentration in the sour water is a key variable of the potential corrosivity of an effluent stream. As concentration of NH_4HS increases, the corrosivity of the solution increases. The results of two industry surveys indicated that an NH_4HS concentration of 2 % is an acceptable upper limit for producing little to no corrosion of carbon steel [4,5]. For many years, the industry has used an upper limit of ~8 % NH_4HS with control of stream velocity to less than 20 ft/s (6.1 m/s) to achieve acceptable carbon steel corrosion control. However, severe corrosion has occurred under certain conditions in some units approaching these levels. Recent JIP industry research [14, 16, 17] has shown that sour-water corrosion is impacted by multiple parameters, including NH_4HS , stream velocity (wall shear stress), temperature, H_2S partial pressure, and NH_3 partial pressure, and accurate corrosion assessment may not be achieved through single parametric limits.

6.1.2 For instance, severe corrosion has occurred under certain conditions in some units even at NH_4HS concentration below 8%. Recent research noted that corrosion rates may be severe at 3 wt % to 4 wt % NH_4HS .