Corrosion Control Document Systems

API RECOMMENDED PRACTICE 970
SECOND EDITION, APRIL 2023

American
Petroleum
Institute

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Corrosion Control Document Systems

1 Scope

This recommended practice (RP) provides users with the basic elements for developing, implementing, and maintaining a Corrosion Control Document (CCD) for refining, and at the owner's discretion, may be applied at petrochemical and chemical process facilities.

A CCD is a document or other repository or system that contains all the necessary information required to understand materials damage susceptibility issues in a specific type of operating process unit at a plant site. CCDs are a valuable addition to an effective Mechanical Integrity Program. They help to identify the damage mechanism susceptibilities of pressure-containing piping and equipment, factors that influence damage mechanism susceptibilities, and recommended actions to mitigate the risk of loss of containment or unplanned outages.

This RP serves as the basis for CCD development, implementation, and maintenance to maintain consistency and to integrate the CCD work process with other plant integrity programs, such as Management of Change (MOC), Process Hazards Analysis (PHA), and Reliability Centered Maintenance (RCM). Some of these programs have significant overlap with the development of CCDs, including Risk-based Inspection studies (see API Recommended Practice 580 and API Recommended Practice 581), Integrity Operating Windows (see API Recommended Practice 584), in-house unit corrosion reviews, circuitization/systemization programs, and similar types of corrosion studies. Development of CCDs can serve as a useful starting point for establishing these programs if they have not been undertaken.

This document provides the owner-operator with information and guidance on the work processes for development and implementation of CCDs for the owner-operator process units. While some generic examples are provided in the text and in 5.9, this document does not contain a complete list of unit-specific CCDs or operating plant variables for the numerous types of hydrocarbon processing units in the industry.

The rigor of review, the level of documentation, and even the need to develop a CCD will depend on the complexity of the process unit under consideration and the inherent risk associated with the process. It is the responsibility of the facility owner-operator to determine the level of detail contained within their CCD.

The scope of this standard includes:

— descriptions of CCDs and definitions of related terminology;

— creating, establishing, and maintaining CCDs;

— data and information typically needed to create CCDs;

— descriptions of the various types of CCDs needed for process units;

— documenting and implementing CCDs;

— reviewing, changing, and updating CCDs;

— integrating CCDs with other risk management practices;

— roles and responsibilities in the CCD work process; and

— knowledge transfer to all stakeholders.

Typical CCDs cover the pressure-containing components of fixed equipment. The types of equipment and associated components typically covered by CCDs are:

— pressure vessels,

— process piping,

— storage tanks atmospheric and pressurized,

— process heaters pressurized components, and

— heat exchangers.

The following equipment is not typically covered by CCDs, but may be at the user's option:

— instrument and control systems,

— pressure relief devices,

— pressure vessel internals,

— machinery components,

— pump casings and valve bodies,

— stacks/flues,

— electrical systems, and

— structural systems.

However, these systems and components may be covered by other types of Risk-based Inspection (RBI) or risk assessment work processes, such as RCM.

This RP outlines the essential elements in defining, monitoring, and maintaining CCDs as a vital component of corrosion management (damage mechanism control strategies) and inspection planning, including RBI.

This RP does not address process operating windows established for normal process control, for the purposes of maintaining product quality, or for other operating factors unrelated to control for the purpose of maintaining equipment integrity and reliability. However, the contents of a comprehensive, good quality CCD can be the basis for establishing Integrity Operating Windows (IOWs) in accordance with API Recommended Practice 584.

This RP is a guideline document for organizing Corrosion Control Documents. The owner-operator of this RP may also develop internal documents that detail how their company will create and implement the processes suggested herein. Section 5 contains key points for establishing a site procedure that documents the CCD work process.

NOTE Even though CCDs are labeled "Documents" for the purposes of this RP, it is recognized that much of the suggested content of a CCD may, in fact, reside in separate repository systems. These separate repository systems are considered suitable alternatives to creating a separate or standalone CCD. It is not the intention of this RP to require operators to create a new document, but instead to have the components discussed in this document available for use in a work process covering integrity management.

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

API Recommended Practice 584, *Integrity Operating Windows*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1
alarm
Primary method of communication for IOW Critical limit and some higher level IOW Standard limit exceedances. Typically, an audible sound (e.g. horn, buzzer, beep) along with a visual signal (e.g. flashing light) in the control room, that alerts operators to a potential deviation in a process condition that needs immediate attention.

3.1.2
circuit
A subsection of a system (see 3.1.4 for definition of "CCD system") that includes piping, equipment and components that are exposed to a process environment of similar corrosivity and expected damage mechanisms and is of similar design conditions and construction material where by the expected type and rate of damage can reasonably be expected to be the same.

NOTE 1 Complex process units or piping systems may be divided into piping circuits to manage the necessary inspections, data analysis, and record keeping.

NOTE 2 When establishing the boundary of a piping circuit, it may be sized to provide a practical package for record keeping and performing field inspection.

3.1.3
corrosion control document (CCD)
A document or other repository or system that contains the necessary information to understand materials damage susceptibility issues in a specific type of operating process unit at a plant site. Generic CCDs can also be developed that provide generic guidance upon which to build a unit-specific CCD, but generic CCDs are not as useful as unit- specific CCDs that are based on actual hardware configurations, actual process conditions and actual materials of construction.

3.1.4
CCD system (systemization)
An assembly of interconnected piping and equipment that typically are subject to the same (or nearly the same) process fluid composition or operating conditions, or both. The term corrosion loop is also used by some owner-operators to describe a CCD system.

3.1.5
corrosion materials diagram (CMD)
A modified process flow diagram (PFD) or database list containing relevant equipment and piping damage mechanisms, operating conditions, materials of construction, systems/circuits, and other information that the CCD Team determines to be useful for each portion of a process unit, as well as the usual PFD information.

3.1.6
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 (includes Critical, Standard and Informational IOWs). Guidance on setting IOWs is given in API Recommended Practice 584.

3.1.7
IOW critical limit
An established IOW level which, if exceeded, could cause rapid deterioration such that the operator should take immediate predetermined actions to return the process variable to the acceptable IOW range to prevent significant

defined risks of potential equipment damage or hazardous fluid release could occur in a short timeframe. Other terminology has been used in place of Critical Limit, such as Safe Operating Limit, Key Operating Limit, Standard Reliability Limit, or Reliability Operating Limit.

3.1.8
IOW standard limit
An established IOW level, defined as one that if exceeded over a specified period of time, could cause increased damage rates, or introduce new damage mechanisms beyond those anticipated. Since the timing of the impact from an exceedance of a Standard IOW Limit can vary significantly, the notification and response to an exceedance can vary. For higher risk exceedances, alarms or alerts are potentially needed and the operator can have some predetermined actions to take. For lower risk exceedances, alerts are only needed for eventual interaction with operating supervisors or appropriate other technical personnel (SMEs).

NOTE Other terminology for standard limits includes Key Operating Limit, Standard Reliability Limit or Reliability Operating Limit.

3.1.9
IOW information limit (IIL)
An established limit or standard operating range for other integrity parameters that are used primarily by SMEs (e.g. process engineer, inspector, corrosion specialist) to predict or control the long-term integrity/reliability of the equipment. These "Informational" IOWs are typically only tracked by the appropriate SMEs and can have alarms or alerts associated with their exceedances. In some cases, the Informational IOWs are used for parameters that cannot be directly (or indirectly) controlled by operators, whose primary duty would be to make sure any exceedances are communicated to the designated SME for attention and corrective action, if necessary.

NOTE Other terminology can be used in place of an Informational Limit, such as Corrosion Control Limit or Reliability Limit.

3.1.10
management of change (MOC)
A documented management system for review and approval of changes in process, equipment or piping systems prior to implementation of the change.

3.1.11
mechanical integrity (MI)
The management systems, work practices, methods and procedures established to protect and preserve the integrity of operating equipment, i.e. avoid loss of containment due to the effect of equipment damage mechanisms.

3.1.12
notification
A message to an operator/SME that an IOW exceedance has occurred which does not necessarily have an alarm associated with it but needs a specific action and response from an operator or SME.

3.1.13
OEMI
Operations, Engineering, Maintenance, Inspection, an acronym sometimes used to describe the makeup of a team formed to address tasks that are best handled through a multidisciplinary approach.

3.1.14
piping and instrumentation diagram (P&ID)
A diagram identifying the piping and instrumentation associated with a piece (or pieces) of equipment in a process.

3.1.15
positive materials identification (PMI) testing
Any physical evaluation or test of a material, including welds, to confirm that the material, which has been, or will be, placed into service, is consistent with the selected or specified alloy material designated by the owner-operator. These evaluations or tests provide either qualitative or quantitative information that is sufficient to verify the nominal alloy composition. See also API Recommended Practice 578.

3.1.16
process flow diagram (PFD)
A simplified diagram of a process unit showing the main pieces of equipment and piping, with limited details of process design and operating parameters.

3.1.17
process hazards analysis (PHA)
A work process to assess and document the hazards and risks associated with operating a process unit and to make recommendations on what actions are necessary to mitigate unacceptable risks.

3.1.18
process variables
Parameters of the process fluids (chemical and physical) that need to be controlled.

3.1.19
process safety management (PSM)
The implementation of the work practices, procedures, management systems, training, and process safety information necessary to prevent the release of hazardous substances from process equipment.

3.1.20
pressure equipment
Stationary or fixed equipment for containing process fluids under pressure, not including rotating equipment. Pressure equipment includes, but is not limited to, such items as piping, vessels, heat exchangers, reactors, tanks, pressure relief devices, columns, towers, heater tubes and filters.

3.1.21
risk-based inspection (RBI)
A risk assessment and management process that is focused on loss of containment of pressurized equipment in processing facilities due to material deterioration. These risks are managed primarily through equipment inspection.

3.1.22
subject-matter expert (SME)
One who has in-depth knowledge and experience on a specific subject as it relates to CCDs. Various types of SMEs are necessary to establish CCDs for each process unit, e.g. corrosion/materials SME, process SME, operations SME, equipment type SME, and inspection SME.

3.1.23
stakeholder
Any individual, group, or organization that affect, be affected by, or perceive itself to be affected by the corrosion issues documented in a CCD, e.g. operations, process engineering, engineering services, maintenance, and inspection.

3.1.24
work process
A series of activities or steps aimed at achieving a set objective, with inputs and outputs, e.g. the CCD work process to create and implement CCDs.

3.2 Acronyms and Abbreviations

The following acronyms and abbreviations are not found in the terms and definitions but are used in the document.

CUI	Corrosion Under Insulation
DCS	Distributed Control System
HSAS	Heat Stable Amine Salts
HTHA	High Temperature Hydrogen Attack
IDMS	Inspection Data Management System
MAT	Minimum Allowable Temperature
MDMT	Minimum Design Metal Temperature
NDE	Non-destructive Examination
PRV	Pressure Relief Valve
PTCV	Process Chemical Treatment Vendor
TAN	Total Acid Number

4 Introduction to Corrosion Control Documents/Systems

4.1 Characteristics

The outcome of a CCD work process is a living repository with the following characteristics:

— a damage control source document or repository or system, available to all stakeholders who have some responsibility for process/asset integrity management;

— a document or repository of information which contains or provides links to key process information, unit specific damage mechanisms, materials used to construct the piping and equipment, inspection history overview, lessons learned, and records of relevant process change/creep; and

— a document or repository of information that serves as the basis for aiding the development of inspection plans, corrosion-related IOWs, RBI strategies, and maintenance planning.

4.2 Key Components of a CCD

The key components of a CCD system could include the following items.

— A description of the purpose and operation of the process unit, including when the unit was constructed and details of subsequent major revamp or expansion projects.

— The actual operating conditions (temperature, pressure, and other operating parameters) of the relevant components in the unit that can affect or promote damage mechanisms.

— Process stream compositions for the components in the unit.

— Equipment and circuits included in the unit with materials of construction.

— Process flow diagram (PFD) or CMD.

— An explanation of how each damage mechanism is prevented, detected, controlled, monitored, or otherwise managed, including documentation of the types of inspections or other monitoring methods used and a description of where inspection or other monitoring records, or both, are kept.

— A list of injection and mix points to be monitored; a listing of deadlegs that require specific monitoring (beyond the normal pipe inspection program; a listing of alloy spec breaks and bimetallic welds that require specific monitoring.

— A list and description of any key operating concerns such as history of excursions, start-up, shutdown, or other auxiliary processes (steam-out, hydrogen stripping), or a combination thereof, that can affect or promote damage mechanisms.

— A list and description of any specific maintenance concerns such as soda ash washing or other layup/ outage procedures, special welding precautions, special equipment handling requirements, e.g. to prevent brittle fracture.

— A list and description of significant failures, repairs or replacements, or a combination thereof, that were a consequence of damage mechanisms.

— A list and description of any key company or industry lessons learned regarding damage mechanisms associated with the unit.

— A list and description of recommended actions developed as a result of the review process.

— A list of IOW limits developed to monitor key process parameters that affect damage and the recommended actions required if limits are exceeded.

4.3 Target Audience

The primary audience for API Recommended Practice 970 is engineering and inspection personnel who have a major role in maintaining the mechanical integrity of equipment covered by this RP. However, while an organization's Corrosion/Materials Engineering group can champion the CCD program, the creation and use of CCDs is not exclusively a Corrosion/Materials Engineering group activity. A CCD program developed in accordance with this RP needs the involvement of various segments of the organization, such as Inspection, Process Engineering, Maintenance and Operations.

The implementation of the resulting CCD product (e.g. plant-wide use as a reference for process descriptions, corrosion/damage mechanisms, IOWs, project planning, and MOC) often rests with more than one segment of the organization. CCDs need the commitment and cooperation of the total plant operating organization. In this context, while the primary users are corrosion/materials engineering and inspection personnel, other stakeholders who are likely to be involved in the CCD development, maintenance and implementation process should be familiar with the concepts and benefits offered by CCDs.

4.4 Inspection Program

Historically, inspection plans in most process plants have been based upon the prior recorded/known history of equipment condition and the requirements of API 510, API 570, and API 653. A fundamental understanding of the process/operating conditions and resulting damage mechanisms is needed to establish and maintain an inspection program that yields the highest probability of detecting potential damage.

Inspection plans should be dynamic and account for changing process conditions and current equipment condition. A fundamental step is the timely alignment with a developed knowledge base of the materials of construction with the operation of the equipment, its inspection history, relevant damage mechanisms, measured corrosion/ erosion rates and known industry incidents. It is vital to identify and track process information that validates or suggests changes to existing inspection plans. Changing process conditions should be communicated to the Corrosion/Materials/ Inspection group for inspection plans to be adjusted, when necessary, to account for those changes. For more information on inspection planning, refer to Section 5 of API 510 and API 570.

Establishing and using information collected during the CCD creation process will help improve and sustain a properly structured inspection program. A detailed CCD can become part of the front-end data input to the RBI process.

Inadequately controlled processes/operations can result in unanticipated damage that inspection programs are generally not designed to find. Under past practices, inspection programs generally assumed that the next inspection interval (calculated based on prior damage rates from past operating experience) should be scheduled on the basis of what is already known and predictable about equipment damage from previous inspections.

Without effective process control based on an accurate and complete list of IOWs, inspections may need to be scheduled on a less than optimum time-based interval just to look for damage occurring from lack of adequate process control. API Recommended Practice 584 should be used in conjunction with this document when creating and implementing IOWs. The work processes are very similar.

4.5 Process Unit Integrity

For purposes of this document, maintaining the integrity of the process unit means avoiding loss of containment, and reliability means avoiding malfunctions of the pressure equipment that might impact the process unit performance (meeting its intended function for a specified time-frame). In that sense, integrity is a part of the larger issue of pressure equipment reliability, since most breaches of containment will impact reliability.

Pressure equipment is generally fabricated from the most cost effective materials of construction to meet specific design criteria for the equipment's intended life based on the intended operation and process conditions. The operating process conditions are then controlled within limits (IOWs) to avoid unacceptable construction material damage and enable damage control, monitoring, and inspection activities to safely predict if and when repairs or replacements will be needed.

5 CCD Work Process

5.1 General

In this section, a general work process is outlined for establishing, implementing, and maintaining CCDs. An example of a more detailed CCD implementation checklist and work flow process appears in Annex A.

The CCD work process can be applied to an overall process unit, multiple equipment items in a group (system), or to a single equipment item. The work process can be standalone or part of an integrated mechanical integrity management work process. The outline in this section and content of Annex A are intended to be examples for implementing a CCD system. Other work process, (e.g. asset strategy process), containing the same elements, are equally effective at meeting the intent of this RP.

For examples that closely follow the flow outlined in this section, see Annex E.

A site or corporate procedure should document the CCD work process or how the elements of a CCD fit into a mechanical integrity management program work process. It typically contains statements addressing the following elements:

— the details of the basis/assumptions concerning CCD Work Process;

— the CCD implementation by a multidisciplinary team of SMEs (the CCD Team);

— the roles, responsibilities, and qualifications for the team members;

— how data and information is reviewed for accuracy;

— how the design and operating parameters are analyzed (e.g. as ranges of operation or discrete values);

— how the unit will be divided into systems;

— what information should be compiled for a system;

— how the damage mechanisms will be determined;

— what is the premised run time;

— the details on how the CCDs are to be implemented;

— the details on how the CCDs will be documented and updated;

— how CCDs will be integrated with existing PSM and operational programs;

— how an existing RBI program interfaces with CCDs;

— the details on how CCDs can be used as a basis for establishing IOWs; and

— the method of deployment, distribution, and training on the CCD for each process unit.

A generic flowchart for an overall work process is depicted in Figure 1. Different companies can assign different roles to different personnel and choose to progress through the stages of the work process in an order that differs from this chart. The CCD work process can be stand-alone or part of an integrated mechanical integrity management work process.

NOTE An example of a more detailed work process/responsibilities flowchart is included in Annex A.

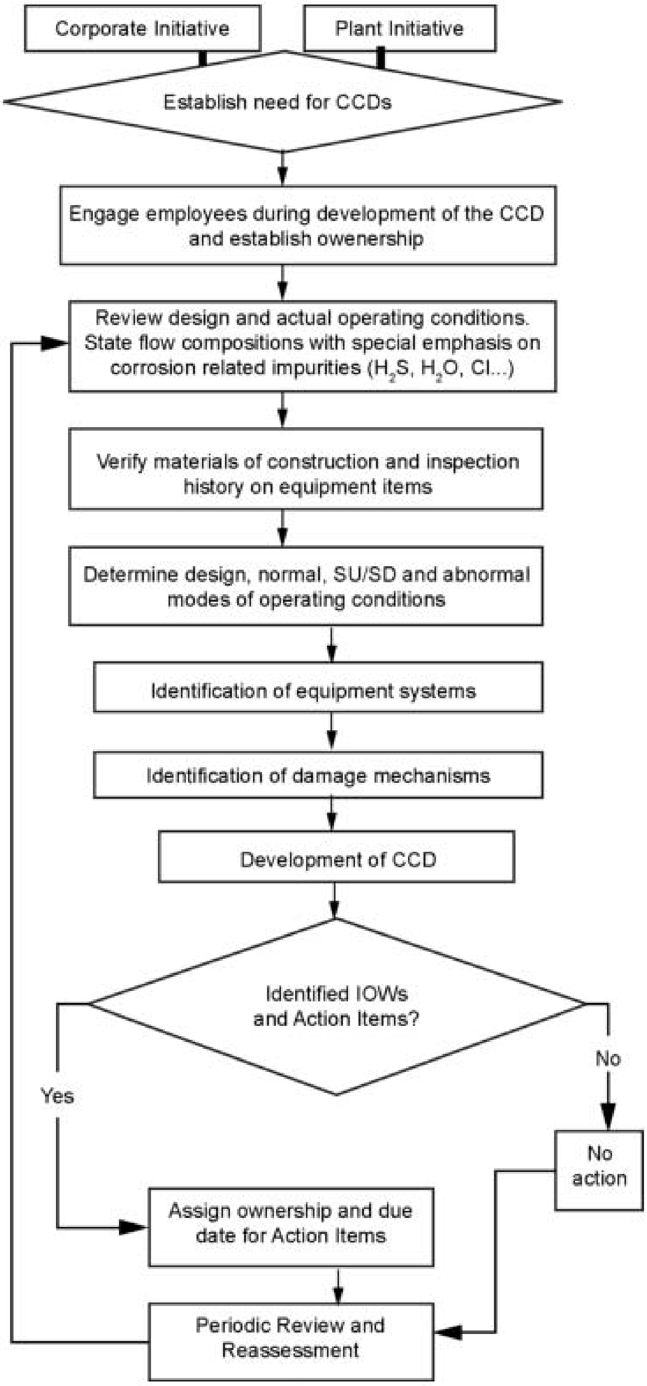

Figure 1—Work Process Map—CCD Development, Review, and Update

5.2 Basis and Assumptions Concerning the CCD Work Process

The first step in the work process is defining the basis. The basis for the CCD work process can change and have a significant impact on the damage mechanism development and assessment. Some of the possible changes could be as follows:

a) discovery of materials of construction that are different from those stated on U-1 forms or P&IDs,

b) revisions in safety and environmental laws and regulations,

c) change in feed amount or composition,

d) changes in operating conditions,

e) change in unit operating lengths between maintenance turnarounds, and

f) changes in inspection codes/standards.

5.3 CCD Team Members

To develop the necessary information and identify potential damage mechanisms and failure scenarios along with consideration for future operating conditions and business objectives, the combined efforts of a multi-disciplinary team are required and SMEs consulted as needed.

The quality of the CCD development process, and therefore the quality of the resultant CCD output, is highly dependent upon an interactive, collaborative effort between qualified, experienced, and knowledgeable team members. Typically, this team will consist of:

— site corrosion/materials specialist;

— unit process engineer/technologist;

— unit inspector;

— experienced unit operations representative(s);

— facilitator knowledgeable in the CCD work process;

— unit-fixed equipment engineer (as needed, ad hoc);

— laboratory personnel (as needed, ad hoc);

— specialists for Licensed Technology (as needed, ad hoc);

— control systems specialist (as needed, ad hoc); and

— process chemical treatment vendor (as needed, ad hoc).

External Subject Matter Experts (SMEs) should be included on the team if the site does not have sufficiently experienced personnel. Some individuals can fulfill multiple roles based on the list referenced in 5.3.

The CCD development process needs significant participation by a corrosion/materials specialist (or corrosion SME). In addition, the CCD support team needs team members that are fully committed to the CCD development and implementation project. Without that commitment to participate in team meetings and follow-up action items, the quality of the CCD work process and final product will suffer.

Table 1 presents documentation categories that are needed to adequately develop a CCD.

Table 1—CCD Documentation Responsibilities

Documentation	Typical Responsible Person
Management of changes	PHA Coordinator or MOC Coordinator
Capital projects	Project/Process Manager or Fixed Equipment Inspector, or Both
Inspection records and history	Fixed Equipment Inspector
CCD and revision logs [a]	Corrosion/Materials Specialist or Fixed Equipment Inspector
Redlined CMD and revision logs [a]	Corrosion/Materials Specialist or Fixed Equipment Inspector
Outstanding CCD action items [a]	Corrosion/Materials Specialist or Fixed Equipment Inspector
Outstanding PHA action items	PHA Coordinator or MOC Coordinator

[a] If a previous CCD or CMD, or both, have been generated.

5.4 Roles, Responsibilities, and Accountabilities for the CCD Work Process

Numerous personnel at the plant site have roles and responsibilities for CCD creation, implementation, and maintenance. Plant Management support is needed for this effort to be successful. Management should specify the individuals accountable for the development and ownership of the CCDs and ensure the process is embedded into the site's work processes. The CCD work effort needs to be adequately staffed with knowledgeable, experienced SMEs and needs to be completed and implemented in a timely manner. Management should also ensure that all necessary training on CCDs is conducted.

Corrosion/Materials Specialists have a role to identify damage mechanisms for the CCD team. A corrosion/ materials specialist is typically responsible to supply/develop the CMDs (where they are available and the site decides to include them as part of the CCD) and estimated damage/corrosion rates (when appropriate or where measured rates for the current operating conditions are not available or not credible, or a combination thereof). They also have a role in understanding the impact of IOW exceedances and advising inspection personnel on how inspection activities may need to be revised to account for the exceedance, if any, as well as advising process engineers on process issues that may need to be considered to avoid long-term materials damage issues. This person will also be involved with systemization/circuitization. A corrosion/materials specialist will typically have the role and responsibility of facilitating the CCD team, as well as documenting and distributing the results of the CCD work process. The corrosion/materials specialist can also have a role in providing operator training on CCDs.

The Unit Process Engineer provides process design, actual operating conditions (this includes current, past, and future operating data if changes are planned), and engineering data to the CCD team. The unit process engineers are typically responsible for ensuring that the operating and processing aspects of the CCD for their unit are properly implemented in the manner specified in the CCD documentation.

Inspection Personnel provide historical inspection and maintenance information, as well as information on equipment failures and experience in the service. The information is used by the CCD team to create and update CCDs. The CCD is also used to adjust inspection activities for a variety of reasons, including when new information is received, when unexpected results are obtained, and when IOW exceedances are reported. Inspection personnel can also serve as NDE SMEs for the CCD process, bringing knowledge of the use and applicability of various NDE methods used to detect types of damage typically experienced in refineries and petrochemical plants. Inspectors should also bring the results of inspections conducted for ongoing special emphasis inspection programs that often provide significant information about damage mechanisms in the process unit.

The Operations Representative is responsible for providing operational data and information about current and past operating practices to the CCD team. He or she will also have information about the frequency of upset or abnormal conditions. He or she will also have a good knowledge of how actual unit operating practices differ from the design operating practices. Additionally, the Operations Representative will provide input on start-up and shutdown procedures that can affect damage mechanisms (e.g. soda ash washing, reactor hot hydrogen stripping, wet catalyst dumping).

The CCD Team Facilitator is often an experienced corrosion/materials or mechanical integrity specialist, either from the plant, a central office, or a third party. It is the responsibility of the team facilitator to organize and lead multidisciplinary team discussions. One of the facilitator's roles should be to elicit information about what is actually happening in the field relative to what is in the documented records or what is "thought to be happening" by those who are not operators. A skilled facilitator will ask the right probing questions in order that the team fully understand issues that impact the CCD work process. It is the responsibility of the team facilitator to document the discussions during the CCD review process and to finalize the necessary revisions and maintain documentation concerning the identified updates of the CCD and CMD in the site's document management system.

The Process Chemical Treatment Vendor (PCTV), in many plants, has a role in tracking and interpreting process chemical treating variables and making recommendations that affect unit corrosion and IOWs. The PCTV can also have a role in operator training for controlling these variables. In these cases, the PCTV becomes a technical resource for the Unit Process Engineer or the Corrosion/Materials Engineer and can be an ad hoc member of the CCD team.

Laboratory Personnel implement, record and report sample analyses used for both corrosion and IOW monitoring in a timely manner, per the CCD documentation requirements.

Control Systems Personnel have a role in designing, purchasing, installing, and maintaining any control and monitoring systems for IOWs recommended per the CCDs.

Fixed Equipment Engineers share responsibility with corrosion/materials engineers and inspectors in identifying previous equipment failures and repair experiences and are responsible for carrying out fitness-for-service or managing fitness-for-service evaluations, as required.

5.5 Data Needed for the Team Meetings

5.5.1 Data Needed Prior to the Team Meetings

Considerable information is needed by the team to construct each unit-specific set of CCDs. To facilitate the effectiveness and efficiency of the CCD work process, this information is often collected/developed, reviewed for accuracy, and provided to the CCD team prior to the meeting to the extent possible. This information typically includes the latest revision of:

— system/circuit boundaries;

— process summaries and reactive chemistry descriptions;

— process flow diagrams to systematically review the process during CCD team meetings;

— P&IDs that show sample points, instruments, and analyzers (that can be used to monitor IOWs);

— drawings that identify injection points, mix points, deadlegs, material spec breaks, heat tracing, insulated locations and other piping or equipment details that affect the inspection program;

— existing integrity operating windows that are already be in effect;

— identification of start-up lines, temporary use lines and normally-closed valves;

— relevant operating and maintenance procedures;

— process chemical treatment programs;

— feed sources, volumes, and compositions, including intermediate products;

— for each stream, data on concentrations of known corrosive agents and whether liquid water is present;

— credible damage mechanisms that could occur in the process unit;

— historical operating, maintenance, and inspection records for the process unit;

— failure analysis, fitness-for-service and lessons-learned reports for the operating unit or similar operating units or both;

— equipment/process design data (U-1 forms, fabrication drawings);

— relevant laboratory data for the process unit;

— start-up, shutdown, and unusual operating conditions;

— MOC records for the operating unit;

— pipe clamp or temporary repair logs, or both;

— existing sample points and sample data;

— existing process variable controls and measurement points, e.g. pressure indicators, temperature indicators, analyzers, flow controllers;

— metallurgical and corrosion information and data (published and company private) related to the damage mechanisms anticipated for the process unit;

— materials of construction and materials engineering knowledge, including CMDs;

— operating knowledge;

— applicable industry and company recommended practices and standards;

— applicable process and corrosion modeling tools; and

— unit feedstock composition history and forecast.

5.5.2 Current Design and Operating Conditions

The first step in the CCD meeting is to review the existing mechanical/materials design and current/prior operating conditions (normal, upset, start-up, shutdown) of all assets covered by the CCD. The identification of the likely or "active" damage mechanisms in Annex B requires a fundamental understanding of the mechanical design, the process operating conditions (temperatures, pressures, service conditions, inhibitors) and the properties and behavior of the materials of construction including the alloy and material grade, method of fabrication, prior thermal and mechanical treatments.

Consideration should be given to both the normal operation and any non-normal operation that could produce unanticipated damage mechanisms or accelerated damage rates or both. Other operating conditions such as start- up, shutdown, catalyst regeneration, decoking, hydrogen stripping, and other operating modes. should also be considered. Evaluate locations of phase changes in the process stream. The potential for fouling-induced changes in the location of dew points and salt points should also be considered.

The review should also examine the location of all materials specification breaks and dissimilar metal welds where there is a change from one alloy to another to be sure they are compatible with the current operating conditions and auxiliary operations (start-up, shutdown) or whether additional inspection or other actions are needed due to the location of the spec breaks.

5.6 Unit Specific Corrosion Systems/Circuits

In the Corrosion Systems section of the CCD, the unit is subdivided into corrosion circuits which are "similar" (common process conditions) from a corrosion and material standpoint. Systems are often defined at a PFD level, and circuits are often defined at the P&ID level. The criteria used to define systems and circuits should enhance the effectiveness of the CCD. Properly developed systems and circuits based on expected/identified damage mechanisms enable the development of concise data analysis. See API 570 for more information on systems and circuits.

Systemization is the first cut for defining the potential corrosion issues and is a convenient reference to the general location of damage mechanisms within the process unit. Systems generally have one or more of the following common characteristics:

— process intent (e.g. overhead reflux system);

— process control scheme (e.g. temperature/end point);

— process stream composition;

— design operating conditions;

— common, similar, or related set of IOWs within the circuit.

Systems can contain (or pass through) one or more equipment items (e.g. exchangers, pumps) and will typically contain multiple piping circuits.

Table 2 illustrates content for Corrosion Systems/circuits as the key part of a Unit's Corrosion Control Document. Column two represents information for each system/circuit and column one represents the section where it appears.

Table 2—Suggested Information to be Reported for Corrosion Systems

Subject	Content
Process Description	Description of the process and operating conditions of the system.
Process Content and Conditions	List of major compositional components and corrosive species contained in the main process streams.
Process Control and Monitoring	Key process parameters, typical and limit values, and concerns, reasons.
Start-up and Shutdown Considerations	Any precautions and procedures during start-up and shutdown.
NOTE The temperature and pressure are the highest operating conditions, unless otherwise specified. For example a mechanism may be more severe at lower conditions.	

Circuitization is a further breakdown of systems into sections that include piping and components that are exposed to a process environment of similar corrosivity and expected damage mechanisms, and is of similar design conditions and construction material, where the expected type and rate of damage can reasonably be expected to be the same.

Circuits are identified to facilitate inspection planning and data analysis and will generally have the following characteristics.

— Common materials of construction.

— Common design conditions.

— Common operating conditions.

— Common set of one or more damage mechanisms.

— Common expected corrosion rate.

— Common expected damage locations/morphology.

For risk-based programs, piping circuits can be further subdivided based on risk level. For example, a pump discharge or upstream of a control valve can have the same corrosion characteristics as pump suction or downstream of the control valve, but the risk may be greater on the high-pressure segments due to higher leak rate potential. In such cases, the higher pressure components can be assigned to a separate circuit.

Table 3 conveys content for Corrosion Circuits that can be useful to the CCD user. Subjects to include when identifying circuits are listed within the table with a brief description and reference documents for further information.

Table 3—Suggested Information to be Reported for Corrosion Circuits

Subject	Content	Reference
Injection and Mixing Points	List of any potentially corrosive injection and mix points and their configuration.	API 574
Deadlegs (including lines to Pressure Relief Valves)	List potentially corrosive stagnant areas that experience corrosion rates different from the primary piping.	API 570 API 574
Equipment and Materials	List of equipment and piping, materials of construction, temperature, and pressure for each item. (See Note in 5.7)	API 574
Damage Mechanisms	List of all damage mechanisms applicable to the circuit, areas affected, likelihood of occurring, and special comments.	API 571
Special Inspection Considerations	Special inspections recommended in addition to those normally required by API 510 for equipment, API 570 for piping, and API 563 tanks or other industry standards.	API 570 API 574 API 571
Online Corrosion Monitoring	Online corrosion monitoring devices existing or recommended.	API 570 API 574
Minimum Allowable Temperature (MAT) or Minimum Design Metal Temperature (MDMT)	List equipment that has identified MAT and MDMT consideration—to avoid the potential for brittle fracture.	ASME VIII Div 1, ASME B31.3, or applicable code
Material Spec Breaks	Where they influence equipment or piping integrity and the need for corrosion measurement.	

5.7 Damage Mechanisms

Several sources of industry information specifically identify typical damage mechanisms for various operating units. Specifically applicable to the refining and petrochemical industry are API Recommended Practice 571, which covers damage mechanisms, and API Recommended Practice 580 and Recommended Practice 581, which cover Risk-based Inspection. A list of common damage mechanisms is also provided in API 579/ASME FFS-1 *Fitness-for-Service*, Annex G.

Other sources of information that can help identify/establish equipment-specific damage mechanisms or risk, or a combination thereof, that should be considered during this process include:

— Risk-based Inspection Projects,

— Corrosion Systemization/Circuitization Programs,

— Equipment Criticality Assessments,

— Corrosion Studies, and

— Industry information exchange forums.

Document the significant damage threats for the specific unit. These can be developed from previous failure analysis reports, historic operating knowledge, discussion with licensees of similar process units, and the process licensor.

Include consideration of past issues that are indicative of potential corrosion problem areas such as requesting a list of indicators of potential corrosion such as thermography, IOW exceedances, temporary repairs, incident reports relating to equipment, and incident reports relating to equipment.

5.8 Desired Run Time

Develop an operating basis that establishes the desired future run time for reliable operation and acceptable economic life of the asset. Generally, the basis would be established on an acceptable damage rate or maximum amount of damage acceptable during the planned run time. In some cases, it can include setting limits on operating conditions that may introduce a new damage mechanism. For instance, a limit can be placed on operating temperature in a Hydroprocessing reactor to avoid High Temperature Hydrogen Attack (HTHA). A key consideration for establishing a basis is the duration over which it applies. In some cases, the established time frame may be very short (for a specific operation to take advantage of an opportunity feedstock for example), but in general, the time frame for setting damage limits should be based on an acceptable life for the equipment or the time period until the next turnaround or both. A basis can be established on an individual equipment basis or on a process unit specific basis, or a combination thereof.

5.9 Process Variables and IOWs

After identifying all applicable damage mechanisms, each contributing process variable related to activation of, or progression of equipment damage mechanisms needs to be identified. These process variables should be considered for potential IOWs developed in accordance with API Recommended Practice 584. See also Section 7.

Examples of unit-specific process data in refineries that can be used during the CCD process include but are not limited to the following.

— Crude Units—Historical crude assays, average sulfur composition for the raw feed and primary cuts or product streams, total acid numbers (TAN), furnace monitoring data (Infrared and process temperatures), side-stream temperatures, overhead process parameters such as velocities, pH, chloride contents, crude salt content, desalter efficiency and reliability, and caustic injection rate (and strength) into desalted crude.

— Hydroprocessing Units—Hydrogen, hydrogen sulfide and ammonia partial pressures, wash water volumes, injection points, and sources and quality of wash water.

— Amine Systems—Type of amine, loading, filtration, overhead bleed/purge rates, chloride content, CO_2, H_2S content, oxygen level, HSAS (Heat Stable Amine Salts) content, amine strength, and steam temperature of amine reboilers.

— Catalytic Crackers—Feed sulfur, polysulfide injection systems, slurry solid content, hydrogen cyanide (HCN) and carbonate concentration in gas plant system, and water wash rates.

— Claus Sulfur Units—Acid gas feed temperature, temperature of cold wall thermal reactor, temperature of final condenser outlet, acid gas loading, and sulfur levels.

— Sour Water Strippers—Concentration of NH_3 in circulating reflux, H_2S concentration, flow rate, and HCN.

— Caustic Treating Units—Sodium content and air controls.

— Selective Hydrogenation Unit—Di-olefins content.

— Sulfuric Acid Alkylation—Spent acid strength to storage, acid strength, acid temperature, water content of acid, acid/hydrocarbon ratio in contactors, contactor isobutane/olefin ratio, acid precipitator amperage draw and voltage, acid circulation rate to fractionators feed acid wash, fractionators acid wash mix valve pressure differential, and caustic strength of alky fractionators caustic wash.

— Hydrofluoric Acid Alkylation—Water content in acid, isostripper and depropanizer temperatures, and defluorinator breakthrough monitoring.

— Catalytic Reformer—Furnace temperatures, H_2S content of reformer recycle gas, water content of recycle gas, and HCl content of hydrogen exiting the hydrogen HCl scrubbers.

— Delayed Coking Unit—Sodium in feed, TAN, cycle times, and tube temperatures and velocity in coker heaters. Annex D illustrates typical systems for selected processes.

5.10 Integration with Existing PSM and Operational Programs

5.10.1 Connection with MOC Process

Define any anticipated future changes and prior changes to unit/equipment operating conditions, feedstock changes or other initial basis and establish how those anticipated future changes apply to the equipment strategy and CCD. Any planned changes to the operation will need to be considered during the identification of the "potential" damage mechanisms that are associated with those planned changes (e.g. higher sulfur or TAN in the feedstock to a refinery or changes in the composition of purchased feeds).

5.10.2 Integration with Inspection and Turnaround Planning

The CCD should be used in conjunction with equipment-specific inspection planning and turnaround planning—including identifying the likely locations for local thinning and cracking and suggesting potential inspection techniques to be applied.

Measures should be taken to review the CCD after each major change, such as a turnaround, for any updates that are necessary. During this process, the corrosion and inspection findings from the inspections should be compared with the predictions. If unexpected corrosion findings were documented during inspection, the process data upon which the CCDs damage rates were predicted should be reevaluated and adjusted as needed. If unanticipated damage mechanisms are revealed during the inspection, a significant reassessment of the CCD damage mechanisms should be conducted.

5.10.3 Coordination with Maintenance and Operating Procedures

The CCD team should provide a list of recommended actions or changes that affect operating and maintenance procedures. The CCD owner is typically responsible to follow-up to ensure that procedures have been updated, as necessary. The CCD team members can assist in interpreting these recommendations or evaluating any alternative solutions. The procedures can include, but are not limited to, the following:

— start-up and shutdown procedures;

— minimum pressurization temperature procedures;

— decontamination procedures (steam-out, soda ash wash, neutralization, acid cleaning, and hydrolancing);

— process upset response procedures;

— catalyst change out and regeneration procedures;

— decoking and online spalling procedures;

— intermittent or continuous water wash procedures;

— loss of water wash procedures;

— hot and cold standby procedures;

— hydrotesting and hydroblasting procedures;

— hot hydrogen stripping procedures; and

— presulfiding procedures.

5.11 Updating the CCD

It is important to maintain and update the CCD to ensure that the most recent inspection, process, and maintenance information is included. Inspection results could indicate a significant change in the rate of piping and equipment deterioration, possibly related to changes in process conditions or maintenance practices. This could trigger the need to perform a reassessment.

It is the responsibility of the owner-operator to determine an appropriate mechanism for CCD review and updating. The following are examples for this process:

— After significant changes to the process. Qualified personnel should evaluate each significant change to determine the potential for a change in equipment and piping deterioration. It can be desirable to conduct a reassessment after significant changes in process conditions, or damage mechanisms/rates/severities.

— After a set period. Although significant changes may not have occurred, over time many small changes can occur and cumulatively cause significant changes in the operating environment. Users should set default maximum time periods for reassessments. The governing inspection codes (such as API 510, API 570, and API 653) and jurisdictional regulations, if any, should be reviewed in this context.

— Before and after maintenance turnarounds. Updates can also be scheduled after maintenance turnarounds. Since a large number of inspections, repairs, and modifications are performed during a typical maintenance turnaround, it can be useful to update the CCD to reflect on lessons learned.

— In the event of an unpredicted corrosion failure or any failure that exceeds site risk tolerance levels. The CCD should be reevaluated to determine whether appropriate corrosion control and mitigation strategies are in place.

6 Implementation

Effective implementation of the CCD is equally as important as developing the unit specific CCD. Unit-specific CCDs should be readily available and communicated to affected personnel, which could typically include:

— operations personnel,

— operations supervision/management,

— business/oil movements,

— inspection personnel,

— process engineers,

— mechanical/reliability engineers,

— fixed equipment engineers,

— corrosion/materials specialists, and

— safety/PSM/environmental personnel.

An important part of CCD implementation is training. When CCDs are established, unit personnel need to be knowledgeable about all of the unit-specific CCDs in their operating area and especially knowledgeable in the reasoning behind them.

Training should include describing the difference between code design conditions (pressure and temperature) and materials selection conditions. In general, the code design conditions are used to determine the mechanical acceptability (for resisting the applied stresses), whereas other damage mechanisms occur at lower conditions. Most original materials selections are done based on the most severe operating conditions, sometimes with safety factors, but not based on design conditions. In many scenarios, selecting materials for design conditions would result in a non-optimum material both from considering all the various potential damage mechanisms, and from a cost- standpoint.

There should be no misunderstanding regarding the differences between the design conditions stamped on the nameplate of the equipment and the actual process operating limits of the equipment based on potential and likely damage mechanisms that may be encountered.

Each site should develop a fit-for-purpose training program to disseminate the information contained in the CCD to all personnel whose jobs and responsibilities are impacted by its contents. Table 4 lists the suggested training roles and responsibilities by personnel group. Annex C contains a suggested training process for implementing CCDs.

Table 4—Personnel Group Training

Personnel Group	Training Role
CCD Team Leader or Fixed Equipment Engineer	Lead the overview/rollout training. Provide training input materials and assist in developing training packages. Assist at training sessions.
Site/Unit Training Coordinator	Develop training presentations, manuals, computer-based training (CBT) modules, quiz/test/examination questions. Schedule training sessions. Execute training sessions. Administer testing. Track personnel trained.
OEMI Personnel	Participate, as appropriate, in scheduled CCD training.

7 Integrating CCDs with Other Related Work Processes

The CCD work process should be closely integrated or an integral component of the pressure equipment integrity work processes (inspection, corrosion management and maintenance) at the plant site. The pressure equipment integrity work process can be enhanced when both work processes (pressure equipment integrity work process and CCD) are performing effectively with close interaction between the work processes.

If a comprehensive set of process unit IOWs have not yet been developed in accordance with API Recommended Practice 584, the CCD is an excellent starting point for the IOW work process. Where IOWs have been developed, process unit IOWs should be reviewed and updated relative to the information contained in the new or updated CCD.

The unit specific CCD can be a useful resource for PHA reviews, and CCD team members can be ad hoc members of the process unit PHA review. A suggested checklist of damage mechanism issues that can be used during PHA reviews is shown in Table B.1 in Annex B.

The CCD work process and documentation can also be a resource for the improvement and further development of the inspection program whether the program utilizes a rule-based inspection approach or RBI methodologies. In fact, a CCD workshop and RBI workshop could be combined where there is complete overlap in resources and timing of the two highly integrated programs.

The analysis of IOW exceedances can affect the inspection plans, including time-based and condition-based inspection plans. The information assembled to produce the more detailed CCD illustrated in Annex E can become part of the front-end data input to the RBI process, which could in turn produce a detailed Risk-based inspection plan for each piece of fixed equipment, including inspection scope, methods, techniques, coverage, and frequency.

API Recommended Practice 580 and API Recommended Practice 581 are the two RPs that address Risk-based Inspection. API Recommended Practice 580 is the generic boundary document detailing what needs to be included in an effective and complete RBI work process. API Recommended Practice 581 contains both qualitative and quantitative step-by-step work processes for developing an RBI program that includes all the elements of API Recommended Practice 580.

As indicated in 5.10, the MOC work process could be closely integrated with the CCD work process to ensure that significant changes, additions, or deletions are recorded in the CCD. The owner-operator should ensure that follow-up actions or recommendations that result from the development, maintenance, or revisions to CCDs are managed in appropriate systems and tracked to closure.

The CCD process can also be integrated into the site's drawing management program to support the corrosion diagrams (CMDs) that are developed using existing PFDs and P&IDs. Sites can integrate the CCD specific information into the common/centrally available drawings such that the CCD specific information on those drawings is kept current and is available to all site personnel.

7.1 CCDs as Part of New Construction or Revamp Project Deliverables

For new processes and projects, the CCDs work process can be a closely integrated, or an integral, component of the pressure equipment integrity work process. It may be requested as part of project deliverables.

During the design phase, the planned process exists only on paper. This is a good time to address potential mechanical and physical property problems. An integrated materials selection and design review at this stage can mitigate future repair/modification expenses by identifying design errors and omissions. Annex F discusses this process.

8 Document Maintenance and Revalidation

All CCDs and their associated drawings and attachments should be stored in such a manner that allows easy access by all stakeholders and controlled revision.

All CCDs and their associated drawings—Corrosion and Materials Diagrams (CMDs), Corrosion Circuit drawings and other relevant drawings—should be reviewed and revalidated at the frequency determined by the plant. They can be reviewed and updated in conjunction with PHA revalidation, during each turnaround cycle, or another set time period. The site project management work process can include creating or updating the CCDs and their associated drawings when they are affected by project implementation.

8.1 Updating CCDs

Periodic team meetings between Operations and the CCD coordinator can be useful to monitor the status and update the CCD.

Between scheduled CCD updates, CCDs should be "red-lined" as needed to account for process and hardware changes (recent and planned), IOW exceedance feedback, inspection results, and new information about variables, damage mechanisms or additional IOWs that were identified after the original CCD was created. The red-lined version then becomes the starting point for the scheduled CCD update.

It may be more efficient for the PHA documentation and CCD documentation reviews and updates to be coordinated because often the issues and personnel for the two efforts are overlapping.

The following steps are suggested to complete the CCD review:

— review and revise process descriptions (include process content and conditions) in each Corrosion Circuit as necessary;

— review inspection findings since the last update;

— review the process unit leak log (or equivalent) to determine if any leaks or releases from the process unit were predicted in the CCD;

— review recorded process safety incidents that have occurred in the unit or similar units for issues that should be included in the CCD;

— discuss all corrosion and materials issues (including those in Annex B) in the Corrosion Circuits and revise the CCD and CMD as necessary, focusing on the changes made by MOC, projects, and other changes captured in the CCD/CMD revision logs; and

— ensure that all action items are captured and risk levels assessed and entered into the site action item tracking system.

8.2 Finalizing the Updated CCD and CMDs

The CCD review and update process should produce an updated CCD and CMD. Responsibility for finalizing the updated CCDs and CMDs should be assigned to the appropriate plant personnel, e.g. the Drawing and Document Control group, or the site or lead corrosion/materials specialist, per the site's practice.

Annex A
(informative)

Example CCD Development and Implementation Process

Table A.1 shows an example of the CCD Development and Implementation Process and Table A.2 provides an example CCD Implementation Checklist.

Table A.1—Example CCD Development and Implementation Process

Category	Process	
Operations, Process Engineer, Corrosion/ Materials Engineer	Define Current Operating Conditions History	Provides current process description and operating conditions for normal start-up and shut-down conditions. Identifies existing operational control and limits for IOWs, process chemical injections.
Design Engineer		Identifies previous and future operational improvements/ changes.
Inspector, Fixed Equipment Engineer	Define Current Mechanical Design	Provides current mechanical design (design pressures, temperatures, materials of construction, design features for injection/mix points).
Corrosion/ Materials Engineer, Inspector, Fixed Equipment Engineer	Define Corrosion Rates and Failure	Provides current equipment condition and identifies corrosion/ damage rate, type of mechanism, locations for damage, morphology, and prior equipment inspection history.
Operations, Process Engineer, Corrosion/ Materials Engineer, Inspector, Fixed Equipment Engineer, Operations Specialist	Team Meeting	Assemble team and review operating/ design data, equipment condition, damage rate, related failure or leak history, inspection findings/scope, and techniques. Develop corrosion/ damage theory and identify key mechanical limits and operational control parameters that need to be in place for monitoring. Validate data.
Corrosion/ Materials Engineer, Inspector, Fixed Equipment Engineer, Operations	Develop CCD	A subset of the team, documents the identified potential damage mechanisms, IOWs, Key process variables, appropriate inspection techniques/locations and scope, special emphasis Inspections (as needed for HTHA, wet H_2S), start-up and shut-down considerations or controls needed (passivation, neutralization, chemical cleaning)
Corrosion/ Materials Engineer, Inspector	Implement	Develop or update specific equipment inspection plan (scope, techniques, locations, and frequency).
Fixed Equipment Engineer		Update IDMS.
Operations Specialist, Design Engineer		Develop IOWs monitoring program, notifications and alerts/ alarms as required.
PSM Coordinator		Include identified key operating variables and limits (IOWs) and damage concerns in PHAs and MOCs.
Corrosion/Materials Engineer	Manage	Update and maintain CCDs.
Inspector		Update and maintain inspection plans.
Fixed Equipment Engineer		Update and maintain IDMS.
Operations Specialist		Provide training to operations on controls and limits (IOWs).
Design Engineer		Define projects for materials/ instrumentation up grades.
PSM Coordinator		Include CCD in PHA process.

Table A.2—CCD Implementation Checklist

Item	Responsibility
Operating and Maintenance Procedures	
List of recommended changes that affect operations or maintenance procedures is provided to Operations, Maintenance, or Turnaround Planning and entered into a site tracking system.	CCD Team Lead
All recommended procedures are reviewed and updated. This can include, but is not limited to: — normal operating conditions; — start-up and shutdown procedures; — decontamination procedures (steam out, soda ash wash, neutralization, acid cleaning); — process upset response procedures; — catalyst change out and regeneration procedures; — decoke and online spalling procedures; — intermittent water wash procedures; — water wash (or loss of water wash) procedures; — hot and cold standby procedures; — hydrotesting and hydroblasting procedures; — hot hydrogen stripping procedures; and — presulfiding procedures.	Operations and Maintenance
Hardware Changes	
Significant recommended hardware changes are risk assessed and risk category assigned.	CCD Team
Cost/risk analysis is performed and justification for any project provided.	Fixed Equipment Inspection Group
Prioritized list of approved hardware changes is provided to site project group or turnaround planning group, or both.	Fixed Equipment Inspection Group
Projects are being tracked as completed, planned, deferred, or rejected.	Site Project Group
Inspection Strategy	
Cross references are established between Corrosion Circuits and Inspection Circuits (if they are different).	Fixed Equipment Inspector
Inspection strategy is entered in an inspection record system.	Fixed Equipment Inspector
Routine inspection coverage and schedule are revised as needed.	Fixed Equipment Inspector
Recommended special inspections are incorporated into the turnaround scope.	Fixed Equipment Inspector
Match damage mechanisms with appropriate detection method	Fixed Equipment Inspector
Findings and Recommended Actions	
Significant findings have been communicated to management.	CCD Team
The responsible group is identified, e.g. Process Engineering, Operations/Maintenance, Projects, or Pressure Equipment.	CCD Team
All action items are risk assessed and risk category assigned.	CCD Team
Risk categories of all items are reviewed by the responsible groups and agreed by their management.	Fixed Equipment Discipline Leader
All items and their associated risk categories are entered in the site tracking systems.	CCD Team Lead
All high-risk items are completed.	Site Process Owner

Table A.2—CCD Implementation Checklist (Continued)

Item	Responsibility
Training	
Training materials for Level 1—Overview Rollout Training has been developed (see Annex C).	CCD Team Lead
Training materials for Level 2—Unit Specific CCD Training has been developed (see Annex C).	SME/CCD Team Lead
Level 1—Overview/Rollout Training is completed.	CCD Team Lead
Level 2—Unit Specific CCD Training is completed.	Site Learning and Development Leader
All OEMI personnel has been tested and passed.	Site Learning and Development (L&D) Leader
CCD training is included as part of new operator training.	Site L&D Leader
Integration with Other Programs	
CCD is adopted by the site MOC process.	Fixed Equipment Discipline Leader
PHA and HazOp review process has been revised to include CCD as base reference material.	Fixed Equipment Discipline Leader
CCD is used for input to RBI.	Fixed Equipment Discipline Leader
CCD is in alignment with the RCM or similar process programs.	Fixed Equipment Discipline Leader
Document Maintenance and Updating	
CCD is maintained in a site document management system for easy access and controlled revision.	CCD Team Leader
All documents are new or have been updated within the past Turnaround cycle (before or in conjunction with PHA revalidation).	CCD Team Leader
All process and hardware changes made by projects or in turnarounds during the past Turnaround cycle are reflected in the current version of CCD.	CCD Team Leader

Annex B
(informative)

Corrosion and Materials Damage Mechanisms Checklist

B.1 Part 1—Corrosion and Materials Damage Mechanisms Checklist

Table B.1 is an example of a corrosion and materials damage mechanisms checklist. This is not a comprehensive list of all possible failures.

B.2 Part 2—Mechanical and Other Damage Mechanisms Checklist

Table B.2 can be used as a mechanical and other damage mechanisms checklist.

Table B.1—Corrosion and Materials Damage Mechanisms Checklist

High Temperature Damage Mechanisms (>450 F)
a) Is there a potential for carbon steel and low alloy steels to exceed the carbon steel Nelson curve (API 941) and be exposed to high temperature hydrogen attack (HTHA), including operation of a normally closed bypass or the bypass piping being overheated by the process piping?
b) Is there a potential for brittle fracture (e.g. hydrogen embrittlement, temper embrittlement, 0.5Mo steel) of heavy wall hydroprocessing equipment from rapid heating/cooling or pressurizing below the minimum pressurization temperature?
c) Is there a potential for accelerated creep from operating outside of the operating window (e.g. higher temperature or pressure or both)?
d) Is there a potential for catastrophic brittle fracture (hydrogen embrittlement) of heavy wall hydroprocessing equipment from rapid cooling?
e) Is there a potential for rapid stress corrosion cracking of equipment by contact with low melting metal compounds, e.g. molten zinc on stainless steels, mercury condensation on aluminum alloys and copper alloys, cadmium plated bolting on hot equipment?
f) Is there a potential for accelerated sulfidic corrosion from gradual increase of sulfur content, temperature, or inadvertent increase of other sulfur species such as H_2S or mercaptan content?
g) Is there a potential for accelerated corrosion from increasing naphthenic acids in crude oil, gas oils or other streams?
h) Is there a potential for accelerated corrosion as a result of organic chloride contamination in crude oil or other purchased feeds?
i) Is there a potential for spontaneous ignition of materials (including titanium, zirconium, structured packing, iron sulfide) from exposure to such substances as HCl, Cl_2, O_2, and air?
j) For alloys operating above ~700 °F, are there any high temperature aging embrittlement phenomena that might lead to brittle behavior when equipment is pressurized at lower temperatures?
k) Is there a degradation effect due to metal dusting, carburization, nitriding?
l) Is there hot spot due to refractory lining failure or any other overheating?

Low Temperature (Aqueous) Corrosion and Stress Corrosion Cracking Damage Mechanisms
a) Is there a potential for unneutralized process streams to be present in materials of construction not designed for the corrosive condition?
b) Is there a potential for rapid corrosion at or downstream of injection or process mixing points due to heating/cooling, condensation/evaporation, reaction, between the injecting and mixing streams?
c) Is there a potential for rapid corrosion at or downstream of injection points as a result of malfunction of the injection facilities (spray nozzle, quill, loss of carrier, flow imbalance)?
d) Is there a potential for rapid corrosion due to change in flow rates, changes in flow regime, e.g. vaporization, flashing, or other multiphase flow conditions?
e) Is there a potential for localized corrosion or cracking of austenitic stainless steels during shutdowns where polythionic acids (PTA) are present?
f) Is there a potential for rapid localized corrosion at hot spots as a result of direct contact between heat tracing and process piping, e.g. lack of standoff or improper use of heat transfer material?
g) Is there a potential for accelerated corrosion from fluids or solids trapped in deadlegs, or both?
h) Is there a potential for accelerated corrosion from precipitation of corrosive salts, e.g. amine/ammonium chlorides?
i) Is there a potential for process upsets to introduce moisture into moisture free environments (e.g. dry HCl or Cl_2) or to remove moisture from environments reliant on moisture for the protection of the system (e.g. anhydrous NH_3 and alcohols)?
j) Is there a potential for accelerated corrosion by the activation or deactivation of piping segments, e.g. bypasses or change from a normal lineup, or the installation of temporary facilities?
k) Can changes in pump or compressor capacity (including the use of spare) lead to increased corrosion rates?
l) Is there a need for internal cathodic protection for equipment and piping?
m) Can increase or decrease in pH (inadvertent or undetected) lead to increased corrosion or stress corrosion cracking?
n) Can minor changes in feed compositions (loss of trace amounts of corrosion inhibitors, presence of organic chlorides, etc.) adversely affect corrosion rates?
o) Can non-post weld heat treated equipment containing caustics or amines be steam cleaned leading to a potential for cracking?
p) Is there a potential for air and moisture ingress into otherwise oxygen free or dry environments, or both (e.g. breather valves on tanks) that could cause accelerated corrosion or cracking?
q) Can solids be present causing increased erosion-corrosion (i.e. catalyst carryover, accumulation of corrosion products)?
r) Is there a potential for increased corrosion or cracking beyond piping spec breaks due to process changes or upsets?
s) Is there potential for increased corrosion in the inlet zone or at a vapor/liquid interface?
t) Is there a potential for caustic cracking of non-post weld heat treated equipment, piping, or other components due to a concentrating mechanism such as boiler feed water leaks or other caustic containing streams?
u) Is there a potential for bolting to be exposed to process environments that could lead to catastrophic fracture due to stress corrosion cracking such as caustic, amine, and wet H_2S?
v) Is there a potential for inadvertent process contamination that could cause stress corrosion cracking? (e.g. wet H_2S, caustic, amines, chlorides, polythionic acids)?
w) Is there a potential for accelerated corrosion from the installation of specified material not properly verified by appropriate PMI procedures in highly hazardous systems?
External Damage Mechanisms
a) Is there a potential for unmitigated and undetected external corrosion that can lead to rupture, e.g. soil-to-air interface, downstream of cooling water sprays?
b) Is there a potential for changes in the monitoring or maintenance of cathodic protection systems that could lead to increased corrosion of buried piping or tank bottoms?
c) Can changes in process conditions lead to increased corrosion under insulation (CUI), e.g. idling of normally hot equipment, equipment in cyclic service above and below 250 °F, or exposure of stainless steel equipment to external chloride cracking?
d) Is CUI possible?

Table B.2—Mechanical and Other Damage Mechanisms Checklist

a) Are there any areas with deadlegs that could freeze and rupture under the proper conditions, especially in light hydrocarbon services?
b) Is there a potential for liquid slugging of piping (including flare lines) that could cause piping failure due to hydraulic shock, water hammer, and other transient overstress conditions?
c) Is there a potential for accelerated corrosion, fouling, or plugging of inlet or outlet piping of relief devices or flare systems?
d) Has the impact on relief capacity been reviewed for any increases in unit throughput?
e) Can inadvertent temperature changes on piping systems cause mechanical overload because of lack of flexibility in piping design?
f) Is there a potential for overstressing or shocking causing brittle fracture of materials that are brittle (e.g. cast iron, aged or embrittled steels)?
g) Is there a potential to overpressure equipment or piping when using high pressure or positive displacement pumps to unplug a line?
h) Is there a potential for brittle fracture of heavy wall equipment from being fully pressurized before the metal temperature has reached MPT?
i) Is there a potential for temperature decreases (such as auto-refrigeration) that cause brittle fracture on materials that are not designed for low temperature conditions?
j) Is there a potential for vibration that could lead to fatigue failure of piping, threaded connections, unsupported overhead weight or exchanger tubes?
k) Is there a potential for thermal fatigue cracking due to large temperature cycling or severe temperature swings?
l) Is there a potential for cavitation from rapid pressure or temperature changes?
m) Could heat tracing be inadvertently shut-off on critical equipment or relief systems that can impair their operability?
n) Are there any vents and drains downstream of block valves that require the additional protection from pipe plugs to prevent releases?
o) Are temporary repairs and clamps identified for scheduled removal at the next maintenance opportunity?
p) Can the failure or malfunction of internal elements such as exchanger bundles, trays, distributors, and steam rings lead to overpressure, accelerated corrosion, or metallurgical damages to pressure containing equipment and piping, or both?

Annex C
(informative)

Training Course Contents

C.1 General

An important part of CCD implementation is training. When CCDs are established, unit personnel need to be knowledgeable concerning the unit-specific CCDs in their operating area and especially knowledgeable in the reasoning behind them.

The following sections provide some examples and suggestions to consider when developing a CCD training system.

C.2 Level 1—Overview/Rollout Training

Level 1, Training for OEMI personnel can include:

— information on how and where to access the CCDs (web link, control room);

— details on the structure of the CCD document (Table of Contents (TOC));

— the key corrosion control variables and IOW Limits (Distributed Control System (DCS) table overview);

— information on how to browse and search for specific information (using the Table of Contents (TOC), hyperlinks); and

— a quiz or test (optional) to check for knowledge transfer.

C.3 Level 2—Unit Specific CCD Training

Level 2, Unit Specific CCD, training for operations can also include process engineering and maintenance craftsmen, and includes:

— review of specific Corrosion Circuits with high probability for corrosion and materials damage;

— explanation of major potential damage mechanisms; and what can happen to equipment if the damage mechanisms are not adequately controlled;

— explanation of corrosion control variables in IOW, their limits, their basis and consequences, the nature and criticality of their threat, maximum durations allowed for their exceedance, and required operator actions/ interventions;

— an understanding of the special operating/maintenance procedures affecting equipment integrity, their basis and consequences, and what to do in case of deviation or exceedance;

— lessons learned (e.g. incidents that have occurred in the unit or units at other sites); and

— a quiz to check (optional) for knowledge transfer.

C.4 Timing and Schedule

Table C.1 provides suggestions on the type of CCD training required (Overview/Rollout or Unit Specific) and training frequency.

Table C.1—Suggested Training Schedule

Type of CCD Training	When Needed
Overview/rollout training	When a new CCD is completed. When there has been significant personnel turnover. Periodic refresher or per site operator refresher training schedule.
Unit specific training when a new CCD is completed or updated.	As part of the operation/process engineering overall training schedule. When a new operator/process engineer is hired. When operational/support responsibility changes. Refresher per training requirements.

C.5 Delivery Media

Training sessions can be delivered using either classroom-style seminars or via computer based training (CBT). See Table C.2 for suggestions.

Table C.2—Suggested CCD Training Styles

Type of CCD Training	Training Style
Overview/rollout training	Classroom-style Seminar or Computer Based Training (CBT)
Unit specific training	First Time Training—Classroom-style Seminar Refresher—CBT

Annex D
(informative)

Typical Systems for Selected Processes

D.1 General

This annex contains partial system templates for the following units:

— D.2, Ammonia Synthesis Unit;

— D.3, Hydrocracker Unit;

— D.4, Crude Oil Distillation Unit;

— D.5, Fluid Catalytic Cracking Unit; and

— D.6, Ethylene Steam Cracking

D.2 Ammonia Syntheses Unit

D.2.1 Process Summary

The main objective of ammonia synthesis unit is to produce anhydrous (water free) ammonia by adding nitrogen to hydrogen in the molar ratio of 1:3 [see Equation (D.1)].

$$N_2 + 3H_2 \rightarrow 2NH_3 \tag{D.1}$$

The majority of ammonia production plants are currently using natural gas, which mostly consists of methane, as the primary feedstock to generate hydrogen by using a catalytic steam reformer.

Syngas from reformer is first compressed and heated before entering the converter. The reaction is exothermic. Increase in temperature will accelerate reaction time and lower ammonia equilibrium at the same time. The reaction rate also increases with pressure, which means the probability of runaway reactions is higher. It is important to keep the optimal condition to maximum ammonia conversion.

Effluent gas from the converter is condensed by refrigeration to separate out liquid ammonia as the final product. Small portion of synthesis gas that is not converted is recycled back to the compressor for further reaction.

D.2.2 Table of Systems

The following comprise the Table of Systems for the Ammonia Synthesis Unit.

— Corrosion System 1—Synthesis gas feed

— Corrosion System 2—Converter

— Corrosion System 3—Anhydrous ammonia

— Corrosion System 4—Syngas purge system

— Corrosion System 5—Hydrogen recovery section (HRU)

— Corrosion System 6—Lean ammonia solution

— Corrosion System 7—Rich ammonia solution

— Corrosion System 8—Recovered hydrogen

D.3 Hydrotreater Unit

D.3.1 Process Summary

The objective of the hydrotreating process is to remove sulfur as well as other unwanted compounds due to increase product specifications, low sulfur limitation for downstream process, and environmental considerations. In this process, sulfur compounds are removed by converting into hydrogen sulfide by reaction with hydrogen in the presence of catalyst. The hydrogen sulfide produced can be easily removed from the product gas stream, for example by an amine absorber. In this way, hydrogen sulfide is recovered as a highly concentrated stream and can be further converted into elemental sulfur via the Claus process.

Two basic processes are applied in hydrotreating, the liquid phase process for kerosene, heavier straight-run fraction and vapor phase process for light straight-run fractions. Both processes use the same basic configuration: the feedstock is mixed with hydrogen-rich makeup gas and recycle gas. The mixture is heated by heat exchange with reactor effluent and by a furnace before it enters a catalytic reactor. In the reactor, the sulfur and nitrogen compounds present in the feedstock are converted into hydrogen sulfide and ammonia respectively. The olefins present are saturated with hydrogen to become diolefins and part of the aromatics will be hydrogenated. If all aromatics need to be hydrogenated, a higher pressure is needed in the reactor compared to the conventional operating mode.

The main reactions are:

— Hydrogenation of sulfur compounds—Sulfur is combined with hydrogen to form H_2S.

— Hydrogenation of nitrogen compounds—Nitrogen compounds are partly converted into ammonia (NH_3) in the reactor under normal hydrodesulphurization conditions.

— Hydrogenations of chlorides—Organic and inorganic chloride compounds are converted to hydrogen chloride (HCl).

— Hydrogenation of unsaturated compounds—Olefins and aromatics compounds are hydrogenated to paraffins.

— Hydrogenation of oxygen compounds—Naphthenic acids and phenols are the best known types of oxygen compounds present in mineral oils and these are converted into hydrocarbons and water.

D.3.2 Table of Systems

The following comprise the Table of Systems for the Hydrocracker Unit.

— Corrosion System 1—Cold feed into preheat exchanger train (T < 450 °F)

— Corrosion System 2—Hot feed (Greater to Heater)

— Corrosion System 3—Charge heater

— Corrosion System 4—Hydrotreater reactor and hot effluent exchangers

— Corrosion System 5—Hydrotreater reactor and hot effluent exchangers

— Corrosion System 6—Cooled reactor effluent to high pressure separator

— Corrosion System 7—Separator liquids

— Corrosion System 8—Stabilizer bottoms

— Corrosion System 9—Sour water

— Corrosion System 10—Amine absorber

— Corrosion System 11—Recycle hydrogen

D.4 Crude Oil Distillation Unit

D.4.1 Process Summary

Desalting is the first step of crude oil processing. Desalters are needed because petroleum contains salts that can cause corrosion in downstream units and cause unplanned outages. The salts of greatest concern are magnesium chloride ($MgCl_2$), calcium chloride ($CaCl_2$), and sodium chloride. Calcium and magnesium chloride will partially decompose (hydrolyze) in the hot preheat exchangers and heater. Upon hydrolysis, the chlorides from these salts convert into hydrogen chloride gas, which is absorbed into condensing water as hydrochloric acid in the upper part of a distillation tower or in overhead condensers. A well performing desalter can reach upwards of 90 % efficiency.

Following the desalter, a system of heat exchangers (preheat) increase the oil temperature until it is almost fully vaporized. The heat is taken from other process streams that require cooling before being sent to rundown. Heat is also exchanged against condensing streams from the main tower. Somewhere in the preheat, a small, dilute caustic stream is often mixed with the crude to form sodium chloride from any hydrochloric acid formed by hydrolysis. The sodium chloride will exit the fractionation tower via the bottom residue stream. The dosing rate of caustic injection is adjusted to control chloride values in the overhead liquid accumulator, commonly to 10 ppm to 25 ppm.

More heat is added with heat exchangers before entering the atmospheric furnace. Typically, the crude is heated up to 392 °F to 536 °F before entering a furnace.

Atmospheric Furnace—The pre-heated crude enters the furnace and is heated to approximately 630 °F to 700 °F in the furnace. The furnace outlet stream is sent directly to the atmospheric crude tower where it is separated into products based on specification boiling ranges.

Distillation is the second step of crude oil processing.

Pre-flash Tower—Downstream of the desalter, somewhere in the pre-heat train before the atmospheric furnace, some refineries will operate a fractionator to remove gases which could increase pressure drop and wastefully absorb unnecessary heat.

Atmospheric Tower—At approximately 630 °F to 700 °F and approximately 15 psig to 30 psig, most of the fractions in the crude oil vaporize and rise up the tower through perforations in the trays, losing heat as they rise. Each fraction condenses to a liquid phase when it reaches the tray just below its boiling point. A continuous liquid flows through “downcomers” from tray to tray and the different fractions are gradually separated from each other on the trays of the fractionation tower. The heaviest fractions condense on the lower trays and the lighter fractions condense on the trays higher up in the tower. At different elevations in the tower, fractions can be drawn out by gravity through pipes for further processing in the refinery.

At the top of the tower, vapor enters an overhead condenser (a heat source for the preheat) then is further cooled by air fin-fans or heat exchangers (which are cooled by cooling towers) to 104 °F. Next, a mixture of gas and liquid naphtha falls into an overhead liquid accumulator. Gases are routed to a compressor for further recovery of LPG (C3/C4), while the liquid (naphtha) is pumped to a hydrotreater unit for sulfur removal.

Side strippers are used to remove lighter hydrocarbons from product streams by using steam injection or a reboiler. The stripping steam rate or reboiler heat duty is controlled to meet the flash point specification of the product. Kerosene is often the lightest side draw from the atmospheric crude tower; boiling range of approximately 320 °F to 540 °F.

The second and third (optional) side draw-offs from the main fractionating tower are gas-oil fractions, with a boiling range of approximately 400 °F to 750 °F, which are ultimately used for blending the final diesel product. Similar to the kerosene product, the gas-oil fractions (light and heavy gas oil) are first sent to a side stripper before being routed to further treating units.

Sometimes called long residue, the atmospheric tower bottoms (ATB) is the heaviest fraction. In order to strip all light hydrocarbons from this fraction properly, the bottom section of the tower is equipped with a set of stripping trays, which are operated by injecting low pressure stripping steam (approximately 1 % to 3 % on ATB rate) into the bottom of the tower.

Vacuum Distillation—To recover additional distillates from long residue, distillation at reduced pressure and high temperature has to be applied. The vacuum distillation process has become an important step in maximizing the upgrading of crude oil. As distillates, vacuum gas oil, lubricating oils or conversion feedstocks, or a combination thereof, are generally produced. The vacuum tower bottoms (VTB), sometimes called short residue, can be used as feedstock for further upgrading, as bitumen feedstock, or as a fuel component. The technology of vacuum distillation has developed considerably in recent decades. The main objectives have been to maximize the recovery of valuable distillates and to reduce the energy consumption of the units.

Heated feed enters the vacuum tower at the flash zone, where the temperature should be high and pressure as low as possible to obtain maximum distillate yield. The flash zone and tower bottoms are typically operated at a maximum temperature of 790 °F and a low residence time to avoid cracking of heavy hydrocarbons.

In the older type of high vacuum units, the required low hydrocarbon partial pressure in the flash zone could not be achieved without the use of "lifting" steam. The steam acts in a similar manner as the stripping steam of crude distillation units. These types of units are called "wet" units. One of the latest developments in vacuum distillation has been the deep vacuum flashers, in which no steam is required. These "dry" units operate at very low flash zone pressures and low pressure drops over the tower internals. For that reason, the conventional reflux sections with fractionation trays have been replaced by low pressure-drop spray sections. Cooled reflux is sprayed via a number of specially designed spray nozzles in the tower counter-current to the up-flowing vapor. This spray of small droplets comes into close contact with the hot vapor, resulting in good heat and mass transfer between the liquid and vapor phase.

To achieve low energy consumption, heat from the circulating refluxes and rundown streams is used to heat up the long residue feed. Surplus heat is used to produce medium- or low-pressure steam or both; or is exported to another process unit (via heat integration). The direct fuel consumption of a modern high-vacuum unit is approximately 1 % on intake, depending on the quality of the feed. The steam consumption of the dry high-vacuum units is significantly lower than that of the "wet" units. They have become net producers of steam instead of steam consumers.

Three types of high-vacuum units for long residue upgrading have been developed for commercial application:

1) Feed Preparation Units,

2) Lube Oil High-Vacuum Units, and

3) High-Vacuum Units for Bitumen Production.

These units make a major contribution to deep conversion upgrading ("cutting deep in the barrel"). They produce distillate feedstocks for further upgrading in catalytic crackers, hydrocrackers, and thermal crackers. To obtain an optimum waxy distillate quality a wash oil section is installed between feed flash zone and waxy distillate draw-off.

The wash oil produced is used as a fuel component or recycled to feed. The flashed residue (short residue) is cooled by heat exchange against long residue feed. A slipstream of this cooled short residue is returned to the bottom of the high-vacuum tower as quench to minimize cracking (maintain low bottom temperature.)

D.4.2 Table of Systems

The following comprise the Table of Systems for the Crude Distillation Unit.

— Corrosion System 1—Crude preheat exchanger train to desalter inlet

— Corrosion System 2—Crude desalter

— Corrosion System 3—Desalted crude through pre-flash tower and preheat train

— Corrosion System 4—Preheat train above 450 °F up to furnace

— Corrosion System 5—Atmospheric furnace

— Corrosion System 6—Lower of atmospheric tower and side cuts

— Corrosion System 7—Middle section of atmospheric tower and side cuts

— Corrosion System 8—Top section of atmospheric tower and overhead system (Wet)

— Corrosion System 9—Cooled atmospheric side streams

— Corrosion System 10—Vacuum furnace

— Corrosion System 11—Vacuum tower bottom and associated side streams

— Corrosion System 12—Top section of vacuum tower and dry overhead systems

— Corrosion System 13—Vacuum tower wet overhead system

— Corrosion System 14—Naphtha to storage

D.5 Fluid Catalytic Cracking Unit (FCCU)

D.5.1 Process Summary

Catalytic cracking is a continuous process for upgrading heavier, less valuable streams (e.g. residues, flashed distillates, gas oils) to lighter, more valuable products (e.g. gasoline, propylene, light cycle oil). In addition to these typical fresh feeds, other streams may be processed in an FCCU.

Preheated feed is contacted with hot regenerated catalyst at the base of the riser. The feed is vaporized, and the mixture of catalyst and hot vapor is lifted up the vertical riser through a combination of steam injection and reactor hydraulics, with simultaneous catalytic reaction. Most of the cracking reaction occurs in the riser. Cracked and uncracked hydrocarbon vapors, along with the spent catalyst exit the riser into cyclones, which separate the vapors from the spent catalyst. The vapors exit the top of the cyclones and travel to the main fractionator, where reaction product separation begins.

Spent catalyst drops out the bottom of the cyclones into a catalyst standpipe or dripleg and travels to a reactor stripper. In this section, steam strips entrained hydrocarbon vapors from the catalyst. The residence time permits additional cracking of some heavy hydrocarbons on the catalyst. The spent (coked) catalyst travels to the regenerator, where the coke is burned off. The regenerated catalyst is returned to the reactor-riser.

The regenerator operates in either partial or total CO combustion. Partial combustion units have significant quantities of CO in the flue gas, whereas full combustion units have very low levels of CO in the flue gas. Flue gas is quenched by injection of steam condensate, boiler feed water, or sour water, and flows through a series of separators to remove any entrained catalyst fines. Once separated from the catalyst, the flue gas passes through a power recovery turbine or restriction orifice chamber. It is either combusted in the CO furnace to generate steam (occasionally also to heat feed) or cooled in a waste heat boiler/flue gas cooler. With increasing restrictions on environmental emissions, some FCCUs have additional equipment for removing SO_x, entrained catalyst, and NO_x from the flue gas.

D.5.2 Table of Systems

The following comprise the Table of Systems for the Fluid Catalytic Cracking Unit.

— Corrosion System 1—Feed preheat

— Corrosion System 2—Feed injection nozzles

— Corrosion System 3—Reactor-riser, termination device and cyclones

— Corrosion System 4—Reactor overhead to the fractionator

— Corrosion System 5—Reactor vessel, stripper section/vessel, spent catalyst standpipe, and slide valve(s)

— Corrosion System 6—Spent catalyst riser

— Corrosion System 7—Regenerator cyclones and plenum

— Corrosion System 8—Regenerator vessel

— Corrosion System 9—Regenerated catalyst standpipe and slide valve(s)

— Corrosion System 10—Regenerator overhead line, pressure control valve and third stage separator vessel

— Corrosion System 11—Third stage separator cyclones and internals

— Corrosion System 12—Third stage separator outlet line, turbo expander and expander bypass line

— Corrosion System 13—Expander outlet line and CO boiler/waste heat boiler

— Corrosion System 14—Electrostatic precipitator (ESP)

— Corrosion System 15—Wet scrubbers (Belco and Exxon types)

— Corrosion System 16—Underflow line, fourth stage separator and spent catalyst hopper

— Corrosion System 17—Flue gas bypass seal pots

— Corrosion System 18—Air blower and piping to O_2 injection point

— Corrosion System 19—O_2 Oxygen enrichment piping

— Corrosion System 20—Air line from O_2 injection point through the air pre-heater

— Corrosion System 21—Combustion air supply piping and distributor grid

— Corrosion System 22—Expansion joints

— Corrosion System 23—Fractionator hot slurry system

— Corrosion System 24—Warm slurry system

— Corrosion System 25—HCO (HGO) system—main fractionator

— Corrosion System 26—LCO (LGO) system—main fractionator

— Corrosion System 27—Top section of main fractionator to accumulator

— Corrosion System 28—Wet gas compression

— Corrosion System 29—Bottom of debutanizer and depentanizer columns

— Corrosion System 30—Top section of depentanizer column and overhead system

— Corrosion System 31—Lean diethanolamine (DEA) to treaters

— Corrosion System 32—DEA (Diethanolamine) treaters including PP/BB and fuel gas

— Corrosion System 33—Caustic treater (PP/BB) and piping

— Corrosion System 34—Depropanizer column including overhead condensing section and bottoms to storage

— Corrosion System 35—Sour water, entire gas plant

— Corrosion System 36—Ammonium polysulfide system (APS)

— Corrosion System 37—Heavy cat-cracked gasoline to treaters

— Corrosion System 38—Dry gas exiting fuel gas treater

— Corrosion System 39—Fresh caustic to treater

— Corrosion System 40—Sponge column, including piping into and out of column

D.6 Ethylene Steam Cracking

D.6.1 Process Summary

Steam cracking is a petrochemical process in which saturated hydrocarbons are broken down into smaller, often unsaturated, products. It is a key method for producing olefins, including ethylene and propylene. In steam cracking, a gaseous or liquid hydrocarbon feed-like naphtha, LPG or ethane is diluted with steam and then briefly heated in a furnace without the presence of oxygen. Depending on feed quality, amine treating can be used to remove carbon dioxide and/or hydrogen sulfide in the feed.

Steam cracking furnaces are highly complex equipment that include many sections of preheat, heat recovery, and reaction coils. The cracking reaction occurs at high temperatures, but the reaction is only allowed to take place very briefly. After the cracking temperature has been reached, the gas is quickly cooled to stop the reaction in a transfer line exchanger. The products produced in the reaction depend on the composition of the feed, the hydrocarbon to steam ratio, cracking temperature, and furnace residence time.

Products are then quenched with water to remove both carbon dioxide and hydrogen sulfide in the feed oil to aid in cooling and separation. Process gases are then compressed, treated with caustic, and dried before being sent to the separation section of the unit. Gases are initially cooled to cryogenic conditions to allow for separation of light gases (such as hydrogen and methane). Additional separation of heavier streams, such as ethane, ethylene, propane, and propylene occur in downstream towers. Any heavier products (butanes and heavier) are also separated.

Ancillary process streams such as dilution steam, quench water, quench oil, and waste water are also processed in other sections of the steam cracking unit.

D.6.2 Table of Systems

The following comprise the Table of Systems for the Ethylene Steam Cracking unit:

— Corrosion System 1—Feed

— Corrosion System 2—Amine Treated Feed

— Corrosion System 3—Rich Amine

— Corrosion System 4—Lean Amine

— Corrosion System 5—Cracking Furnace

— Corrosion System 6—Cracking Furnace Effluent

— Corrosion System 7—Quench Water

— Corrosion System 8—Quench Oil and Heavy Oil

— Corrosion System 9—Process Gas Compression

— Corrosion System 10—Caustic Wash

— Corrosion System 11—Treated and Dried Process Gas

— Corrosion System 12—Hydrogen Product and Methanation

— Corrosion System 13—Methane Product

— Corrosion System 14—Ethylene Product

— Corrosion System 15—Ethane Recycle

— Corrosion System 16—Propylene Product

— Corrosion System 17—Propane Recycle

— Corrosion System 18—Mixed Butanes Product

— Corrosion System 19—Light Naphtha Product

— Corrosion System 20—Fuel Gas and Treating

— Corrosion System 21—Wash Oil

— Corrosion System 22—Waste Water Treatment and Benzene Stripping

Annex E
(informative)

Example of Information Contained in a CCD System

E.1 Corrosion System #125—Butane/Butylene (BB) Feed

This system is organized into the following inspection circuits:

— 125–01: BB Feed from storage to feed dryers—this corrosion circuit starts at the battery limit and ends at the mix point of recycle isobutene at the reactor risers. The BB Feed is mixed with makeup isobutene from storage and dried in the V-1002A/B dryers.

— 125–02: Regeneration Water—this circuit includes the water from the V-1003 regeneration coalescer to the

— V-005 flare knockout drum. The water is stripped off during regeneration of the V-1002A/B feed dryers and coalesced in the V-1003. There is a small amount of BB in the water going to the flare knockout drum.

— 125–03: Wet BB—this circuit goes from the V1003 to storage; it is the wet BB removed from the dryers during regeneration.

— 125–04: Regenerating BBs—this circuit begins at the junction at the outlet of preheat exchanger E-1005 and ends at the inlet to the V-1003 coalescer. The circuit contains BB feed that is used to regenerate the feed dryers.

Process Content and Conditions:

— Butane and Butylene

— Water containing a small amount of butane and butylene

— Wet BBs leaving the V-1003 to storage

Corrosion Precursors:

— Water

Reason for Materials of Construction:

— Carbon Steel (CS) is adequate for the pressure and temperature condition.

— The E-1006 tubes are admiralty for cooling water corrosion resistance but the CS is now sufficient due to improved cooling water treatment. The tube sheet is naval-rolled brass-clad, which is from the design of the unit; CS is adequate alone.

Process Operation Problem History:

— The desired temperature for regeneration of the dryers is 400 °F, but the E-1005 is limiting the process to 350 °F.

— Regeneration cycles are once every three to six days and last only a few hours.

For this example, Tables E.1 through E.9 list the equipment and materials, injection mix points, inspection history, active and potential damage mechanisms, equipment operating envelope/limits, special inspection considerations for equipment and piping, critical bundles, and critical thermowells.

Table E.1—Corrosion System #125 Example Equipment and Materials

Item	Description	T (°F)	P (psig)	Material	Insulation?
Circuit 125–01					
125–01	Piping from the battery limit to the dryers to the mix point with isobutene recycle	85		CS + 1/10"	Yes
P-1002	BB charge pump	85		Case: CS Imp: CS	No
V-1002A/B	Feed dryers	85		Shell and heads: CS + 1/8"	Yes
Circuit 125–02					
V-1003	Regeneration coalescer			CS	No
125–02	Piping from the V-1003 to the V-1005	300		CS	No
Circuit 125–03					
125–03	Piping from the V-1003 to storage	300		CS	No
Circuit 125–04					
E-1005 (shell side)	Regeneration heater			Shell: CS + 1/8"	Yes
E-1005 (tube side)	Regeneration heater-steam		415	Tubes: CS	
125–04	Piping from outlet E-1005 to V-1003	350		CS	Yes
E-1006 (shell side)	BB regeneration cooler	300		Shell: CS + 1/8"	Yes
E-1006 (tube side)	BB regeneration cooler-cooling water	70 to 100		Tubes: ADM Tubesheet: CS + 1/8" NRB CLAD Channel: CS + 1/8"	No

Table E.2—Corrosion System #125 Example Injection and Mix Points

ID	Description	Configuration	Category
None	—	—	—

Table E.3—Corrosion System #125 Example Inspection History

Item	Major Findings	Corrosion Rate (ipy)		
		Short	Long	Suggested
Circuit 125-01				
125–01				<0.005
E-1005 (shell side)			0.005	0.003
V-1002A/B	Localized pitting observed; a catalyst can cause erosion.		0.004	0.004
Circuit 125-02				
125–02				0.005 to 0.01
V-1003	Vessel is too small to enter, requires external in lieu of internal.		0.005	0.003
Circuit 125-03				
125-03				<0.005
Circuit 125–04				
125-04				<0.005

Table E.4—Corrosion System #125 Example Active/Potential Damage Mechanisms

Damage Mechanism	Areas Affected	Likelihood or Established Rates	Notes
Aqueous Corrosion			
General	Piping from the water boot of V-1003 drains.	M	Water can be slightly acidic.
Caustic Corrosion	At deadlegs, downward facing deadlegs specifically.	Very low	Caustic corrosion can be an issue in deadlegs if there is an upset upstream at the Merox treater.
Other			
CUI	Insulated CS lines operating at <300 °F, V-1002A/B, E-1005. Piping in intermittent service and vessels that cycle from 85 °F to 350 °F.	M/H	Consider eliminating insulation where not needed.

Online Corrosion Monitoring:

— Laboratory samples are taken of the feed contaminants daily.

— An analyzer is in place on the outlet of the dryers to measure feed water content.

Table E.5—Corrosion System #125 Example Operating Envelope Limits

Parameter	L3	L2	L1	Reasons/Causes/Actions
Total contaminant loading		85 %, max.	100 %, max.	Increases HF acid corrosion in the reaction section of the unit. Investigate the BB, PP, and IC4 feed composition for direct source of high contaminants.
BB feed sulfur	10 ppm, max.		20 ppm, max.	Increases the contaminant loading, and thus corrosion.
BB feed butadienes	0.3 %—max.			Increases the contaminant loading, and thus corrosion.
BB feed oxygenates	200 ppmv, max.			Increases the contaminant loading, and thus corrosion.
BB feed chlorides	5 ppm, max.		10 ppm, max.	Increases the contaminant loading, and thus corrosion.
Water in the feed	20 ppm		50 ppm	When limit reaches the L1 limit, it is time to regenerate the dryers.

Table E.6—Corrosion System #125 Example Special Inspection Considerations—Equipment and Piping (in addition to API 570)

Item	Location	Comments
All insulated and sweating service		Inspect for CUI, especially in any areas where the insulation weather jacketing shows damage. Inspect bolting on flanges for thinning due to atmospheric condensation.
All piping	deadlegs	Deadleg corrosion can be an issue if there is caustic carryover.

Startup and Shutdown Considerations:

— None

Table E.7—Corrosion System #125 Example Critical Bundles

Item	Risk Ranking and Consequence of Failure
E-1005	Medium. This bundle will leak hydrocarbons into the steam system; however, it can be isolated for repair.

Table E.8—Corrosion System #125 Example Critical Thermowells

Item	Location	Consequence of Failure
None	—	—

Findings and Recommended Actions:

— Recommend a process for communicating any caustic carryover events to inspection so additional monitoring can be completed.

— Recommend dryers are regenerated at 20 ppm instead of 50 ppm. There is a preparation time for the dryers before they are regenerated, so there can be times where the water content in the feed is higher than desired.

E.2 Example of a Simplified Corrosion Control Document

E.2.1 System 3—Vacuum Tower Bottoms (VTB)

This system contains the equipment and piping for the bottom portion of the PPPE1 Vacuum Tower and the vacuum tower bottoms (VTB) circuit. VTBs are pumped from the bottom of the Vacuum Tower and provide heat to the unit feed in PPPC200A-D Vacuum Bottoms/Reduced Crude Exchanger. Downstream of PPPC200A-D, a stream is circulated back to the bottom of the tower for quench, and the remainder of the VTB is product. The product VTB can either be sent to the Coker Unit hot or cooled in PPPC80 Resid Cooling Box and sent to storage.

E.2.1.1 Process Summary

— PPPC200A-D Vacuum Bottoms/Reduced Crude Exchangers

— Exchanger pairs are A/B and C/D—hot VTB flows through PPPC200/B and PPPC200/D First

— Few VTB samples have been taken, but TAN numbers average ~2 and S is >3 weight percentage. A phosphate-based nap acid corrosion inhibitor is added to the bottoms stream with a quill in the outlet piping when running YYY high TAN crude, which has low S. This inhibitor is there to protect the CS portion of piping.

E.2.1.2 Reason for Materials of Construction

This system contains many different types of materials. 410 SS, 316 and 317L SS, Alloy 625 weld overlay 9 % Cr and CS. Each of these alloys have specific resistance to sulfidation as well as NAC with varying degrees of protection. The higher the alloy content—the more resistance the material will be to corrosion. Carbon steel is also included within this system and there is a vulnerability in one pipe section that operates at 560 °F. The ability of CS to resist corrosion from sulfidation (≥500 °F) and NAC (≥450 °F) will decrease as temperature rises.

E.2.1.3 Injection Points (IJ), Mix Points (MP) and Deadlegs (DL)

Table E.10 lists the injection points, mix points, and deadlegs for Example System 3.

E.2.1.4 Inspection History Highlights

— The bottom of the tower has needed numerous repairs over the years, with the 410 strip lining cracking. This has led to product being trapped behind the strip lining and causing extensive delays in gas freeing the tower during shutdowns. Sections have corroded, and in one case had a through-wall hole in the tower, causing shutdown.

— The carbon steel spool in the piping after the exchanger has been replaced twice.

— The vacuum bottoms pump had a seal leak and caused a fire in 2004. Extensive fire damage assessment was conducted and only small sections of piping were replaced.

— The 300-series stainless steel vacuum bottoms piping failed in 2005 due to PTA SCC. Only a small pup was replaced.

Table E.9—System 3 Example Injection and Mix Points and Deadlegs

ID	Description/Purpose	Configuration
IP-1	$^3/_4$-in. inline 317L SS quill to inject corrosion inhibitor.	PID-65432
IP-12	H_2S Scavenger to O-1724-8"-3P1A7—As needed when going to storage.	P&ID 60491 SK 3-PPP-093/158
DL 1	PPPC80 "A" Coil Bypass.	P&ID 60486 SK 3-PPP-093/158
MP 101A	FCCU Fractionator Sully Oil Bottoms (From O-1005-4"-3PG1LC to O-1009-4"-3PG1LC to O-0084-4"-1P1A to O-1724-8"-3P1A7).	P&ID 60491 SK 3-PPP-093/158
MO 101B	Viscbreaker feed—Intermittent service when Viscbreaker is out of service. (From O-1005-4"-3PG1LC to O-1009-4"-3PG1LC to O-0084-4"-1P1A to O-1724-8"-3P1A7).	P&ID 60491 SK 3-PPP-093/158

E.2.1.5 Integrity Operating Windows (IOWs)

See Table E.11 for Example System 3 IOWs.

Table E.10—Example 3 System Integrity Operating Windows

IOW Number	Description	Parameter
4	PPP E1 Flash Zone Temperature	°F
5	PPP E1 VTB Sulfur	Wt %
6	PPP E1 VTB TAN	#
	PPP E1 VTB S/TAN ratio	#
7	Piping from PPPC200A&C to Coker 1 Temperature	F

E.2.1.6 Equipment and Materials

See Table E.12 for Example System 3 equipment and materials parameters.

Table E.11—Example System 3 Equipment and Material Parameters

Type of Equipment/Piping	Fluid	Temp. °F	Material/ PWHT Status (Y/N)	Insulation
PPPE1—Vacuum Tower—Bottom Section	VTB	680	Tarpot: 410 SS plug welded liner with repaired areas of Alloy 625 weld overlay; Bottom Head: 410 clad with repairs with 316L SS. Resid/Vapor Horn: 410 SS plug welded liner/Alloy 625 overlay/ random repaired areas of 316 SS overlay. Wash Section: Alloy 625 overlay/N.	Yes
Piping from PPPE1 to PPPC200B&D tube side	VTB	680	317L SS Clad/N	Yes
PPPC200A-D—Vacuum Bottoms/ Reduced Crude Exchanger—Tube Side Process	VTB	Inlet 680 Outlet 560	Channel: 316 clad Tube: (A/B) 316 SS and (C/D) CS/N	Yes
Piping from PPPC200A&C to Coker 1	VTB	560	CS/N	Yes
Piping from PPPC200A&C to PPPE1	VTB Quench	560	9Cr/Y	Yes
Piping from PPPC200A&C to PPPC80 "A" Coil	VTB	560	9Cr/Y	Yes
PPPC80 "A" Coil—Resid Cooling Box	VTB	Inlet 560 Outlet 475	CS/N	No
Piping from PPPC80 "A" Coil to Coker 1	VTB	475	CS/N	Yes

E.2.1.7 Damage Mechanism Review

— DM 01—Sulfidation

Sulfidation attacks CS and Cr-Mo steels at temperatures ≥500 °F in crude oil with organic sulfur compounds. The corrosion occurs in both liquid and vapor phases and is usually uniform. Corrosion rates increase with increasing temperature (up to ~800 °F) and increasing sulfur content. Carbon steel in this system operates at 475 °F to 560 °F and the 9 % Cr. operates at 560 °F. The carbon steel section at 560 °F has predicted rates of 15 mpy. A low Si inspection program per API Recommended Practice 939-C has been conducted on the CS piping in this system and no vastly differing corrosion rates were found. Retrospective alloy verification was also conducted on the 9Cr section of piping and one spool was found to be 5Cr.

— DM 06—Naphthenic Acid Corrosion (NAC)

Naphthenic acid corrodes CS, Cr-Mo steels, and stainless steels with no or low Mo contents at temperatures ≥450 °F. Corrosion is generally correlated with the Total Acid Number (TAN) although very low S contents can aid NAC because of the lack of protective sulfide scale. Typically NAC is found in high velocity or turbulent locations such as elbows, return bends, and downstream of pumps and thermowells or a combination thereof. Highest wall shear stresses are in the furnace outlets and the transfer line where liquid vaporizes and in two-phase flow regions, such as the heater and corrosion will be worse in the liquid space. To date, there has not been a lot of NAC in these areas. Experience with 410 SS cladding has been mixed. Typically 410 SS does not work well with high TAN crudes, but the S/TAN ratio is sufficiently high to minimize corrosion for most crudes processed.

— DM 5—Polythionic Acid SCC

The 317L SS line to the bottoms exchangers has failed once before due to PTASCC, which was discovered on start-up in 2005. The operating temperature is below the typical temperature at which one would expect sensitization to occur and have this mechanism operative. It appears that a previous operating mode when producing asphalt, allowed this line to operate at 750 °F for some time. The weld overlay in the tower is considered immune.

— DM 23—Chloride Stress Corrosion Cracking (Cl SCC)

The bundles of PPPC200A/B are 316 SS and the PPPC200AD shells are 316 SS clad. During shutdown and start-up of the unit, care needs to be taken to ensure all free water is removed. If free water is present during start-up, as temperatures increase, the chlorides in the water can concentrate and cause Cl SCC. 316 SS and 317 are susceptible to Cl SCC.

— DM 12—Thermal Fatigue and DM 33 885 F Embrittlement

The 410 cladding has cracked repeatedly due to start-up/shutdown cycles and operating at temperatures where the 410 can embrittle due to 885 °F embrittlement, which is an aging mechanism where submicroscopic phases form which lowers ductility and toughness.

— General Corrosion

Typically occurs on carbon steel materials. At temperatures ≤500 °F, corrosion rates will be ≤2 mpy as sulfur content has very little effect on corrosion rates at lower temperatures.

E.2.1.8 Active/Potential Degradation Mechanisms

See Table E.13 for active or potential degradation mechanisms.

E.2.1.9 Special Downtime Protection/Start-up Considerations

— The 316L outlet line has cracked due to PTASCC. It was sensitized during previous higher temperature operations. This line should be kept air free and dry by either keeping under a nitrogen purge or soda ash washing per plant procedure YYY-ZZZ.

E.2.1.10 Recommendations

— Consider alloying up the CS piping to Coker 1 with 9Cr or 316L SS. This line operates at 560 °F and has needed to be replaced twice and necessitates inhibitor injection at times. It is challenging to manage sulfidation/NAC at rates of 15 mpy, because damage can be localized and being >10 in. in diameter needed to UT scan, which is difficult at these temperatures.

— Consider removing the old 12Cr cladding and overlaying the bottom of tower with 316L/317L to eliminate product getting behind cladding and causing entry delays during shutdowns and length repairs of the cladding. This also will prevent 12Cr corrosion.

— Develop an inspection strategy for PPPC80 "A" Coil Bypass. This is a 9 % Cr/CS bypass which can see temperatures of 560 °F when in service. Carbon steel at this temperature can see corrosion rates in the 15+ mpy range. Consider upgrading this bypass to 9Cr.

— If downtime protection of the 316L outlet piping is not feasible, consider replacement of the line.

— Understanding the side stream TANs (i.e. ≥450 °F) and Sulfur (i.e. ≥500 °F) is important when analyzing corrosion rates. It is recommended to establish a TAN and S measurement on a weekly frequency.

Table E.12—Active/Potential Equipment Degradation Mechanism Characteristics

Areas Affected (Material and Type of Equipment/Piping)	Corrosion Precursors	Degradation Mechanism	Likelihood	Notes
Alloy 625 overlay	Sulfur	Sulfidation	L [a]	CR = 1 mpy
	TAN	Naphthenic Acid Corrosion		
317L SS overlay	Sulfur	Sulfidation	L	CR = 1 mpy
	TAN	Naphthenic Acid Corrosion		
	Chlorides	Cl SCC	L	During normal operation, risk is extremely low to nil, During SD, risk is low
316 SS equipment	Sulfur	Sulfidation	L	CR = 2 mpy
	TAN	Naphthenic Acid Corrosion		
	Chlorides	Cl SCC	L	During normal operation, risk is extremely low to nil, During SD, risk is low
316L Outlet piping	Temp, S, O, Moisture	PTA SCC	H [c]	Has failed before
410 SS equipment	Sulfur	Sulfidation	L	Most 2 mpy, but local spots 7 mpy
	TAN	Naphthenic Acid Corrosion		
9 % Chrome piping	Sulfur	Sulfidation	L	CR = 4 mpy
	TAN	Naphthenic Acid Corrosion		
CS equipment and piping	Sulfur Temp ≥560 °F	Sulfidation	H	CR = 15 mpy
	TAN Temp ≥560 °F	Naphthenic Acid Corrosion		
CS equipment and piping	450–475 °F TAN	Naphthenic Acid Corrosion	M [b]	CR = 6 mpy
CS piping and equipment	Temp <500 °F	General Corrosion	L	CR = 2 mpy

[a] L = Low.
[b] M = Medium.
[c] H = High.

Annex F
(informative)

CCDs as Part of New Construction and Revamp Project Deliverables

F.1 Introduction

In the design phase, the planned process exists only on paper. This is the best time to address potential mechanical and physical property problems. An integrated materials selection and design review at this stage can mitigate substantial future repair/modification expenses by identifying design errors and omissions.

The materials selection and design review process begins with a review and understanding of the process and operation. The proposed design should be assessed for anticipated resistance to its operating environment, by considering all potential damage mechanisms. For existing processes, reviewing "Lessons Learned" provides "Foresight through Hindsight" by taking what has been learned through previous operating problems and failure analysis, and using it to avoid design and operating decisions that could prove costly and aggravating later.

It is common for the process design to evolve from the initial conception. Therefore, the work to create a CCD is typically begun around the 80 % process design completion point. The CCD is typically developed prior to any final design drawings are issued for procurement. This allows "finds" from the initial CCD study to be incorporated into the finished detail.

Project Management should document how the CCD will be included in the project development process. Common steps include the following:

1) Define the CCDs project scope. Provide a brief description of the project and its goals, including a brief statement about time and cost.

    a) Is this CCD project going to cover just one unit or a complete facility?

    b) Will there be a CCD for each process unit or will there be one overall document for the entire facility?

    c) Will materials be selected first and then a CCD written to confirm the material selections or will the CCD be used as the material selection document?

    d) Will RBI be part of the design process? If so, make sure the CCD work is coordinated with the RBI work and deliverables.

    e) Will identifying and determining how to measure IOWs be part of the design process? If so, coordinate the CCD work with the IOW work and deliverables.

    f) Will Utilities be covered?

    g) Will the bundles of shell and tube heat exchangers be included in both the shell side and tube side corrosion circuits?

    h) Will Outside Battery Limits (OSBL) piping or equipment, or both, be included?

2) Develop a project schedule and budget.

    a) Identify key milestones and details for completion.

    b) Include timing for when each CCD should be finished—as it relates to preliminary design and detailed design.

c) Create a budget to estimate the cost over the course of the CCD project as well as the cost for each phase of the project.

3) Identify plans for outsourcing the CCD work. If outsourcing is planned for any portions of the project, it is helpful to develop an interface plan, a work authorization plan, and a procurement plan.

4) Write a stakeholder management plan to describe what each group or member of the team will be responsible for, including communication and proactive planning schemes.

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