

Risk-Based Inspection Methodology

API RECOMMENDED PRACTICE 581
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Risk-based Inspection Methodology

Part 1—Introduction to Risk-based Inspection Methodology

1 Scope

1.1 Purpose

This recommended practice, API 581, provides semiquantitative analysis procedures to establish an inspection program using risk-based methods for pressurized fixed equipment including pressure vessel, piping, tankage, pressure-relief devices (PRDs), and heat exchanger tube bundles. API 580 provides guidance for developing Risk-Based Inspection (RBI) programs on fixed equipment in refining, petrochemical, chemical process plants, and oil and gas production facilities. The intent is for API 580 to introduce the principles and present minimum general guidelines for RBI, while this recommended practice provides examples of semiquantitative calculation methods to determine risk and associated inspection plan.

1.2 General

The calculation of risk outlined in API 581 involves the determination of a probability of failure (POF) combined with the consequence of failure (COF). Failure is defined as a loss of containment from the pressure boundary resulting in leakage to the atmosphere or rupture of a pressurized component. Risk increases as damage accumulates during in-service operation as the risk tolerance or risk target is approached and an inspection is recommended of sufficient effectiveness to better quantify the damage state of the component. The inspection action itself does not reduce the risk; however, it does reduce uncertainty and therefore allows more accurate quantification of the damage present in the component.

1.3 Risk Management

In most situations, once risks have been identified, alternate opportunities are available to reduce them. However, nearly all major commercial losses are the result of a failure to understand or manage risk. In the past, the focus of a risk assessment has been on-site safety-related issues. Presently, there is an increased awareness of the need to assess risk resulting from:

- a) on-site risk to employees,
- b) off-site risk to the community,
- c) business interruption risks, and
- d) risk of damage to the environment.

Any combination of these types of risks may be factored into decisions concerning when, where, and how to inspect equipment.

The overall risk of a plant may be managed by focusing inspection efforts on the process equipment with higher risk. API 581 provides a basis for managing risk by making an informed decision on inspection frequency, level of detail, and types of nondestructive examination (NDE). It is a consensus document containing methodology that owner–operators may apply to their RBI programs. In most plants, a large percent of the total unit risk will be concentrated in a relatively small percent of the equipment items. These potential higher risk components may require greater attention, perhaps through a revised inspection plan. The cost of the increased inspection effort can sometimes be offset by reducing excessive inspection efforts in the areas identified as having lower risk. Inspection will continue to be conducted as defined in existing working documents, but priorities, scope, and frequencies can be guided by the methodology contained in API 581.

This approach can be made cost-effective by integration with industry initiatives and government regulations, such as *Process Safety Management of Highly Hazardous Chemicals* (OSHA 29 CFR 1910.119), or the EPA risk management programs for chemical accident release prevention [Section 112(r) of the Clean Air Act amendments], or *Oil and Gas and Sulphur Operations in the Outer Continental Shelf* (30 CFR Part 250).

1.4 Organization and Use

The API 581 methodology is presented in a five-part volume:

- 1) [Part 1](#)—*Introduction to Risk-Based Inspection Methodology*,
- 2) [Part 2](#)—*Probability of Failure Methodology*,
- 3) [Part 3](#)—*Consequence of Failure Methodology*,
- 4) [Part 4](#)—*Inspection Planning Methodology*, and
- 5) [Part 5](#)—*Special Equipment*.

[Part 1](#) introduces the user to RBI methodology. This document provides the methodology to develop inspection plans for fixed equipment including pressure vessels, piping, atmospheric storage tanks (ASTs), PRDs, heat exchanger tube bundles, and steam systems.

[Part 2](#) provides methods for calculating the POF for fixed equipment. The POF is based on the component type and damage mechanisms present based on the process fluid characteristics, design conditions, materials of construction, and the original construction code. The pressure boundaries of rotating equipment may also be evaluated using the methods in [Part 2](#).

[Part 3](#) provides methods for computing the COF. Two methods are provided: Level 1 is based on equations with a finite set of well-known variables generated for common fluids or fluid groups found in refinery and petrochemical processing units, while Level 2 is a more rigorous method that can be used for any fluid stream composition.

[Part 4](#) provides methods used to develop an inspection plan for fixed equipment, including pressure vessels and piping.

[Part 5](#) provides RBI methods for equipment that are not represented well using the [Part 2](#) methodology directly. This includes storage tanks, PRDs, heat exchanger tube bundles, and steam systems.

An overview of the POF and COF methodology calculations, with reference to the associated sections within this document, is provided in [Table 1.1](#).

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 580, *Elements of a Risk-Based Inspection*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 2—Probability of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 3—Consequence of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 4—Inspection Planning Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 5—Special Equipment*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

aerosol

Liquid droplets small enough to be entrained in a vapor stream.

3.1.2

atmospheric dispersion

The low momentum mixing of a gas or vapor with air. The mixing is the result of turbulent energy exchange, which is a function of wind (mechanical eddy formation) and atmospheric temperature profile (thermal eddy formation).

3.1.3

autoignition temperature

AIT

The lowest temperature at which a fluid mixture can ignite without a source of ignition.

3.1.4

boiling liquid expanding vapor explosion

BLEVE

An event that occurs from the sudden release of a large mass of pressurized liquid (above the boiling point) to the atmosphere. A primary cause is an external flame impinging on the shell of a vessel above the liquid level, weakening the shell and resulting in sudden rupture.

3.1.5

business interruption costs

financial consequence

Includes the costs that are associated with any failure of equipment in a process plant. These include, but are not limited to, the cost of equipment repair and replacement, downtime associated with equipment repair and replacement, costs due to potential injuries associated with a failure, and environmental cleanup costs.

3.1.6

component

Any part that is designed and fabricated to a recognized code or standard. For example, a pressure boundary may consist of components (cylindrical shell sections, formed heads, nozzles, AST shell courses, AST bottom plate, etc.).

3.1.7

component type

Category of any part of a covered equipment (see component) and is used to assign gff , calculate t_{min} , and develop inspection plans.

3.1.8

consequence

The outcome of an event or situation expressed qualitatively or quantitatively, being a loss, injury, disadvantage, or gain.

3.1.9

consequence analysis

The analysis of the expected effects of incident outcome cases independent of frequency or probability.

3.1.10**consequence area**

The area impacted as a result of an equipment failure using calculations defined in API 581.

3.1.11**consequence of failure****COF**

The outcome of a failure event used in relative ranking of equipment. COF can be determined for safety, environmental, or financial events.

3.1.12**consequence methodology**

The consequence modeling approach that is defined in API 581.

3.1.13**consequence modeling**

Prediction of failure consequences based on a set of empirical equations, using release rate (for continuous releases) or mass (for instantaneous releases).

3.1.14**continuous release**

A release that occurs over a longer period of time. In consequence modeling, a continuous release is modeled as steady-state plume.

3.1.15**corrosion allowance**

The excess thickness available above the minimum required thickness (e.g. based initially on furnished thickness or measured thickness and is not necessarily the initial or nameplate corrosion allowance).

3.1.16**critical point**

The thermodynamic state in which liquid and gas phases of a substance coexist in equilibrium at the highest possible temperature. At higher temperatures than the critical, no liquid phase can exist.

3.1.17**damage factor****DF**

An adjustment factor applied to the generic failure frequency (GFF) of a component to account for damage mechanisms that are active in a component.

3.1.18**damage mechanism**

A process that induces deleterious micro and/or macro material changes over time that is harmful to the material condition or mechanical properties. Damage mechanisms are usually incremental, cumulative, and in some instances unrecoverable. Common damage mechanisms include corrosion, chemical attack, creep, erosion, fatigue, fracture, and thermal aging.

3.1.19**deflagration**

A release of energy caused by the propagation of a chemical reaction in which the reaction front advances into the unreacted substance at less than sonic velocity in the unreacted material. Where a blast wave is produced with the potential to cause damage, the term **explosive deflagration** may be used.

3.1.20**dense gas**

A gas with density exceeding that of air at ambient temperature.

3.1.21**detonation**

A release of energy caused by the extremely rapid chemical reaction of a substance in which the reaction front advances into the unreacted substance at greater than sonic velocity.

3.1.22**dispersion**

When a vapor or volatile liquid is released to the environment, a vapor cloud is formed. The vapor cloud can be dispersed or scattered through the mixing of air, thermal action, gravity spreading, or other mixing methods until the concentration reaches a safe level or is ignited.

3.1.23**entrainment**

The suspension of liquid as an aerosol in the atmospheric dispersion of a two-phase release or the aspiration of air into a jet discharge.

3.1.24**equipment**

An individual item that is part of a system; equipment is comprised of an assemblage of components. Examples include pressure vessels, PRDs, piping, boilers, and heaters.

3.1.25**event**

An incident or situation that occurs in a particular place during a particular interval of time.

3.1.26**event tree**

Model used to show how various individual event probabilities should be combined to calculate the probability for the chain of events that may lead to undesirable outcomes.

3.1.27**failure**

The loss of function of a system, structure, asset, or component to perform its required or intended function(s). The main function of the systems, assets, and components included in the scope of this document is considered to be containment of fluid. Therefore, for pressure boundary components, failure is associated with a loss of containment due to operating conditions, discontinuities, damage, loss of material properties, or a combination of these parameters.

3.1.28**fireball**

The atmospheric burning of a fuel–air cloud in which the energy is mostly emitted in the form of radiant heat. The inner core of the fuel release consists of almost pure fuel, whereas the outer layer in which ignition first occurs is a flammable fuel–air mixture. As buoyancy forces of the hot gases begin to dominate, the burning cloud rises and becomes more spherical in shape.

3.1.29**Fitness-For-Service****FFS**

A methodology whereby damage or flaws/imperfections contained within a component or equipment item are assessed in order to determine acceptability for continued service.

3.1.30**flammability range**

Difference between upper and lower flammability limits.

3.1.31**flammable consequence**

Result of the release of a flammable fluid in the environment.

3.1.32**flash fire**

The combustion of a flammable vapor and air mixture in which flame passes through that mixture at less the sonic velocity, such that negligible damaging overpressure is generated.

3.1.33**flashpoint temperature**

Temperature above which a material can vaporize to form a flammable mixture.

3.1.34**generic failure frequency****GFF**

A POF developed for specific component types based on a large population of component data that does not include the effects of specific damage mechanisms. The population of component data may include data from all plants within a company or from various plants within an industry, from literature sources, past reports, and commercial databases.

3.1.35**hazard and operability study**

A structured brainstorming exercise that utilizes a list of guidewords to stimulate team discussions. The guidewords focus on process parameters such as flow, level, temperature, and pressure and then branch out to include other concerns, such as human factors and operating outside normal parameters.

3.1.36**hydraulic conductivity**

Also referred to as the coefficient of permeability. This value is based on soil properties and indicates the ease with which water can move through the material. It has the same units as velocity.

3.1.37**inspection**

A series of activities performed to evaluate the condition of the equipment or component.

3.1.38**inspection effectiveness**

The ability of the inspection activity to reduce the uncertainty in the damage state of the equipment or component. Inspection effectiveness categories are used to reduce uncertainty in the models for calculating the POF (see [Part 2, Annex 2.C](#)).

3.1.39**inspection plan**

A documented set of actions detailing the scope, extent, methods, and timing of the inspection activities for equipment to determine the current condition.

3.1.40**inspection program**

A program that develops, maintains, monitors, and manages a set of inspection, testing, and preventative maintenance activities to maintain the mechanical integrity of equipment.

3.1.41**instantaneous release**

A release that occurs so rapidly that the fluid disperses as a single large cloud or pool.

3.1.42**intrusive**

Requires entry into the equipment.

3.1.43**inventory group**

Inventory of attached equipment that can realistically contribute fluid mass to a leaking equipment item.

3.1.44**iso-risk**

A line of constant risk and method of graphically showing POF and COF values in a log-log, two-dimensional plot where risk increases toward the upper right-hand corner. Components near an iso-risk line (or iso-line for risk) represent an equivalent level of risk, while the contribution of POF and COF may vary significantly.

3.1.45**jet fire**

Results when a high-momentum gas, liquid, or two-phase release is ignited.

3.1.46**loss of containment**

Occurs when the pressure boundary is breached.

3.1.47**management systems factor**

An adjustment factor that accounts for the portions of the facility's management system that most directly impact the POF of a component. Adjusts the GFFs for differences in process safety management (PSM) systems. The factor is derived from the results of an evaluation of a facility or operating unit's management systems that affect plant risk.

3.1.48**minimum required thickness**

$t_{\min}$

The minimum thickness without corrosion allowance for an element or component of a pressure vessel or piping system based on the appropriate design code calculations and code allowable stress that considers pressure, mechanical, and structural loadings. Alternatively, minimum required thickness can be reassessed using a Fitness-For-Service (FFS) analysis in accordance with API 579-1/ASME FFS-1.

3.1.49**mitigation systems**

System designed to detect, isolate, and reduce the effects of a release of hazardous materials.

3.1.50**neutrally buoyant gas**

A gas with density approximately equal to that of air at ambient temperature.

3.1.51**nonintrusive**

Can be performed externally.

3.1.52**owner-operator**

The party who owns the facility where the asset is operated. The owner is typically also the operator.

3.1.53**physical explosion**

The catastrophic rupture of a pressurized gas-filled vessel.

3.1.54**plan date**

Date set by the owner–operator that defines the end of plan period.

3.1.55**plan period**

Time period set by the owner–operator that the equipment or component risk is calculated, criteria evaluated, and the recommended inspection plan is valid.

3.1.56**pool fire**

Caused when liquid pools of flammable materials ignite.

3.1.57**probability**

Extent to which an event is likely to occur within the time frame under consideration. The mathematical definition of probability is a real number in the scale 0 to 1 attached to a random event. Probability can be related to a long-run relative frequency of occurrence or to a degree of belief that an event will occur. For a high degree of belief, the probability is near 1. Frequency rather than probability may be used in describing risk. Degrees of belief about probability can be chosen as classes or ranks, such as

- rare, unlikely, moderate, likely, almost certain, or
- incredible, improbable, remote, occasional, probable, frequent.

3.1.58**probability of failure****POF**

Likelihood of an equipment or component failure due to a single damage mechanism or multiple damage mechanisms occurring under specific operating conditions.

3.1.59**probit**

The random variable with a mean of 5 and a variance of 1, which is used in various effect models.

3.1.60**process safety management****PSM**

A management system that is focused on prevention of, preparedness for, mitigation of, response to, and restoration from catastrophic releases of chemicals or energy from a process associated with a facility.

3.1.61**process unit**

A group of systems arranged in a specific fashion to produce a product or service. Examples of processes include power generation, acid production, fuel oil production, and ethylene production.

3.1.62**RBI date**

Date set by the owner–operator that defines the start of a plan period.

3.1.63**risk**

The combination of the probability of an event and its consequence. In some situations, risk is a deviation from the expected. Risk is defined as the product of probability and consequence when probability and consequence are expressed numerically.

3.1.64**risk analysis**

Systematic use of information to identify sources and to estimate the risk. Risk analysis provides a basis for risk evaluation, risk mitigation, and risk acceptance. Information can include historical data, theoretical analysis, informed opinions, and concerns of stakeholders.

3.1.65**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 damage mechanisms. These risks are managed primarily through equipment inspection.

3.1.66**risk driver**

An item affecting either the probability, consequence, or both such that it constitutes a significant portion of the risk.

3.1.67**risk management**

Coordinated activities to direct and control an organization with regard to risk. Risk management typically includes risk assessment, risk mitigation, risk acceptance, and risk communication.

3.1.68**risk mitigation**

Process of selection and implementation of measures to modify risk. The term risk mitigation is sometimes used for measures themselves.

3.1.69**risk target**

A level of acceptable risk that triggers the inspection planning process. The risk target may be expressed in safety (ft²/yr), financial (\$/yr), or injury (serious injuries/yr) terms, based on the owner–operator preference.

3.1.70**safe dispersion**

Occurs when a nontoxic, flammable fluid is released and then disperses without ignition.

3.1.71**side-on pressure**

The pressure that would be recorded on the side of a structure parallel to the blast.

3.1.72**SLAB**

A model for denser-than-air gaseous plume releases that utilizes the one-dimensional equations of momentum, conservation of mass and energy, and the equation of state. SLAB handles point source ground-level releases, elevated jet releases, releases from volume sources, and releases from the evaporation of volatile liquid spill pools.

3.1.73**soil porosity**

The percentage of an entire volume of soil that is either vapor or liquid phase (i.e. air, water, etc.). Clays typically have higher values due to their ability to hold water and air in its structure.

3.1.74**source model or term**

A model used to determine the rate of discharge, the total quantity released (or total time) of a discharge of material from a process, and the physical state of the discharged material.

3.1.75**system**

A collection of equipment assembled for a specific function within a process unit. Examples of systems include service water system, distillation systems, and separation systems.

3.1.76**target date**

Date where the risk target is expected to be reached and is the date at or before the recommended inspection should be performed.

3.1.77**TNO multi-energy model**

A blast model based on the theory that the energy of explosion is highly dependent on the level of congestion and less dependent on the fuel in the cloud.

3.1.78**TNT equivalency model**

An explosion model based on the explosion of a thermodynamically equivalent mass of trinitrotoluene (TNT).

3.1.79**transmissivity**

The fraction of radiant energy that is transmitted from the radiating object through the atmosphere to a target; the transmissivity is reduced due to the absorption and scattering of energy by the atmosphere itself.

3.1.80**toxic chemical**

Any chemical that presents a physical or health hazard or an environmental hazard according to the appropriate material safety data sheet (MSDS). These chemicals (when ingested, inhaled, or absorbed through the skin) can cause damage to living tissue, impairment of the central nervous system, severe illness, or in extreme cases, death. These chemicals may also result in adverse effects to the environment (measured as ecotoxicity and related to persistence and bioaccumulation potential).

3.1.81**vapor cloud explosion****VCE**

When a flammable vapor is released, its mixture with air will form a flammable vapor cloud. If ignited, the flame speed may accelerate to high velocities and produce significant blast overpressure.

3.2 Acronyms and Abbreviations

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

ACFM	alternating current field measurement
ACSCC	alkaline carbonate stress corrosion cracking
AE	acoustic emission
AEGL	acute exposure guideline level
AHF	anhydrous hydrofluoric acid

AIHA	American Industrial Hygiene Association
AIT	autoignition temperature
ASME	American Society of Mechanical Engineers
AST	atmospheric storage tank
ASTM	American Society for Testing and Materials
AU	additional uncertainty
AWWA	American Water Works Association
BFW	boiler feed water
BLEVE	boiling liquid expanding vapor explosion
BOD	biological oxygen demand
CCPS	Center for Chemical Process Safety
CDL	condensate discharge location
CFR	<i>Code of Federal Regulations</i>
CISCC	chloride stress corrosion cracking
CML	condition monitoring location
COD	chemical oxygen demand
COF	consequence of failure
COFOD	consequence of failure to open on demand
COL	consequence of leakage
CP	cathodic protection
CUI	corrosion under insulation
CUI CISCC	external chloride stress corrosion cracking under insulation
DCVG	direct current voltage gradient
DEA	diethanolamine
DEGADIS	dense gas dispersion
DF	damage factor
DGA	diglycolamine
DIPA	diisopropanolamine

DIPPR	Design Institute of Physical Properties
DO	dissolved oxygen
DPO	device partially open
DRRF	demand rate reduction factor
DSO	device stuck open
EPA	Environmental Protection Agency
ERPG	Emergency Response Planning Guidelines
EVA	extreme value analysis
ExtCISCC	external chloride stress corrosion cracking
FAIL	fails to open as designed
FCC	fluid catalytic cracking
FCCU	fluid catalytic cracking unit
FFS	Fitness-For-Service
FRP	fiberglass reinforced plastic
FSM	field signature method
FTO	fail to open
GFF	generic failure frequency
GOR	gas–oil ratio
HAZ	heat-affected zone
HCl	hydrochloric acid
HF	hydrofluoric acid
	hydrogen fluoride
HGO	heavy gas oil
HIC	hydrogen-induced cracking
HSAS	heat stable amine salts
HSC	hydrogen stress cracking
HTHA	high temperature hydrogen attack
ID	inside diameter

IDLH	immediately dangerous to life or health
IOW	integrity operating windows
KO	knock-out
LBC	lower bound confidence
LFL	lower flammability limit
LNG	liquefied natural gas
LoIE	level of inspection effectiveness
LOPA	layer of protection analysis
LP	low pressure
	linear polarization
LPD	leakage past device
LPG	liquefied petroleum gas
LSI	Langelier Saturation Index
LV	liquid volume
MAT	minimum allowable temperature
MAWP	maximum allowable working pressure
MDEA	methyldiethanolamine
MDMT	minimum design metal temperature
MEA	monoethanolamine
MEM	multi-energy method
MFL	magnetic flux leakage
MIC	microbiologically induced corrosion
MO	methyl orange
MOC	management of change
MSDS	material safety data sheet
MT	magnetic testing
MTR	material test report
MTTF	mean time to failure

MW	molecular weight
NACE	National Association of Corrosion Engineers
NBP	normal boiling point
NDE	nondestructive examination
NFPA	National Fire Protection Association
NIOSH	National Institute for Occupational Safety and Health
OASP	opens above set pressure
OD	outside diameter
OSHA	Occupational Safety and Health Administration
P/A	pumparound
PASCC	polythionic acid stress corrosion cracking
PE	polyethelene
PHAST	process hazard analysis software tools
P&ID	pipng and instrumentation diagram
PMA	maximum allowable pressure
POF	probability of failure
POFOD	probability of failure on demand
POL	probability of leakage
PP	polypropelene
PRD	pressure-relief device
PRV	pressure-relief valve
PSM	process safety management
PT	penetrant testing
PTA	polythionic acid
PTFE	polytetrafluoroethylene
P/V	pressure/vacuum vent
PVC	polyvinyl chloride
PWHT	postweld heat treatment
RBI	risk-based inspection

REM	rare earth mineral
RH	relative humidity
RPB	release prevention barrier
RSI	Ryznar Stability Index
RT	radiographic testing
SCC	stress corrosion cracking
SFPE	Society of Fire Protection Engineers
SOHIC	stress-oriented hydrogen-induced cracking
SPO	spurious or premature opening
SRB	sulfate-reducing bacteria
SS	stainless steel
SSC	sulfide stress cracking
TAN	total acid number
TDS	total dissolved solids
TEEL	temporary emergency exposure limit
TEMA	Tubular Exchanger Manufacturers Association
TKS	total key species
TMA	maximum allowable temperature
TMO	maximum operating temperature
TNO	The Netherlands Organization for Applied Scientific Research
TNT	trinitrotoluene
TOFD	time of flight diffraction
UFL	upper flammability limit
UNS	unified numbering system
UT	ultrasonic testing
VCE	vapor cloud explosion
VT	visual testing
WFMT	wet fluorescent magnetic (particle) testing

4 Basic Concepts

4.1 Probability of Failure (POF)

4.1.1 Overview

Two methods of calculating POF are used within the text: the GFF method and a two-parameter Weibull distribution method. The GFF method is used to predict loss of containment POF from pressure boundary equipment. The Weibull distribution method is used to predict POF for PRDs and heat exchanger bundles.

4.1.2 GFF Method

4.1.2.1 General

The POF using the GFF method is calculated from [Equation \(1.1\)](#).

$$P_f(t) = gff \cdot F_{MS} \cdot D_f(t) \quad (1.1)$$

The POF as a function of time, $P_f(t)$, is determined as the product of a generic failure frequency, gff , a damage factor, $D_f(t)$, and a management systems factor, F_{MS} .

4.1.2.2 GFF

The GFF for different component types is set at a value representative of the refining and petrochemical industry's failure data (see [Part 2, Section 3.3](#)).

4.1.2.3 Management Systems Factor

The management systems factor, F_{MS} , is an adjustment factor that accounts for the influence of the facility's management system on the mechanical integrity of the plant equipment. This factor is derived from the results of an evaluation of facility or operating unit management systems that affect plant risk. The management systems evaluation is provided in [Part 2, Annex 2.A](#) of this document. Owner–operators may elect to use a management systems factor of 1.0 and forego the evaluation if their site management systems are believed to be industry average or better.

4.1.2.4 Damage Factors (DFs)

The DF is determined based on the applicable damage mechanisms relevant to the materials of construction and the process service, the physical condition of the component, and the inspection techniques used to quantify damage. The DF modifies the industry GFF and makes it specific to the component under evaluation.

DFs do not provide a definitive FFS assessment of the component. FFS analyses for pressurized component are covered by API 579-1/ASME FFS-1 [\[1\]](#). The basic function of the DF is to statistically evaluate the amount of damage that may be present as a function of time in service and the effectiveness of the inspection activity to quantify that damage.

Methods for determining DFs are provided in [Part 2](#) for the following damage mechanisms:

- 1) thinning (both general and local);
- 2) component lining damage;
- 3) external damage (thinning and cracking);

- 4) stress corrosion cracking (SCC);
- 5) high temperature hydrogen attack (HTHA);
- 6) mechanical fatigue (piping only);
- 7) brittle fracture, including low-temperature brittle fracture, low alloy embrittlement, 885 °F embrittlement, and sigma phase embrittlement.

When more than one damage mechanism is active, the DF for each mechanism is calculated and then combined to determine a total DF for the component, as defined in [Part 2, Section 3.4.2](#).

4.1.3 Two-parameter Weibull Distribution Method

4.1.3.1 General

The POF is using the Weibull method is calculated from [Equation \(1.2\)](#):

$$P_f(t) = 1 - \exp \left[- \left(\frac{t}{\eta} \right)^\beta \right] \quad (1.2)$$

where

- β is the Weibull shape parameter (unitless);
- η is the Weibull characteristic life parameter in years;
- t is the independent variable time in years.

4.1.3.2 Weibull Shape Factor

The β parameter shows how the failure rate develops over time. Failure modes related with infant mortality, random, or wear-out have significantly different β values. The β parameter determines which member of the Weibull family of distributions is most appropriate. Different members have different shapes. The Weibull distribution fits a broad range of life data compared to other distributions.

4.1.3.3 Weibull Characteristic Life

The η parameter is defined as the time at which 63.2 % of the units have failed. For $\beta = 1$, the mean time to failure (MTTF) and η are equal. Adjustments are made to the characteristic life parameter to increase or decrease the POF as a result of environmental factors, asset types, or as a result of actual inspection data. These adjustments may be viewed as an adjustment to the MTTF.

4.2 Consequence of Failure (COF)

4.2.1 Overview

Loss of containment of hazardous fluids from pressurized processing equipment may result in damage to surrounding equipment, serious injury to personnel, production losses, and undesirable environmental impacts. The consequence of a loss of containment is determined using well-established consequence analysis techniques [\[2\]](#) [\[3\]](#) [\[4\]](#) [\[5\]](#) [\[6\]](#) and is expressed as an affected impact area or in financial terms. Impact areas from event outcomes such as pool fires, flash fires, fireballs, jet fires, and vapor cloud explosions (VCEs) are quantified based on the effects of thermal radiation and overpressure on surrounding equipment and personnel. Additionally, cloud dispersion analysis methods are used to quantify the magnitude of flammable releases and to determine the extent and duration of personnel exposure to toxic releases. Event

trees are used to assess the probability of each of the various event outcomes and to provide a mechanism for probability weighting the loss of containment consequences.

An overview of the COF methodology is provided in [Part 3, Figure 1.1](#).

Methodologies for two levels of consequence analysis are provided in [Part 3](#). A Level 1 consequence analysis provides a method to estimate the consequence area based on lookup tables for a limited number of generic or reference hazardous fluids. A Level 2 consequence analysis is more rigorous because it incorporates a detailed calculation procedure that can be applied to a wider range of hazardous fluids.

4.2.2 Level 1 COF

The Level 1 consequence analysis evaluates the consequence of hazardous releases for a limited number of reference fluids (reference fluids are shown in [Part 3, Table 4.1](#)). The reference fluid that closely matches the normal boiling point (NBP) and molecular weight (MW) of the fluid contained within the process equipment should be used. The flammable consequence area is then determined from a simple polynomial expression that is a function of the release magnitude.

For each discrete hole size, release rates are calculated based on the phase of the fluid, as described in [Part 3, Section 4.3](#). These releases are then used in closed form equations to determine the flammable consequence.

For the Level 1 analysis, a series of consequence analyses were performed to generate consequence areas as a function of the reference fluid and release magnitude. In these analyses, the major consequences were associated with pool fires for liquid releases and VCEs for vapor releases. Probabilities of ignition, probabilities of delayed ignition, and other probabilities in the Level 1 event tree were selected based on expert opinion for each of the reference fluids and release types (i.e. continuous or instantaneous). These probabilities were constant and independent of release rate or mass. The closed form flammable consequence area equation is shown in [Equation \(1.3\)](#) based on the analysis developed to calculate consequence areas.

$$CA_f = a \cdot x^b \quad (1.3)$$

Values for variables a and b in [Equation \(1.3\)](#) are provided for the reference fluids in [Part 3, Table 4.8](#) and [Table 4.9](#). If the fluid release is steady state and continuous (such as the case for small hole sizes), the release rate is used for x in [Equation \(1.3\)](#). However, if the release is considered instantaneous (e.g. as a result of a vessel or pipe rupture), the release mass is used for x in [Equation \(1.3\)](#). The transition between a continuous release and an instantaneous release is defined as a release where more than 10,000 lb (4,536 kg) of fluid mass escapes in less than 3 minutes; see [Part 3, Section 4.5](#).

The final flammable consequence areas are determined as a probability weighted average of the individual consequence areas calculated for each release hole size. Four hole sizes are used; the lowest hole size represents a small leak, and the largest hole size represents a rupture or complete release of contents. This is performed for both the equipment damage and the personnel injury consequence areas. The probability weighting uses the hole size distribution and the GFFs of the release hole sizes selected. The equation for probability weighting of the flammable consequence areas is given by [Equation \(1.4\)](#).

$$C_f^{\text{flam}} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{f,n}^{\text{flam}}}{gff_{\text{total}}} \right) \quad (1.4)$$

The total GFF, gff_{total} , in the above equation is determined using [Equation \(1.5\)](#).

$$gff_{total} = \sum_{n=1}^4 gff_n \quad (1.5)$$

The Level 1 consequence analysis is a method for approximating the consequence area of a hazardous release. The inputs required are basic fluid properties (such as MW, density, and ideal gas specific heat ratio, k) and operating conditions. A calculation of the release rate or the available mass in the inventory group (i.e. the inventory of attached equipment that contributes fluid mass to a leaking equipment item) is also required. Once these terms are known, the flammable consequence area is determined from [Equation \(1.3\)](#) and [Equation \(1.4\)](#).

A similar procedure is used for determining the consequence associated with release of toxic chemicals such as H_2S , ammonia, or chlorine. Toxic impact areas are based on probit equations and can be assessed whether the stream is pure or a percentage of a process stream.

4.2.3 Level 2 COF

A detailed procedure is provided for determining the consequence of loss of containment of hazardous fluids from pressurized equipment. The Level 2 consequence analysis was developed as a tool to use where the assumptions of Level 1 consequence analysis were not valid. Examples of where Level 2 calculations may be desired or necessary are cited below.

- 1) The specific fluid is not represented adequately within the list of reference fluids provided in [Part 3, Table 4.1](#), including cases where the fluid is a wide-range boiling mixture or where the fluid's toxic consequence is not represented adequately by any of the reference fluids.
- 2) The stored fluid is close to its critical point, in which case, the ideal gas assumptions for the vapor release equations are invalid.
- 3) The effects of two-phase releases, including liquid jet entrainment as well as rainout, need to be included in the methodology.
- 4) The effects of boiling liquid expanding vapor explosion (BLEVE) are to be included in the methodology.
- 5) The effects of pressurized nonflammable explosions, such as are possible when nonflammable pressurized gases (e.g. air or nitrogen) are released during a vessel rupture, are to be included in the methodology.
- 6) The meteorological assumptions used in the dispersion calculations that form the basis for the Level 1 COF table lookups do not represent the site data.

The Level 2 consequence procedures presented in [Part 3, Section 5](#) provide equations and background information necessary to calculate consequence areas for several flammable and toxic event outcomes. A summary of these events is provided in [Part 3, Table 3.1](#).

To perform Level 2 calculations, the actual composition of the fluid stored in the equipment is modeled. Fluid property solvers are available that allow the analyst to calculate fluid physical properties more accurately. The fluid solver also provides the ability to perform flash calculations to better determine the release phase of the fluid and to account for two-phase releases. In many of the consequence calculations, physical properties of the released fluid are required at storage conditions as well as conditions after release to the atmosphere.

A cloud dispersion analysis must also be performed as part of a Level 2 consequence analysis to assess the quantity of flammable material or toxic concentration throughout vapor clouds that are generated after a release of volatile material. Modeling a release depends on the source term conditions, the atmospheric conditions, the release surroundings, and the hazard being evaluated. Employment of many commercially available models, including SLAB or dense gas dispersion (DEGADIS) [\[7\]](#), account for these important factors and will produce the desired data for the Level 2 analysis.

The event trees used in the Level 2 consequence analysis are shown in [Part 3, Figure 5.3](#) and [Figure 5.4](#). Improvement in the calculations of the probabilities on the event trees have been made in the Level 2 procedure. Unlike the Level 1 procedure, the probabilities of ignition on the event tree are not constant with release magnitude. Consistent with the work of Cox et al. [\[8\]](#), the Level 2 event tree ignition probabilities are directly proportional to the release rate. The probabilities of ignition are also a function of the flash point temperature of the fluid. The probability that an ignition will be a delayed ignition is also a function of the release magnitude and how close the operating temperature is to the autoignition temperature (AIT) of the fluid. These improvements to the event tree will result in consequence impact areas that are more dependent on the size of release and the flammability and reactivity properties of the fluid being released.

4.3 Risk Analysis

4.3.1 Determination of Risk

In general, the calculation of risk is determined in accordance with [Equation \(1.6\)](#), as a function of time. The equation combines the POF and the COF described in [Section 4.1](#) and [Section 4.2](#), respectively.

$$R(t) = P_f(t) \cdot C_f \quad (1.6)$$

The POF, $P_f(t)$, is a function of time since the DF shown in [Equation \(1.1\)](#) increases as the damage in the component accumulates with time.

Process operational changes over time can result in changes to the POF and COF. Process operational changes, such as in temperature, pressure, or corrosive composition of the process stream, can result in an increased POF due to increased damage rates or initiation of additional damage mechanisms. These types of changes are identified by the plant management of change (MOC) procedure and/or integrity operating windows (IOW) program.

The COF is assumed to be invariant as a function of time. However, significant process changes can result in COF changes. Process change examples may include changes in the flammable, toxic, and nonflammable/nontoxic components of the process stream, changes in the process stream from the production source, variations in production over the lifetime of an asset or unit, and repurposing or revamping of an asset or unit that impacts the operation and/or service of gas/liquid processing plant equipment. In addition, modifications to detection, isolation, and mitigation systems will affect the COF. Factors that may impact the financial COF may include but are not limited to personnel population density, fluid values, and the cost of lost production. As defined in API 580, a reassessment is required when the original risk basis for the POF and/or COF changes significantly.

[Equation \(1.6\)](#) is rewritten in terms of area-, financial-, and safety-based risk, as shown in [Equation \(1.7\)](#) through [Equation \(1.9\)](#).

$$R(t) = P_f(t) \cdot C_f^{\text{area}} \quad \text{for area-based risk} \quad (1.7)$$

$$R(t) = P_f(t) \cdot C_f^{\text{fin}} \quad \text{for financial-based risk} \quad (1.8)$$

$$R(t) = P_f(t) \cdot C_f^{\text{inj}} \quad \text{for safety-based risk} \quad (1.9)$$

In these equations:

C_f^{area} is the COF impact area expressed in units of area;

C_f^{fin} is the financial COF expressed in economic terms;

C_f^{inj} is the safety COF expressed in term of injuries.

Note that risk in [Equation \(1.7\)](#), [Equation \(1.8\)](#), and [Equation \(1.9\)](#) varies as a function of time because POF varies as a function of time. [Figure 1.1](#) illustrates that the risk associated with individual damage mechanisms can be added together by superposition to provide the overall risk as a function of time.

4.3.2 Risk Plotting

4.3.2.1 General

Plotting POF and COF values on a risk matrix is an effective method of representing risk graphically. POF is plotted along one axis, increasing in magnitude from the origin, while COF is plotted along the other axis. It is the responsibility of the owner–operator to define and document the basis for POF and COF category ranges and risk targets used. This section provides risk matrix examples only.

4.3.2.2 Risk Matrix Examples

Presenting the risk results in a matrix is an effective way of showing the distribution of risks for components in a process unit without using numerical values. In the risk matrix, POF and COF categories are arranged so that the highest risk components are toward the upper right-hand corner.

Two risk matrix examples are shown in [Figure 1.1](#) and [Figure 1.2](#). In both figures, POF is expressed in terms of the number of failures over time, $P_f(t)$, or DF. COF is expressed in area, financial, or safety terms. Example numerical values associated with POF and COF (as safety, financial, or injury) categories are shown in [Table 1.1](#) and [Table 1.2](#). The matrices do not need to be square (i.e. 4×5 risk matrix, 7×5 risk matrix, etc.).

- a) Unbalanced Risk Matrix ([Figure 1.1](#))—POF and COF value ranges are assigned numerical and lettered categories, respectively, increasing in order of magnitude. Risk categories (i.e. Low, Medium, Medium High, and High) are assigned to the boxes with the risk category shading asymmetrical. For example, using [Table 1.1](#) values, a POF of 5.00E-04 is assigned as Category 3 and as COF of 800 ft² corresponds to a Category B. The 3B box is Low risk category when plotted on [Figure 1.1](#).
- b) Balanced Risk Matrix ([Figure 1.2](#))—Similar to [Figure 1.1](#), POF and COF value ranges are assigned numerical and lettered categories, respectively, increasing in order of magnitude. In this example, risk categories (i.e. Low, Medium, Medium High, and High) are assigned symmetrically to the boxes. When values from [Table 1.1](#) are used, a POF of 5.00E-04 failures/yr is assigned as Category 3 and a COF of 800 ft² corresponds to a Category B. However, the 3B box in [Figure 1.2](#) example corresponds to a Medium risk category.

Note that all ranges and risk category shading provided in [Table 1.1](#) and [Table 1.2](#) as well as [Figure 1.1](#) and [Figure 1.2](#) are examples of dividing the plot into risk categories and are not recommended risk targets and/or thresholds. It is the owner–operators' responsibility to establish the ranges and target values for their risk-based programs.

4.3.2.3 Iso-risk Plot Example

Another effective method of presenting risk results is an iso-risk plot. An iso-risk plot graphically shows POF and COF values in a log-log, two-dimensional graph where risk increases toward the upper right-hand corner. Examples of iso-risk plots for safety, financial, and injury COF are shown in [Figure 1.4](#), [Figure 1.5](#), and [Figure 1.6](#), respectively. Components near an iso-risk line represent an equivalent level of risk. Components are ranked based on risk for inspection, and inspection plans are developed for components based on the defined risk acceptance criteria that has been set.

As in a risk matrix, POF is expressed in failures over time, $P_f(t)$, or DF, while COF is expressed in area, financial, or safety terms. Risk categories (i.e. Low, Medium, Medium High, and High) are assigned to the areas between the iso-risk lines and dependent upon the level of risk assigned as a threshold between risk categories, as shown in [Figure 1.4](#). For example, a POF of 5.00E-04 and a COF of \$125,000 are assigned a Medium risk category.

4.3.3 General Comments Concerning Risk Plotting

Note the following when using the examples in [Figure 1.2](#) through [Figure 1.5](#):

- a) as the POF values increase, the risk becomes more POF driven;
- b) as the COF values increase, the risk becomes more COF driven.

In risk mitigation planning, equipment items residing toward the upper right-hand corner of the risk matrix will most likely take priority for inspection planning because these items have the highest risk. Similarly, items residing toward the lower left-hand corner of the risk matrix tend to take lower priority because these items have the lowest risk. A risk matrix is used as a screening tool during the prioritization process.

Using the examples in [Figure 1.2](#) though [Figure 1.5](#) in consideration to risk mitigation planning:

- a) if POF drives the risk (the data drift toward the POF axis), the risk mitigation strategy may be weighted more toward inspection-based methods;
- b) if COF drives the risk (the data drift toward the COF axis), the risk mitigation strategy may be weighted more toward engineering/management methods;
- c) if both POF and COF drive risk, the risk mitigation strategy may require both inspection-based methods coupled with engineering and management methods.

It is the responsibility of the owner–operator to:

- 1) determine the type of plot to be used for reporting and prioritization,
- 2) determine the risk acceptance criteria (POF and COF category ranges),
- 3) document the risk plotting process, and
- 4) provide for risk mitigation strategies based upon the plot chosen.

4.4 Inspection Planning Based on Risk Analysis

4.4.1 Overview

Inspection planning based on risk assumes that at some point in time, the risk as defined by [Equation \(1.7\)](#), [Equation \(1.8\)](#), and [Equation \(1.9\)](#) will reach or exceed a user-defined area, financial, or safety risk target. When or before the user-defined risk target is reached, an inspection of the equipment is recommended based on the component damage mechanisms with the highest DFs. The user may set additional targets to initiate an inspection, such as POF, DF, COF, or thickness. In addition, inspection may be conducted solely to gather information to reduce uncertainty in the component condition or based on an engineering evaluation of the fitness for continued service rather than the RBI results.

Although inspection of a component does not reduce the inherent risk, inspection provides improved knowledge of the current state of the component and therefore reduces uncertainty. The probability that loss of containment will occur is directly related to the known condition of the component based on information from inspection and the ability to accurately quantify damage.

Reduction in uncertainty in the damage state of a component is a function of the effectiveness of the inspection to identify the type and quantify the extent of damage. Inspection plans are designed to detect and quantify the specific types of damage expected such as local or general thinning, cracking, and other types of damage. An inspection technique that is appropriate for general thinning will not be effective in detecting and

quantifying damage due to local thinning or cracking. Therefore, the inspection effectiveness is a function of the inspection method and extent of coverage used for detecting the type of damage expected.

Risk is a function of time, as shown in Equation (1.7), Equation (1.8), and Equation (1.9), as well as a function of the knowledge of the current state of the component determined from past inspections. When inspection effectiveness is introduced into risk Equation (1.7), Equation (1.8), and Equation (1.9), the equations can be rewritten as Equation (1.10), Equation (1.11), and Equation (1.12):

$$R(t, I_E) = P_f(t, I_E) \cdot C_f^{\text{area}} \quad \text{for area-based risk} \quad (1.10)$$

$$R(t, I_E) = P_f(t, I_E) \cdot C_f^{\text{fin}} \quad \text{for financial-based risk} \quad (1.11)$$

$$R(t, I_E) = P_f(t, I_E) \cdot C_f^{\text{inj}} \quad \text{for safety-based risk} \quad (1.12)$$

4.4.2 Targets

A target is defined as the maximum value acceptable for continued operation without requiring a mitigating action. Once the target has been met or exceeded, an activity such as inspection is triggered. Several targets can be defined in an RBI program to initiate and define risk mitigation activities, as follows.

- a) Risk Target—A level of acceptable risk that triggers the inspection planning process. The risk target may be expressed in area (ft²/yr), financial (\$/yr), or safety (injuries/yr) terms, based on the owner–operator preference.
- b) POF Target—A frequency of failure or leak (#/yr) that is considered unacceptable and triggers the inspection planning process.
- c) DF Target—A damage state that reflects an unacceptable failure frequency factor greater than the generic and triggers the inspection planning process.
- d) COF Target—A level of unacceptable consequence in terms of area consequence (C_f^{area}), financial consequence (C_f^{fin}), or safety consequence (C_f^{inj}) based on owner–operator preference. Because risk driven by COF is not reduced by inspection activities, risk mitigation activities to reduce release inventory or ignition are required.
- e) Thickness Target—A specific thickness, often the minimum required thickness, $t_{\min}$, considered unacceptable, triggering the inspection planning process.
- f) Maximum Inspection Interval Target—A specific inspection frequency considered unacceptable, triggering the inspection planning process. A maximum inspection interval may be set by the owner–operator’s corporate standards or may be set based on a jurisdictional requirement.

It is important to note that defining targets is the responsibility of the owner–operator and that specific target criteria is not provided within this document. The above targets should be developed based on owner–operator internal guidelines and overall risk tolerance. Owner–operators often have corporate risk criteria defining acceptable and prudent levels of safety, environmental, and financial risks. These owner–operator criteria should be used when making RBI decisions since acceptable risk levels and risk management decision-making will vary among companies.

4.4.3 Inspection Effectiveness—The Value of Inspection

An estimate of the POF for a component depends on how well the independent variables of the limit state are known and understood. Using examples and guidance for inspection effectiveness provided in Part 2, Annex 2.C, an inspection plan is developed as risk results require. The inspection strategy is implemented to

obtain the necessary information to decrease uncertainty about the actual damage state of the equipment by confirming the presence of damage, obtaining a more accurate estimate of the damage rate, and evaluating the extent of damage.

An inspection plan is the combination of NDE methods (i.e. visual, ultrasonic, radiographic, etc.), frequency of inspection, and the location and coverage of an inspection to find a specific type of damage. Inspection plans vary in their overall effectiveness for locating and sizing specific damage and understanding the extent of the damage.

Inspection effectiveness is introduced into the POF calculation using Bayesian analysis, which updates the POF when additional data are gathered through inspection. The extent of reduction in the POF depends on the effectiveness of the inspection to detect and quantify a specific damage type of damage mechanism. Therefore, higher inspection effectiveness levels will reduce the uncertainty of the damage state of the component and reduce the POF. The POF and associated risk may be calculated at a current and/or future time period using [Equation \(1.10\)](#), [Equation \(1.11\)](#), and [Equation \(1.12\)](#).

Examples of the levels of inspection effectiveness categories for various damage mechanisms and the associated generic inspection plan (i.e. NDE techniques and coverage) for each damage mechanism are provided in [Part 2, Annex 2.C](#). These tables provide examples of the levels of generic inspection plans for a specific damage mechanism. The tables are provided as a matter of example only, and it is the responsibility of the owner–operator to create, adopt, and document their own specific levels of inspection effectiveness tables.

4.4.4 Inspection Planning

The methodology for developing inspection plans for a defined plan period is provided in [Part 4](#).

5 Nomenclature

C_f is the COF, ft² (m²), \$ or injuries

C_f^{area} is the flammable COF impact area, ft² (m²)

C_f^{fin} is the financial COF, \$

C_f^{inj} is the safety COF, injuries

$D_{f\text{-total}}$ is total DF for POF calculation

$P_f(t)$ is the POF as a function of time, failures/yr

$P_f(t, I_E)$ is the POF as a function of time and inspection effectiveness, failures/yr

$R(t)$ is the risk as a function of time, ft²/yr (m²/yr), \$/yr or injuries/yr

$R(t, I_E)$ is the risk as a function of time and inspection effectiveness, ft²/yr (m²/yr) or \$/yr

6 Tables

Table 1.1—POF, COF, Risk, and Inspection Planning Calculations ¹

Equipment Type	POF Calculation	COF Calculation		Risk Calculation	Inspection Planning
		Safety	Financial		
Pressure vessels	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Section 4.3	Part 4
Heat exchangers ²	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Section 4.3	Part 4
Air fin heat exchanger header boxes	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Section 4.3	Part 4
Pipes and tubes	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Section 4.3	Part 4
AST—shell courses	Part 2	Part 3, Section 4 or 5	Part 5, Section 4.16	Section 4.3	Part 4
AST—tank bottom	Part 5, Section 4.1	N/A	Part 5, Section 4.25	Section 4.3	Part 4
Compressors ³	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Section 4.3	Part 4
Pumps ³	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Section 4.3	Part 4
PRDs ⁴	Part 5, Sections 6.3 and 6.4	N/A	Part 5, Sections 6.5 and 6.6	Part 5, Section 6.7	Part 5, Section 6.8
Heat exchanger tube bundles	Part 5, Section 5.5	N/A	Part 5, Section 5.6	Part 5, Section 5.7	Part 5, Section 5.8
NOTE 1 All referenced sections and parts refer to API 581. NOTE 2 Shellside and tubeside pressure boundary components. NOTE 3 Pressure boundary only. NOTE 4 Including protected equipment.					

Table 1.2—Numerical Values Associated with POF and Area-based COF Categories

Category	Probability Category ^{1 2 3}		Consequence Category ⁴	
	Probability Range	DF Range	Category	Range (ft ²)
1	$P_f(t, I_E) \leq 3.06E-05$	$D_{f-total} \leq 1$	A	$C_f^{area} \leq 100$
2	$3.06E-05 < P_f(t, I_E) \leq 3.06E-04$	$1 < D_{f-total} \leq 10$	B	$100 < C_f^{area} \leq 1,000$
3	$3.06E-04 < P_f(t, I_E) \leq 3.06E-03$	$10 < D_{f-total} \leq 100$	C	$1,000 < C_f^{area} \leq 10,000$
4	$3.06E-03 < P_f(t, I_E) \leq 3.06E-02$	$100 < D_{f-total} \leq 1,000$	D	$10,000 < C_f^{area} \leq 100,000$
5	$P_f(t, I_E) > 3.06E-02$	$D_{f-total} > 1,000$	E	$C_f^{area} > 100,000$
NOTE 1 POF values are based on a <i>gff</i> of 3.06E-05 and an F_{MS} of 1.0. If the suggested <i>gff</i> values in Part 2, Table 3.1 are used, the probability range does not apply to AST shell course, AST bottoms, and centrifugal compressors.				
NOTE 2 In terms of POF, see Section 4.1 .				
NOTE 3 In terms of the total DF, see Part 2, Section 3.4.2 .				
NOTE 4 In terms of consequence area, see Part 3, Section 4.11 .				

Table 1.2M—Numerical Values Associated with POF and Area-based COF Categories

Category	Probability Category ^{1 2 3}		Consequence Category ⁴	
	Probability Range	DF Range	Category	Range (m ²)
1	$P_f(t, I_E) \leq 3.06E-05$	$D_{f-total} \leq 1$	A	$C_f^{area} \leq 9.29$
2	$3.06E-05 < P_f(t, I_E) \leq 3.06E-04$	$1 < D_{f-total} \leq 10$	B	$9.29 < C_f^{area} \leq 92.9$
3	$3.06E-04 < P_f(t, I_E) \leq 3.06E-03$	$10 < D_{f-total} \leq 100$	C	$92.9 < C_f^{area} \leq 929$
4	$3.06E-03 < P_f(t, I_E) \leq 3.06E-02$	$100 < D_{f-total} \leq 1000$	D	$929 < C_f^{area} \leq 9290$
5	$P_f(t, I_E) > 3.06E-02$	$D_{f-total} > 1000$	E	$C_f^{area} > 9290$
NOTE 1 POF values are based on a <i>gff</i> of 3.06E-05 and an F_{MS} of 1.0. If the suggested <i>gff</i> values of Part 2, Table 3.1 are used, the probability range does not apply to AST shell course, AST bottoms, and centrifugal compressors.				
NOTE 2 In terms of POF, see Section 4.1 .				
NOTE 3 In terms of the total DF, see Part 2, Section 3.4.2 .				
NOTE 4 In terms of consequence area, see Part 3, Section 4.11 .				

Table 1.3—Numerical Values Associated with POF and Financial-based COF Categories

Category	Probability Category ^{1 2 3}		Consequence Category ⁴	
	Probability Range	DF Range	Category	Range (\$)
1	$P_f(t, I_E) \leq 3.06E-05$	$D_{f-total} \leq 1$	A	$C_f^{fin} \leq 10,000$
2	$3.06E-05 < P_f(t, I_E) \leq 3.06E-04$	$1 < D_{f-total} \leq 10$	B	$10,000 < C_f^{fin} \leq 100,000$
3	$3.06E-04 < P_f(t, I_E) \leq 3.06E-03$	$10 < D_{f-total} \leq 100$	C	$100,000 < C_f^{fin} \leq 1,000,000$
4	$3.06E-03 < P_f(t, I_E) \leq 3.06E-02$	$100 < D_{f-total} \leq 1,000$	D	$1,000,000 < C_f^{fin} \leq 10,000,000$
5	$P_f(t, I_E) > 3.06E-02$	$D_{f-total} > 1,000$	E	$C_f^{fin} > 10,000,000$
NOTE 1 POF values are based on a <i>gff</i> of 3.06E-05 and an F_{MS} of 1.0. If the suggested <i>gff</i> values of Part 2, Table 3.1 are used, the probability range does not apply to AST shell course, AST bottoms, and centrifugal compressors.				
NOTE 2 In terms of POF, see Section 4.1 .				
NOTE 3 In terms of the total DF, see Part 2, Section 3.4.2 .				
NOTE 4 In terms of consequence area, see Part 3, Section 4.12 .				

Table 1.4—Numerical Values Associated with POF and Safety-based COF Categories

Category	Probability Category ^{1 2 3}		Consequence Category ⁴	
	Probability Range	DF Range	Category	Range (injuries)
1	$P_f(t, I_E) \leq 3.06E-05$	$D_{f-total} \leq 1$	A	$C_f^{inj} \leq 3.27E-04$
2	$3.06E-05 < P_f(t, I_E) \leq 3.06E-04$	$1 < D_{f-total} \leq 10$	B	$3.27E-04 < C_f^{inj} \leq 3.27E-03$
3	$3.06E-04 < P_f(t, I_E) \leq 3.06E-03$	$10 < D_{f-total} \leq 100$	C	$3.27E-03 < C_f^{inj} \leq 3.27E-02$
4	$3.06E-03 < P_f(t, I_E) \leq 3.06E-02$	$100 < D_{f-total} \leq 1000$	D	$3.27E-02 < C_f^{inj} \leq 3.27E-01$
5	$P_f(t, I_E) > 3.06E-02$	$D_{f-total} > 1000$	E	$C_f^{inj} > 3.27E-01$
NOTE 1 POF values are based on a <i>gff</i> of 3.06E-05 and an F_{MS} of 1.0. If the suggested <i>gff</i> values of Part 2, Table 3.1 are used, the probability range does not apply to AST shell course, AST bottoms, and centrifugal compressors.				
NOTE 2 In terms of POF, see Section 4.1 .				
NOTE 3 In terms of the total DF, see Part 2, Section 3.4.2 .				
NOTE 4 In terms of consequence area, see Part 3, Section 4.13 .				

7 Figures

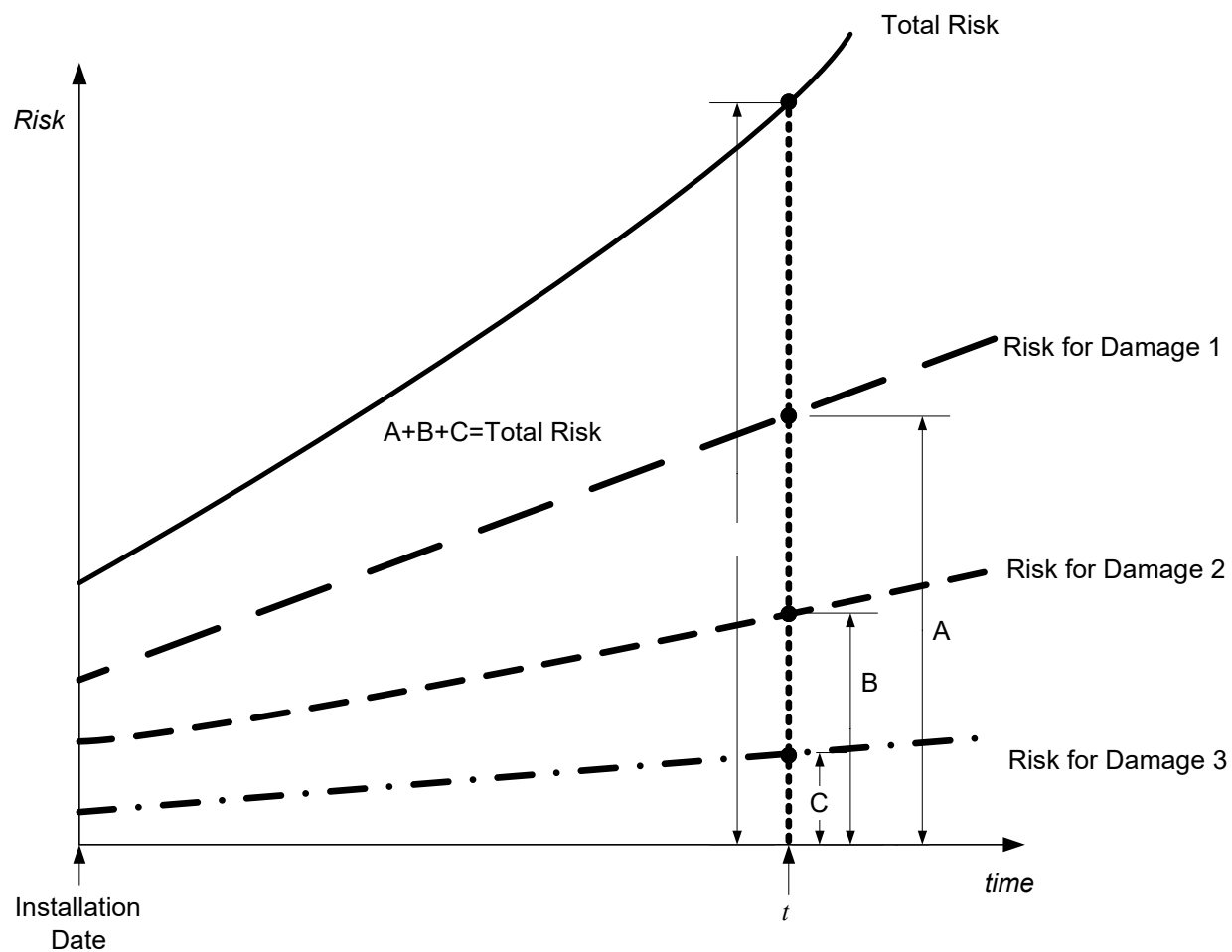
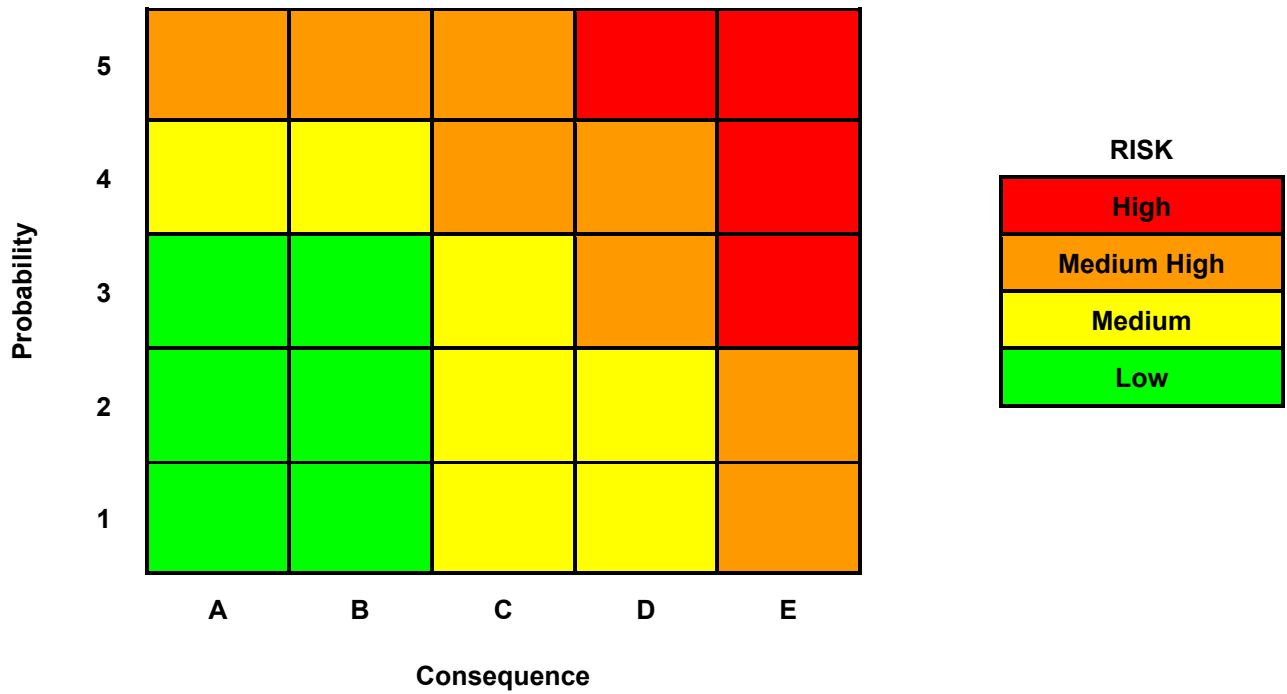
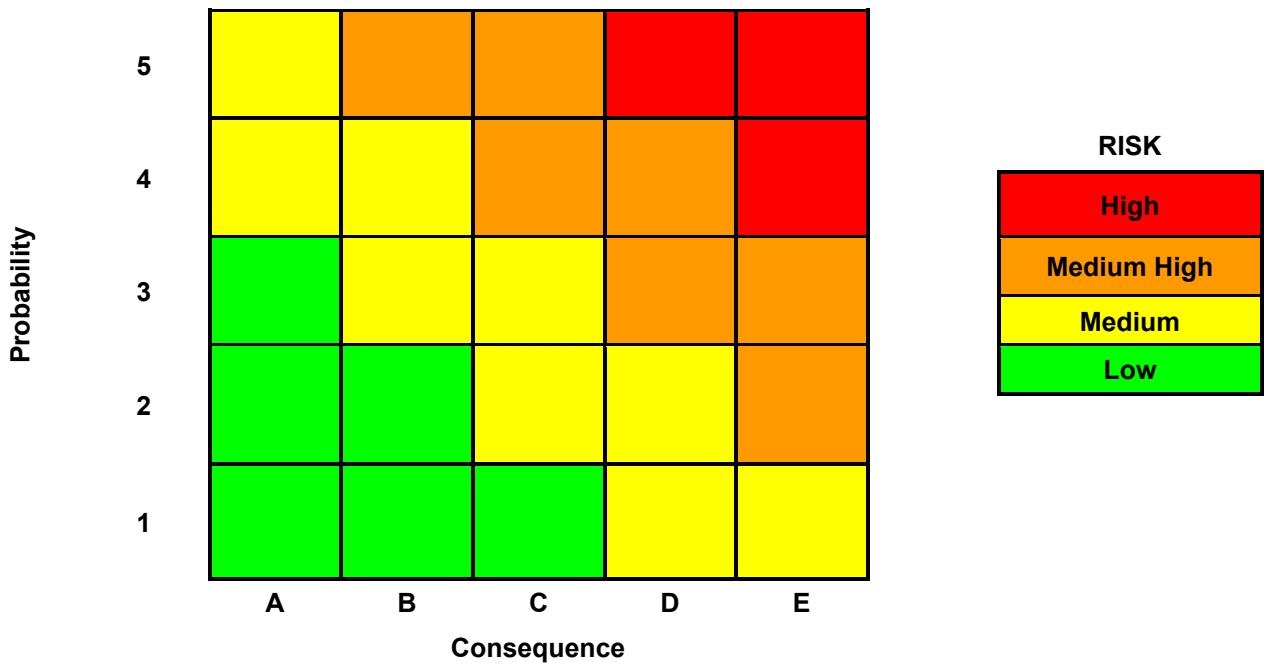


Figure 1.1—Superposition Principle for the Calculation of Risk



NOTE See [Table 1.2](#), [Table 1.3](#), and [Table 1.4](#) for ranges in probability and consequence categories.

Figure 1.2—Unbalanced Risk Matrix Example



NOTE See [Table 1.2](#), [Table 1.3](#), and [Table 1.4](#) for ranges in probability and consequence categories.

Figure 1.3—Balanced Risk Matrix Example

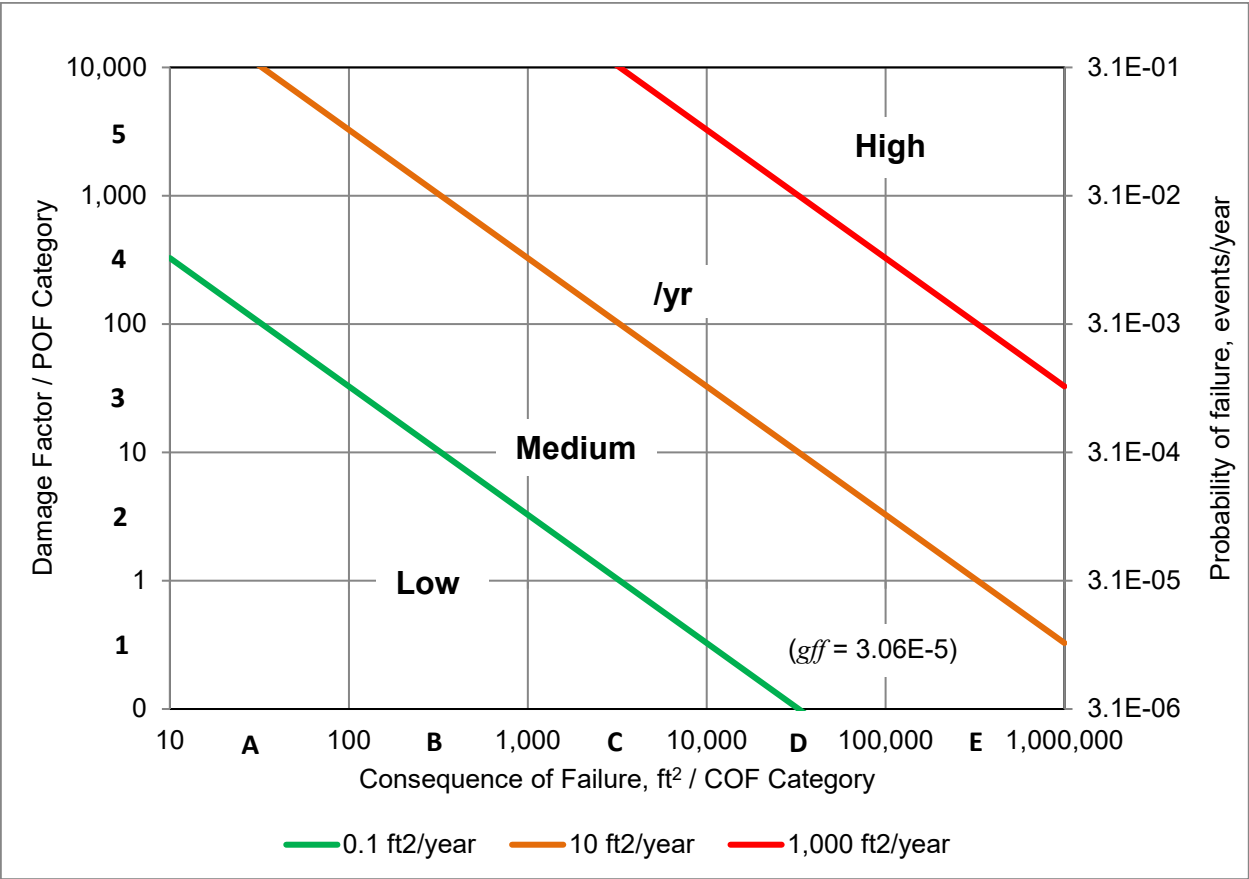


Figure 1.4—Example Iso-risk Plot for Consequence Area

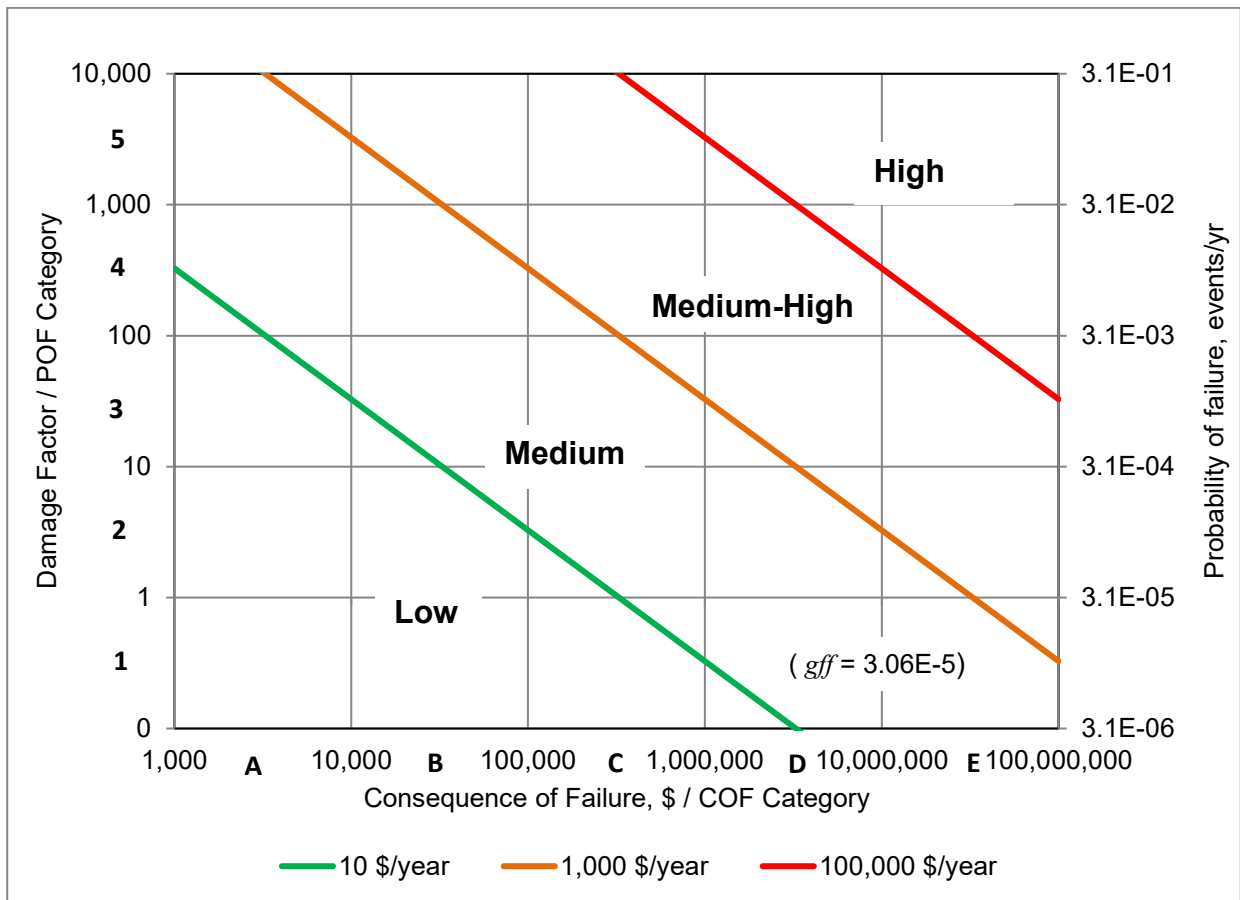


Figure 1.5—Example Iso-risk Plot for Financial Consequence

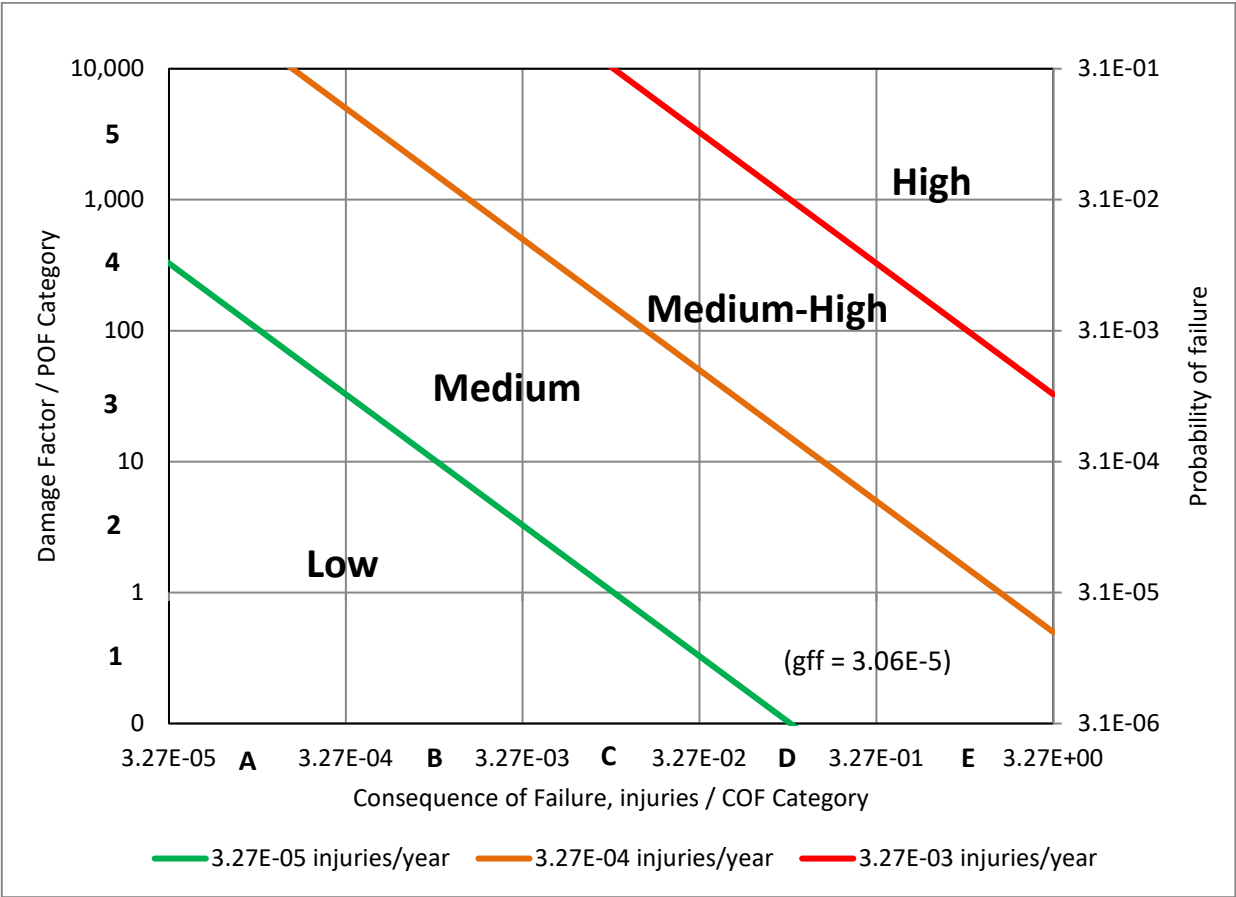


Figure 1.6—Example Iso-risk Plot for Safety Consequence

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Risk-Based Inspection Methodology

Part 1—Introduction to Risk-Based Inspection Methodology

Annex 1.A—Bibliography

1.A.1 General

The references for [Part 1](#) of this document are provided in [Section 1.A.2](#) of this annex.

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Risk-based Inspection Methodology

Part 2—Probability of Failure Methodology

1 Scope

The calculation of the POF of a component is covered in this document. This document is [Part 2](#) of a five-volume set presenting the API 581 methodology.

The POF calculated using the methodology in this part is used with the COF to provide a risk ranking and not for a rigorous reliability analysis of a component. Alternatively, the POF provided in this part provides a risk ranking and inspection plan for a component subject to process and environmental conditions typically found in refining, petrochemical industry, and exploration and production facilities.

2 Normative References

The following referenced documents are indispensable for the application of this document. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 580, *Elements of a Risk-Based Inspection*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 1—Introduction to Risk-Based Inspection Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 3—Consequence of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 4—Inspection Planning Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 5—Special Equipment*

3 Probability of Failure (POF) Methodology

3.1 Overview

The POF is calculated from [Equation \(2.1\)](#).

$$P_f(t) = gff_{total} \cdot D_f(t) \cdot F_{MS} \quad (2.1)$$

In this equation, the POF, $P_f(t)$, is determined as the product of a total GFF, gff_{total} , a DF, $D_f(t)$, and a management systems factor, F_{MS} .

The adjustment factors to the GFF reflect differences between damage mechanisms and the reliability management processes within a plant. The DF adjusts the GFF based on active damage mechanisms of the component and considers the susceptibility to the damage mechanism and/or the rate at which the damage accumulates. In addition, the DF considers historical inspection data and the effectiveness of past and future inspections. The F_{MS} adjusts the POF for the influence of the facility's management system on the mechanical integrity of the plant. The DF is applied on a component and damage mechanism specific basis, while the F_{MS} is applied equally to all components within a plant. Adjustment factors with a value greater than 1.0 will increase the POF, while those with a value less than 1.0 will decrease POF. Both adjustment factors are positive values.

3.2 Calculation of POF

The POF may be determined based on one, or a combination of, the following methods.

- 1) **Structural Reliability Models**—In this method, a limit state is defined based on a structural model that includes all relevant damage mechanisms, and uncertainties in the independent variables of this model are defined in terms of statistical distributions. The resulting model is solved directly for the POF.
- 2) **Statistical Models Based on Generic Data**—In this method, generic data are obtained for the component and damage mechanism under evaluation, and a statistical model is used to evaluate the POF.
- 3) **Expert Judgment**—In this method, where expert solicitation is used to evaluate the component and damage mechanism, a POF can be assigned on a relative basis.

A combination of the above is used to evaluate the POF in terms of a GFF and DF.

3.3 Generic Failure Frequency (GFF)

If enough data are available for a given component, true probabilities of failure can be calculated from actual observed failures. Even if a failure has not occurred in a component, the true POF is likely to be greater than zero because the component may not have operated long enough to experience a failure. As a first step in estimating this nonzero probability, it is necessary to examine a larger set of data of similar components to find enough failures so that a reasonable estimate of a true POF can be made. This generic component set of data is used to produce a GFF for each component. GFFs provided in [Table 3.1](#) are representative of the refining and petrochemical industry's failure data.

The GFF of a component type is estimated using records from all plants within a company, from various plants within an industry, from literature sources, and from commercial reliability databases. Therefore, these generic values represent an industry in general rather than the true failure frequencies for a specific component subject to a specific damage mechanism. The GFF is intended to be the failure frequency in relatively benign service prior to accounting for any specific operating environment and is provided for several discrete hole sizes for various types of processing equipment (i.e. process vessels, drums, towers, piping systems, tankage, etc.).

The failure frequencies associated with discrete hole sizes and an associated failure frequency are introduced into the methodology to model release scenarios. Four hole sizes are used to model the release scenarios covering a full range of events (i.e. small leak to rupture). The overall GFF for each component type was divided across the relevant hole sizes (i.e. the sum of the GFF for each hole size is equal to the total GFF for the component) and are provided in [Table 3.1 \[1\]–\[8\]](#). The GFFs are assumed to follow a log-normal distribution, with error rates ranging from 3 % to 10 %. Median values are given in [Table 3.1](#) with data presented based on the best available sources and experience to date from owner–operators.

3.4 Damage Factor (DF)

3.4.1 Overview

DFs provide a screening tool to determine inspection priorities and optimize inspection efforts. DFs do not provide a definitive FFS assessment of the component. The basic function of the DF is to statistically evaluate the amount of damage present as a function of time in service and the effectiveness of inspection activity. DFs are calculated based on the techniques described in [Section 3.2](#) but are not intended to reflect the actual POF for the purposes of reliability analysis. DFs reflect a relative level of concern about the component based on the stated assumptions in each of the applicable sections of the document.

DF estimates are currently provided for the following damage mechanisms.

- a) Thinning, D_{f-gov}^{thin} .
- b) SCC, D_{f-gov}^{scc} .
- c) External damage, D_{f-gov}^{extd} .
- d) HTHA, D_f^{htha} .
- e) Mechanical fatigue (piping only), D_f^{mfat} .
- f) Brittle fracture, D_{f-gov}^{brit} .

3.4.2 DF Combination for Multiple Damage Mechanisms

DFs for multiple mechanisms are assessed using the following.

- a) Total DF, $D_{f-total}$ —If more than one damage mechanism is present, the following rules are used to combine the DFs. The total DF is given by Equation (2.2) when the external and thinning damage are classified as local and therefore unlikely to occur at the same location.

$$D_{f-total} = \max \left[D_{f-gov}^{thin}, D_{f-gov}^{extd} \right] + D_{f-gov}^{scc} + D_f^{htha} + D_{f-gov}^{brit} + D_f^{mfat} \quad (2.2)$$

If the external or thinning damage are general or if both external and thinning damage are general, damage is likely to occur at the same location and the total DF is given by Equation (2.3).

$$D_{f-total} = D_{f-gov}^{thin} + D_{f-gov}^{extd} + D_{f-gov}^{scc} + D_f^{htha} + D_{f-gov}^{brit} + D_f^{mfat} \quad (2.3)$$

NOTE Summation of DFs can be less than or equal to 1.0, meaning that the component POF can be less than the GFF.

- b) Governing Thinning DF, D_{f-gov}^{thin} —The governing thinning DF is determined based on the presence of an internal liner using Equation (2.4) and Equation (2.5).

$$D_{f-gov}^{thin} = D_f^{thin} \quad (2.4)$$

- c) Governing SCC DF, D_{f-gov}^{scc} —The governing SCC DF is determined by using Equation (2.5).

$$D_{f-gov}^{scc} = \max \left[D_f^{caustic}, D_f^{amine}, D_f^{ssc}, D_f^{HIC/SOHC-H_2S}, D_f^{ACSCC}, D_f^{PASCC}, D_f^{CISCC}, D_f^{HSC-HF}, D_f^{HIC/SOHC-HF} \right] \quad (2.5)$$

- d) Governing External DF, D_{f-gov}^{extd} —The governing external DF is determined from Equation (2.6).

$$D_{f-gov}^{extd} = \max \left[D_f^{extf}, D_f^{CUIF}, D_f^{ext-CISCC}, D_f^{CUI-CISCC} \right] \quad (2.6)$$

- e) Governing Brittle Fracture DF, D_{f-gov}^{brit} —The governing brittle fracture DF is determined from Equation (2.7). Summation of DFs in Equation (2.7) when the $DF \leq 1.0$ (i.e. the damage is inactive), the DF shall be set to zero.

$$D_{f-gov}^{brit} = \max \left[\left(D_f^{brit} + D_f^{tempe} \right), D_f^{885F}, D_f^{sigma} \right] \quad (2.7)$$

- f) A description of the DFs shown above and the associated section number that contains the step-by-step calculations is provided in Table 3.2.

3.4.3 Inspection Effectiveness Category

DFs are calculated as a function of inspection effectiveness. A discussion of inspection effectiveness and example tables are provided in Annex 2.C. Inspection effectiveness categories are provided as example guidelines for the user in assigning inspection effectiveness.

The effectiveness of each inspection performed within the designated time period is characterized for each damage mechanism. The number of inspections and effectiveness of each inspection is used in the DF calculation. The number and effectiveness of each inspection for thinning and external corrosion is included directly in the calculation of the DFs (see Section 4, and Annex 2.D, Section 2.D.2 and Section 2.D.3).

If multiple inspections have been performed, equivalent relationships are used for SCC, external chloride stress corrosion cracking (ExtCISCC), external chloride stress corrosion cracking under insulation (CUI CISCC)], and HTHA. Inspections of different grades (A, B, C, and D) are approximated as equivalent inspection effectiveness in accordance with the following relationships.

- a) 2 Usually Effective (B) Inspections = 1 Highly Effective (A) Inspection, or $2B = 1A$.
- b) 2 Fairly Effective (C) Inspections = 1 Usually Effective (B) Inspection, or $2C = 1B$.
- c) 2 Poorly Effective (D) Inspections = 1 Fairly Effective (C) Inspection, or $2D = 1C$.

NOTE 1 Equivalent inspection values are not used for thinning and external corrosion DF calculations.

NOTE 2 The equivalent higher inspection rules shall not be applied to No Inspections (E).

3.5 Management Systems Factor

3.5.1 General

The effectiveness of a company's PSM system can have a pronounced effect on mechanical integrity. The methodology includes an evaluation tool to assess the portions of the facility's management system that most directly impact the POF of a component. The POF is generally increased by the F_{MS} when the management systems in place show issues that could negatively influence the confidence in the RBI program. POF is decreased by the F_{MS} when management systems are above average, providing a higher than typical confidence in the RBI analysis. This evaluation consists of a series of interviews with plant management, operations, inspection, maintenance, engineering, training, and safety personnel. The importance of an effective management system evaluation has long been recognized in preventing releases of hazardous materials and maintaining the mechanical integrity of process equipment.

The F_{MS} globally impacts the risk assessment of every component at a site and can have a significant impact on inspection planning. The F_{MS} is an evaluation of the site culture, which typically changes slowly over time. Therefore, F_{MS} reviews and adjustments should not be taken lightly or performed on a frequent basis. A good practice is to include a review of the evaluation during the periodic RBI reassessment effort.

3.5.2 Overview

A F_{MS} is used to adjust POF for differences in PSM systems. This factor is derived from the results of a facility evaluation or operating unit's management systems (provided in [Annex 2.A](#)) that affect plant risk. Different practices within units at a facility might create differences in the F_{MS} between the units. However, within any one study, the F_{MS} should be the same. The F_{MS} is applied equally to all components and, as a result, does not change the order of the risk-based ranking of the components. The F_{MS} can, however, have a pronounced effect on the total level of risk calculated for each item and for the summed risk for the study. This becomes important when risk levels of entire units are compared or when risk values for similar components are compared between different units or plant sites.

The management systems evaluation covers all areas of a plant's management system that impact directly or indirectly on the mechanical integrity of process equipment. The management systems evaluation is based in large part on the requirements contained in API recommended practices and inspection codes. It also includes other proven techniques in effective safety management. A listing of the subjects covered in the management systems evaluation and the weight given to each subject is presented in [Table 3.3](#).

It is not the intent of the management systems evaluation to measure overall compliance with all API recommendations or OSHA requirements since the emphasis is on mechanical integrity issues. Mechanical integrity is the largest single section with questions in the other subject areas either closely related to mechanical integrity or impacting the total unit risk. The evaluation consists of numerous questions with multiple parts. Each answer is weighed based on the appropriateness of the answer and the importance of the topic. This system provides a qualitative, numerical score for the management systems evaluation. The number of questions and the breadth of subject matter covered enable the management systems evaluation to differentiate between different levels of program effectiveness.

There is no specific score that indicates compliance vs noncompliance. A score of 100 equates to a plant having a best-in-industry management system in place in key areas that influence confidence in the RBI analysis, which impacts the POF. A score of 72 indicates industry average performance and does not change the POF. Some owner-operators may choose to use this score rather than performing the evaluation. A score below 72 indicates issues exist with the management system that could negatively impact the confidence in the RBI program and results in an increased POF and risk.

3.5.3 Auditing Technique

The management systems evaluation covers a wide range of topics and, as a result, requires input from several different disciplines within the facility to answer all questions. Ideally, representatives from the following plant functions should be interviewed:

- a) Plant Management,
- b) Operations,
- c) Maintenance,
- d) Safety,
- e) Inspection,
- f) Training, and
- g) Engineering.

The number of separate interviews required to complete the management systems evaluation will vary from application to application. In many cases, one individual can effectively answer the questions concerning two or more of the above functions. Normally at least four interviews are required.

The number of auditors involved is not defined, but there is some advantage in using more than one. With two or more auditors, the management systems evaluation team can compare notes and often avoid overlooking or misinterpreting important information.

Roles to be interviewed should be defined and a subset of specific questions should be selected from the total management systems evaluation to match the expertise of the role interviewed. All audit questions should be answered with some audit questions included in more than one interview to provide continuity and clarity during the interview. In addition, it can be revealing to compare answers from different disciplines as perceptions may differ.

The intent of the management systems evaluation is to arrive at the single best answer for each question. In addition to comparing answers from different interviews, many of the responses should be verified by physical review of the appropriate written procedures, files, and records. The auditor must ensure that the facts substantiate the answer and that the intent of the question is met before credit is awarded for the answer.

3.5.4 Calculation of the Management Systems Factor

The formula for converting a management systems evaluation score, $pscore$, to a management systems factor, F_{MS} , is based on the assumption that the “average” plant would score 72 % on the management systems. Based on this ranking, Equation (2.8) is used to calculate an F_{MS} for a management systems evaluation score,

$$F_{MS} = 2.38 \cdot e^{(-0.012 \cdot pscore)} \quad (2.8)$$

The above assumptions can be modified and improved over time as more data becomes available on management systems evaluation results.

It should be restated that the F_{MS} applies equally to all components and therefore does not change the risk ranking of components for inspection prioritization. The F_{MS} value is in comparing one operating unit or plant site to another.

3.6 Nomenclature

score is the numeric value assigned to a given score obtained from the management system evaluation question and summed to provide a section score and further multiplied by a weight % to develop the *pscore*

e is the mathematical constant rounded to 2.718

3.7 Tables

Table 3.1—Suggested Component GFFs

Equipment Type	Component Type	GFF as a Function of Hole Size (failures/yr)				gff_{total} (failures/yr)
		Small	Medium	Large	Rupture	
Compressor	COMPC	8.00E-06	2.00E-05	2.00E-06	0	3.00E-05
Compressor	COMPR	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Heat exchanger	HEXSS, HEXTS	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Pipe	PIPE-1, PIPE-2	2.80E-05	0	0	2.60E-06	3.06E-05
Pipe	PIPE-4, PIPE-6	8.00E-06	2.00E-05	0	2.60E-06	3.06E-05
Pipe	PIPE-8, PIPE-10, PIPE-12, PIPE-16, PIPEGT16	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Pump	PUMP2S, PUMPR, PUMP1S	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Tank620	TANKBOTTOM	7.20E-04	0	0	2.00E-06	7.22E-04
Tank620	TANKBOTEDGE	7.20E-04	0	0	2.00E-06	7.22E-04
Tank620	COURSE-1-10	7.00E-05	2.50E-05	5.00E-06	1.00E-07	1.00E-04
Tank650	TANKBOTTOM	7.20E-04	0	0	2.00E-06	7.22E-04
Tank650	TANKBOTEDGE	7.20E-04	0	0	2.00E-06	7.22E-04
Tank650	COURSE-1-10	7.00E-05	2.50E-05	5.00E-06	1.00E-07	1.00E-04
FinFan	FINFAN TUBES, FINFAN HEADER	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Vessel	KODRUM, COLBTM, FILTER, DRUM, REACTOR, COLTOP, COLMID	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05

NOTE 1 See References [1] through [8] for discussion of failure frequencies for equipment.

NOTE 2 TANKBOTEDGE refers to the near shell region of the tank bottom and is considered to extend 24 in. to 30 in. inside the shell. This is consistent with most annular ring dimensions. This component type can be used for tanks with or without an annular ring. TANKBOTTOM refers to the entire tank bottom, or if a TANKBOTEDGE is modeled, it refers to the remaining part of the tank bottom that does not include the edge component.

NOTE 3 Tank620 Course components are the primary pressure boundary in the case of a double-walled tank. The secondary wall may be considered as having an effect on leak detection, isolation, and mitigation.

Table 3.2—DF Section References

DF Variable	DF Description	Section
D_f^{thin}	DF for general and localized thinning	4
D_f^{caustic}	DF for caustic cracking	2.C.4
D_f^{amine}	DF for amine cracking	2.C.3
D_f^{SSC}	DF for SSC	2.C.10
$D_f^{\text{HIC/SOHIC-H}_2\text{S}}$	DF for hydrogen-induced cracking/stress-oriented hydrogen-induced cracking (HIC/SOHIC) cracking in H_2S environments	2.C.9
D_f^{ACSCC}	DF for alkaline carbonate stress corrosion cracking (ACSCC)	2.C.2
D_f^{PTA}	DF for polythionic acid (PTA) cracking in austenitic stainless steel (SS) and nonferrous alloy components	2.C.8
D_f^{CISCC}	DF for chloride stress corrosion cracking (CISCC)	2.C.5
$D_f^{\text{HSC-HF}}$	DF for hydrogen stress cracking (HSC) in hydrofluoric acid (HF) environments	2.C.7
$D_f^{\text{HIC/SOHIC-HF}}$	DF for HIC/SOHIC cracking in HF environments	2.C.6
D_f^{extcor}	DF for external corrosion on ferritic components	2.D.2
D_f^{CUIF}	DF for CUI on insulated ferritic components	2.D.3
$D_f^{\text{ext-CISCC}}$	DF for ExtCISCC on austenitic SS components	2.D.4
$D_f^{\text{CUI-CISCC}}$	DF for CUI CISCC on austenitic SS insulated components	2.D.5
D_f^{htha}	DF for HTHA	2.E.2
D_f^{brit}	DF for brittle fracture of carbon steel and low-alloy components	2.E.3
D_f^{tempe}	DF for low-alloy steel embrittlement of Cr-Mo low-alloy components	2.E.4
$D_f^{885\text{F}}$	DF for 885 °F embrittlement	2.E.5
D_f^{sigma}	DF for sigma phase embrittlement	2.E.6
D_f^{mfat}	DF for mechanical fatigue	2.E.7

Table 3.3—Management Systems Evaluation

Table	Title	Weight	Score	Weighted Score
2.A.1	Site Management	17 %	0	0
2.A.2	Process Safety	5 %	0	0
2.A.3	Management of Change	13 %	0	0
2.A.4	Operating Procedures	5 %	0	0
2.A.5	Mechanical Integrity	50 %	0	0
2.A.6	Equipment Failure Investigation	10 %	0	0
Total		100 %	<i>pscore</i> =	0

$$pscore = \sum [(weight\%) \cdot Score] \quad (2.9)$$

4 Thinning DF

4.1 Scope

The DF calculation for components subject to damage mechanisms that cause general or local thinning is covered in this section, including components with internal liners, strip lining, or cladding. Thinning associated with external corrosion and CUI should be evaluated according to the procedures in [Annex 2.D](#), [Section 2.D.2](#), and [Section 2.D.3](#), respectively.

4.2 Screening Criteria

All components should be checked for thinning.

4.3 Required Data

The basic component data required for analysis are given in [Table 4.1](#). Component types and required geometry data are shown in [Table 4.2](#) and [Table 4.3](#), respectively. The data required for determination of the thinning DF are provided in [Table 4.4](#).

4.4 Basic Assumptions

In the thinning DF calculation, it is assumed that the thinning corrosion rate is constant over time. This corrosion rate is updated based on the knowledge gained from subsequent inspections (see [Section 4.5.6](#)). An A_{rt} parameter is determined by calculating the ratio of total component wall loss (using the assigned corrosion rate during the in-service time period) to the wall thickness.

The DF is calculated using structural reliability theory [\[17\] \[18\] \[91\]](#). A statistical distribution is applied to the thinning corrosion rate, accounting for the variability of the actual thinning corrosion rate, which can be greater than the rate assigned. The amount of uncertainty in the corrosion rate is determined by the number and effectiveness of inspections and the online monitoring that has been performed (see [Section 4.5.3](#)). Confidence that the assigned corrosion rate is the rate experienced in service increases with more thorough inspection, a greater number of inspections, and/or more relevant information gathered through the online monitoring. The DF is updated based on increased confidence in the measured corrosion rate provided by using Bayes Theorem (see [Section 4.5.3](#) and [Table 4.5](#)) and the improved knowledge of the component condition (see [Section 4.5.5](#), [Section 4.5.6](#), and [Table 4.6](#)). The composite wall may consist of three separate

components that affect the thinning DF calculation. Each component may have factors resulting in an impact on thickness and age. The three components are as follows.

- a) **Base Material**—Represents the structural component of the total wall thickness and is typically carbon or low-alloy steel.
- b) **Cladding Material**—Represents explosion-bonded cladding, roll-bonded cladding, or weld overlay, which are typically provided to protect the base material from thinning.
- c) **Internal Lining**—Represents any organic, metallic, or nonmetallic protection (e.g. refractory, alloy strip lining). See [Table 4.7](#) for more examples.

All internal liners provide a degree of protection from the operating environment. Many liners will provide protection for an indefinite period of time, essentially being immune to damage mechanisms that may occur. Other liners will slowly degrade with time and have a finite life. In cases of liners with finite life, the age of the liner (or the years since the last inspection) becomes important in calculating the thinning DF. In the case of organic linings, the assumption is made that the liner is compatible with the environment, has operated within design temperature limits (including steam out), was applied after proper surface preparation, and was followed by curing of coatings and refractories or adequate heat treatment for an alloy liner. The thinning DF is calculated for a defined time period or plan period. The start of the plan period can be the component installation date with a furnished thickness, an inspection date with a reliable thickness measurement, or the date of a process service change with a reliable thickness measurement. In the DF calculation, it is assumed that thinning damage would eventually result in failure by plastic collapse or a small leak.

4.5 Determination of the DF

4.5.1 Overview

The following sections provide additional information and the calculation procedure to determine DF. The thinning DF is calculated for a defined time period or plan period. The start of the plan period can be the component installation date with a furnished thickness, an inspection date with a reliable thickness measurement, or the date of a process service change with a reliable thickness measurement. In the DF calculation, it is assumed that thinning damage would eventually result in failure by plastic collapse or a leak or rupture.

Uncertainty in the component condition is determined with consideration for the corrosion rate assigned (see [Section 4.5.2](#) and [Section 4.5.3](#)) and an improved confidence in the assigned rate provided by subsequent inspection ([Section 4.5.5](#)).

4.5.2 Corrosion Rate

The corrosion rate can be obtained by several methods, as follows.

- a) **Calculated**—[Annex 2.B](#) of this document provides conservative methods for determining a corrosion rate for various corrosion environments.
- b) **Measured**—These are based on recorded thicknesses over time at condition monitoring location(s) (CMLs). See API 510 [\[15\]](#) and API 570 [\[16\]](#) for definition of CML.
- c) **Estimated**—A corrosion specialist experienced with the process is usually the best source of providing realistic and appropriate estimated rates. See API 510 [\[15\]](#) and API 570 [\[16\]](#) for a definition of corrosion specialist.

As discussed in [Section 4.4](#), the thinning corrosion rate is assumed to be constant over the plan period. For this reason, using long-term average corrosion rates is recommended for the DF calculation. Since the

corrosion rate in practice may not be constant over time, use of short-term corrosion rates can lead to overly conservative and, in some cases, nonconservative results.

The measured corrosion rate should be used, if available. If a measured corrosion rate based on inspection history is not available, an estimated corrosion rate based on expert advice may be used to assign the expected corrosion rate, or a calculated corrosion rate may be determined for each potential thinning mechanism using [Annex 2.B](#). If multiple thinning mechanisms are possible, the maximum corrosion rate should be used. If cladding is present, the cladding will corrode prior to corrosion being applied to the base material. If an internal liner is present, the liner will provide corrosion protection for the liner remaining life before corrosion initiates on the base material.

4.5.3 Corrosion Rate Confidence Levels

The corrosion rate in process equipment is often not known with certainty. The ability to state the corrosion rate precisely is limited by equipment complexity, process and metallurgical variations, inaccessibility for inspection, and limitations of inspection and test methods. The best information comes from inspection results for the current equipment process operating conditions. Other sources of information include databases of plant experience or reliance on a knowledgeable corrosion specialist.

The uncertainty in the corrosion rate varies, depending on the source and quality of the corrosion rate data. The reliability of the information sources used to establish a corrosion rate are defined in the following categories for general thinning.

- a) Low Confidence Information Sources for Corrosion Rates—Sources such as published data, corrosion rate tables, and expert opinion. Although they are often used for design decisions, the actual corrosion rate that will be observed in a given process situation may significantly differ from the design value.
- b) Medium Confidence Information Sources for Corrosion Rates—Sources such as laboratory testing with simulated process conditions or limited in situ corrosion coupon testing. Corrosion rate data developed from sources that simulate the actual process conditions usually provide a higher level of confidence in the predicted corrosion rate.
- c) High Confidence Information Sources for Corrosion Rates—Sources such as extensive field data from thorough inspections. Coupon data, reflecting five or more years of experience with the process equipment (assuming significant process changes have not occurred), provide a high level of confidence in the predicted corrosion rate. If enough data are available from actual process experience, the actual corrosion rate is very likely to be close to the expected value under normal operating conditions.

Thinning DF calculations are based on the presence of three damage states used in [Section 4.5.7](#) and are defined as follows.

- 1) Damage State 1—Damage is no worse than expected, or a factor of 1 applied to the expected corrosion rate.
- 2) Damage State 2—Damage is somewhat worse than expected, or a factor of 2 applied to the expected corrosion rate.
- 3) Damage State 3—Damage considerably worse than expected, or a factor of 4 applied to the expected corrosion rate.

General corrosion rates are rarely more than four times the expected rate, while localized corrosion can be more variable. The default values provided here are expected to apply to many plant processes. The uncertainty in the corrosion rate varies, depending on the source and quality of the corrosion rate data. [Table 4.5](#) provides suggested probabilities (prior probabilities) for the damage states based on the reliability of the information sources used with Bayes Theorem. However, the user may choose to customize the prior probabilities based on actual experience and confidence in the measured thickness values.

4.5.4 Thinning Type

The thinning type is used to define the inspection to be performed depending on whether thinning is expected to be localized wall loss or general in nature. Thinning type is assigned for each potential thinning mechanism. If the thinning type is not known, guidance provided in [Annex 2.B](#) should be used to help determine the local or general thinning type expected for various mechanisms. The localized thinning type should be used if multiple thinning mechanisms are possible and both general and localized thinning mechanisms are assigned.

4.5.5 Thickness and Age

The thickness used for the DF calculation is either the furnished thickness (the thickness at the start of component in-service life) or the measured thickness (the thickness at any point of time in the component in-service life as a result of an inspection).

A furnished thickness may be replaced with a measured thickness as a result of a high-quality inspection (for thinning and external corrosion, as applicable) and high confidence in the measurement accuracy. Key reasons for replacing the furnished thickness with a measured thickness are as follows.

- a) The component service start date when combined with a reasonably conservative corrosion rate predicts an unrealistically high wall loss when the measured wall loss based on quality inspection is much lower than predicted.
- b) The process conditions differ significantly from historical service conditions that are the basis for historical measured corrosion rate.
- c) The furnished thickness based on design is significantly different than the thickness measured by a baseline inspection or lack of reliable baseline data.

The start date for DF calculation should be consistent with the date of the installation in the case of a furnished thickness, or date of inspection in the case of a measured thickness. The inspection credit for the DF calculation should be only for those inspections performed during the time period assessed. Inspection performed prior to the start date is not typically included in the DF calculation.

The component corrosion rate is used to calculate DF and is assumed to be constant over time. Since this is not the case in reality, using long-term average rates for the current process conditions may be the preferred rate.

4.5.6 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting thinning and correctly predicting the rate of thinning. [Table 4.6](#) provides the conditional probabilities for each inspection effectiveness category in the thinning DF calculations. These probabilities are used with the three damage states and Bayes Theorem described in [Section 4.5.3](#). The actual effectiveness of a given inspection technique depends on the characteristics of the thinning mechanism (i.e. whether it is general or local thinning type).

Examples of inspection activities for specific applications are provided in [Annex 2.F](#) for:

- a) general and localized thinning that are either intrusive or nonintrusive in [Table 2.F.7.1](#) and [Table 2.F.7.2](#),
- b) buried components in [Table 2.F.6.1](#).

For local thinning, selection of locations for examination must be based on a thorough understanding of the damage mechanism in the specific process.

The effectiveness of each inspection performed within the designated time period must be characterized in a manner similar to the examples provided in [Annex 2.F](#), as applicable. The number and effectiveness of each inspection is used to determine the DF. Inspections performed prior to the designated time period are typically not used to determine the DF.

4.5.7 Calculation of Thinning DF

The following procedure may be used to determine the DF for thinning. This procedure assumes that if cladding is present, it corrodes prior to any corrosion of the base material. If an internal liner is used, the procedure assumes that the liner prevents corrosion during the internal liner life.

- a) Step 1—Determine the furnished thickness, t , and age, age . For components with cladding determine the cladding thickness, t_{cm} , for the component from the installation date. If the component has an internal liner, determine the liner age, age_{liner} , from the liner installation date.
- b) Step 2—Determine the base material corrosion rate, $C_{r,bm}$, and the cladding corrosion rate, $C_{r,cm}$, as applicable, based on the material of construction and process environment, using guidance from [Section 4.5.2](#) and examples in [Annex 2.B](#) for establishing corrosion rates.
- c) Step 3—Determine the time in service, age_{tk} , since the last inspection and last known thickness, t_{rdi} . The last known thickness is the furnished thickness, t , or measured thickness reading from a previous inspection, t_{rdi} (see [Section 4.5.5](#)).
 - 1) Determine the date of the last inspection with a measured thickness and calculate the service age since the inspection, age_{tk} , and the measured thickness, t_{rdi} . If no measured thickness is available, set $t_{rdi} = 1$ and $age_{tk} = age$ from Step 1.
 - 2) For pressure vessels with cladding, calculate the remaining life of the cladding, age_{rc} , using the cladding thickness, t_{cm} , and corrosion rate, $C_{r,cm}$, using [Equation \(2.10\)](#). If the component does not contain cladding, set $C_{r,cm} = 0$ and go to next step.

$$age_{rc} = \max \left[\left(\frac{t_{cm}}{C_{r,cm}} \right), 0.0 \right] \quad (2.10)$$

NOTE 1 t_{cm} is calculated by $t_{rdi} - t_{bm}$.

- 3) For pressure vessel components with internal liners, determine the liner type and expected age using [Table 4.7](#), the condition of liner during the last inspection using [Table 4.8](#), and remaining life of the internal liner, age_{rc} , using age_{liner} from Step 1 and [Equation \(2.11\)](#). If the component does not contain an internal liner, set $age_{rc} = 0$ and go to Step 4.

$$age_{rc} = \frac{RL_{liner}^{exp} - age_{liner}}{F_{LC}} \cdot F_{liner,OM} \quad (2.11)$$

- i) Adjustment for Lining Condition, F_{LC} —The adjustment factors are given in [Table 4.8](#) based on a qualitative assessment of the lining condition.
- ii) Adjustment for Online Monitoring, $F_{liner,OM}$ —Some lined components have monitoring to allow early detection of a leak or other failure of the lining. The monitoring allows orderly shutdown of the component before failure occurs. If online monitoring is used and it is known to be effective at detecting lining deterioration, $F_{OM} = 0.1$; otherwise, $F_{OM} = 1.0$. Examples of monitoring systems include thermography or heat sensitive paint (refractory linings), weep holes with detection devices (loose alloy linings), and electrical resistance detection (glass linings).

- d) Step 4—Determine $t_{\min}$ using one of the following methods.
- 1) For cylindrical, spherical, rectangular, or head components, determine the allowable stress, S , and weld joint efficiency, E , and calculate the minimum required thickness, $t_{\min}$, using component type in [Table 4.2](#), geometry type in [Table 4.3](#), and per the original construction code or API 579-1/ASME FFS-1 [\[10\]](#).
 - 2) In cases where components are constructed of uncommon shapes or where the component's minimum structural thickness, t_c , may govern, the user may use the t_c in lieu of $t_{\min}$.
 - 3) A specific $t_{\min}$ calculated by another method and documented in the asset management program may be used at the owner–operator's discretion.
- e) Step 5—Determine the A_{rt} parameter using [Equation \(2.12\)](#), based on t from Step 2, and age_{tk} and t_{rdi} from Step 3.

For components with or without cladding, use [Equation \(2.12\)](#).

$$A_{rt} = \max\left(\frac{C_{r,bm} \cdot (age_{tk} - age_{rc})}{t_{rdi}}, 0\right) \quad (2.12)$$

- f) Step 6—Calculate the flow stress, FS^{Thin} , using E from Step 4 and [Equation \(2.13\)](#).

$$FS^{\text{Thin}} = \frac{(YS + TS)}{2} \cdot E \cdot 1.1 \quad (2.13)$$

NOTE 2 Use flow stress (FS^{Thin}) at design temperature for conservative results, using the appropriate [Equation \(2.14\)](#) or [Equation \(2.15\)](#).

- g) Step 7—Calculate the strength ratio parameter, SR_p^{Thin} , using the appropriate [Equation \(2.14\)](#) or [Equation \(2.15\)](#). For [Equation \(2.14\)](#), use t_{rdi} from Step 3, $t_{\min}$ or t_c from Step 4, S and E from Step 5, and flow stress, FS^{Thin} , from Step 6.

$$SR_p^{\text{Thin}} = \frac{S \cdot E}{FS^{\text{Thin}}} \cdot \frac{\max(t_{\min}, t_c)}{t_{rdi}} \quad (2.14)$$

NOTE 3 The $t_{\min}$ is based on a design calculation that includes evaluation for internal pressure hoop stress, external pressure, and/or structural considerations, as appropriate.

NOTE 4 The minimum required thickness calculation is the design code $t_{\min}$. Consideration for internal pressure hoop stress alone may not be sufficient. t_c as defined in Step 4 should be used when appropriate.

Using [Equation \(2.15\)](#) with t_{rdi} from Step 3 and FS^{Thin} from Step 6.

$$SR_p^{\text{Thin}} = \frac{P \cdot D}{\alpha \cdot FS^{\text{Thin}} \cdot t_{rdi}} \quad (2.15)$$

where α is the shape factor for the component type. $\alpha = 2$ for a cylinder, 4 for a sphere, 1.13 for a head.

NOTE 5 This strength ratio parameter is based on internal pressure hoop stress only. It is not appropriate where external pressure and/or structural considerations dominate. When t_c dominates or if the $t_{\min}$ is calculated using another method, [Equation \(2.14\)](#) should be used.

- h) Step 8—Determine the number of inspections for each of the corresponding inspection effectiveness, N_A^{Thin} , N_B^{Thin} , N_C^{Thin} , and N_D^{Thin} , using [Section 4.5.6](#) for past inspections performed during the in-service time.
- i) Step 9—Calculate the inspection effectiveness factors, I_1^{Thin} , I_2^{Thin} , and I_3^{Thin} , using [Equation \(2.16\)](#), prior probabilities, Pr_{p1}^{Thin} , Pr_{p2}^{Thin} , and Pr_{p3}^{Thin} , from [Table 4.5](#), the conditional probabilities (for each inspection effectiveness level), Co_{p1}^{Thin} , Co_{p2}^{Thin} , and Co_{p3}^{Thin} , from [Table 4.6](#), and the number of inspections, N_A^{Thin} , N_B^{Thin} , N_C^{Thin} , and N_D^{Thin} , in each effectiveness level from Step 8.

$$\begin{aligned}
 I_1^{\text{Thin}} &= Pr_{p1}^{\text{Thin}} \left(Co_{p1}^{\text{ThinA}} \right)^{N_A^{\text{Thin}}} \left(Co_{p1}^{\text{ThinB}} \right)^{N_B^{\text{Thin}}} \left(Co_{p1}^{\text{ThinC}} \right)^{N_C^{\text{Thin}}} \left(Co_{p1}^{\text{ThinD}} \right)^{N_D^{\text{Thin}}} \\
 I_2^{\text{Thin}} &= Pr_{p2}^{\text{Thin}} \left(Co_{p2}^{\text{ThinA}} \right)^{N_A^{\text{Thin}}} \left(Co_{p2}^{\text{ThinB}} \right)^{N_B^{\text{Thin}}} \left(Co_{p2}^{\text{ThinC}} \right)^{N_C^{\text{Thin}}} \left(Co_{p2}^{\text{ThinD}} \right)^{N_D^{\text{Thin}}} \\
 I_3^{\text{Thin}} &= Pr_{p3}^{\text{Thin}} \left(Co_{p3}^{\text{ThinA}} \right)^{N_A^{\text{Thin}}} \left(Co_{p3}^{\text{ThinB}} \right)^{N_B^{\text{Thin}}} \left(Co_{p3}^{\text{ThinC}} \right)^{N_C^{\text{Thin}}} \left(Co_{p3}^{\text{ThinD}} \right)^{N_D^{\text{Thin}}}
 \end{aligned} \tag{2.16}$$

See [Section 4.5.3](#) for guidance on selection of the prior probabilities. Conservatively, the low confidence data could be chosen from [Table 4.5](#).

- j) Step 10—Calculate the posterior probabilities, Po_{p1}^{Thin} , Po_{p2}^{Thin} , and Po_{p3}^{Thin} , using [Equation \(2.17\)](#) with I_1^{Thin} , I_2^{Thin} , and I_3^{Thin} in Step 9.

$$\begin{aligned}
 Po_{p1}^{\text{Thin}} &= \frac{I_1^{\text{Thin}}}{I_1^{\text{Thin}} + I_2^{\text{Thin}} + I_3^{\text{Thin}}} \\
 Po_{p2}^{\text{Thin}} &= \frac{I_2^{\text{Thin}}}{I_1^{\text{Thin}} + I_2^{\text{Thin}} + I_3^{\text{Thin}}} \\
 Po_{p3}^{\text{Thin}} &= \frac{I_3^{\text{Thin}}}{I_1^{\text{Thin}} + I_2^{\text{Thin}} + I_3^{\text{Thin}}}
 \end{aligned} \tag{2.17}$$

- k) Step 11—Calculate the parameters, β_1^{Thin} , β_2^{Thin} , and β_3^{Thin} , using [Equation \(2.18\)](#) and assigning $COV_{\Delta t} = 0.20$, $COV_{S_f} = 0.20$, and $COV_p = 0.05$.

$$\begin{aligned}
 \beta_1^{\text{Thin}} &= \frac{1 - D_{S_1} \cdot A_{rt} - SR_p^{\text{Thin}}}{\sqrt{D_{S_1}^2 \cdot A_{rt}^2 \cdot COV_{\Delta t}^2 + \left(1 - D_{S_1} \cdot A_{rt}\right)^2 \cdot COV_{S_f}^2 + (SR_p^{\text{Thin}})^2 \cdot COV_p^2}}, \\
 \beta_2^{\text{Thin}} &= \frac{1 - D_{S_2} \cdot A_{rt} - SR_p^{\text{Thin}}}{\sqrt{D_{S_2}^2 \cdot A_{rt}^2 \cdot COV_{\Delta t}^2 + \left(1 - D_{S_2} \cdot A_{rt}\right)^2 \cdot COV_{S_f}^2 + (SR_p^{\text{Thin}})^2 \cdot COV_p^2}}, \\
 \beta_3^{\text{Thin}} &= \frac{1 - D_{S_3} \cdot A_{rt} - SR_p^{\text{Thin}}}{\sqrt{D_{S_3}^2 \cdot A_{rt}^2 \cdot COV_{\Delta t}^2 + \left(1 - D_{S_3} \cdot A_{rt}\right)^2 \cdot COV_{S_f}^2 + (SR_p^{\text{Thin}})^2 \cdot COV_p^2}}.
 \end{aligned} \tag{2.18}$$

where $D_{S_1} = 1$, $D_{S_2} = 2$, and $D_{S_3} = 4$.

These are the corrosion rate factors for damage states 1, 2, and 3 as discussed in [Section 4.5.3 \[17\]](#).

NOTE 6 The DF calculation is very sensitive to the value used for the coefficient of variance for thickness, COV_{At} . The COV_{At} is in the range $0.10 \leq COV_{At} \leq 0.20$, with a recommended conservative value of $COV_{At} = 0.20$.

- l) Step 12—For all components, calculate the base DF, D_{fB}^{thin} .

$$D_{fB}^{Thin} = \left[\frac{\left(P_{o_{p1}}^{Thin} \Phi(-\beta_1^{Thin}) \right) + \left(P_{o_{p2}}^{Thin} \Phi(-\beta_2^{Thin}) \right) + \left(P_{o_{p3}}^{Thin} \Phi(-\beta_3^{Thin}) \right)}{1.56E-04} \right] \quad (2.19)$$

where Φ is the standard normal cumulative distribution function (NORMSDIST in Excel).

- m) Step 13—Determine the DF for thinning, D_f^{Thin} , using [Equation \(2.20\)](#).

$$D_f^{Thin} = \max \left[\left(\frac{D_{fB}^{Thin} \cdot F_{IP} \cdot F_{DL}}{F_{OM}} \right), 0.1 \right] \quad (2.20)$$

The adjustment factors are determined as described below.

- 1) Adjustment to DF for Online Monitoring, F_{OM} —In addition to inspection, online monitoring of corrosion (or key process variables affecting corrosion) is commonly used in many processes to prevent corrosion failures. The advantage of online monitoring is that changes in corrosion rates as a result of process changes can be detected long before they would be detected with normal periodic inspections. This earlier detection usually permits more timely action to be taken that should decrease the POF. Various methods are employed, ranging from corrosion probes, corrosion coupons, and monitoring of key process variables. If online monitoring is employed, then credit should be given to reflect higher confidence in the predicted thinning rate. However, these methods have a varying degree of success depending on the specific thinning mechanism. Using knowledge of the thinning mechanism and the type of online monitoring, determine the online monitoring factor from [Table 4.9](#). If more than one monitoring method is used, only the highest monitoring factor should be used (i.e. the factors are not additive).
- 2) Adjustment for Injection/Mix Points, F_{IP} —An injection/mix point is defined as a point where a chemical (including water) is being added to the main flow stream. A corrosive mix point is defined as:
 - mixing of vapor and liquid streams where vaporization of the liquid stream can occur;
 - water is present in either or both streams; or
 - temperature of the mixed streams is below the water dew point of the combined stream.

If a piping circuit contains an injection/mix point, then an adjustment factor equal to $F_{IP} = 3$ should be used to account for the higher likelihood of thinning activity at this location. If an effective inspection program specifically for injection/mix point corrosion within the injection point circuit (according to API 570) is performed, the adjustment factor is $F_{IP} = 1$.

- 3) Adjustment for Dead-legs, F_{DL} —A dead-leg is defined as a section of piping or piping circuit that is used only during intermittent service such as start-ups, shutdowns, or regeneration cycles rather than continuous service. Dead-legs include components of piping that normally have no significant flow. If a piping circuit contains a dead-leg, then an adjustment should be made to the thinning DF to account for the higher likelihood of thinning activity at this location. The adjustment factor is $F_{DL} = 3$. If an effective inspection program is in place to address the potential of localized corrosion in the dead-leg, the adjustment is $F_{DL} = 1$.

4.6 Nomenclature

A_{rt}	is the component wall loss fraction since last inspection thickness measurement or service start date
age	is the in-service time that the damage is applied, years
age_{liner}	is the in-service time that the damage is applied, years
age_{rc}	is the remaining life of the internal liner or cladding associated with the date of the starting thickness, years
age_{tk}	is the component in-service time since the last inspection thickness measurement or service start date, years
$C_{r,bm}$	is the corrosion rate for the base material, in./yr (mm/yr)
$C_{r,cm}$	is the corrosion rate for the cladding, in./yr (mm/yr)
CA	is the corrosion allowance, in. (mm)
Co_{p1}^{Thin}	is the conditional probability of inspection history inspection effectiveness for damage state 1
Co_{p2}^{Thin}	is the conditional probability of inspection history inspection effectiveness for damage state 2
Co_{p3}^{Thin}	is the conditional probability of inspection history inspection effectiveness for damage state 3
COV_p	is the pressure coefficient of variance
COV_{Sf}	is the flow stress coefficient of variance
$COV_{\Delta t}$	is the thinning coefficient of variance
D_f^{Thin}	is the DF for thinning
D_{fB}^{Thin}	is the base value of the DF for thinning
D	is the component inside diameter, in. (mm)
D_{S1}	is the corrosion rate factor for damage state 1
D_{S2}	is the corrosion rate factor for damage state 2
D_{S3}	is the corrosion rate factor for damage state 3
E	is the weld joint efficiency or quality code from the original construction code

F_{DL}	is the DF adjustment for dead-legs
F_{IP}	is the DF adjustment for injection points
F_{LC}	is the DF adjustment for lining condition
F_{OM}	is the DF adjustment for online monitoring
F_S^{Thin}	is the flow stress, psi (MPa)
I_1^{Thin}	is the first order inspection effectiveness factor
I_2^{Thin}	is the second order inspection effectiveness factor
I_3^{Thin}	is the third order inspection effectiveness factor
N_A^{Thin}	is the number of A level inspections
N_B^{Thin}	is the number of B level inspections
N_C^{Thin}	is the number of C level inspections
N_D^{Thin}	is the number of D level inspections
P	is the pressure (operating, design, PRD overpressure, etc.), psi (MPa)
$P_{o_{p1}}^{Thin}$	is the posterior probability for damage state 1
$P_{o_{p2}}^{Thin}$	is the posterior probability for damage state 2
$P_{o_{p3}}^{Thin}$	is the posterior probability for damage state 3
$P_{r_{p1}}^{Thin}$	is the prior probability of corrosion rate data confidence for damage state 1
$P_{r_{p2}}^{Thin}$	is the prior probability of corrosion rate data confidence for damage state 2
$P_{r_{p3}}^{Thin}$	is the prior probability of corrosion rate data confidence for damage state 3
RL_{liner}^{exp}	is the expected remaining life of the liner using Table 4.7 , years
S	is the allowable stress, psi (MPa)
SR_p^{Thin}	is the strength ratio parameter defined as the ratio of hoop stress to flow stress
TS	is the tensile strength at design temperature, psi (MPa)

t	is the furnished thickness of the component calculated as the sum of the base material and cladding thickness, as applicable, in. (mm)
t_{bm}	is the furnished or remaining base materials thickness of the component, in. (mm)
t_c	is the minimum structural thickness of the component base material, in. (mm)
t_{cm}	is the furnished or remaining cladding material thickness of the component, in. (mm)
t_{min}	is the minimum required thickness based on the applicable construction code, in. (mm)
t_{rdi}	the furnished thickness, t , or measured thickness reading from previous inspection, in. (mm)
YS	is the yield strength at design temperature, psi (MPa)
α	is the component geometry shape factor
β_1^{Thin}	is the β reliability indices for damage state 1
β_2^{Thin}	is the β reliability indices for damage state 2
β_3^{Thin}	is the β reliability indices for damage state 3
Φ	is the standard normal cumulative distribution function

4.7 Tables

Table 4.1—Basic Component Data Required for Analysis

Basic Data	Comments
Start date	The date the component was placed in service.
Thickness, in. (mm)	The thickness used for the DF calculation, either the furnished thickness or the measured thickness (see Section 4.5.5).
Corrosion allowance, in. (mm)	The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current service.
Design temperature, °F (°C)	The design temperature, shell side and tube side for a heat exchanger.
Design pressure, psi (MPa)	The design pressure, shell side and tube side for a heat exchanger.
Operating temperature, °F (°C)	The highest expected operating temperature expected during operation including normal and unusual operating conditions, shell side and tube side for a heat exchanger.
Operating pressure, psi (MPa)	The highest expected operating pressure expected during operation including normal and unusual operating conditions, shell side and tube side for a heat exchanger.
Design code	The design code of the component containing the component.
Equipment type	The type of equipment.
Component type	The type of component; see Table 4.2 .
Component geometry data	Component geometry data depending on the type of component (see Table 4.3).
Material specification	The specification of the material of construction, the ASME SA or SB specification for pressure vessel components or of ASTM specification for piping and tankage components. Data entry is based on material specification, grade, year, UNS number, and class/condition/temper/size/thickness; these data are readily available in the ASME Code [12] .
Yield strength, psi (MPa)	The design yield strength of the material based on material specification.
Tensile strength, psi (MPa)	The design tensile strength of the material based on material specification.
Weld joint efficiency	Weld joint efficiency per the code of construction.
Heat tracing	Is the component heat traced? (Yes or No)

Table 4.2—Component and Geometry Types Based on the Equipment Type

Equipment Type	Component Type	Geometry Type
Compressor	COMPC, COMPR	CYL
Heat exchanger	HEXSS, HEXTS	CYL, ELB, SPH, HEM, ELL, TOR, CON, NOZ
Pipe	PIPE-1, PIPE-2, PIPE-4, PIPE-6, PIPE-8, PIPE-10, PIPE-12, PIPE-16, PIPEGT16	CYL, ELB
Pump	PUMP2S, PUMPR, PUMP1S	CYL
Tank620	TANKBOTEDGE	PLT
Tank620	TANKBOTTOM	PLT
Tank620	COURSE-1-10	CYL
Tank650	TANKBOTEDGE	PLT
Tank650	TANKBOTTOM	PLT
Tank650	COURSE-1-10	CYL
FinFan	FINFAN TUBE, FINFAN HEADER	CYL, RECT, CYL, ELB, HEM, ELL, NOZ
Vessel	KODRUM, COLBTM, FINFAN, FILTER, DRUM, REACTOR, COLTOP, COLMID	CYL, ELB, SPH, HEM, ELL, TOR, CON, NOZ

NOTE 1 Tank620 Course components are the primary pressure boundary in the case of a double-walled tank. The secondary wall may be considered as having an effect on leak detection, isolation, and mitigation.

NOTE 2 TANKBOTEDGE refers to the near shell region of the tank bottom and is considered to extend 24 in. to 30 in. inside the shell. This is consistent with most annular ring dimensions. This component type can be used for tanks with or without an annular ring. TANKBOTTOM refers to the entire bottom of the tank, or if a TANKBOTEDGE is modeled, it refers to the remaining part of the tank bottom that does not include the edge component.

Table 4.3—Required Geometry Data Based on the Geometry Type

Geometry Type	Geometry Description	Geometry Data
CYL	Cylindrical shell	— Diameter — Length — Volume
ELB	Elbow or pipe bend	— Diameter — Bend radius — Volume
SPH	Spherical shell	— Diameter — Volume
HEM	Hemispherical head	— Diameter — Volume
ELL	Elliptical head	— Diameter — Major-to-minor axis ratio — Volume
TOR	Torispherical head	— Diameter — Crown radius (inner radius) — Knuckle (inner radius) — Volume
CON	Conical shell	— Diameter — Length — Cone angle — Volume
RECTNOZ	Rectangular cross section	— Length — Width — Height — Volume
NOZ	Nozzle	— Diameter — Length — Volume

Table 4.4—Data Required for Determination of the Thinning DF

Basic Data	Comments
Thinning type (general or localized)	Determine whether the thinning is general or localized based on inspection results of effective inspections. General corrosion is defined as affecting more than 10 % of the surface area and the wall thickness variation is less than 50 mils (1.27 mm). Localized corrosion is defined as affecting less than 10 % of the surface area or a wall thickness variation greater than 50 mils (1.27 mm).
Corrosion rate (mpy or mmpy)	The current rate of thinning calculated from thickness data, if available. Corrosion rates calculated from thickness data typically vary from one inspection to another. These variations may be due to variations in the wall thickness, or they may indicate a change in the actual corrosion rate. If the short-term rate (calculated from the difference between the current thickness and the previous thickness) is significantly different from the long-term rate (calculated from the difference between the current thickness and the original thickness), then the component may be evaluated using the short-term rate, but the appropriate time and thickness must be used. Consider base material corrosion rate and cladding corrosion rate, if applicable.
Inspection effectiveness category	The effectiveness category of each inspection that has been performed on the component during the time period (specified above).
Number of inspections	The number of inspections in each effectiveness category that have been performed during the time period (specified above).
Online monitoring	The types of proactive online monitoring methods or tools employed, such as corrosion probes, coupons, process variables (coupons, probes, process variables, or combinations, etc.).
Thinning mechanism	If credit is to be taken for online monitoring, the potential thinning mechanisms must be known. A knowledgeable materials/corrosion engineer should be consulted for this information; also see API 571 [13] .
Presence of injection/mix point (Yes or No)	For piping, determine if there is an injection or mix point in the circuit.
Type of injection/mix point inspection	For piping circuits that contain an injection or mix point, determine whether not the inspection program is highly effective or not highly effective to detect local corrosion at these points.
Presence of a dead-leg (Yes or No)	For piping, determine if there is a dead-leg in the circuit.
Type of inspection for dead-leg corrosion	For piping circuits that contain a dead-leg, determine if the inspection program currently being used is highly effective or not highly effective to detect local corrosion in dead-legs has been performed.
Liner type	The type of internal liner or strip liner, if applicable. Liner types are provided in Table 4.7 .
Liner installation date	The date the internal liner or strip liner was installed, if applicable.
Liner inspection date	The date of the last internal liner inspection, if applicable.
Liner condition	The condition of the liner, if applicable.
Liner online monitoring	The type of online monitoring for liner condition, if applicable.

Table 4.5—Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidence Data	Medium Confidence Data	High Confidence Data
$P_{r_{p1}}^{\text{Thin}}$	0.5	0.7	0.8
$P_{r_{p2}}^{\text{Thin}}$	0.3	0.2	0.15
$P_{r_{p3}}^{\text{Thin}}$	0.2	0.1	0.05

Table 4.6—Conditional Probability for Inspection Effectiveness

Conditional Probability of Inspection	E—None or Ineffective	D—Poorly Effective	C—Fairly Effective	B—Usually Effective	A—Highly Effective
$C_{o_{p1}}^{\text{Thin}}$	0.33	0.4	0.5	0.7	0.9
$C_{o_{p2}}^{\text{Thin}}$	0.33	0.33	0.3	0.2	0.09
$C_{o_{p3}}^{\text{Thin}}$	0.33	0.27	0.2	0.1	0.01

Table 4.7—Internal Liner Types

Liner Type	Lining Resistance	Expected Age
Cladding	Based on corrosion review and cladding corrosion rate assigned. Subject to failure by corrosion.	Calculated based on thickness and corrosion rate of cladding/weld overly
Alloy strip liner	Subject to failure at seams, particularly on flange faces in high pressure applications. Also subject to failure at areas where plug-welding was used to secure to pressure boundary.	5 to 15 years
Organic coating—low-quality immersion grade coating (spray applied, to 40 mils)	Limited life	1 to 3 years
Organic coating—medium-quality immersion grade coating (filled, trowel applied, to 80 mils)	Limited life	3 to 5 years
Organic coating—high-quality immersion grade coating (reinforced, trowel applied, ≥ 80 mils)	Limited life	5 to 10 years
Thermal resistance service: castable refractory plastic refractory refractory brick ceramic fiber refractory refractory/alloy combination	Subject to occasional spalling or collapse	1 to 5 years
Thermal resistance service: castable refractory ceramic tile	Limited life in highly abrasive service	1 to 5 years
Glass liners	Complete protection, subject to failure due to thermal or mechanical shock	5 to 10 years
Acid brick	Partial protection. The brick provides thermal protection but is not intended to keep the fluid away from the base material.	10 to 20 years

Table 4.8—Lining Condition Adjustment

Qualitative Condition	Description	Adjustment Multiplier, F_{LC}
Poor	The lining has either had previous failures or exhibits conditions, such as distortions, thinning, cracks, or seepage that may lead to failure in the near future. Repairs to previous failures are not successful or are of poor quality.	10
Average	The lining is not showing signs of excessive attack by any damage mechanisms. Local repairs may have been performed, but they are of good quality and have successfully corrected the lining condition.	2
Good	The lining is in "like new" condition with no signs of attack by any damage mechanisms. There has been no need for any repairs to the lining.	1

Table 4.9—Online Monitoring Adjustment Factors

Thinning Mechanism	Adjustment Factors as a Function of Online Monitoring, F_{OM}		
	Key Process Variable	Electrical Resistance Probes ^c	Corrosion Coupons ^c
Hydrochloric acid (HCl) corrosion	10 (20 if in conjunction with probes)	10	2
High-temperature sulfidic/naphthenic acid corrosion	10	10	2
High-temperature H ₂ S/H ₂ corrosion	1	10	1
Sulfuric acid (H ₂ S/H ₂) corrosion Low velocity ≤ 3 ft/s for CS ≤ 5 ft/s for SS ≤ 7 ft/s for higher alloys High velocity > 3 ft/s for CS > 5 ft/s for SS > 7 ft/s for higher alloys	20	10	2
	10 (20 if in conjunction with probes)	10	1
HF corrosion	10	1	1
Sour water corrosion Low velocity ≤ 20 ft/s High velocity > 20 ft/s	20	10	2
	10	2	2
Amine Low velocity High velocity	20	10	2
	10	10	1
Other corrosion mechanism	1	1	1

^a The adjustment factors shown above are estimates providing a measure of the relative effectiveness of various online monitoring methods. Factors based on the user's experience can be used as a substitute for the values presented in this table.

^b Factors shall not be added unless noted. This table assumes that an organized online monitoring plan is in place that recognizes the potential corrosion mechanism. Key process variables are, for example, oxygen, pH, water content, velocity, Fe content, temperature, pressure, H₂S content, CN levels, etc. The applicable variable(s) should be monitored at an appropriate interval, as determined by a knowledgeable specialist. For example, coupons may be monitored quarterly, while pH, chlorides, etc. may be monitored weekly.

^c The effectiveness of other online corrosion monitoring methods [e.g. hydrogen flux, field signature method (FSM), LP probe] shall be evaluated by a corrosion engineer or other knowledgeable specialist.

Part 2, Annex 2.A—Management Systems Workbook

2.A.1	Recommended Auditing Technique	1
2.A.2	Example Workbook Scoring Instructions	1

Risk-Based Inspection Methodology

Part 2—Probability of Failure Methodology

Annex 2.A—Management Systems Workbook

2.A.1 Recommended Auditing Technique

The management systems evaluation covers a wide range of topics and, as a result, requires input from several different disciplines within the facility to answer all questions. Ideally, representatives from the following plant functions should be interviewed:

- a) Plant Management,
- b) Operations,
- c) Maintenance,
- d) Safety,
- e) Inspection
- f) Training,
- g) Engineering.

The number of separate interviews required to complete the management systems evaluation will vary from application to application. In many cases, one individual can effectively answer the questions concerning two or more of the above functions. Normally at least four interviews are required.

The number of auditors involved is not defined, but there is some advantage in using more than one. With two or more auditors, the management systems evaluation team can compare notes and often avoid overlooking or misinterpreting important information.

The representative interviewed should be designated, and then a subset of questions selected from the total management systems evaluation, to match the expertise of each role interviewed. All audit questions should be answered with some of the audit questions included in more than one interview. This is sometimes important to provide continuity and clarity during the interview. In addition, it can be revealing to compare answers from different disciplines as perceptions can differ.

The intent of the management systems evaluation is to arrive at the single best answer for each question. In addition to comparing answers from different interviews, many of the responses should be verified by physical review of the appropriate written procedures, files, and records. The auditor must ensure that the facts substantiate the answer and that the intent of the question is met before credit is awarded for the answer.

2.A.2 Example Workbook Scoring Instructions

The management system evaluation/audit should be conducted per the guidance outlined in [Section 2.A.1](#). The team should review each question and develop a score by consensus. The team members should be set up for each section to include the appropriate subject matter experts and stakeholders.

The following guidance should be used in assigning points to each question:

- a) where scoring guidance is supplied with the question, that guidance should be applied;
- b) where the question is a simple yes/no, either the full points should be awarded or no points as appropriate;
- c) for questions that are related to more broad requirements, and larger point values are assigned, partial credit may be assigned based on how *well* the site meets the requirement;

- d) if a question does not apply because it relates to something that is not physically at the site, or is outside the scope of the RBI program, full points should be awarded. An example would be questions related to cathodic protection (CP) where a site has no underground equipment or atmospheric tanks with floors in contact with the earth where CP provides benefit, or if such equipment is outside the scope of the RBI program and is covered by time-based inspections.

The total points for each section should be added up after the scoring for each question is complete. This score provides a rating of how well the site is doing on a scale of 1 to 100 for that section, showing the sites their strengths and weaknesses in their management systems. The section scores are then multiplied by the weighting as shown in [Part 2, Table 3.3](#) and totaled to provide a final management system evaluation, *pscore*, from 1 to 100.

Table 2.A.1—Site Management

Item	Question	Possible Score	Actual Score	Score Guidance
1	Does site management receive KPIs from the inspection group periodically regarding overdue inspection and recommendations?	15		
2	Is site management required to review and approve deferrals for mechanical integrity program inspections and recommendations, prior to them becoming overdue, and receives sufficient technical information to understand the risk associated with those deferrals?	10		5 pts for having written requirement. + 5 pts for following requirement (no overdue without deferral). + 3 pts for completeness of technical information provided to management on risk associated with deferral.
3	Is the site management aware of the requirements of a successful RBI program such as training, MOC involvement, and periodic RBI reassessments, and do they support providing adequate resources for these activities?	25		0 to 25 points based on interview with leadership staff.
4	Does site management approve and provide resources for the annual plan for the inspections to maintain equipment at an acceptable risk?	15		5 pts for having an annual plan. +5 for approval. +5 for evidence plan is sufficient to meet inspection requirements.
6	Do other departments (e.g. operations, maintenance and capital project group) communicate with RBI assessment group for anything that could change equipment risks such as equipment and piping replacements, modifications, or changes in operations?	10		
7	The site conducts periodic internal assessments:			
	PSM-based assessment or other overall plant bench marking, which includes fixed equipment mechanical integrity programs;	5		5 pts for every 3 years or more frequent, 2 points for having done it at all.
	Fixed equipment mechanical integrity program-specific assessment vs site and company requirements OR external assessment such as from API utilizing third-party subject matter experts.	10		10 pts for annual, 8 pts for at least every 3 yr, 3 pts for in last 10 yr.
8	Is there evidence of the site continuously improving their practices in accordance with industry best practices?	10		0 to 10 pts depending on strength of examples.
Total for Section		100	0	

Table 2.A.2—Process Safety

Item	Question	Possible Score	Actual Score	Score Guidance
1	Is a block flow diagram or simplified process flow diagram available to aid in the understanding of the process?	10		0 to 10 pts based on percentage of process flow diagrams available for RBI units.
2	Are as-built/up-to-date piping and instrumentation diagrams (P&IDs) available for all units at the site (in the RBI program)?	30		0 to 30 pts based on the percentage of P&IDs that are currently up to date.
3	Does documentation show all equipment and piping in the unit (in the RBI program) is designed and constructed in compliance with all applicable codes, standards, and generally accepted good engineering practices?	20		0 pts if the documentation is lacking or if the site does not have equipment/piping designed and fabricated to recognized standards. 10 pts if some documentation is found missing. 20 pts if documentation is complete and requirements are robust.
4	IOW limits are established per API 584 with clear corrective action, communication, and inspection follow-up requirements.	40		15 pts for establishing IOW. +13 pts for having corrective actions documented. +12 pts for having communication plan with inspection.
	Total for Section	100	0	

Table 2.A.3—Management of Change

Item	Question	Possible Score	Actual Score	Score Guidance
1	a. Does the facility have a written MOC procedure that must be followed whenever new facilities are added or changes are made to a process?	3		
	b. Does the MOC process include MI reviewing the change during various stages of the project before the actual installation is complete (i.e. concept, design, issue for construction, and as-built)?	3		
	c. Are authorization procedures clearly stated, approved by an appropriate discipline, and at an appropriate level?	3		
	d. Is there a requirement in the procedure to update RBI information and inspection plans with the changes?	10		
2	Do the following types of “changes” invoke the MOC procedure?			
	a. Physical changes to the facility, other than replacement in kind [expansions, equipment modifications, instrument or alarm system revisions (that are part of an IOW program), etc.].	3		
	b. Changes in process chemicals (feedstocks, catalysts, solvents, etc.).	3		
	c. Changes in process conditions (operating temperatures, pressures, production rates, etc.).	3		
	d. Significant changes in operating procedures (start-up or shutdown sequences, unit staffing level or assignments, etc.).	2		
3	a. Is there a clear definition of what constitutes a “temporary changes”?	3		
	b. Does MOC handle temporary changes as well as permanent changes?	2		
	c. Are items that are installed as “temporary” tracked to ensure that they are either removed after a defined period of time or reclassified as permanent?	3		
	d. Are items that are installed as “temporary” have an inspection plan implemented until the permanent repair has been installed or document justification for no inspection require for the life of the repair?	3		

Item	Question	Possible Score	Actual Score	Score Guidance
4	Do the MOC procedures specifically require the following actions whenever a change is made to a process?			
	a. Update all affected maintenance programs, corrosion management programs (e.g. corrosion control documents, damage mechanism reviews), inspection plans, and inspection schedules.	2		
	b. Modify P&IDs, statement of operating limits, safety data sheets, and any other process safety information affected.	2		
	c. Notify all impacted FEMI and maintenance employees who work in the area of the change, and provide training as required.	2		
	d. Review the effect of the proposed change on all separate but interrelated upstream and downstream facilities.	2		
5	When changes are made in the process or operating procedures, are there written procedures requiring that the impact of these changes on the equipment and materials of construction be reviewed to determine whether they will cause any increased rate of damage or failure, or will result in different failure mechanisms in the process equipment?	5		
6	When the equipment or materials of construction are changed through replacement or maintenance items, is there a system in place to formally review any metallurgical change to ensure that the new material is suitable for the process?	10		
7	Is the MOC program audited periodically to ensure the MOC procedures are being followed and to verify all past MOC updates (including RBI information) are being completed in a timely manner.	10		
9	Is there a robust system to ensure an MOC cannot be closed out without verification that equipment documentation, inspection plans, RBI information is completely updated.	20		
10	Is there an MOC process for changes in personnel or organizations? This could be when you add, reduce replace personnel.	4		
11	Are in-kind replacements appropriately communicated to the FEMI team (i.e. pressure vessels are typically never true in-kind replacements)? Materials of construction, year/version of design code, U1 form. Calculations, fabrication drawings will all be different.	2		
Total for Section		100	0	

Table 2.A.4—Operating Procedures

Item	Question	Possible Score	Actual Score	Score Guidance
1	Are written operating procedures available to operations, maintenance and subject matter expert personnel in all units?	10		
2	Do the operating procedures clearly define the position of the person or persons responsible for operation of each applicable area?	10		
3	Are the following operating considerations covered in all standard operating procedures?			
	a. Initial start-up.	4		
	b. Normal (as well as emergency) operation.	4		
	c. Normal shutdown.	4		
	d. Emergency shutdown.	4		
	e. Is the position of the person or persons who may initiate these procedures defined?	4		
	f. Steps required to correct or avoid deviation from operating limits and consequences of the deviation.	4		
	g. Start-up following a turnaround.	4		
	h. Safety systems and their functions.	4		
	i. IOW limits and corrective actions/communication required when those limits are exceeded.	15		
4	Operating training covers the IOW concepts and provide the operators with an understanding of the importance of IOW related to the RBI program and understand their role in the program.	10		
5	a. Are key process parameters that may affect equipment integrity (i.e. IOW) identified and monitored to determine whether operations are maintained within established reliability limits?	5		
	b. Are systems in place that alert appropriate personnel when operation exceeds IOW limits?	4		
	c. Are response protocols established and used in a timely manner when IOW limits are exceeded?	4		
6	An unbiased evaluation is made of the level of compliance with written operating procedures on a periodic basis?	10		10 pts for having a periodic evaluation program. +3 pts for performing the reviews once every 2 years or more frequent.
	Total for Section	100	0	

Table 2.A.5—Mechanical Integrity

Item	Question	Possible Score	Actual Score	Scoring Guidance
1	Has a written inspection program for the facility been developed that includes the following elements.			
	a. All equipment needing inspection has been identified including at minimum: tanks, pressure vessels, piping and piping components, and PRDs?	5		
	b. The responsibilities to conduct the inspections have been assigned?	1		
	c. The inspection methods and locations have been specified for all equipment in the program?	3		
	d. Inspection interval basis have been established for all equipment in the program (time based, condition based, RBI)?	3		
	e. Inspection reporting requirements have been defined?	1		
2	Is there a complete, up-to-date, central storage location for all inspection program information available to everyone who works with the process?	3		2 pts for central location. + 1 pt for controlled access with appropriate availability.
3	Is there a permanent and progressive record for all equipment in the program that includes all of the following:			
	a. manufacturers' data reports and other pertinent design data records;	1		
	b. equipment drawings;	1		
	c. results of all inspections, repairs, alterations, or re-ratings that have occurred to date.	3		0 to 3 pts depending on completeness of records.
4	Does the written inspection program for the facility require an appropriate level of review and authorization prior to any permanent changes in inspection interval basis or methods and testing procedures?	3		
5	Have adequate inspection checklists been developed, are in use, and are maintained?	1		
6	Are all inspections, tests and repairs performed on the process equipment being documented and documentation reviewed for quality and consistency in a timely manner, including all of the following information. a. The date of the inspection. b. The name of the person who performed the inspection. c. Identification of the equipment inspected. d. A description of the inspection or testing. e. Assessment of identified defects based on company established protocol. f. The results of the inspection. g. All recommendations resulting from the inspection. h. A date and description of all maintenance performed. i. RBI effectiveness is correctly/consistently applied and assigned for each RBI damage mechanism addressed.	3		+1/3 pt for each item, round up.
7	Does the written inspection program for the facility include an established inspection effectiveness table based on API 581?	2		

Item	Question	Possible Score	Actual Score	Scoring Guidance
8	Does the written inspection program for the facility require all deficiencies identified in process equipment pressure boundaries be evaluated to determine if corrective action is required and if continued operation is acceptable?	3		
	a. Are decisions to continue to operate the equipment based on sound engineering assessment such as fitness for service?	2		
	b. If corrective actions are required, is a system used to determine priorities for action and tracking to completion ahead of established due dates?	1		
9	Has all equipment within the process unit(s) been evaluated for inclusion in the RBI program and where excluded, the basis for exclusion is clearly documented?	3		
10	a. Does the written inspection program for the facility include a formal, external visual inspection program?	2		
	b. Are all the following factors considered in the external visual inspection program: the condition of the outside of equipment, insulation, painting/coatings, supports and attachments, and identifying mechanical damage, corrosion, vibration, leakage or improper components or repairs, skirt, grounding wire, ladders, platforms, decks, bolted connections, gasket conditions, flange makeup, etc.?	2		
	c. Based on the inspection program for the facility, does all equipment in the program receive a visual external inspection at the required interval (or deferred date if there is an approved deferral)?	1		0 pts if there are a significant number of overdue inspections.
11	Based on the inspection program, do all pressure vessels in the unit receive an internal, or detailed external inspection using appropriate NDE procedures, as required by the applicable code/standard/jurisdictional requirements (or deferred date if there is an approved deferral)?	5		2 pt for having inspections set up. +1 pt for having process to approve NDE in lieu of internal inspection. +2 pts for not having past due inspections.
12	a. Has each item of process equipment been reviewed by appropriate personnel to identify the probable causes of damage or failure?	2		
	b. Has this information been used to establish the inspection methods, locations, and frequencies and the preventive maintenance programs?	3		
	c. Have defect limits for expected damage mechanisms been established based on sound engineering assessments?	2		

Item	Question	Possible Score	Actual Score	Scoring Guidance
13	a. Is a formal program for condition monitoring of stationary equipment been established for the facility?	3		
	b. When the locations for condition monitoring are chosen:			
	1. is the likelihood and consequence of failure considered?	1		
	2. is localized corrosion and erosion considered?	1		
	c. Are condition monitoring locations clearly marked on inspection drawings and on the equipment to allow repetitive measurements at precisely the same locations?	2		
	d. Are condition monitoring surveys up to date?	2		
	e. Are the results used to calculate a representative corrosion rate for RBI assessments?	2		
14	Procedures and processes are in place to ensure thickness and wall loss measurements used for RBI analysis are accurate?	4		
15	Has the maximum allowable working pressure (MAWP) been established for all piping systems and equipment, using applicable codes and current operating conditions?	1		
16	Does the program require formal risk evaluation and approval of date changes for inspection and repair plans (i.e. deferrals) related to operational needs?	3		1 pt for written procedure. 1 pt for detailed risk evaluation guidance. 1 pt for demonstrable full adherence.
17	a. Have all employees involved in maintaining and inspecting the equipment been trained in all procedures applicable to their job tasks to ensure that they can perform the job tasks effectively?	1		
	b. At completion of the training described above, are formal methods used to verify that the employees understand what they were trained on?	1		
18	Are inspectors certified for performance in accordance with applicable industry codes and standards (e.g. API 510, 570, and/or 653)?	2		
19	Does the facility have a quality assurance program for construction and maintenance to ensure that:			
	a. proper materials of construction are used?	2		
	b. fabrication, welding, and inspection procedures are proper?	2		
	c. equipment maintenance and repairs are completed in compliance with codes and standards?	1		
	d. flanges are properly assembled and tightened?	1		
	e. replacement and maintenance materials are properly specified, inspected, and stored?	1		

Item	Question	Possible Score	Actual Score	Scoring Guidance
20	Are systems in place, such as written requirements with appropriate approval, sufficient to ensure that all design repair and alteration done on equipment types in the program is done in accordance with the code to which the equipment was built, or in-service repair and inspection code?	3		2 pts for meeting some requirements. 3 pts for all of the above.
21	Are systems in place, such as written requirements with appropriate approval, sufficient to ensure that new equipment design, for all equipment types in the program, is done in accordance with the applicable codes and standards?	3		2 pts for meeting some requirements. 3 pts for all of the above.
22	Are RBI assessments updated and maintained in a timely manner after events that would change the basis of the risk evaluation so that the most recent process, inspection, and maintenance information is included?	5		3 pts for periodic full-unit reassessments before the end of the plan period. +1 pt for evergreening after each inspection event. +1 pt for evergreening after process excursions and applicable MOCs.
23	If credit for CP being taken in RBI, is the CP system inspected on a periodic basis and maintained in effective status?	3		If CP is not applicable to facility equipment, full credit may be taken.
	Total for Section	100	0	

Table 2.A.6—Equipment Failure Investigation

Item	Question	Possible Score	Actual Score	Scoring Guidance
1	a. Is there a written equipment failure investigation procedure that includes both loss of containment and threats to loss of containment?	5		
	b. Does the procedure require that findings and recommendations of investigations be addressed and resolved promptly? Do records demonstrate timely completion?	5		
2	Does the procedure require that the investigation team include:			
	a. a member trained in root cause analysis techniques?	8		
	b. cross-functional attendees competent in their area (corrosion, inspection, operations, equipment design, etc.)?	5		
3	Indicate whether the investigation procedure requires an investigation of the following items with the results recorded on a standard form(s).			
	a. Loss of primary containment.	8		
	b. Unexpected equipment damage.	6		
	c. Chronic equipment failures.	3		
4	Is there a standard form(s) for equipment failure investigation that includes the following information?			
	a. Date of failure.	1		
	b. Investigation attendees.	1		
	c. Description of the incident.	1		
	d. Underlying causes of the incident.	5		
	e. Evaluation of the potential severity and probable frequency of recurrence.	2		
5	f. Recommendations are generated to prevent recurrence not just in the exact incident scenario but more globally where a similar occurrence is possible on other equipment or units.	10		
	Based on a review of plant records (leaks, lost production, etc.), to what degree does it appear that the established equipment failure investigation procedures are being followed?	5		5 pts: > 95 % of the time. 3 pts: Only major impacts.
6	Are appropriate inspection or engineering people required to be involved in a failure analysis to identify the conditions or practices that caused the failure?	5		

Item	Question	Possible Score	Actual Score	Scoring Guidance
7	Are incident investigation reports reviewed with all affected personnel whose job tasks are relevant to the incident findings, including contract employees, where applicable?	5		
8	Are incident or accident reports or report conclusions transmitted to other sites that operate similar facilities within the company?	5		
9	a. Do the procedures for incident reporting require that the findings related to stationary equipment loss of primary containment include a review of the RBI data, IOW, and corrosion management programs to ensure the RBI assessment, IOW program, and corrosion management documents accurately reflect the active damage mechanisms, rate of degradation, and consequence.	10		
	b. RBI data is updated as a result of incident investigations that show the RBI data is not accurate.	10		
	Total for Section	100	0	

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Risk-Based Inspection Methodology
Part 2—Probability of Failure Methodology
Annex 2.B—Determination of Corrosion Rates

2.B.1 Overview

2.B.1.1 Determination of Corrosion Rate

The corrosion rate should be calculated from measured thickness data available from equipment inspection(s). However, if a calculated corrosion rate is not available, estimated corrosion rates may be determined for each potential thinning mechanism using this document or as estimated by a corrosion specialist.

Screening questions are used to determine which of the thinning mechanism sections apply. These applicable sections will be entered to determine conservative estimated corrosion rates for possible thinning mechanisms. The screening questions listed in [Table 2.B.1.1](#) are used to select the applicable thinning mechanism.

2.B.1.2 Determination of Thinning Type

The results of effective inspections that have been performed on the equipment or piping should be used to designate the type of thinning (i.e. general vs local). If this information is not known, then [Table 2.B.1.2](#) lists the type of thinning (general or local) expected for various thinning mechanisms. If both general and local thinning mechanisms are possible, then the type of thinning should be designated as local. The type of thinning designated will be used to determine the effectiveness of inspection performed.

2.B.1.3 Tables

Table 2.B.1.1—Screening Questions for Corrosion Rate Calculations

Screening Questions	Action
HCl Corrosion - Does the process contain HCl? - Is free water present in the process stream (including initial condensing condition)? - Is the pH < 7.0?	If Yes to all, proceed to Section 2.B.2
High-temperature Sulfidic/Naphthenic Acid Corrosion - Does the process contain oil with sulfur compounds? - Is the operating temperature > 400 °F (204 °C)?	If Yes to both, proceed to Section 2.B.3
High-temperature H₂S/H₂ Corrosion - Does the process contain H₂S and hydrogen? - Is the operating temperature > 400 °F (204 °C)?	If Yes to both, proceed to Section 2.B.4
Sulfuric Acid (H₂SO₄) Corrosion Does the process contain H₂SO₄?	If Yes, proceed to Section 2.B.5
HF Corrosion Does the process stream contain HF?	If Yes, proceed to Section 2.B.6
Sour Water Corrosion Is free water with H₂S present?	If Yes, proceed to Section 2.B.7
Amine Corrosion Is equipment exposed to acid gas treating amines [monoethanolamine (MEA), diethanolamine (DEA), diisopropanolamine (DIPA), or methyldiethanolamine (MDEA)]?	If Yes, proceed to Section 2.B.8
High-temperature Oxidation - Is the temperature ≥ 900 °F (482 °C)? - Is there oxygen present?	If Yes to both, proceed to Section 2.B.9
Acid Sour Water - Is free water with H₂S present and pH < 7.0? - Does the process contain < 50 ppm chlorides?	If Yes to both, proceed to Section 2.B.10
Cooling Water Is equipment in cooling water service?	If Yes, proceed to Section 2.B.11
Soil-side corrosion - Is equipment in contact with soil (buried or partially buried)? - Is the material of construction carbon steel?	If Yes to both, proceed to Section 2.B.12
CO₂ Corrosion - Is free water with CO₂ present (including consideration for dew point condensation)? - Is the material of construction carbon steel or < 13 % Cr?	If Yes to both, proceed to Section 2.B.13
AST Bottom Is the equipment item an AST tank bottom?	If Yes, proceed to Section 2.B.14

Table 2.B.1.2—Type of Thinning

Thinning Mechanism	Condition	Type of Thinning
HCl corrosion	—	Local
High-temperature sulfidic/naphthenic acid corrosion	Total acid number (TAN) ≤ 0.5	General
	TAN > 0.5	Local
High-temperature H ₂ S/H ₂ corrosion	—	General
Sulfuric acid (H ₂ SO ₄) corrosion	Low Velocity ≤ 2 ft/s (0.61 m/s) for carbon steel, ≤ 4 ft/s (1.22 m/s) for stainless steel (SS), and ≤ 6 ft/s (1.83 m/s) for higher alloys	General
	High Velocity ≥ 2 ft/s (0.61 m/s) for carbon steel, ≥ 4 ft/s (1.22 m/s) for SS, and ≥ 6 ft/s (1.83 m/s) for higher alloys	Local
HF corrosion	—	Local
Sour water corrosion	Low Velocity: ≤ 20 ft/s (6.1 m/s)	General
	High Velocity: > 20 ft/s (6.1 m/s)	Local
Amine corrosion	Low Velocity < 5 ft/s (1.5 m/s) rich amine < 20 ft/s (6.1 m/s) lean amine	General
	High Velocity > 5 ft/s (1.5 m/s) rich amine > 20 ft/s (6.1 m/s) lean amine	Local
High-temperature oxidation	—	General
Acid sour water corrosion	< 6 ft/s (1.83 m/s)	General
	≥ 6 ft/s (1.83 m/s)	Local
Cooling water corrosion	≤ 3 ft/s (0.91 m/s)	Local
	3 to 9 ft/s (0.91 to 2.74 m/s)	General
	> 9 ft/s (2.74 m/s)	Local
Soil-side corrosion	—	Local
CO ₂ corrosion	—	Local
AST bottom	Product side	Local
	Soil side	Local

2.B.2 HCl Corrosion

2.B.2.1 Description of Damage

HCl corrosion is a concern in some of the most common refining process units. HCl is aggressive to many common materials of construction across a wide range of concentrations and is often localized in nature, particularly when it is associated with localized or shock condensation or the deposition of chloride containing ammonia or amine salts. Austenitic SS will often suffer pitting attack and may experience crevice corrosion and/or CISCC. Some of the nickel-based alloys may experience accelerated corrosion if oxidizing agents are present or if the alloys are not in the solution annealed heat treatment condition.

The primary refining units where HCl corrosion is a concern are crude distillation, hydrotreating, and catalytic reforming. HCl forms in crude units by the hydrolysis of magnesium and calcium chloride salts and results in dilute HCl in the overhead system. In hydrotreating units, HCl may form by hydrogenation of organic chlorides in the feed or can enter the unit with hydrocarbon feed or hydrogen and condense with water in the effluent train. In catalytic reforming units, chlorides may be stripped off of the catalyst and hydrogenate resulting in HCl corrosion in the effluent train or regeneration systems.

2.B.2.2 Basic Data

The data listed in [Table 2.B.2.1](#) are required to estimate the rate of corrosion in dilute HCl. More concentrated acid is outside the scope of this section. If precise data has not been measured, a knowledgeable process specialist should be consulted.

2.B.2.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.2.1](#). The HCl corrosion rate may be determined using the basic data in [Table 2.B.2.1](#) in conjunction with [Tables 2.B.2.3](#) through [2.B.2.6](#).

2.B.2.4 References

See References [\[46\]](#), [\[78\]](#), [\[79\]](#), [\[80\]](#), [\[92\]](#), and [\[93\]](#) in [Annex 2.G](#).

2.B.2.5 Tables

Table 2.B.2.1—HCl—Basic Data Required for Analysis

Material of Construction	Determine the Material of Construction of the Equipment Item
pH or Cl ⁻ concentration	pH is preferred for estimating the corrosion rate at dilute concentrations for carbon steel and 300 series SS. Table 2.B.2.2 may be used to estimate pH from the Cl⁻ concentration if it is known. The presence of neutralizing agents may elevate the pH, however. For high-alloy materials, Cl⁻ concentration is used to estimate the corrosion rate. NOTE The pH used should be of the separated acid phase within this equipment or nearest equipment downstream, e.g. the overhead accumulator boot water downstream of the overhead condenser.
Maximum temperature, °F (°C)	Determine the maximum temperature present in this equipment/piping. This may be the maximum process temperature, but local heating condition such as effect of the sun or heat tracing should be considered.
Presence of air or oxidants (Yes or No)	Presence of air (oxygen) may increase corrosion rates, particularly for Alloy 400 and Alloy B-2. Other oxidants such as ferric and cupric ions will have a similar effect on these alloys.

Table 2.B.2.2—HCl Corrosion—Determination of pH from Cl⁻ Concentration

Cl ⁻ Concentration (wppm)	pH
3,601 to 12,000	0.5
1,201 to 3,600	1.0
361 to 1,200	1.5
121 to 360	2.0
36 to 120	2.5
16 to 35	3.0
6 to 15	3.5
3 to 5	4.0
1 to 2	4.5
< 1	5.0
NOTE Assumes no alkaline agent present (NH ₃ , neutralizing amines or caustic).	

Table 2.B.2.3—HCl Corrosion—Estimated Corrosion Rates for Carbon Steel (mpy)

pH	Temperature (°F)			
	100	125	175	200
0.5	999	999	999	999
0.80	900	999	999	999
1.25	400	999	999	999
1.75	200	700	999	999
2.25	100	300	400	560
2.75	60	130	200	280
3.25	40	70	100	140
3.75	30	50	90	125
4.25	20	40	70	100
4.75	10	30	50	70
5.25	7	20	30	40
5.75	4	15	20	30
6.25	3	10	15	20
6.80	2	5	7	10

Table 2.B.2.3M—HCl Corrosion—Estimated Corrosion Rates for Carbon Steel (mm/yr)

pH	Temperature (°C)			
	38	52	79	93
0.5	25.37	25.37	25.37	25.37
0.80	22.86	25.37	25.37	25.37
1.25	10.16	25.37	25.37	25.37
1.75	5.08	17.78	25.37	25.37
2.25	2.54	7.62	10.16	14.22
2.75	1.52	3.30	5.08	7.11
3.25	1.02	1.78	2.54	3.56
3.75	0.76	1.27	2.29	3.18
4.25	0.51	1.02	1.78	2.54
4.75	0.25	0.76	1.27	1.78
5.25	0.18	0.51	0.76	1.02
5.75	0.10	0.38	0.51	0.76
6.25	0.08	0.25	0.38	0.51
6.80	0.05	0.13	0.18	0.25

Table 2.B.2.4—HCl Corrosion—Estimated Corrosion Rates for Type 304, 316, 321, 347 Series Stainless Steels (mpy)

pH	Temperature (°F)			
	100	125	175	200
0.5	900	999	999	999
0.80	500	999	999	999
1.25	300	500	700	999
1.75	150	260	400	500
2.25	80	140	200	250
2.75	50	70	100	120
3.25	30	40	50	65
3.75	20	25	30	35
4.25	10	15	20	25
4.75	5	7	10	12
5.25	4	5	6	7
5.75	3	4	5	6
6.25	2	3	4	5
6.80	1	2	3	4

NOTE These rates are 10 times the general corrosion rates to account for localized pitting corrosion.

Table 2.B.2.4M—HCl Corrosion—Estimated Corrosion Rates for Type 304, 316, 321, 347 Series Stainless Steels (mm/yr)

pH	Temperature (°C)			
	38	52	79	93
0.5	22.86	25.37	25.37	25.37
0.80	12.70	25.37	25.37	25.37
1.25	7.62	12.70	17.78	25.37
1.75	3.81	6.60	10.16	12.70
2.25	2.03	3.56	5.08	6.35
2.75	1.27	1.78	2.54	3.05
3.25	0.76	1.02	1.27	1.65
3.75	0.51	0.64	0.76	0.89
4.25	0.25	0.38	0.51	0.64
4.75	0.13	0.18	0.25	0.30
5.25	0.10	0.13	0.15	0.18
5.75	0.08	0.10	0.13	0.15
6.25	0.05	0.08	0.10	0.13
6.80	0.03	0.05	0.08	0.10

NOTE These rates are 10 times the general corrosion rates to account for localized pitting corrosion.

Table 2.B.2.5—HCl Corrosion—Estimated Corrosion Rates for Alloys 825, 20, 625, C-276 (mpy)

Alloy	Cl ⁻ Concentration (wt %)	Temperature (°F)			
		100	125	175	200
Alloy 825 and Alloy 20	0.50	1	3	40	200
	0.75	2	5	80	400
	1.0	10	70	300	999
Alloy 625	0.50	1	2	15	75
	0.75	1	5	25	125
	1.0	2	70	200	400
Alloy C-276	0.50	1	2	8	30
	0.75	1	2	15	75
	1.0	2	10	60	300

Table 2.B.2.5M—HCl Corrosion—Estimated Corrosion Rates for Alloys 825, 20, 625, C-276 (mm/yr)

Alloy	Cl ⁻ Concentration (wt %)	Temperature (°C)			
		38	52	79	93
Alloy 825 and Alloy 20	0.50	0.03	0.08	1.02	5.08
	0.75	0.05	0.13	2.03	10.16
	1.0	0.25	1.78	7.62	25.37
Alloy 625	0.50	0.03	0.05	0.38	1.91
	0.75	0.03	0.13	0.64	3.18
	1.0	0.05	1.78	5.08	10.16
Alloy C-276	0.50	0.03	0.05	0.20	0.76
	0.75	0.03	0.05	0.38	1.91
	1.0	0.05	0.25	1.52	7.62

Table 2.B.2.6—HCl Corrosion—Estimated Corrosion Rates for Alloy B-2 and Alloy 400 (mpy)

Alloy	Cl ⁻ Concentration (wt %)	Temperature (°F)							
		100		125		175		200	
		Oxygen/Oxidants Present?							
		No	Yes	No	Yes	No	Yes	No	Yes
Alloy B-2	0.50	1	4	1	4	2	8	4	16
	0.75	1	4	1	4	5	20	20	80
	1.0	2	8	5	20	10	40	25	100
Alloy 400	0.50	1	4	3	12	30	120	300	999
	0.75	2	10	5	20	80	320	800	999
	1.0	19	40	25	100	150	600	900	999

Table 2.B.2.6M—HCl Corrosion—Estimated Corrosion Rates for Alloy B-2 and Alloy 400 (mm/yr)

Alloy	Cl ⁻ Concentration (wt %)	Temperature (°C)							
		38		52		79		93	
		Oxygen/Oxidants Present?							
		No	Yes	No	Yes	No	Yes	No	Yes
Alloy B-2	0.50	0.03	0.1	0.03	0.1	0.05	0.2	0.1	0.41
	0.75	0.03	0.1	0.03	0.1	0.13	0.51	0.51	2.03
	1.0	0.05	0.2	0.13	0.51	0.25	1.02	0.64	2.54
Alloy 400	0.50	0.03	0.1	0.08	0.3	0.76	3.05	7.62	25.37
	0.75	0.05	0.25	0.13	0.51	2.03	8.13	20.32	25.37
	1.0	0.48	1.02	0.64	2.54	3.81	15.24	22.86	25.37

2.B.2.6 Figures

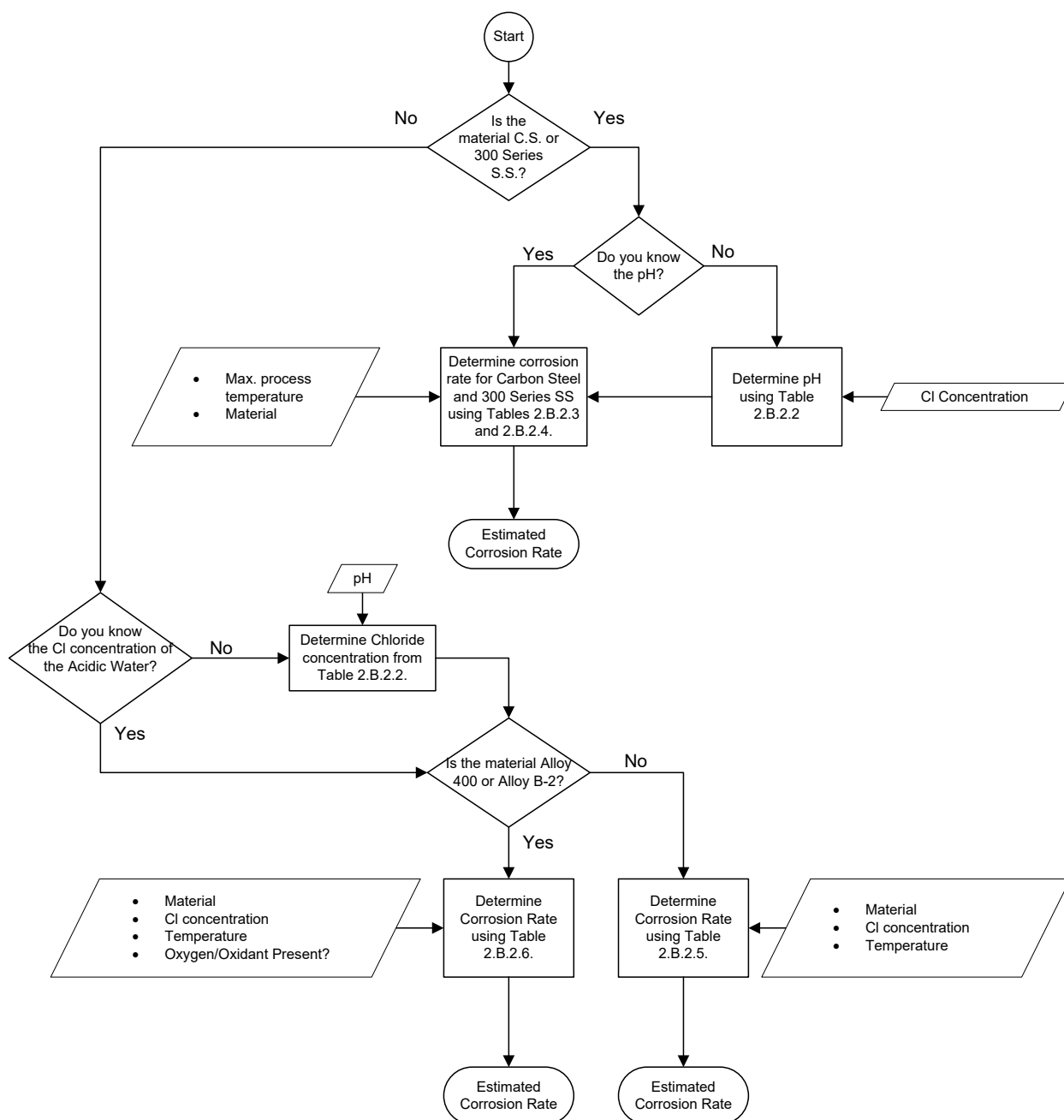


Figure 2.B.2.1—HCl Corrosion—Determination of Corrosion Rate

2.B.3 High-temperature Sulfidic and Naphthenic Acid Corrosion

2.B.3.1 Description of Damage

2.B.3.1.1 High-temperature Sulfidic Corrosion

High-temperature sulfidic corrosion is a form of normally uniform corrosion that can occur at temperatures typically above about 400 °F (204 °C). This form of corrosion sometimes occurs along with naphthenic acid corrosion depending on the oil being processed. Naphthenic acid corrosion, when it occurs, is normally localized.

Sulfur species occur naturally in most crude oils, but their concentrations vary from crude-to-crude. These naturally occurring compounds may be corrosive themselves as well as when they are converted to hydrogen sulfide through thermal decomposition. Catalytic conversion of sulfur compounds to 2S occurs in the presence of hydrogen and a catalyst bed in hydroprocessing units. Corrosion in vapor streams containing both H₂S and hydrogen is covered in [Section 2.B.4](#).

2.B.3.1.2 Naphthenic Acid Corrosion

As with sulfur compounds, naphthenic acids occur naturally in some crude oils. During distillation, these acids tend to concentrate in higher boiling point fractions such as heavy atmospheric gas oil, atmospheric resid, and vacuum gas oils. The acids may also be present in vacuum resid, but often many of the more corrosive ones will have distilled into the vacuum side streams. Lower boiling point streams are usually low in naphthenic acids. Corrosion may appear either as pitting, more common at lower acid levels, or grooving and gouging at higher acid levels and, particularly, at higher velocities. Naphthenic acids may destabilize protective films (sulfides or oxides) on the material and thus allow a high sulfidation corrosion rate to continue or it may itself directly attack the base material.

2.B.3.1.3 Combined Corrosion Effects

The corrosion rate in high-temperature sulfidic environments is a function of the material, temperature, and the concentration of the sulfur compound(s) present. The presence of naphthenic acid in sufficient amounts, however, can dramatically decrease a material's corrosion resistance where it might otherwise have suitable corrosion resistance. The following summarizes the key variables in corrosion.

- a) In high-temperature sulfidic environments, materials such as carbon and low-alloy steels form sulfide corrosion products. The extent to which these are protective depends on the environmental factors mentioned. At high enough temperatures and/or sulfur levels, the corrosion products may become less protective so corrosion can occur at an accelerated rate.
- b) Moderate additions of chromium to carbon steel increase the material's corrosion resistance. Alloys containing 5Cr-0.5Mo, 7Cr-1Mo, and 9Cr-1Mo are often sufficient to provide acceptable material performance in these environments. Lower alloys such as 1.25Cr-0.5Mo and 2.25Cr-1Mo generally do not offer sufficient benefits over carbon steel to justify their use. Stainless steels such as 12Cr (Type 405, 410, 410S) and Type 304 may be required at higher sulfur levels and temperatures.
- c) High-temperature sulfidic corrosion is related to the amount of sulfur present in the stream and is usually reported simply as wt % sulfur. Corrosion generally increases with increasing sulfur content.
- d) High-temperature sulfidic corrosion occurs at temperatures greater than about 450 °F (232 °C). Naphthenic acid corrosion typically has been observed in the 450 °F to 800 °F (232 °C to 427 °C) temperature range although corrosion that exhibits naphthenic acid characteristics has been reported outside this temperature range. Above 800 °F (427 °C), the naphthenic acids either break down or distill into the vapor phase. While sulfidation will occur in both liquid and vapor phases, naphthenic acid corrosion occurs only where liquid phase is present.
- e) The materials most vulnerable to naphthenic acid corrosion are carbon steel and the iron-chrome (5 % to 12 % Cr) alloys commonly used in corrosive refining services. 12Cr may experience corrosion rates greater than that of carbon steel. Type 304 SS offers some resistance to naphthenic acid corrosion at lower acid levels, but normally the molybdenum containing austenitic SS (Type 316 or Type 317 SS) are required for resistance to greater acid concentrations. It has been found that a minimum Mo content of 2.5 % is required in Type 316 SS to provide the best resistance to naphthenic acids.
- f) The amount of naphthenic acid present is most commonly indicated by a neutralization number or TAN. The various acids which comprise the naphthenic acid family can have distinctly different corrosivities. The TAN is determined by an ASTM standard titration and is reported in mg KOH/g, which is the amount of potassium hydroxide (KOH) required to neutralize the acidity of one gram of oil sample. While both colorimetric and potentiometric titration methods are available, the potentiometric method covered by

ASTM D664 is the more commonly used method. It should be noted that the titration neutralizes all of the acids present and not just the naphthenic acids. For example, dissolved hydrogen sulfide will be represented in the TAN of a sample. From a corrosion standpoint, the TAN of the liquid hydrocarbon stream being evaluated rather than the TAN of the whole crude is the important parameter in determining susceptibility to naphthenic acid corrosion.

- g) Another important factor in corrosion is the stream velocity, particularly where naphthenic acid is a factor in corrosion. Increased velocity increases the corrosivity by enhancing removal of protective sulfides. This effect is most pronounced in mixed liquid-vapor phase systems where velocities may be high.
- h) At particularly low sulfur levels, naphthenic acid corrosion may be more severe, even at low TAN since protective sulfides may not readily form.

2.B.3.2 Corrosion Rate Variability

There are several factors that influence the variability in the corrosion rates for sulfidation, when values obtained from the modified McConey curves and measured corrosion rates are compared. Factors including sulfur content, silicon content of the carbon steel, and flow regime/velocity should be considered when determining the estimated corrosion rates, specifically when little or no information is available for the specific unit components.

In general, the stream corrosivity will increase as the sulfur content of the stream increases. Many different sulfur species exist in crude oil and can affect corrosion differently. Sulfur in the crude can be in the form of H_2S , mercaptans, elemental sulfur, polysulfides, thiophenes, aliphatic sulfides, and aliphatic disulfides. Each one of these species has a different reactivity or effect on corrosion rates. As a result, different crudes with same total sulfur content can have very different corrosivity due to the sulfur species combination. Crude analysis of crude oils and its fractions is performed to identify the various sulfur species present. Predictive models can be developed based on a combination of laboratory testing and field experience.

Corrosion rates are accelerated when components are put in service due to the exposed steel surface in the sulfur-containing environment. Corrosion rates slow down as a protective sulfide scale forms and reduces diffusion. The protective sulfide scale is a relatively weak crystal lattice that may be removed in high velocity conditions that induces shear stress and/or by naphthenic acid. Exposing the unprotected material surface to the sulfur compounds causes accelerated corrosion. The repeated process of stripping the protective sulfide scale to expose the material and reforming the sulfide scale results in high corrosion rates. A flow velocity > 100 ft/s (30.48 m/s) is known to strip the sulfide protective scale and prevent formation of the sulfide scale and result in severe corrosion.

No flow or very low flow can cause stratification of corrosive species and result in preferential corrosion attack. Silicon content of < 0.10 % in carbon steel components can also result in accelerated sulfidation corrosion rates. In some applications, carbon steel may appear to be performing well with low measured corrosion rates until an unexpected failure occurs at an unidentified, low-silicon component in the circuit.

The process units where sulfidic and naphthenic acid corrosion is most commonly observed are atmospheric and vacuum crude distillation as well as the feed systems of downstream units such as hydrotreaters, catalytic crackers, and cokers. In hydrotreaters, naphthenic acid corrosion has not been reported downstream of the hydrogen addition point, even upstream of the reactor. Catalytic crackers and cokers thermally decompose naphthenic acids so this form of corrosion is also not normally reported in the fractionation sections of these units unless uncracked feed is carried in. Naphthenic acids can appear in high concentrations in lube extract oil streams when naphthenic acid containing feeds are processed. It should be noted that where naphthenic acids may thermally decompose, lighter organic acids or carbon dioxide may form that can affect the corrosivity of condensed waters.

2.B.3.3 Basic Data

The data listed in [Table 2.B.3.1](#) are required to determine the estimated rate of corrosion in high-temperature sulfidic and naphthenic acid service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.3.4 Determination of Corrosion Rate

The corrosion rate may be determined using the basic data in [Table 2.B.3.1](#) in conjunction with [Table 2.B.3.2](#) through [Table 2.B.3.10](#).

The corrosion rate in high-temperature sulfidic environments in the absence of a naphthenic acid influence is based upon the modified McConey curves. For components in service with no naphthenic acid, the corrosion rate follows the McConey curves represented by the lowest TAN content ($\text{TAN} < 0.3$) in each of [Tables 2.B.3.2](#) through [2.B.2.10](#).

While various papers have been presented on naphthenic acid corrosion, no widely accepted correlations have yet been developed between corrosion rate and the various factors influencing it. Due to the lack of accurate industry tools for estimating naphthenic acid corrosion, the estimate rates provided in [Table 2.B.3.2](#) through [Table 2.B.3.10](#) should be adjusted to improve accuracy as high quality plant corrosion rate data becomes available through ultrasonic testing (UT) scans, radiographic testing (RT) surveys, well-placed corrosion and/or ultrasonic probes, and other monitoring methods. Consequently, the corrosion rates provided in the tables for naphthenic acid is a rough estimate of the actual corrosion rate in the specific service.

Once a corrosion rate is selected from the appropriate table, it should be multiplied by a factor of 5 if the velocity is $> 100 \text{ ft/s}$ (30.48 m/s).

2.B.3.5 References

See References [\[94\]](#), [\[95\]](#) (Appendix 3), [\[96\]](#), and [\[97\]](#) in [Annex 2.G](#).

2.B.3.6 Tables

Table 2.B.3.1—High-temperature Sulfidic and Naphthenic Acid Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping. For 316 SS, if the Mo content is not known, assume it is $< 2.5 \text{ wt } \%$.
Maximum temperature, $^{\circ}\text{F}$ ($^{\circ}\text{C}$)	Determine the maximum temperature of the process stream.
Sulfur content of the stream	Determine the sulfur content of the stream that is in this piece of equipment. If sulfur content is not known, contact a knowledgeable process engineer for an estimate.
TAN ($\text{TAN} = \text{mg KOH/g oil sample}$)	The TAN of importance is that of the liquid hydrocarbon phase present in the equipment/piping being evaluated. If not known, consult a knowledgeable process engineer for an estimate.
Velocity	Determine the maximum velocity in this equipment/piping. Although conditions in a vessel may be essentially stagnant, the velocity in flowing nozzles should be considered.

Table 2.B.3.2—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for Carbon Steel (mpy)

Sulfur (wt %)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	> 750
0.2	0.3	1	3	7	15	20	35	50	60
	0.65	5	15	25	35	45	55	65	75
	1.5	20	25	35	65	120	150	180	200
	3.0	30	60	60	120	150	160	240	240
	4.0	40	80	100	160	180	200	280	300
0.4	0.3	1	4	10	20	30	50	70	80
	0.65	5	10	15	25	40	60	80	90
	1.5	8	15	25	35	50	75	90	110
	3.0	10	20	35	50	70	100	120	130
	4.0	20	30	50	70	90	120	140	160
0.6	0.3	1	5	10	25	40	60	90	100
	0.65	5	10	15	30	50	80	110	130
	1.5	10	15	30	50	80	100	130	150
	3.0	15	30	50	80	100	120	140	170
	4.0	25	40	60	100	120	150	180	200
1.5	0.3	2	5	15	30	50	80	110	130
	0.65	7	10	20	35	55	100	130	150
	1.5	15	20	35	55	100	120	140	170
	3.0	20	30	55	85	110	150	170	200
	4.0	30	45	75	120	140	180	200	260
2.5	0.3	2	7	20	35	55	95	130	150
	0.65	7	10	30	45	60	120	140	170
	1.5	15	20	40	60	75	140	170	200
	3.0	20	35	60	90	120	170	200	260
	4.0	35	50	80	120	150	200	260	280
3.0	0.3	2	8	20	40	60	100	140	160
	0.65	8	15	25	45	65	120	150	170
	1.5	20	25	35	65	120	150	180	200
	3.0	30	60	60	120	150	160	240	240
	4.0	40	80	100	160	180	200	280	300

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.2M—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for Carbon Steel (mm/yr)

Sulfur (wt %)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	> 399
0.2	0.3	0.03	0.08	0.18	0.38	0.51	0.89	1.27	1.52
	0.65	0.13	0.38	0.64	0.89	1.14	1.40	1.65	1.91
	1.5	0.51	0.64	0.89	1.65	3.05	3.81	4.57	5.08
	3.0	0.76	1.52	1.52	3.05	3.81	4.06	6.10	6.10
	4.0	1.02	2.03	2.54	4.06	4.57	5.08	7.11	7.62
0.4	0.3	0.03	0.10	0.25	0.51	0.76	1.27	1.78	2.03
	0.65	0.13	0.25	0.38	0.64	1.02	1.52	2.03	2.29
	1.5	0.20	0.38	0.64	0.89	1.27	1.91	2.29	2.79
	3.0	0.25	0.51	0.89	1.27	1.78	2.54	3.05	3.30
	4.0	0.51	0.76	1.27	1.78	2.29	3.05	3.56	4.06
0.6	0.3	0.03	0.13	0.25	0.64	1.02	1.52	2.29	2.54
	0.65	0.13	0.25	0.38	0.76	1.27	2.03	2.79	3.30
	1.5	0.25	0.38	0.76	1.27	2.03	2.54	3.30	3.81
	3.0	0.38	0.76	1.27	2.03	2.54	3.05	3.56	4.32
	4.0	0.64	1.02	1.52	2.54	3.05	3.81	4.57	5.08
1.5	0.3	0.05	0.13	0.38	0.76	1.27	2.03	2.79	3.30
	0.65	0.18	0.25	0.51	0.89	1.40	2.54	3.30	3.81
	1.5	0.38	0.51	0.89	1.40	2.54	3.05	3.56	4.32
	3.0	0.51	0.76	1.40	2.16	2.79	3.81	4.32	5.08
	4.0	0.76	1.14	1.91	3.05	3.56	4.57	5.08	6.60
2.5	0.3	0.05	0.18	0.51	0.89	1.40	2.41	3.30	3.81
	0.65	0.18	0.25	0.76	1.14	1.52	3.05	3.56	4.32
	1.5	0.38	0.51	1.02	1.52	1.91	3.56	4.32	5.08
	3.0	0.51	0.89	1.52	2.29	3.05	4.32	5.08	6.60
	4.0	0.89	1.27	2.03	3.05	3.81	5.08	6.60	7.11
3.0	0.3	0.05	0.20	0.51	1.02	1.52	2.54	3.56	4.06
	0.65	0.20	0.38	0.64	1.14	1.65	3.05	3.81	4.32
	1.5	0.51	0.64	0.89	1.65	3.05	3.81	4.57	5.08
	3.0	0.76	1.52	1.52	3.05	3.81	4.06	6.10	6.10
	4.0	1.02	2.03	2.54	4.06	4.57	5.08	7.11	7.62

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.3—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 1Cr-0.2 Mo, 1Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mpy)

Sulfur (wt %)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	> 750
0.2	0.3	1	1	4	7	13	21	25	30
	0.65	3	8	15	20	25	30	35	40
	1.5	10	15	20	30	60	75	90	100
	3.0	15	30	30	60	75	85	120	120
	4.0	20	40	50	80	100	120	140	160
0.4	0.3	1	2	5	10	20	30	35	40
	0.65	3	5	8	15	20	30	40	45
	1.5	4	8	15	20	25	40	45	55
	3.0	5	10	20	25	35	50	60	65
	4.0	10	15	25	35	45	60	70	80
0.8	0.3	1	3	6	15	25	40	45	50
	0.65	3	5	8	20	30	45	55	60
	1.5	5	8	15	25	40	50	65	75
	3.0	7	15	25	40	50	60	70	85
	4.0	12	20	30	50	60	75	90	100
1.5	0.3	2	3	8	15	30	50	55	65
	0.65	4	5	10	20	40	55	65	75
	1.5	6	10	20	30	50	65	70	80
	3.0	10	15	30	45	60	75	85	100
	4.0	15	20	35	60	75	90	100	130
2.5	0.3	2	4	9	20	35	55	65	75
	0.65	4	5	15	25	40	60	70	80
	1.5	7	10	20	30	45	70	80	100
	3.0	10	15	30	45	60	80	100	120
	4.0	15	25	40	60	80	100	120	140
3.0	0.3	2	4	10	20	35	60	70	80
	0.65	5	8	15	25	40	70	75	85
	1.5	10	15	20	30	60	75	90	100
	3.0	15	30	30	60	75	85	120	120
	4.0	20	40	50	80	100	120	140	160

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.3M—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 1Cr-0.2 Mo, 1Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mm/yr)

Sulfur (wt %)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	> 399
0.2	0.3	0.03	0.03	0.10	0.18	0.33	0.53	0.64	0.76
	0.65	0.08	0.20	0.38	0.51	0.64	0.76	0.89	1.02
	1.5	0.25	0.38	0.51	0.76	1.52	1.91	2.29	2.54
	3.0	0.38	0.76	0.76	1.52	1.91	2.16	3.05	3.05
	4.0	0.51	1.02	1.27	2.03	2.54	3.05	3.56	4.06
0.4	0.3	0.03	0.05	0.13	0.25	0.51	0.76	0.89	1.02
	0.65	0.08	0.13	0.20	0.38	0.51	0.76	1.02	1.14
	1.5	0.10	0.20	0.38	0.51	0.64	1.02	1.14	1.40
	3.0	0.13	0.25	0.51	0.64	0.89	1.27	1.52	1.65
	4.0	0.25	0.38	0.64	0.89	1.14	1.52	1.78	2.03
0.8	0.3	0.03	0.08	0.15	0.38	0.64	1.02	1.14	1.27
	0.65	0.08	0.13	0.20	0.51	0.76	1.14	1.40	1.52
	1.5	0.13	0.20	0.38	0.64	1.02	1.27	1.65	1.91
	3.0	0.18	0.38	0.64	1.02	1.27	1.52	1.78	2.16
	4.0	0.30	0.51	0.76	1.27	1.52	1.91	2.29	2.54
1.5	0.3	0.05	0.08	0.20	0.38	0.76	1.27	1.40	1.65
	0.65	0.10	0.13	0.25	0.51	1.02	1.40	1.65	1.91
	1.5	0.15	0.25	0.51	0.76	1.27	1.65	1.78	2.03
	3.0	0.25	0.38	0.76	1.14	1.52	1.91	2.16	2.54
	4.0	0.38	0.51	0.89	1.52	1.91	2.29	2.54	3.30
2.5	0.3	0.05	0.10	0.23	0.51	0.89	1.40	1.65	1.91
	0.65	0.10	0.13	0.38	0.64	1.02	1.52	1.78	2.03
	1.5	0.18	0.25	0.51	0.76	1.14	1.78	2.03	2.54
	3.0	0.25	0.38	0.76	1.14	1.52	2.03	2.54	3.05
	4.0	0.38	0.64	1.02	1.52	2.03	2.54	3.05	3.56
3.0	0.3	0.05	0.10	0.25	0.51	0.89	1.52	1.78	2.03
	0.65	0.13	0.20	0.38	0.64	1.02	1.78	1.91	2.16
	1.5	0.25	0.38	0.51	0.76	1.52	1.91	2.29	2.54
	3.0	0.38	0.76	0.76	1.52	1.91	2.16	3.05	3.05
	4.0	0.51	1.02	1.27	2.03	2.54	3.05	3.56	4.06

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.4—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 5Cr-0.5Mo (mpy)

Sulfur (wt %)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	> 750
0.2	0.7	1	1	2	4	6	8	10	15
	1.1	2	3	4	6	10	10	15	20
	1.75	7	10	15	20	25	35	45	50
	3.0	10	15	20	30	40	45	50	60
	4.0	15	20	30	40	50	60	70	80
0.4	0.7	1	2	3	5	8	10	15	20
	1.1	2	3	4	6	10	15	20	25
	1.75	2	4	6	8	15	20	25	30
	3.0	4	6	8	10	15	20	30	35
	4.0	6	8	10	10	20	25	35	40
0.75	0.7	1	2	4	6	10	15	23	25
	1.1	2	4	6	8	15	20	25	30
	1.75	4	6	8	10	15	20	30	35
	3.0	6	8	10	10	20	25	35	40
	4.0	8	10	10	15	20	30	40	50
1.5	0.7	1	2	5	8	15	20	30	35
	1.1	3	5	10	15	20	30	35	40
	1.75	5	10	15	20	30	35	40	45
	3.0	10	15	20	30	35	40	45	50
	4.0	15	20	30	35	40	50	60	70
2.5	0.7	1	3	6	9	15	20	35	40
	1.1	5	7	10	15	20	25	40	45
	1.75	7	10	15	20	25	35	45	50
	3.0	10	15	20	30	40	45	50	60
	4.0	15	20	30	40	50	60	70	80
3.0	0.7	2	3	6	10	15	25	35	40
	1.1	5	7	10	15	20	30	40	45
	1.75	7	10	15	20	25	35	45	50
	3.0	10	15	20	30	40	45	50	60
	4.0	15	20	30	40	50	60	70	80

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.4M—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 5Cr-0.5Mo (mm/yr)

Sulfur (wt %)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	> 399
0.2	0.7	0.03	0.03	0.05	0.10	0.15	0.20	0.25	0.38
	1.1	0.05	0.08	0.10	0.15	0.25	0.25	0.38	0.51
	1.75	0.18	0.25	0.38	0.51	0.64	0.89	1.14	1.27
	3.0	0.25	0.38	0.51	0.76	1.02	1.14	1.27	1.52
	4.0	0.38	0.51	0.76	1.02	1.27	1.52	1.78	2.03
0.4	0.7	0.03	0.05	0.08	0.13	0.20	0.25	0.38	0.51
	1.1	0.05	0.08	0.10	0.15	0.25	0.38	0.51	0.64
	1.75	0.05	0.10	0.15	0.20	0.38	0.51	0.64	0.76
	3.0	0.10	0.15	0.20	0.25	0.38	0.51	0.76	0.89
	4.0	0.15	0.20	0.25	0.25	0.51	0.64	0.89	1.02
0.75	0.7	0.03	0.05	0.10	0.15	0.25	0.38	0.58	0.64
	1.1	0.05	0.10	0.15	0.20	0.38	0.51	0.64	0.76
	1.75	0.10	0.15	0.20	0.25	0.38	0.51	0.76	0.89
	3.0	0.15	0.20	0.25	0.25	0.51	0.64	0.89	1.02
	4.0	0.20	0.25	0.25	0.38	0.51	0.76	1.02	1.27
1.5	0.7	0.03	0.05	0.13	0.20	0.38	0.51	0.76	0.89
	1.1	0.08	0.13	0.25	0.38	0.51	0.76	0.89	1.02
	1.75	0.13	0.25	0.38	0.51	0.76	0.89	1.02	1.14
	3.0	0.25	0.38	0.51	0.76	0.89	1.02	1.14	1.27
	4.0	0.38	0.51	0.76	0.89	1.02	1.27	1.52	1.78
2.5	0.7	0.03	0.08	0.15	0.23	0.38	0.51	0.89	1.02
	1.1	0.13	0.18	0.25	0.38	0.51	0.64	1.02	1.14
	1.75	0.18	0.25	0.38	0.51	0.64	0.89	1.14	1.27
	3.0	0.25	0.38	0.51	0.76	1.02	1.14	1.27	1.52
	4.0	0.38	0.51	0.76	1.02	1.27	1.52	1.78	2.03
3.0	0.7	0.05	0.08	0.15	0.25	0.38	0.64	0.89	1.02
	1.1	0.13	0.18	0.25	0.38	0.51	0.76	1.02	1.14
	1.75	0.18	0.25	0.38	0.51	0.64	0.89	1.14	1.27
	3.0	0.25	0.38	0.51	0.76	1.02	1.14	1.27	1.52
	4.0	0.38	0.51	0.76	1.02	1.27	1.52	1.78	2.03

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.5—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 7Cr-1Mo (mpy)

Sulfur (wt %)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	> 750
0.2	0.7	1	1	1	2	4	6	7	8
	1.1	1	2	3	5	7	8	10	15
	1.75	4	7	10	15	20	25	30	35
	3.0	7	10	15	20	25	30	35	45
	4.0	10	15	20	25	30	35	45	60
0.4	0.7	1	1	2	4	5	8	10	15
	1.1	1	2	4	5	8	10	15	15
	1.75	2	4	5	6	10	15	15	20
	3.0	3	5	6	9	12	15	20	20
	4.0	4	6	9	10	15	20	20	25
0.8	0.7	1	1	3	4	6	10	15	15
	1.1	2	3	4	6	10	15	15	20
	1.75	3	4	6	10	12	15	20	25
	3.0	4	6	10	12	15	20	25	30
	4.0	5	10	12	15	20	25	30	35
1.5	0.7	1	2	3	6	8	15	15	20
	1.1	2	3	6	10	15	15	20	25
	1.75	3	6	10	15	20	20	25	30
	3.0	6	10	15	20	20	25	30	35
	4.0	10	15	20	20	25	30	35	45
2.5	0.7	1	2	4	6	9	15	20	25
	1.1	6	7	9	10	15	20	25	30
	1.75	7	9	10	15	20	25	30	35
	3.0	9	10	15	20	30	35	35	40
	4.0	10	15	20	30	35	40	50	55
3.0	0.7	1	2	4	7	10	15	20	25
	1.1	2	4	7	10	15	20	25	30
	1.75	4	7	10	15	20	25	30	35
	3.0	7	10	15	20	25	30	35	45
	4.0	10	15	20	25	30	35	45	60

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.5M—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 7Cr-1Mo (mm/yr)

Sulfur (wt %)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	> 399
0.2	0.7	0.03	0.03	0.03	0.05	0.10	0.15	0.18	0.20
	1.1	0.03	0.05	0.08	0.13	0.18	0.20	0.25	0.38
	1.75	0.10	0.18	0.25	0.38	0.51	0.64	0.76	0.89
	3.0	0.18	0.25	0.38	0.51	0.64	0.76	0.89	1.14
	4.0	0.25	0.38	0.51	0.64	0.76	0.89	1.14	1.52
0.4	0.7	0.03	0.03	0.05	0.10	0.13	0.20	0.25	0.38
	1.1	0.03	0.05	0.10	0.13	0.20	0.25	0.38	0.38
	1.75	0.05	0.10	0.13	0.15	0.25	0.38	0.38	0.51
	3.0	0.08	0.13	0.15	0.23	0.30	0.38	0.51	0.51
	4.0	0.10	0.15	0.23	0.25	0.38	0.51	0.51	0.64
0.8	0.7	0.03	0.03	0.08	0.10	0.15	0.25	0.38	0.38
	1.1	0.05	0.08	0.10	0.15	0.25	0.38	0.38	0.51
	1.75	0.08	0.10	0.15	0.25	0.30	0.38	0.51	0.64
	3.0	0.10	0.15	0.25	0.30	0.38	0.51	0.64	0.76
	4.0	0.13	0.25	0.30	0.38	0.51	0.64	0.76	0.89
1.5	0.7	0.03	0.05	0.08	0.15	0.20	0.38	0.38	0.51
	1.1	0.05	0.08	0.15	0.25	0.38	0.38	0.51	0.64
	1.75	0.08	0.15	0.25	0.38	0.51	0.51	0.64	0.76
	3.0	0.15	0.25	0.38	0.51	0.51	0.64	0.76	0.89
	4.0	0.25	0.38	0.51	0.51	0.64	0.76	0.89	1.14
2.5	0.7	0.03	0.05	0.10	0.15	0.23	0.38	0.51	0.64
	1.1	0.15	0.18	0.23	0.25	0.38	0.51	0.64	0.76
	1.75	0.18	0.23	0.25	0.38	0.51	0.64	0.76	0.89
	3.0	0.23	0.25	0.38	0.51	0.76	0.89	0.89	1.02
	4.0	0.25	0.38	0.51	0.76	0.89	1.02	1.27	1.40
3.0	0.7	0.03	0.05	0.10	0.18	0.25	0.38	0.51	0.64
	1.1	0.05	0.10	0.18	0.25	0.38	0.51	0.64	0.76
	1.75	0.10	0.18	0.25	0.38	0.51	0.64	0.76	0.89
	3.0	0.18	0.25	0.38	0.51	0.64	0.76	0.89	1.14
	4.0	0.25	0.38	0.51	0.64	0.76	0.89	1.14	1.52

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.6—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 9Cr-1Mo (mpy)

Sulfur (wt %)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	> 750
0.2	0.7	1	1	1	2	3	4	5	6
	1.1	1	2	2	4	4	5	6	8
	1.75	2	4	5	8	10	15	15	20
	3.0	3	6	10	12	15	20	20	25
	4.0	5	8	12	15	20	25	30	30
0.4	0.7	1	1	2	3	4	6	7	8
	1.1	1	1	2	4	5	7	8	10
	1.75	2	2	3	5	8	8	10	10
	3.0	3	3	5	8	10	10	12	15
	4.0	4	5	8	10	10	12	15	15
0.8	0.7	1	1	2	3	5	8	9	10
	1.1	1	2	3	5	8	10	10	10
	1.75	2	3	5	8	10	10	10	15
	3.0	3	5	8	10	10	15	15	15
	4.0	5	8	10	10	15	15	20	20
1.5	0.7	1	1	2	4	6	10	10	15
	1.1	1	2	3	5	7	10	15	15
	1.75	2	4	4	6	8	12	15	20
	3.0	3	6	5	8	10	15	20	20
	4.0	5	8	10	12	15	20	20	25
2.5	0.7	1	1	3	5	7	10	15	15
	1.1	1	2	4	6	8	10	15	15
	1.75	2	4	5	8	10	15	15	20
	3.0	3	6	10	12	15	20	20	25
	4.0	5	8	12	15	20	25	30	30
3.0	0.7	1	1	3	5	8	10	15	15
	1.1	2	3	5	8	10	15	15	20
	1.75	3	5	10	12	15	20	20	25
	3.0	5	8	12	15	20	25	30	30
	4.0	7	9	15	20	25	30	35	40

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.6M—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 9Cr-1Mo (mm/yr)

Sulfur (wt %)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	> 399
0.2	0.7	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
	1.1	0.03	0.05	0.05	0.10	0.10	0.13	0.15	0.20
	1.75	0.05	0.10	0.13	0.20	0.25	0.38	0.38	0.51
	3.0	0.08	0.15	0.25	0.30	0.38	0.51	0.51	0.64
	4.0	0.13	0.20	0.30	0.38	0.51	0.64	0.76	0.76
0.4	0.7	0.03	0.03	0.05	0.08	0.10	0.15	0.18	0.20
	1.1	0.03	0.03	0.05	0.10	0.13	0.18	0.20	0.25
	1.75	0.05	0.05	0.08	0.13	0.20	0.20	0.25	0.25
	3.0	0.08	0.08	0.13	0.20	0.25	0.25	0.30	0.38
	4.0	0.10	0.13	0.20	0.25	0.25	0.30	0.38	0.38
0.8	0.7	0.03	0.03	0.05	0.08	0.13	0.20	0.23	0.25
	1.1	0.03	0.05	0.08	0.13	0.20	0.25	0.25	0.25
	1.75	0.05	0.08	0.13	0.20	0.25	0.25	0.25	0.38
	3.0	0.08	0.13	0.20	0.25	0.25	0.38	0.38	0.38
	4.0	0.13	0.20	0.25	0.25	0.38	0.38	0.51	0.51
1.5	0.7	0.03	0.03	0.05	0.10	0.15	0.25	0.25	0.38
	1.1	0.03	0.05	0.08	0.13	0.18	0.25	0.38	0.38
	1.75	0.05	0.10	0.10	0.15	0.20	0.30	0.38	0.51
	3.0	0.08	0.15	0.13	0.20	0.25	0.38	0.51	0.51
	4.0	0.13	0.20	0.25	0.30	0.38	0.51	0.51	0.64
2.5	0.7	0.03	0.03	0.08	0.13	0.18	0.25	0.38	0.38
	1.1	0.03	0.05	0.10	0.15	0.20	0.25	0.38	0.38
	1.75	0.05	0.10	0.13	0.20	0.25	0.38	0.38	0.51
	3.0	0.08	0.15	0.25	0.30	0.38	0.51	0.51	0.64
	4.0	0.13	0.20	0.30	0.38	0.51	0.64	0.76	0.76
3.0	0.7	0.03	0.03	0.08	0.13	0.20	0.25	0.38	0.38
	1.1	0.05	0.08	0.13	0.20	0.25	0.38	0.38	0.51
	1.75	0.08	0.13	0.25	0.30	0.38	0.51	0.51	0.64
	3.0	0.13	0.20	0.30	0.38	0.51	0.64	0.76	0.76
	4.0	0.18	0.23	0.38	0.51	0.64	0.76	0.89	1.02

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.7—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 12 % Cr Steel (mpy)

Sulfur (wt %)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	> 750
0.2	0.7	1	1	1	1	1	1	2	2
	1.1	1	1	1	1	1	2	4	5
	1.75	2	2	2	4	4	5	8	10
	3.0	5	10	15	20	25	30	25	40
	4.0	10	15	20	25	30	25	40	45
0.4	0.7	1	1	1	1	1	2	3	3
	1.1	1	1	1	1	1	2	3	3
	1.75	1	2	2	2	2	4	5	5
	3.0	2	3	3	3	3	5	10	15
	4.0	3	4	5	8	10	12	15	20
0.8	0.7	1	1	1	1	1	2	3	4
	1.1	1	1	1	1	1	2	3	4
	1.75	2	2	4	5	6	6	7	8
	3.0	3	3	5	8	10	12	15	20
	4.0	4	5	5	8	10	15	20	25
1.5	0.7	1	1	1	1	2	3	4	5
	1.1	1	1	1	1	2	3	4	5
	1.75	2	2	3	5	7	8	10	10
	3.0	3	3	5	8	10	12	15	20
	4.0	5	8	10	12	15	20	25	30
2.5	0.7	1	1	1	1	2	3	5	6
	1.1	1	1	1	1	2	3	5	6
	1.75	2	5	7	9	10	12	15	15
	3.0	3	8	10	15	20	20	25	30
	4.0	5	10	15	20	25	30	35	40
3.0	0.7	1	1	1	1	2	4	5	6
	1.1	1	1	1	1	2	4	5	6
	1.75	3	5	7	9	10	12	15	15
	3.0	4	8	10	15	20	20	25	30
	4.0	5	10	15	20	25	30	35	40

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.7M—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 12 % Cr Steel (mm/yr)

Sulfur (wt %)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	> 399
0.2	0.7	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05
	1.1	0.03	0.03	0.03	0.03	0.03	0.05	0.10	0.13
	1.75	0.05	0.05	0.05	0.10	0.10	0.13	0.20	0.25
	3.0	0.13	0.25	0.38	0.51	0.64	0.76	0.64	1.02
	4.0	0.25	0.38	0.51	0.64	0.76	0.64	1.02	1.14
0.4	0.7	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08
	1.1	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08
	1.75	0.03	0.05	0.05	0.05	0.05	0.10	0.13	0.13
	3.0	0.05	0.08	0.08	0.08	0.08	0.13	0.25	0.38
	4.0	0.08	0.10	0.13	0.20	0.25	0.30	0.38	0.51
0.8	0.7	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.10
	1.1	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.10
	1.75	0.05	0.05	0.10	0.13	0.15	0.15	0.18	0.20
	3.0	0.08	0.08	0.13	0.20	0.25	0.30	0.38	0.51
	4.0	0.10	0.13	0.13	0.20	0.25	0.38	0.51	0.64
1.5	0.7	0.03	0.03	0.03	0.03	0.05	0.08	0.10	0.13
	1.1	0.03	0.03	0.03	0.03	0.05	0.08	0.10	0.13
	1.75	0.05	0.05	0.08	0.13	0.18	0.20	0.25	0.25
	3.0	0.08	0.08	0.13	0.20	0.25	0.30	0.38	0.51
	4.0	0.13	0.20	0.25	0.30	0.38	0.51	0.64	0.76
2.5	0.7	0.03	0.03	0.03	0.03	0.05	0.08	0.13	0.15
	1.1	0.03	0.03	0.03	0.03	0.05	0.08	0.13	0.15
	1.75	0.05	0.13	0.18	0.23	0.25	0.30	0.38	0.38
	3.0	0.08	0.20	0.25	0.38	0.51	0.51	0.64	0.76
	4.0	0.13	0.25	0.38	0.51	0.64	0.76	0.89	1.02
3.0	0.7	0.03	0.03	0.03	0.03	0.05	0.10	0.13	0.15
	1.1	0.03	0.03	0.03	0.03	0.05	0.10	0.13	0.15
	1.75	0.08	0.13	0.18	0.23	0.25	0.30	0.38	0.38
	3.0	0.10	0.20	0.25	0.38	0.51	0.51	0.64	0.76
	4.0	0.13	0.25	0.38	0.51	0.64	0.76	0.89	1.02

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.8—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for Austenitic SS Without Mo (mpy)

Sulfur (wt %)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	> 750
0.2	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	2	3	4	4
	4.0	1	1	1	2	3	4	5	6
0.4	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	2	3	4	4
	4.0	1	1	1	2	3	4	5	6
0.8	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	1	1	2	3	4	5	6
	4.0	1	2	2	4	6	8	10	12
1.5	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	1	1	2	3	4	5	6
	4.0	1	2	2	4	6	8	10	12
2.5	1.0	1	1	1	1	1	1	1	1
	1.5	1	1	1	1	1	1	1	1
	3.0	1	2	2	4	6	8	10	12
	4.0	1	2	4	7	10	14	17	20
3.0	1.0	1	1	1	1	1	1	1	2
	1.5	1	1	1	1	1	2	2	2
	3.0	1	2	2	4	6	8	10	12
	4.0	1	2	4	7	10	14	17	20

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.8M—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for Austenitic SS Without Mo (mm/yr)

Sulfur (wt %)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	> 399
0.2	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.05	0.08	0.10	0.10
	4.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
0.4	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.05	0.08	0.10	0.10
	4.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
0.8	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
	4.0	0.03	0.05	0.05	0.10	0.15	0.20	0.25	0.30
1.5	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.15
	4.0	0.03	0.05	0.05	0.10	0.15	0.20	0.25	0.30
2.5	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	1.5	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.05	0.05	0.10	0.15	0.20	0.25	0.30
	4.0	0.03	0.05	0.10	0.18	0.25	0.36	0.43	0.51
3.0	1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05
	1.5	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05
	3.0	0.03	0.05	0.05	0.10	0.15	0.20	0.25	0.30
	4.0	0.03	0.05	0.10	0.18	0.25	0.36	0.43	0.51

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.9—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 316 SS with < 2.5 % Mo (mpy)

Sulfur (wt %)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	> 750
0.2	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	1	2	2	2
	4.0	1	1	1	2	4	5	7	10
0.4	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	2	2	2	2
	4.0	1	1	2	3	4	5	7	10
0.8	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	2	2	2	3
	4.0	1	1	2	3	5	5	7	10
1.5	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	1	3	3	3	4
	4.0	1	1	3	5	5	5	7	10
2.5	0.2	1	1	1	1	1	1	1	1
	3.0	1	1	1	2	3	3	4	5
	4.0	1	1	3	5	5	6	8	10
3.0	0.2	1	1	1	1	1	1	1	2
	3.0	1	1	1	2	4	5	5	6
	4.0	1	2	3	5	5	6	8	10

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.9M—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 316 SS with < 2.5 % Mo (mm/yr)

Sulfur (wt %)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	> 399
0.2	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.05
	4.0	0.03	0.03	0.03	0.05	0.10	0.13	0.18	0.25
0.4	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.05
	4.0	0.03	0.03	0.05	0.08	0.10	0.13	0.18	0.25
0.8	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.08
	4.0	0.03	0.03	0.05	0.08	0.13	0.13	0.18	0.25
1.5	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.03	0.08	0.08	0.08	0.10
	4.0	0.03	0.03	0.08	0.13	0.13	0.13	0.18	0.25
2.5	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	3.0	0.03	0.03	0.03	0.05	0.08	0.08	0.10	0.13
	4.0	0.03	0.03	0.08	0.13	0.13	0.15	0.20	0.25
3.0	0.2	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05
	3.0	0.03	0.03	0.03	0.05	0.10	0.13	0.13	0.15
	4.0	0.03	0.05	0.08	0.13	0.13	0.15	0.20	0.25

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.10—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 316 SS with ≥ 2.5 % Mo and 317 SS (mpy)

Sulfur (wt %)	TAN (mg/g)	Temperature (°F)							
		≤ 450	500	550	600	650	700	750	> 750
0.2	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	1	1	2	4	5
	6.0	1	1	1	2	4	5	7	10
0.4	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	1	2	4	4	5
	6.0	1	1	2	3	4	5	7	10
0.8	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	1	2	4	4	5
	6.0	1	1	2	3	4	5	7	10
1.5	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	1	2	3	5	7
	6.0	1	1	3	5	5	5	7	10
2.5	4.0	1	1	1	1	1	1	1	1
	5.0	1	1	1	2	3	4	5	7
	6.0	1	1	3	5	5	6	8	10
3.0	4.0	1	1	1	1	1	1	1	2
	5.0	1	1	1	2	3	4	5	7
	6.0	1	2	3	5	5	6	8	10

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

Table 2.B.3.10M—High-temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 316 SS with ≥ 2.5 % Mo and 317 SS (mm/yr)

Sulfur (wt %)	TAN (mg/g)	Temperature (°C)							
		≤ 232	260	288	315	343	371	399	> 399
0.2	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.03	0.03	0.05	0.10	0.13
	6.0	0.03	0.03	0.03	0.05	0.10	0.13	0.18	0.25
0.4	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.03	0.05	0.10	0.10	0.13
	6.0	0.03	0.03	0.05	0.08	0.10	0.13	0.18	0.25
0.8	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.03	0.05	0.10	0.10	0.13
	6.0	0.03	0.03	0.05	0.08	0.10	0.13	0.18	0.25
1.5	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.03	0.05	0.08	0.13	0.18
	6.0	0.03	0.03	0.08	0.13	0.13	0.13	0.18	0.25
2.5	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	5.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.18
	6.0	0.03	0.03	0.08	0.13	0.13	0.15	0.20	0.25
3.0	4.0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05
	5.0	0.03	0.03	0.03	0.05	0.08	0.10	0.13	0.18
	6.0	0.03	0.05	0.08	0.13	0.13	0.15	0.20	0.25

NOTE The corrosion rates in this table are estimates and may be nonconservative. The corrosion rate should be multiplied by a factor of 5 if the velocity is > 100 ft/s (30.48 m/s). Monitoring method and a field measurement data should be used when available for corrosion rate assignment in the RBI assessment.

2.B.3.7 Figures

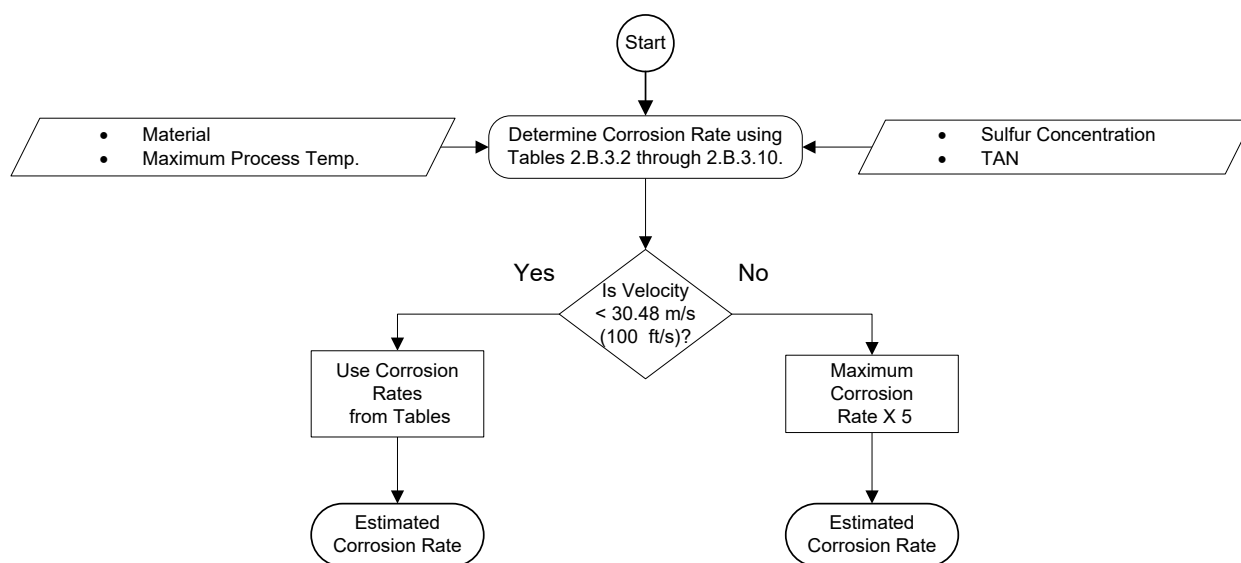


Figure 2.B.3.1—High-temperature Sulfidic and Naphthenic Acid Corrosion

2.B.4 High-temperature H₂S/H₂ Corrosion

2.B.4.1 Description of Damage

High-temperature H₂S/H₂ corrosion is a form of normally uniform corrosion that can occur at temperatures typically above about 400 °F (204 °C). This form of sulfidation corrosion differs from high-temperature sulfidic and naphthenic corrosion described in [Section 2.B.3](#). H₂S/H₂ corrosion occurs in hydroprocessing units, e.g. hydrodesulfurizers and hydrocrackers, once sulfur compounds are converted to hydrogen sulfide via catalytic reaction with hydrogen. Conversion of sulfur compounds to H₂S/H₂ typically does not occur to a significant extent in the presence of hydrogen, even at elevated temperatures, unless a catalyst is present. The corrosion rate is a function of the material of construction, temperature, nature of the process stream, and the concentration of H₂S.

In H₂S/H₂ environments, low levels of chromium (e.g. 5 % to 9 % Cr) provide only a modest increase to the corrosion resistance of steel. A minimum of 12 % Cr is needed to provide a significant decrease in corrosion rate. Further addition of chromium and nickel provides a substantial increase in corrosion resistance. The nature of the process stream is a factor in determining the corrosion rate. In H₂S/H₂ environments alone (all vapor), corrosion rates may be as much as 50 % greater than in the presence of hydrocarbons as suggested by the referenced NACE committee report. Nevertheless, the correlations developed by Couper and Gorman [\[100\]](#) are used for estimating corrosion rates in both hydrocarbon-free and hydrocarbon-containing services. The predicted rates in both services are very high at high H₂S levels and temperatures, and the one set of data is satisfactory for RBI assessment purposes of either situation.

2.B.4.2 Basic Data

The data listed in [Table 2.B.4.1](#) are required to determine the rate of corrosion in high-temperature H₂S/H₂ service. If precise data has not been measured, a knowledgeable process specialist should be consulted.

2.B.4.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.4.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.4.1](#) in conjunction with [Tables 2.B.4.2](#) through [2.B.4.7](#).

The estimated corrosion rates in H_2S/H_2 environments in these tables were determined using data from the correlations developed by Couper and Gorman [\[100\]](#).

2.B.4.4 References

See References [\[95\]](#), [\[98\]](#), [\[99\]](#), and [\[100\]](#) in [Annex 2.G](#).

2.B.4.5 Tables

Table 2.B.4.1—High-temperature H_2S/H_2 Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping.
Type of hydrocarbon present (naphtha or gas oil)	The Couper–Gorman corrosion rate curves are dependent on the type of hydrocarbon stream present [95] [100] . There are two categories as follows. 1) Naphtha refers to those hydrocarbon streams of both light and heavy naphtha as well as light distillates (streams typically boiling at < 430 °F). 2) Gas oil refers to those hydrocarbon streams that include distillate, atmospheric gas oils, resid, and other heavier process hydrocarbons (streams typically boiling at > 430 °F).
Maximum temperature, °F (°C)	Determine the maximum process temperature.
H_2S content of the vapor (mole %)	Determine the H_2S content in the vapor. NOTE mole % = volume % (not wt %).

Table 2.B.4.2—High-temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for Carbon Steel, 1Cr-0.2 Mo, 1Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mpy)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°F)											
		425	475	525	575	625	675	725	775	825	875	925	975
0.002	Naphtha	1	1	1	1	2	3	4	6	8	10	14	18
	Gas oil	1	1	1	2	3	5	7	10	14	20	26	34
0.0035	Naphtha	1	1	1	2	4	6	8	12	16	22	29	37
	Gas oil	1	2	3	4	7	11	16	22	31	41	55	71
0.008	Naphtha	1	1	2	3	5	7	11	15	21	29	38	50
	Gas oil	1	2	4	6	9	14	21	29	41	55	73	94
0.035	Naphtha	1	2	3	5	9	13	19	27	38	51	67	87
	Gas oil	2	4	6	10	16	25	36	51	71	96	130	170
0.08	Naphtha	1	2	4	7	10	16	23	33	46	62	82	110
	Gas oil	2	4	8	13	20	30	44	63	87	120	160	200
0.30	Naphtha	2	3	6	10	15	23	34	48	66	90	120	150
	Gas oil	3	6	11	18	29	44	64	91	130	170	230	300
0.75	Naphtha	2	4	7	11	17	26	38	54	75	100	130	170
	Gas oil	4	7	12	21	32	49	72	100	140	190	250	330
1.0	Naphtha	3	5	8	13	21	32	47	67	93	130	170	220
	Gas oil	5	9	15	26	40	61	89	130	180	240	310	410

Table 2.B.4.2M—High-temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for Carbon Steel, 1Cr-0.2 Mo, 1Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mm/yr)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°C)											
		218	246	274	302	329	357	385	413	441	468	496	524
0.002	Naphtha	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.25	0.36	0.46
	Gas oil	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.36	0.51	0.66	0.86
0.0035	Naphtha	0.03	0.03	0.03	0.05	0.1	0.15	0.2	0.3	0.41	0.56	0.74	0.94
	Gas oil	0.03	0.05	0.08	0.1	0.18	0.28	0.41	0.56	0.79	1.04	1.4	1.8
0.008	Naphtha	0.03	0.03	0.05	0.08	0.13	0.18	0.28	0.38	0.53	0.74	0.97	1.27
	Gas oil	0.03	0.05	0.1	0.15	0.23	0.36	0.53	0.74	1.04	1.4	1.85	2.39
0.035	Naphtha	0.03	0.05	0.08	0.13	0.23	0.33	0.48	0.69	0.97	1.3	1.7	2.21
	Gas oil	0.05	0.1	0.15	0.25	0.41	0.64	0.91	1.3	1.8	2.44	3.3	4.32
0.08	Naphtha	0.03	0.05	0.1	0.18	0.25	0.41	0.58	0.84	1.17	1.57	2.08	2.79
	Gas oil	0.05	0.1	0.2	0.33	0.51	0.76	1.12	1.6	2.21	3.05	4.06	5.08
0.30	Naphtha	0.05	0.08	0.15	0.25	0.38	0.58	0.86	1.22	1.68	2.29	3.05	3.81
	Gas oil	0.08	0.15	0.28	0.46	0.74	1.12	1.63	2.31	3.3	4.32	5.84	7.62
0.75	Naphtha	0.05	0.1	0.18	0.28	0.43	0.66	0.97	1.37	1.91	2.54	3.3	4.32
	Gas oil	0.1	0.18	0.3	0.53	0.81	1.24	1.83	2.54	3.56	4.83	6.35	8.38
1.0	Naphtha	0.08	0.13	0.2	0.33	0.53	0.81	1.19	1.7	2.36	3.3	4.32	5.59
	Gas oil	0.13	0.23	0.38	0.66	1.02	1.55	2.26	3.3	4.57	6.1	7.87	10.41

Table 2.B.4.3—High-temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 5Cr-0.5Mo (mpy)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°F)											
		425	475	525	575	625	675	725	775	825	875	925	975
0.002	Naphtha	1	1	1	1	1	2	3	4	6	8	11	14
	Gas oil	1	1	1	2	3	4	6	8	12	16	21	27
0.0035	Naphtha	1	1	1	2	3	5	7	9	13	18	23	30
	Gas oil	1	1	2	4	6	9	13	18	25	33	44	57
0.008	Naphtha	1	1	2	2	4	6	9	12	17	23	31	40
	Gas oil	1	2	3	5	7	11	17	24	33	44	58	76
0.035	Naphtha	1	2	3	4	7	10	15	22	30	41	54	70
	Gas oil	2	3	5	8	13	20	29	41	57	77	100	130
0.08	Naphtha	1	2	3	5	8	13	19	27	37	50	66	85
	Gas oil	2	4	6	10	16	24	36	51	70	94	130	160
0.30	Naphtha	1	3	5	8	12	19	27	39	53	72	95	120
	Gas oil	3	5	9	15	23	35	52	73	100	140	180	240
0.75	Naphtha	2	3	5	9	14	21	31	44	60	81	110	140
	Gas oil	3	6	10	17	26	40	58	82	110	150	200	270
1.0	Naphtha	2	4	7	11	17	26	38	54	75	100	130	170
	Gas oil	4	7	12	21	32	49	72	100	140	190	250	330

**Table 2.B.4.3M—High-temperature H₂S/H₂ Corrosion—Estimated
Corrosion Rates for 5Cr-0.5Mo (mm/yr)**

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°C)											
		218	246	274	302	329	357	385	413	441	468	496	524
0.002	Naphtha	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.28	0.36
	Gas oil	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.3	0.41	0.53	0.69
0.0035	Naphtha	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.23	0.33	0.46	0.58	0.76
	Gas oil	0.03	0.03	0.05	0.1	0.15	0.23	0.33	0.46	0.64	0.84	1.12	1.45
0.008	Naphtha	0.03	0.03	0.05	0.05	0.1	0.15	0.23	0.3	0.43	0.58	0.79	1.02
	Gas oil	0.03	0.05	0.08	0.13	0.18	0.28	0.43	0.61	0.84	1.12	1.47	1.93
0.035	Naphtha	0.03	0.05	0.08	0.1	0.18	0.25	0.38	0.56	0.76	1.04	1.37	1.78
	Gas oil	0.05	0.08	0.13	0.2	0.33	0.51	0.74	1.04	1.45	1.96	2.54	3.3
0.08	Naphtha	0.03	0.05	0.08	0.13	0.2	0.33	0.48	0.69	0.94	1.27	1.68	2.16
	Gas oil	0.05	0.1	0.15	0.25	0.41	0.61	0.91	1.3	1.78	2.39	3.3	4.06
0.30	Naphtha	0.03	0.08	0.13	0.2	0.3	0.48	0.69	0.99	1.35	1.83	2.41	3.05
	Gas oil	0.08	0.13	0.23	0.38	0.58	0.89	1.32	1.85	2.54	3.56	4.57	6.1
0.75	Naphtha	0.05	0.08	0.13	0.23	0.36	0.53	0.79	1.12	1.52	2.06	2.79	3.56
	Gas oil	0.08	0.15	0.25	0.43	0.66	1.02	1.47	2.08	2.79	3.81	5.08	6.86
1.0	Naphtha	0.05	0.1	0.18	0.28	0.43	0.66	0.97	1.37	1.91	2.54	3.3	4.32
	Gas oil	0.1	0.18	0.3	0.53	0.81	1.24	1.83	2.54	3.56	4.83	6.35	8.38

**Table 2.B.4.4—High-temperature H₂S/H₂ Corrosion—Estimated
Corrosion Rates for 7Cr Steel (mpy)**

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°F)											
		425	475	525	575	625	675	725	775	825	875	925	975
0.002	Naphtha	1	1	1	1	1	2	3	4	6	8	10	13
	Gas oil	1	1	1	2	2	4	5	8	11	14	19	25
0.0035	Naphtha	1	1	1	2	3	4	6	9	12	16	21	28
	Gas oil	1	1	2	3	5	8	11	16	23	30	40	52
0.008	Naphtha	1	1	1	2	4	5	8	11	16	21	28	37
	Gas oil	1	2	3	4	7	10	15	22	30	40	53	69
0.035	Naphtha	1	1	2	4	6	10	14	20	28	37	49	64
	Gas oil	1	3	5	8	12	18	27	38	52	71	94	120
0.08	Naphtha	1	2	3	5	8	12	17	24	34	46	60	78
	Gas oil	2	3	6	9	15	22	33	46	64	86	110	150
0.30	Naphtha	1	2	4	7	11	17	25	35	49	66	87	110
	Gas oil	3	5	8	13	21	32	47	67	93	130	170	220
0.75	Naphtha	2	3	5	8	13	19	28	40	55	74	98	130
	Gas oil	3	5	9	15	24	36	53	76	100	140	190	240
1.0	Naphtha	2	3	6	10	16	24	35	49	68	92	120	160
	Gas oil	4	7	11	19	30	45	66	94	130	180	230	300

**Table 2.B.4.4M—High-temperature H₂S/H₂ Corrosion—Estimated
Corrosion Rates for 7Cr Steel (mm/yr)**

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°C)											
		218	246	274	302	329	357	385	413	441	468	496	524
0.002	Naphtha	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.25	0.33
	Gas oil	0.03	0.03	0.03	0.05	0.05	0.1	0.13	0.2	0.28	0.36	0.48	0.64
0.0035	Naphtha	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.23	0.3	0.41	0.53	0.71
	Gas oil	0.03	0.03	0.05	0.08	0.13	0.2	0.28	0.41	0.58	0.76	1.02	1.32
0.008	Naphtha	0.03	0.03	0.03	0.05	0.1	0.13	0.2	0.28	0.41	0.53	0.71	0.94
	Gas oil	0.03	0.05	0.08	0.1	0.18	0.25	0.38	0.56	0.76	1.02	1.35	1.75
0.035	Naphtha	0.03	0.03	0.05	0.1	0.15	0.25	0.36	0.51	0.71	0.94	1.24	1.63
	Gas oil	0.03	0.08	0.13	0.2	0.3	0.46	0.69	0.97	1.32	1.8	2.39	3.05
0.08	Naphtha	0.03	0.05	0.08	0.13	0.2	0.3	0.43	0.61	0.86	1.17	1.52	1.98
	Gas oil	0.05	0.08	0.15	0.23	0.38	0.56	0.84	1.17	1.63	2.18	2.79	3.81
0.30	Naphtha	0.03	0.05	0.1	0.18	0.28	0.43	0.64	0.89	1.24	1.68	2.21	2.79
	Gas oil	0.08	0.13	0.2	0.33	0.53	0.81	1.19	1.7	2.36	3.3	4.32	5.59
0.75	Naphtha	0.05	0.08	0.13	0.2	0.33	0.48	0.71	1.02	1.4	1.88	2.49	3.3
	Gas oil	0.08	0.13	0.23	0.38	0.61	0.91	1.35	1.93	2.54	3.56	4.83	6.1
1.0	Naphtha	0.05	0.08	0.15	0.25	0.41	0.61	0.89	1.24	1.73	2.34	3.05	4.06
	Gas oil	0.1	0.18	0.28	0.48	0.76	1.14	1.68	2.39	3.3	4.57	5.84	7.62

Table 2.B.4.5—High-temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 9Cr-1Mo (mpy)

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°F)											
		425	475	525	575	625	675	725	775	825	875	925	975
0.002	Naphtha	1	1	1	1	1	2	3	4	5	7	9	12
	Gas oil	1	1	1	1	2	3	5	7	10	13	17	23
0.0035	Naphtha	1	1	1	2	2	4	6	8	11	15	19	25
	Gas oil	1	1	2	3	5	7	11	15	21	28	37	48
0.008	Naphtha	1	1	1	2	3	5	7	10	14	20	26	34
	Gas oil	1	1	2	4	6	10	14	20	27	37	49	64
0.035	Naphtha	1	1	2	4	6	9	13	18	25	34	45	59
	Gas oil	1	2	4	7	11	17	24	35	48	65	86	110
0.08	Naphtha	1	2	3	4	7	11	16	22	31	42	55	72
	Gas oil	2	3	5	9	13	20	30	42	59	79	110	140
0.30	Naphtha	1	2	4	7	10	16	23	32	45	61	80	100
	Gas oil	2	4	7	12	19	30	43	61	85	120	150	200
0.75	Naphtha	1	3	4	7	12	18	26	37	51	68	90	120
	Gas oil	3	5	8	14	22	33	49	69	96	130	170	220
1.0	Naphtha	2	3	6	9	14	22	32	45	63	85	110	150
	Gas oil	3	6	10	17	27	41	60	86	120	160	210	280

**Table 2.B.4.5M—High-temperature H₂S/H₂ Corrosion—Estimated
Corrosion Rates for 9Cr-1Mo (mm/yr)**

H ₂ S (mole %)	Type of Hydrocarbon	Temperature (°C)											
		218	246	274	302	329	357	385	413	441	468	496	524
0.002	Naphtha	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.13	0.18	0.23	0.3
	Gas oil	0.03	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.33	0.43	0.58
0.0035	Naphtha	0.03	0.03	0.03	0.05	0.05	0.1	0.15	0.2	0.28	0.38	0.48	0.64
	Gas oil	0.03	0.03	0.05	0.08	0.13	0.18	0.28	0.38	0.53	0.71	0.94	1.22
0.008	Naphtha	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.36	0.51	0.66	0.86
	Gas oil	0.03	0.03	0.05	0.1	0.15	0.25	0.36	0.51	0.69	0.94	1.24	1.63
0.035	Naphtha	0.03	0.03	0.05	0.1	0.15	0.23	0.33	0.46	0.64	0.86	1.14	1.5
	Gas oil	0.03	0.05	0.1	0.18	0.28	0.43	0.61	0.89	1.22	1.65	2.18	2.79
0.08	Naphtha	0.03	0.05	0.08	0.1	0.18	0.28	0.41	0.56	0.79	1.07	1.4	1.83
	Gas oil	0.05	0.08	0.13	0.23	0.33	0.51	0.76	1.07	1.5	2.01	2.79	3.56
0.30	Naphtha	0.03	0.05	0.1	0.18	0.25	0.41	0.58	0.81	1.14	1.55	2.03	2.54
	Gas oil	0.05	0.1	0.18	0.3	0.48	0.76	1.09	1.55	2.16	3.05	3.81	5.08
0.75	Naphtha	0.03	0.08	0.1	0.18	0.3	0.46	0.66	0.94	1.3	1.73	2.29	3.05
	Gas oil	0.08	0.13	0.2	0.36	0.56	0.84	1.24	1.75	2.44	3.3	4.32	5.59
1.0	Naphtha	0.05	0.08	0.15	0.23	0.36	0.56	0.81	1.14	1.6	2.16	2.79	3.81
	Gas oil	0.08	0.15	0.25	0.43	0.69	1.04	1.52	2.18	3.05	4.06	5.33	7.11

Table 2.B.4.6—High-temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 12Cr Steels (mpy)

H ₂ S (mole %)	Temperature (°F)											
	425	475	525	575	625	675	725	775	825	875	925	975
0.002	1	1	1	1	2	3	4	5	6	9	11	14
0.0035	1	1	1	1	2	3	4	6	8	11	14	18
0.008	1	1	1	2	2	4	5	7	9	12	15	19
0.035	1	1	1	2	3	4	6	9	12	15	19	25
0.08	1	1	1	2	3	5	7	10	13	17	22	27
0.30	1	1	2	3	4	6	9	12	16	21	27	34
0.75	1	1	2	3	5	7	10	13	18	23	30	38
1.0	1	2	3	4	7	10	13	18	25	32	42	53

Table 2.B.4.6M—High-temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for 12Cr Steels (mm/yr)

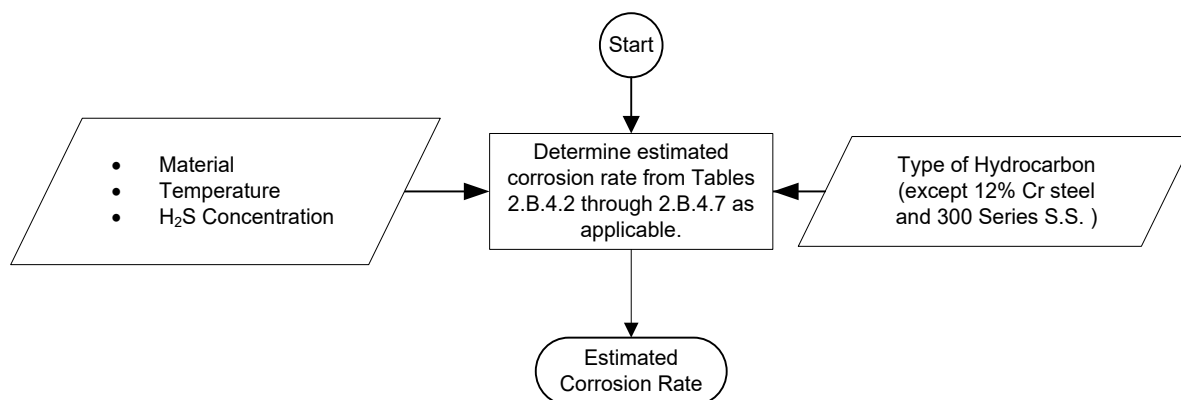
H ₂ S (mole %)	Temperature (°C)											
	218	246	274	302	329	357	385	413	441	468	496	524
0.002	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.13	0.15	0.23	0.28	0.36
0.0035	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.2	0.28	0.36	0.46
0.008	0.03	0.03	0.03	0.05	0.05	0.1	0.13	0.18	0.23	0.3	0.38	0.48
0.035	0.03	0.03	0.03	0.05	0.08	0.1	0.15	0.23	0.3	0.38	0.48	0.64
0.08	0.03	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.33	0.43	0.56	0.69
0.30	0.03	0.03	0.05	0.08	0.1	0.15	0.23	0.3	0.41	0.53	0.69	0.86
0.75	0.03	0.03	0.05	0.08	0.13	0.18	0.25	0.33	0.46	0.58	0.76	0.97
1.0	0.03	0.05	0.08	0.1	0.18	0.25	0.33	0.46	0.64	0.81	1.07	1.35

Table 2.B.4.7—High-temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for Type 304, 304L, 316, 316L, 321, 347 Stainless Steel (mpy)

H ₂ S (mole %)	Temperature (°F)											
	425	475	525	575	625	675	725	775	825	875	925	975
0.002	1	1	1	1	1	1	1	1	1	1	2	2
0.0035	1	1	1	1	1	1	1	1	1	2	2	3
0.008	1	1	1	1	1	1	1	1	2	2	3	3
0.035	1	1	1	1	1	1	1	1	2	3	3	4
0.08	1	1	1	1	1	1	1	1	2	3	4	5
0.30	1	1	1	1	1	1	1	1	3	4	5	6
0.75	1	1	1	1	1	1	1	2	3	4	5	6
1.0	1	1	1	1	1	1	2	2	4	5	7	9

Table 2.B.4.7M—High-temperature H₂S/H₂ Corrosion—Estimated Corrosion Rates for Type 304, 304L, 316, 316L, 321, 347 Stainless Steel (mm/yr)

H ₂ S (mole %)	Temperature (°C)											
	218	246	274	302	329	357	385	413	441	468	496	524
0.002	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05
0.0035	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.08
0.008	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.08	0.08
0.035	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.08	0.1
0.08	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.13
0.30	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.08	0.1	0.13	0.15
0.75	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1	0.13	0.15
1.0	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.1	0.13	0.18	0.23

2.B.4.6 Figures**Figure 2.B.4.1—High-temperature H₂S/H₂ Corrosion—Determination of Corrosion Rate**

2.B.5 Sulfuric Acid Corrosion

2.B.5.1 Description of Damage

Sulfuric acid (H_2SO_4) is one of the most widely used industrial chemicals. One common use of concentrated H_2SO_4 is as a catalyst for the alkylation process. H_2SO_4 is a very strong acid that can be extremely corrosive under certain conditions. The corrosiveness of H_2SO_4 varies widely and depends on many factors. Acid concentration and temperature are the foremost factors that influence corrosion. In addition, velocity effects and presence of impurities in the acid, especially oxygen or oxidants, can have a significant impact on corrosion.

Although H_2SO_4 corrodes carbon steel, it is the material typically chosen for equipment and piping handling concentrated H_2SO_4 at near ambient temperatures. The corrosion rate of steel by H_2SO_4 as a function of acid concentration and temperature under stagnant conditions is provided in NACE Publication 5A151 [101]. Stagnant or low flow (< 3 ft/s or 0.91 m/s) conditions typically cause general thinning of carbon steel. The ferrous sulfate corrosion product film is somewhat protective, and as it builds on the metal surface, the corrosion rate decreases. The mass transfer of ferrous sulfate away from the corroding steel surface is the rate-limiting step for the corrosion. Acid solution velocity above approximately 3 ft/s (0.91 m/s) (turbulent flow) has a significant impact on this mass transfer rate and thus the corrosion rate. Corrosion rates for steel pipelines carrying H_2SO_4 at various conditions and velocities have been calculated from a well-established mathematical model [13]. The calculated rates were based on pure H_2SO_4 solutions with no ferrous sulfate present in the acid solution. These rates for turbulent flow in straight pipes were then multiplied by a factor of 3 (based on experience cited in reference [13]) to account for the enhanced localized corrosion that occurs at elbows, tees, valves, and areas of internal surface roughness such as protuberances at welded joints. This provides maximum estimated corrosion rates. Actual corrosion rates could be 20 % to 50 % of these estimated maximum corrosion rates.

Although the performance of many alloys in H_2SO_4 service is primarily related to the acid concentration and temperature, velocity and the presence of an oxidant can play a significant role as well. This is because these alloys often depend upon formation of a protective oxide film to provide passivity and, therefore, corrosion resistance. The presence of an oxidant usually improves the corrosion performance in H_2SO_4 service of alloys such as stainless steel and many nickel alloys. This is not the case with Alloy B-2, which can suffer drastically high corrosion rates if an oxidant is present in the acid. The corrosion rates provided in these tables are from published literature, and the corrosion rates for non-aerated acid services are used to provide conservatism, except for Alloy B-2. This conservatism is appropriate because other acid contaminants and velocity can affect the material's passivity. The effect of velocity on corrosion rates is assumed to hold over a wide range of conditions for very little information on the effect of velocity is published.

2.B.5.2 Basic Data

The data listed in Table 2.B.5.1 are required to determine the estimated corrosion rate for H_2SO_4 service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.5.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in Figure 2.B.5.1. The corrosion rate may be determined using the basic data in Table 2.B.5.1 in conjunction with Tables 2.B.5.2 through 2.B.5.7.

NOTE The corrosion rates of Alloy B-2 can increase drastically in the presence of an oxidant (e.g. oxygen or ferric ions), which is not reflected in Table 2.B.5.7. For this environment, a corrosion engineer should be consulted to establish an estimated corrosion rate.

2.B.5.4 References

See References [106], [101], [102], [103], and [104] in [Annex 2.G](#).

2.B.5.5 Tables

Table 2.B.5.1—H₂SO₄ Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping.
Acid concentration (wt %)	Determine the concentration of the H ₂ SO ₄ present in this equipment/piping. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Maximum temperature, °F (°C)	Determine the maximum temperature present in this equipment/piping. This may be the maximum process temperature, but local heating conditions such as effect of the sun or heat tracing should be considered.
Velocity of acid, ft/s (m/s)	Determine the maximum velocity of the acid in this equipment/piping. Although conditions in a vessel may be essentially stagnant, the acid velocity in flowing nozzles (inlet, outlet, etc.) should be considered.
Oxygen/oxidant present? (Yes or No)	Determine whether the acid contains oxygen or some other oxidant. If in doubt, consult a knowledgeable process engineer. These data are only necessary if the material of construction is Alloy B-2. For carbon steel and other alloys, the corrosion rates in the tables assume the acid does not contain oxygen/oxidants.

Table 2.B.5.2—H₂SO₄ Corrosion—Estimated Corrosion Rate for Carbon Steel (mpy)

Acid Conc (wt %)	Acid Temp (°F)	Acid Velocity (ft/s)								
		0	1	2	3	4.5	6.5	8.5	11.5	12
100	42	5	7	9	12	45	60	75	95	120
	59.5	12	14	17	20	65	85	110	140	170
	91	50	55	60	70	270	360	450	580	720
	122.5	100	150	200	300	999	999	999	999	999
98	42	4	6	8	10	35	45	60	75	90
	59.5	5	10	15	20	80	110	140	180	220
	91	15	25	40	60	290	390	490	640	780
	122.5	40	80	120	250	999	999	999	999	999
96	42	8	10	12	15	60	80	110	130	160
	59.5	15	20	25	40	170	220	270	350	430
	91	25	40	60	100	500	650	820	999	999
	122.5	50	100	200	500	999	999	999	999	999
93.5	42	10	15	20	25	120	160	200	260	330
	59.5	20	25	40	70	340	450	570	740	910
	91	30	40	75	130	640	850	999	999	999
	122.5	60	120	250	600	999	999	999	999	999
91	42	15	25	45	70	320	430	540	710	870
	59.5	25	40	80	120	700	940	999	999	999
	91	35	60	100	200	940	999	999	999	999
	122.5	70	150	300	800	999	999	999	999	999
87	42	20	30	50	80	380	500	630	810	999
	59.5	30	160	300	420	690	920	999	999	999
	91	45	450	850	999	999	999	999	999	999
	122.5	80	999	999	999	999	999	999	999	999
83	42	20	25	35	45	210	280	350	460	570
	59.5	30	50	100	150	680	910	999	999	999
	91	40	100	200	400	999	999	999	999	999
	122.5	80	200	400	999	999	999	999	999	999
78	42	15	20	20	25	110	150	190	250	300
	59.5	20	40	70	120	570	760	950	999	999
	91	30	60	120	250	999	999	999	999	999
	122.5	60	120	300	900	999	999	999	999	999

Acid Conc (wt %)	Acid Temp (°F)	Acid Velocity (ft/s)								
		0	1	2	3	4.5	6.5	8.5	11.5	12
72.5	42	10	15	20	25	130	170	220	280	350
	59.5	15	30	50	100	490	650	810	999	999
	91	25	50	100	200	980	999	999	999	999
	122.5	50	100	250	800	999	999	999	999	999
67	42	20	30	40	60	280	370	460	600	740
	59.5	30	50	100	170	830	999	999	999	999
	91	50	100	180	300	999	999	999	999	999
	122.5	100	200	400	999	999	999	999	999	999
62	42	75	85	100	120	570	760	950	999	999
	59.5	120	170	250	400	999	999	999	999	999
	91	200	300	600	900	999	999	999	999	999
	122.5	500	750	999	999	999	999	999	999	999

Table 2.B.5.2M—H₂SO₄ Corrosion—Estimated Corrosion Rate for Carbon Steel (mm/yr)

Acid Conc (wt %)	Acid Temp (°C)	Acid Velocity (m/s)								
		0	.30	0.61	0.91	1.37	1.98	2.59	3.51	3.66
100	6	0.13	0.18	0.23	0.3	1.14	1.52	1.91	2.41	3.05
	15	0.3	0.36	0.43	0.51	1.65	2.16	2.79	3.56	4.32
	33	1.27	1.4	1.52	1.78	6.86	9.14	11.43	14.73	18.29
	50	2.54	3.81	5.08	7.62	25.37	25.37	25.37	25.37	25.37
98	6	0.1	0.15	0.2	0.25	0.89	1.14	1.52	1.91	2.29
	15	0.13	0.25	0.38	0.51	2.03	2.79	3.56	4.57	5.59
	33	0.38	0.64	1.02	1.52	7.37	9.91	12.45	16.26	19.81
	50	1.02	2.03	3.05	6.35	25.37	25.37	25.37	25.37	25.37
96	6	0.2	0.25	0.3	0.38	1.52	2.03	2.79	3.3	4.06
	15	0.38	0.51	0.64	1.02	4.32	5.59	6.86	8.89	10.92
	33	0.64	1.02	1.52	2.54	12.7	16.51	20.83	25.37	25.37
	50	1.27	2.54	5.08	12.7	25.37	25.37	25.37	25.37	25.37
93.5	6	0.25	0.38	0.51	0.64	3.05	4.06	5.08	6.6	8.38
	15	0.51	0.64	1.02	1.78	8.64	11.43	14.48	18.8	23.11
	33	0.76	1.02	1.91	3.3	16.26	21.59	25.37	25.37	25.37
	50	1.52	3.05	6.35	15.24	25.37	25.37	25.37	25.37	25.37
91	6	0.38	0.64	1.14	1.78	8.13	10.92	13.72	18.03	22.1
	15	0.64	1.02	2.03	3.05	17.78	23.88	25.37	25.37	25.37
	33	0.89	1.52	2.54	5.08	23.88	25.37	25.37	25.37	25.37
	50	1.78	3.81	7.62	20.32	25.37	25.37	25.37	25.37	25.37
87	6	0.51	0.76	1.27	2.03	9.65	12.7	16	20.57	25.37
	15	0.76	4.06	7.62	10.67	17.53	23.37	25.37	25.37	25.37
	33	1.14	11.43	21.59	25.37	25.37	25.37	25.37	25.37	25.37
	50	2.03	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
83	6	0.51	0.64	0.89	1.14	5.33	7.11	8.89	11.68	14.48
	15	0.76	1.27	2.54	3.81	17.27	23.11	25.37	25.37	25.37
	33	1.02	2.54	5.08	10.16	25.37	25.37	25.37	25.37	25.37
	50	2.03	5.08	10.16	25.37	25.37	25.37	25.37	25.37	25.37
78	6	0.38	0.51	0.51	0.64	2.79	3.81	4.83	6.35	7.62
	15	0.51	1.02	1.78	3.05	14.48	19.3	24.13	25.37	25.37
	33	0.76	1.52	3.05	6.35	25.37	25.37	25.37	25.37	25.37
	50	1.52	3.05	7.62	22.86	25.37	25.37	25.37	25.37	25.37

[illegible]

Table 2.B.5.3—H₂SO₄ Corrosion—Estimated Corrosion Rates for Type 304 SS (mpy)

Acid Concentration (wt %)	Temperature								
	86 °F			104.5 °F			140.5 °F		
	2 ft/s	6 ft/s	7 ft/s	2 ft/s	6 ft/s	7 ft/s	2 ft/s	6 ft/s	7 ft/s
98	5	10	15	20	40	60	200	400	600
92.5	20	40	60	40	80	120	500	999	999
87	40	80	120	80	160	240	999	999	999
82	100	200	300	500	999	999	999	999	999
75	500	999	999	999	999	999	999	999	999
65	999	999	999	999	999	999	999	999	999
50	999	999	999	999	999	999	999	999	999
30	999	999	999	999	999	999	999	999	999
15	400	800	999	999	999	999	999	999	999
8	200	400	600	800	999	999	999	999	999
3.5	50	100	150	200	400	600	500	999	999
2	20	40	60	70	140	210	200	400	600

Table 2.B.5.3M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Type 304 SS (mm/yr)

Acid Concentration (wt %)	Temperature								
	30 °C			40 °C			60 °C		
	0.61 m/s	1.83 m/s	2.13 m/s	0.61 m/s	1.83 m/s	2.13 m/s	0.61 m/s	1.83 m/s	2.13 m/s
98	0.13	0.25	0.38	0.51	1.02	1.52	5.08	10.16	15.24
92.5	0.51	1.02	1.52	1.02	2.03	3.05	12.7	25.37	25.37
87	1.02	2.03	3.05	2.03	4.06	6.1	25.37	25.37	25.37
82	2.54	5.08	7.62	12.7	25.37	25.37	25.37	25.37	25.37
75	12.7	25.37	25.37	25.37	25.37	2.51	25.37	25.37	25.37
65	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
50	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
30	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
15	10.16	20.32	25.37	25.37	25.37	25.37	25.37	25.37	25.37
8	5.08	10.16	15.24	20.32	25.37	25.37	25.37	25.37	25.37
3.5	1.27	2.54	3.81	5.08	10.16	15.24	12.7	25.37	25.37
2	0.51	1.02	1.52	1.78	3.56	5.33	5.08	10.16	15.24

Table 2.B.5.4—H₂SO₄ Corrosion—Estimated Corrosion Rates for Type 316 SS (mpy)

Acid Concentration (wt %)	316 SS Corrosion Rate (mpy)								
	86 °F			104.5 °F			140.5 °F		
	2 ft/s	6 ft/s	7 ft/s	2 ft/s	6 ft/s	7 ft/s	2 ft/s	6 ft/s	7 ft/s
98	5	10	15	15	30	45	100	200	300
92.5	10	20	30	30	60	90	400	800	999
87	20	40	60	50	100	150	800	999	999
82	50	100	150	400	800	999	999	999	999
75	300	600	900	999	999	999	999	999	999
65	600	999	999	999	999	999	999	999	999
50	900	999	999	999	999	999	999	999	999
30	200	400	600	999	999	999	999	999	999
15	30	60	90	60	120	180	200	400	600
8	10	20	30	30	60	90	80	160	240
3.5	5	10	15	20	40	60	40	80	120
2	5	10	15	5	10	15	10	20	30

Table 2.B.5.4M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Type 316 SS (mm/yr)

Acid Concentration (wt %)	Temperature								
	30 °C			40 °C			60 °C		
	0.61 m/s	1.83 m/s	2.13 m/s	0.61 m/s	1.83 m/s	2.13 m/s	0.61 m/s	1.83 m/s	2.13 m/s
98	0.13	0.25	0.38	0.38	0.76	1.14	2.54	5.08	7.62
92.5	0.25	0.51	0.76	0.76	1.52	2.29	10.16	20.32	25.37
87	0.51	1.02	1.52	1.27	2.54	3.81	20.32	25.37	25.37
82	1.27	2.54	3.81	10.16	20.32	25.37	25.37	25.37	25.37
75	7.62	15.24	22.86	25.37	25.37	25.37	25.37	25.37	25.37
65	15.24	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
50	22.86	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
30	5.08	10.16	15.24	25.37	25.37	25.37	25.37	25.37	25.37
15	0.76	1.52	2.29	1.52	3.05	4.57	5.08	10.16	15.24
8	0.25	0.51	0.76	0.76	1.52	2.29	2.03	4.06	6.1
3.5	0.13	0.25	0.38	0.51	1.02	1.52	1.02	2.03	3.05
2	0.13	0.25	0.38	0.13	0.25	0.38	0.25	0.51	0.76

Table 2.B.5.5—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy 20 (mpy)

Acid Concentration (wt %)	Temperature											
	100 °F			125 °F			163.5 °F			195.5 °F		
	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s
98	2	4	6	5	10	15	15	30	45	40	80	120
92.5	3	6	9	10	20	30	25	50	75	50	100	150
85	3	6	9	10	20	30	30	60	90	60	120	180
70	3	6	9	15	30	45	50	100	150	100	200	300
55	3	6	9	10	20	30	30	60	90	60	120	180
45	3	6	9	10	20	30	30	60	90	50	100	150
35	3	6	9	10	20	30	25	50	75	40	80	120
25	2	4	6	5	10	15	20	40	60	40	80	120
15	2	4	6	5	10	15	20	40	60	35	70	105
8	2	4	6	3	6	9	5	10	15	25	50	75
5	2	4	6	3	6	9	3	6	9	20	40	60

Table 2.B.5.5M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy 20 (mm/yr)

Acid Concentration (wt %)	Temperature											
	38 °C			52 °C			70 °C			91 °C		
	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s
98	0.05	0.1	0.15	0.13	0.25	0.38	0.38	0.76	1.14	1.02	2.03	3.05
92.5	0.08	0.15	0.23	0.25	0.51	0.76	0.64	1.27	1.91	1.27	2.54	3.81
85	0.08	0.15	0.23	0.25	0.51	0.76	0.76	1.52	2.29	1.52	3.05	4.57
70	0.08	0.15	0.23	0.38	0.76	1.14	1.27	2.54	3.81	2.54	5.08	7.62
55	0.08	0.15	0.23	0.25	0.51	0.76	0.76	1.52	2.29	1.52	3.05	4.57
45	0.08	0.15	0.23	0.25	0.51	0.76	0.76	1.52	2.29	1.27	2.54	3.81
35	0.08	0.15	0.23	0.25	0.51	0.76	0.64	1.27	1.91	1.02	2.03	3.05
25	0.05	0.1	0.15	0.13	0.25	0.38	0.51	1.02	1.52	1.02	2.03	3.05
15	0.05	0.1	0.15	0.13	0.25	0.38	0.51	1.02	1.52	0.89	1.78	2.67
8	0.05	0.1	0.15	0.08	0.15	0.23	0.13	0.25	0.38	0.64	1.27	1.91
5	0.05	0.1	0.15	0.08	0.15	0.23	0.08	0.15	0.23	0.51	1.02	1.52

Table 2.B.5.6—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy C-276 (mpy)

Acid Concentration (wt %)	Temperature											
	125 °F			137.5 °F			162.5 °F			187.5 °F		
	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s
98	3	6	9	4	8	12	5	10	15	20	40	60
92.5	4	8	12	5	10	15	20	40	60	50	100	150
85	5	10	15	10	20	30	20	40	60	60	120	180
75	5	10	15	10	20	30	20	40	60	50	100	150
55	5	10	15	10	20	30	15	30	45	40	80	120
20	4	8	12	5	10	15	15	30	45	40	80	120
8	4	8	12	5	10	15	10	20	30	30	60	90
5	3	6	9	4	8	12	5	10	15	15	30	45

Table 2.B.5.6M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy C-276 (mm/yr)

Acid Concentration (wt %)	Temperature											
	52 °C			59 °C			73 °C			86 °C		
	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s
98	0.08	0.15	0.23	0.1	0.2	0.3	0.13	0.25	0.38	0.51	1.02	1.52
92.5	0.1	0.2	0.3	0.13	0.25	0.38	0.51	1.02	1.52	1.27	2.54	3.81
85	0.13	0.25	0.38	0.25	0.51	0.76	0.51	1.02	1.52	1.52	3.05	4.57
75	0.13	0.25	0.38	0.25	0.51	0.76	0.51	1.02	1.52	1.27	2.54	3.81
55	0.13	0.25	0.38	0.25	0.51	0.76	0.38	0.76	1.14	1.02	2.03	3.05
20	0.1	0.2	0.3	0.13	0.25	0.38	0.38	0.76	1.14	1.02	2.03	3.05
8	0.1	0.2	0.3	0.13	0.25	0.38	0.25	0.51	0.76	0.76	1.52	2.29
5	0.08	0.15	0.23	0.1	0.2	0.3	0.13	0.25	0.38	0.38	0.76	1.14

Table 2.B.5.7—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy B-2 (mpy)

Acid Concentration (wt %)	Temperature											
	125 °F			137.5 °F			162.5 °F			187.5 °F		
	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s	3 ft/s	8.5 ft/s	10 ft/s
75	2	4	6	3	6	9	4	8	12	5	10	15
45	3	6	9	4	8	12	4	8	12	5	10	15
32.5	4	8	12	5	10	15	5	10	15	5	10	15
25	5	10	15	10	20	30	10	20	30	10	20	30

NOTE 1 Oxidants present (even in a few ppm) accelerate corrosion rates and pitting.

NOTE 2 Alloy B-2 should not be used in oxidizing conditions.

Table 2.B.5.7M—H₂SO₄ Corrosion—Estimated Corrosion Rates for Alloy B-2 (mm/yr)

Acid Concentration (wt %)	Temperature											
	52 °C			59 °C			73 °C			86 °C		
	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s	0.91 m/s	2.59 m/s	3.05 m/s
75	0.05	0.1	0.15	0.08	0.15	0.23	0.1	0.2	0.3	0.13	0.25	0.38
45	0.08	0.15	0.23	0.1	0.2	0.3	0.1	0.2	0.3	0.13	0.25	0.38
32.5	0.1	0.2	0.3	0.13	0.25	0.38	0.13	0.25	0.38	0.13	0.25	0.38
25	0.13	0.25	0.38	0.25	0.51	0.76	0.25	0.51	0.76	0.25	0.51	0.76

NOTE 1 Oxidants present (even in a few ppm) accelerate corrosion rates and pitting.

NOTE 2 Alloy B-2 should not be used in oxidizing conditions.

2.B.5.6 Figures

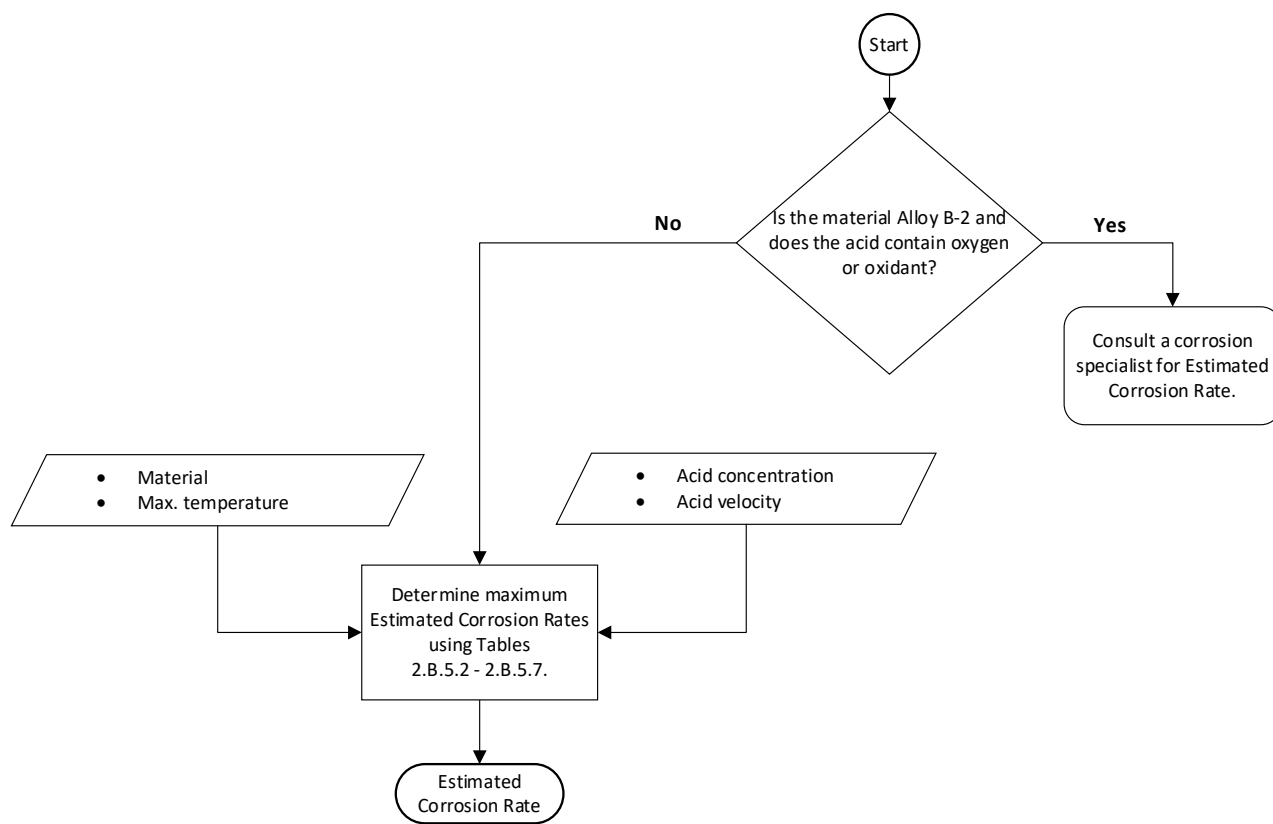


Figure 2.B.5.1—H₂SO₄ Corrosion—Determination of Corrosion Rate

2.B.6 HF Corrosion

2.B.6.1 Description of Damage

Concentrated HF is used as the acid catalyst in HF alkylation units. The alkylation reaction chemically combines an alkane (usually isobutane) with an olefin (butylene, propylene, amylene) in the presence of the acid catalyst. HF presents severe health hazards as both a liquid and vapor. If spilled, HF may form a dense, low lying, toxic cloud. Extreme caution should be exercised when using HF.

Corrosion of materials in HF primarily depends on the HF-in-water concentration and the temperature. Other variables, such as velocity, turbulence, aeration, impurities, etc., can strongly influence corrosion. Some metals will form a protective fluoride film or scale that protects the surface. Loss of this protective film, especially through high velocity or turbulence, will likely result in greatly accelerated corrosion rates. Corrosion in 80 % and stronger HF-in-water solutions is equivalent to corrosion in anhydrous hydrofluoric acid (AHF) (200 ppm H₂O). Below 80 % HF, the acid is considered aqueous, and metal corrosion is highly temperature and velocity dependent and usually accelerated. The usual HF-in-water concentrations in typical HF alkylation units are 96 % to 99+ %, and the temperatures are generally below 150 °F (66 °C). Under these conditions, carbon steel is widely used for all equipment except where close tolerances are required for operation (i.e. pumps, valves, instruments). Where close tolerances are required and at temperatures over 150 °F (66 °C) to approximately 300 °F (149 °C), Alloy 400 is typically used.

Accelerated corrosion from water dilution of the acid is often encountered in low points (bleeders, line pockets, etc.) if unit dry-out leaves residual free water in these areas.

2.B.6.2 Basic Data

The data listed in [Table 2.B.6.1](#) are required to determine the estimated corrosion rate for HF acid service. If precise data has not been measured, a knowledgeable process specialist should be consulted.

2.B.6.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.6.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.6.1](#) in conjunction with [Tables 2.B.6.2](#) through [2.B.6.3](#).

It is important to note that the corrosion rate is very high in the initial stages of exposure to HF as the protective fluoride scale is being established. Once established, the fluoride scale protects the steel resulting in low corrosion rates unless the scale is disturbed or removed.

Alloy steels have been found to exhibit higher corrosion rates than mild carbon steel in both dilute and concentrated HF and generally are not specified for this service. Higher alloys are sometimes used in HF service, and corrosion rates, if unknown, should be obtained from published literature or from the manufacturer [\[105\]](#). It is important to consider the galvanic effects of welding carbon steel to Alloy 400 or other corrosion-resistant alloys. Accelerated and localized attack of the carbon steel may result from galvanic coupling. Increased rates of corrosion have also been reported in carbon steels that contain high levels of residual elements, notably Cu, Ni, and Cr [\[16\]](#).

Corrosion caused by HF results in general thinning except in the event of potential galvanic attack. The presence of HF may also result in HSC and blistering. These degradation modes are considered in [Part 2](#), [Annex 2.C](#), [Sections 2.C.6](#) and [2.C.7](#).

2.B.6.4 References

See References [\[81\]](#), [\[82\]](#), [\[106\]](#), [\[107\]](#), [\[108\]](#), and [\[109\]](#) in [Annex 2.G](#).

2.B.6.5 Tables

Table 2.B.6.1—HF Corrosion—Basic Data Required for Analysis

Basic Data	Comments
HF-in-water concentration (wt %)	Determine the concentration of HF in the water.
Material of construction	Determine the material used to fabricate the equipment/piping.
Maximum service temperature, °F (°C)	Determine the maximum temperature of the process stream.
Velocity, ft/s (m/s)	Determine the velocity range of the process stream.
Oxygen/oxidizers present? (Yes or No)	Oxidizers can greatly accelerate corrosion of Alloy 400. No definition in terms of concentration of dissolved oxygen (DO) in the acid can be given. Acid in shipment and transfer will usually be completely air-free, and air is typically present only after opening of equipment for inspection, leaks, or improperly prepared feed to the unit.

Table 2.B.6.2—HF Corrosion—Estimated Corrosion Rates (mpy) for Carbon Steel

[illegible]

Table 2.B.6.2M—HF Corrosion—Estimated Corrosion Rates (mmpy) for Carbon Steel

[illegible]

Table 2.B.6.3—HF Corrosion—Estimated Corrosion Rates (mpy) for Alloy 400

Temp. (°F)	Aerated?	HF-in-Water Concentration (%)							
		1	2	5	6	63	64	80	81
80	No	1	1	1	10	10	1	1	2
	Yes	10	10	10	25	25	10	10	15
125	No	1	1	1	15	15	5	5	3
	Yes	10	10	10	30	30	20	20	15
175	No	5	5	5	20	20	10	10	5
	Yes	20	20	20	100	100	50	50	20
200	No	10	10	10	20	20	20	20	10
	Yes	100	100	100	200	200	200	200	100

Table 2.B.6.3M—HF Corrosion—Estimated Corrosion Rates (mm/yr) for Alloy 400

Temp (°C)	Aerated?	HF-in-Water Concentration (%)							
		1	2	5	6	63	64	80	81
27	No	0.03	0.03	0.03	0.25	0.25	0.03	0.03	0.05
	Yes	0.25	0.25	0.25	0.64	0.64	0.25	0.25	0.38
52	No	0.03	0.03	0.03	0.38	0.38	0.13	0.13	0.08
	Yes	0.25	0.25	0.25	0.76	0.76	0.51	0.51	0.38
79	No	0.13	0.13	0.13	0.51	0.51	0.25	0.25	0.13
	Yes	0.51	0.51	0.51	2.54	2.54	1.27	1.27	0.51
93	No	0.25	0.25	0.25	0.51	0.51	0.51	0.51	0.25
	Yes	2.54	2.54	2.54	5.08	5.08	5.08	5.08	2.54

2.B.6.6 Figures

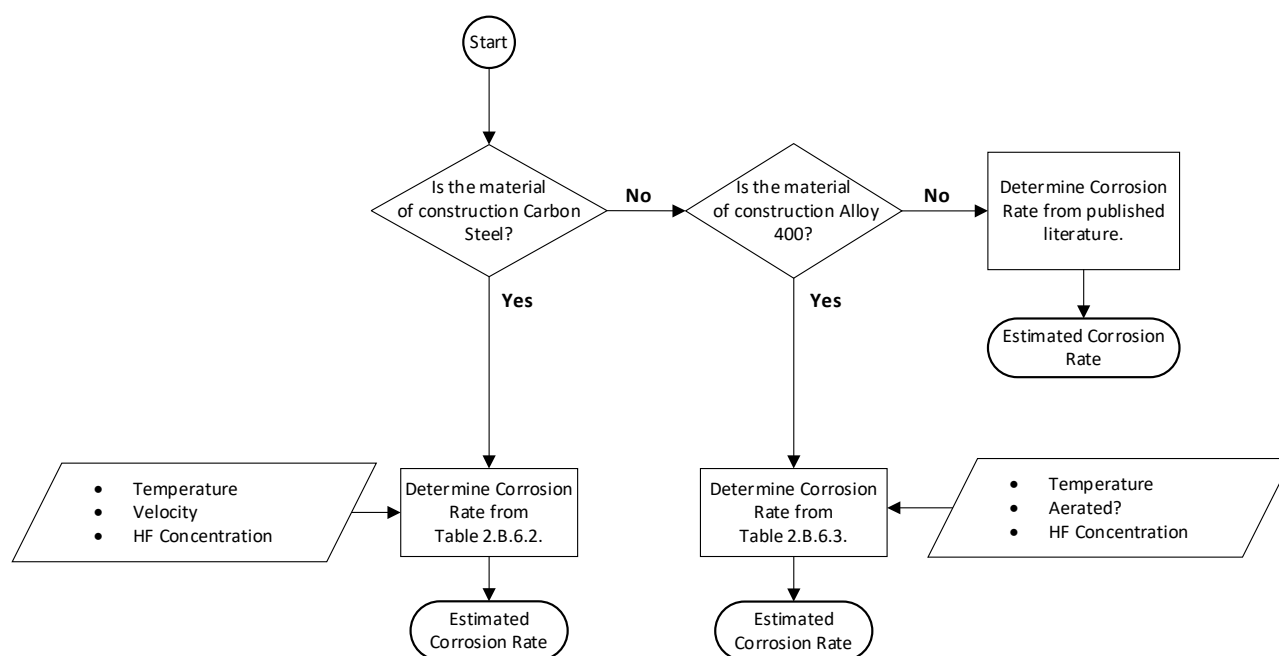


Figure 2.B.6.1—HF Corrosion—Determination of Corrosion Rate

2.B.7 Alkaline Sour Water Corrosion

2.B.7.1 Description of Damage

Alkaline sour water corrosion is broadly defined as corrosion by water containing H_2S and NH_3 , and it is typically a concern for carbon steel above neutral pH. This corrosion is caused by aqueous ammonium bisulfide (NH_4HS). The primary variables that influence alkaline sour water corrosion rates are the NH_4HS concentration of the water velocity (wall shear stress) and H_2S partial pressure. Secondary variables include temperature and hydrocarbon to water ratios. Alkaline sour water corrosion is of concern across a broad range of the most common refining process units, notably hydroprocessing treating, catalytic cracking, amine treating, coking, and light ends recovery. H_2S is typically formed by thermal breakdown or catalytic conversion of sulfur compounds. NH_3 is similarly formed from nitrogen compounds. NH_4HS is formed as a result of the reaction between these two gases and precipitates out of the gas phase in the reactor effluent stream as temperatures are reduced below about 150 °F (66 °C).

2.B.7.2 Basic Data

The data listed in [Table 2.B.7.1](#) are required to determine the estimated corrosion rate for NH_4HS service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.7.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.7.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.7.1](#) in conjunction with the baseline corrosion rates and equations in [Table 2.B.7.2](#) to correct for H_2S partial pressure.

2.B.7.4 References

See References [110], [111], [112], [113], and [114] in Annex 2.G.

2.B.7.5 Tables

Table 2.B.7.1—Alkaline Sour Water Corrosion—Basic Data Required for Analysis

Basic Data	Comments
NH ₄ HS concentration (wt %)	Determine the NH ₄ HS concentration of the condensed water. It is suggested to determine this value with ionic process models. However, approximate values may be calculated from analyses of H ₂ S and NH ₃ as follows. — If wt % H ₂ S < 2 × (wt % NH ₃), wt % NH ₄ HS = 1.5 × (wt % H ₂ S) — If wt % H ₂ S > 2 × (wt % NH ₃), wt % NH ₄ HS = 3.0 × (wt % NH ₃)
Stream velocity, m/s (ft/s)	The vapor phase velocity should be used in a two-phase system. The liquid phase velocity should be used in a liquid full system.
H ₂ S partial pressure, psia (kPa)	Determine the partial pressure of H ₂ S by multiplying the mole % of H ₂ S in the gas phase by the total system pressure.

Table 2.B.7.2—Alkaline Sour Water Corrosion—Baseline Corrosion Rates for Carbon Steel (mpy)

NH ₄ HS (wt %)	Velocity (ft/s)				
	10	15	20	25	30
2	3	4	5	8	11
5	6	9	12	15	18
10	20	27	35	43	50
15	45	70	100	150	200
NOTE 1 For pH₂S < 50 psia: Adjusted CR = $\max \left[\left\{ \left(\frac{\text{Baseline CR}}{25} \right) \cdot (\text{pH}_2\text{S} - 50) + \text{Baseline CR} \right\}, 0 \right]$. NOTE 2 For pH₂S ≥ 50 psia: Adjusted CR = $\max \left[\left\{ \left(\frac{\text{Baseline CR}}{40} \right) \cdot (\text{pH}_2\text{S} - 50) + \text{Baseline CR} \right\}, 0 \right]$.					

Table 2.B.7.2M—Alkaline Sour Water Corrosion—Baseline Corrosion Rates for Carbon Steel (mm/yr)

NH₄HS (wt %)	Velocity (m/s)				
	3.05	4.57	6.10	7.62	9.14
2	0.08	0.10	0.13	0.20	0.28
5	0.15	0.23	0.30	0.38	0.46
10	0.51	0.69	0.89	1.09	1.27
15	1.14	1.78	2.54	3.81	5.08
NOTE 1 For $p_{H_2S} < 345$ kPa: Adjusted $CR = \max \left[\left\{ \left(\frac{\text{Baseline } CR}{173} \right) \cdot (p_{H_2S} - 345) + \text{Baseline } CR \right\}, 0 \right]$. NOTE 2 For $p_{H_2S} \geq 345$ kPa: Adjusted $CR = \max \left[\left\{ \left(\frac{\text{Baseline } CR}{276} \right) \cdot (p_{H_2S} - 345) + \text{Baseline } CR \right\}, 0 \right]$.					

2.B.7.6 Figures

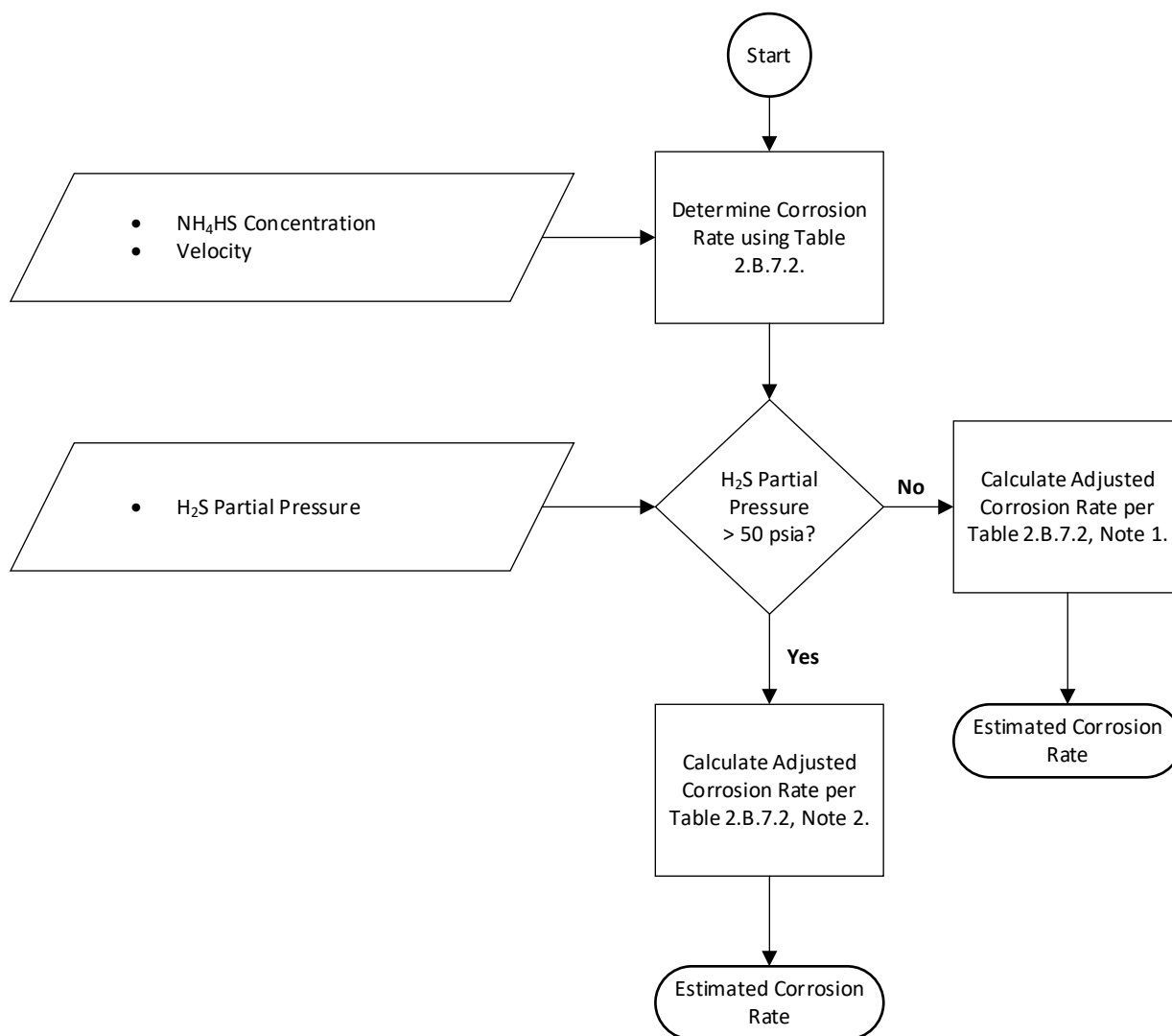


Figure 2.B.7.1—Alkaline Sour Water Corrosion—Determination of Corrosion Rate

2.B.8 Amine Corrosion

2.B.8.1 Description of Damage

Amine corrosion is a form of often-localized corrosion that occurs principally on carbon steel in some gas treating processes. Carbon steel is also vulnerable to SCC in gas treating amines if it is not postweld heat treated. Gas treating amines fall into two major categories—chemical solvents and physical solvents. This supplement deals with corrosion in the most common chemical solvents, MEA, DEA, and MDEA. These amines are used to remove acid gases, primarily H₂S, from plant streams. MEA and DEA will also remove CO₂, but MDEA is selective to H₂S and will remove little CO₂ if it is present. Generally, corrosion in MDEA is less than in MEA and DEA when contaminants are well controlled.

Carbon steel corrosion in amine treating processes is a function of a number of interrelated factors, the primary ones being the concentration of the amine solution, the acid gas content of the solution (“loading”),

and the temperature. The most commonly used amine concentrations are 20 wt % MEA, 30 wt % DEA, and 40 to 50 wt % MDEA. At greater concentrations, corrosion rates increase.

Acid gas loading is reported in terms of moles of acid gas per mole of active amine. “Rich” solution is amine of higher acid gas loading, and “lean” solution has lower acid gas loading (typically < 0.1 mole/mole). Corrosion in poorly regenerated amine with high lean loadings is not an uncommon problem, particularly because lean solution temperatures are often greater than rich solution temperatures. Both H₂S and CO₂ must be measured to determine the acid gas loading. In addition, only the amount of available or “active” amine should be considered when calculating the loading. In H₂S-only systems, rich amine loadings up to 0.70 mole/mole have been satisfactory. In H₂S + CO₂ systems, rich loading is often limited to 0.35 to 0.45 mole/mole. In MDEA units, and particularly those used for selective H₂S removal in sulfur plant tail gas cleanup, rich loadings are often below these levels. As with most corrosion mechanisms, higher temperature increases the corrosion rate.

Another important factor in amine corrosion is the presence of amine degradation products, usually referred to as “heat stable amine salts” or HSAS. These amine degradation products act in two ways. On the one hand, they reduce the amount of active amine available to absorb acid gas, resulting in higher acid gas loadings. In addition, some amine degradation products themselves are corrosive. In MEA and DEA systems, HSAS above 0.5 wt % can begin to increase corrosion although a common operating limit is 2 wt %. Corrosion can be particularly significant, even at low acid gas loadings, at > 2.0 wt % HSAS. MDEA will also form HSAS, but the primary influence on corrosion in these units is organic acid contaminants (formate, oxalate, and acetate). Thermal reclaimers are often provided in MEA units to reduce HSAS, but DEA and MDEA salts are more stable and cannot be thermally reclaimed. DEA degrades less readily than MEA and MDEA. Velocity or turbulence also influences amine corrosion. In the absence of high velocities and turbulence, amine corrosion can be fairly uniform. Higher velocities and turbulence can cause acid gas to evolve from solution, particularly at elbows and where pressure drops occur such as valves, resulting in more localized corrosion. Higher velocity and turbulence may also disrupt protective iron sulfide films that may form. Where velocity is a factor, corrosion may appear either as pitting or grooving. For carbon steel, common velocity limits are about 1.52 m/s (5 ft/s) for rich amine and about 6.01 m/s (20 ft/s) for lean amine.

Austenitic SS are commonly used in areas that are corrosive to carbon steel with good success unless temperatures, amine concentration, and degradation product levels are particularly high. Common applications for stainless steels are reboiler, reclaimers, and hot rich-lean exchanger tubes as well as pressure let-down valves and downstream piping/equipment. 12 % Cr steels have been used for scrubber (absorber) tower internals successfully. Copper alloys are subject to accelerated corrosion and SCC and are normally avoided.

2.B.8.2 Basic Data

The data listed in [Table 2.B.8.1](#) are required to determine the estimated corrosion rate for amine service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.8.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.8.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.8.1](#) in conjunction with [Tables 2.B.8.2](#) through [2.B.8.5](#).

The estimated corrosion rate for carbon steel should be obtained from [Table 2.B.8.2](#) for 20 wt % MEA and 30 wt % DEA and from [Table 2.B.8.3](#) for 50 wt % MDEA. If higher amine concentrations are used, the corrosion rate obtained should be multiplied by the appropriate factor from [Table 2.B.8.4](#).

The estimated corrosion rate for stainless steel may be obtained from [Table 2.B.8.5](#).

NOTE At extreme conditions of amine concentrations, temperatures, and levels of degradation products, the corrosion rate of stainless steel can be as much as 200 times the value in the [Table 2.B.8.5](#).

2.B.8.4 References

See References [23] (Appendix B—Considerations for Corrosion Control), [115], [116], [117], [118], [119], [120], [121], [122], [123], and [124] in Annex 2.G.

2.B.8.5 Tables

Table 2.B.8.1—Amine Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction (CS or SS)	Determine the material of construction of equipment/piping.
Amine concentration, wt %	Determine the amine concentration in the equipment/piping. Due to vaporization of water, a local increase in amine concentration may need to be considered in evaluating the corrosion of some reboilers and reclaimers.
Maximum process temperature, °F (°C)	Determine the maximum process temperature. In reboilers and reclaimers, tube metal temperatures may be higher than the bulk process temperature.
Acid gas loading (mole acid gas/mole active amine)	Determine the acid gas loading in the amine. If analytical results are not available, it should be estimated by a knowledgeable process engineer.
Velocity, ft/s (m/s)	Determine the maximum velocity of the amine in this equipment/piping.
HSAS concentration: MEA and DEA (≤ 2 wt %, 2 to 4 wt %, > 4 wt %) MDEA (< 500, 500 to 4000, > 4000 wppm)	In MEA and DEA, “HSAS” represents the normal family of amine degradation products. In MDEA “HSAS” refers to organic acid contaminants, mainly formate, oxalate, and acetate.

**Table 2.B.8.2—Amine Corrosion Estimated Rate of Carbon Steel
in MEA (≤ 20 wt %) and DEA (≤ 30 wt %), mpy**

Acid Gas Loading (mol/mol)	HSAS (wt %)	Temperature (°F)											
		190		200		220		240		260		270	
		Velocity (ft/s)											
		≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20
< 0.1	2	1	3	1	3	3	10	5	15	10	25	15	40
	3.0	2	6	2	6	6	20	15	40	20	45	30	80
	4.0	5	10	5	15	15	40	30	60	40	90	60	120
		Velocity (ft/s)											
		≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	> 5
0.15	2	1	3	2	6	5	15	10	30	15	45	20	60
	3.0	2	6	4	12	10	30	20	60	30	90	40	80
	4.0	5	15	8	25	20	60	40	80	60	120	120	150
0.25	2	2	6	3	9	7	20	10	30	20	60	25	75
	3.0	4	10	6	20	15	40	20	50	40	80	50	100
	4.0	8	25	15	45	30	60	40	80	80	120	100	150
0.35	2	2	6	4	10	7	20	15	40	25	70	30	80
	3.0	4	10	8	25	15	45	30	60	50	100	100	150
	4.0	8	25	15	40	35	70	60	100	100	140	150	180
0.45	2	3	9	5	15	10	30	15	45	35	70	45	100
	3.0	6	15	10	30	20	60	45	90	70	130	90	150
	4.0	10	30	20	40	40	80	90	120	120	150	150	180
0.55	2	3	9	7	20	10	30	25	75	40	100	50	120
	3.0	6	20	15	45	20	60	50	100	80	140	100	150
	4.0	10	30	30	60	45	90	100	150	140	180	160	200
0.65	2	4	10	9	30	15	40	30	100	50	120	60	150
	3.0	8	15	20	40	30	60	60	100	90	140	100	150
	4.0	15	35	40	80	60	100	100	150	140	180	160	200
0.7	2	5	15	10	30	20	60	40	100	60	120	70	150
	3.0	10	30	20	60	40	80	70	120	100	150	120	150
	4.0	20	45	40	80	60	100	100	150	150	180	170	220

**Table 2.B.8.2M—Amine Corrosion Estimated Corrosion Rate of Carbon Steel
in MEA (≤ 20 wt %) and DEA (≤ 30 wt %), mm/yr**

Acid Gas Loading (mol/mol)	HSAS (wt %)	Temperature (°C)											
		88		93		104		116		127		132	
		Velocity (m/s)											
		≤ 6.1	> 6.1	≤ 6.1	> 6.1	≤ 6.1	> 6.1	≤ 6.1	> 6.1	≤ 6.1	> 6.1	≤ 6.1	> 6.1
<0.1	2	0.03	0.08	0.03	0.08	0.08	0.25	0.13	0.38	0.25	0.64	0.38	1.02
	3.0	0.05	0.15	0.05	0.15	0.15	0.51	0.38	1.02	0.51	1.14	0.76	2.03
	4.0	0.13	0.25	0.13	0.38	0.38	1.02	0.76	1.52	1.02	2.29	1.52	3.05
		Velocity (m/s)											
		≤ 1.5	> 1.5	≤ 1.5	> 1.5	≤ 1.5	> 1.5	≤ 1.5	> 1.5	≤ 1.5	> 1.5	≤ 1.5	> 1.5
0.15	2	0.03	0.08	0.05	0.15	0.13	0.38	0.25	0.76	0.38	1.14	0.51	1.52
	3.0	0.05	0.15	0.1	0.3	0.25	0.76	0.51	1.52	0.76	2.29	1.02	2.03
	4.0	0.13	0.38	0.2	0.64	0.51	1.52	1.02	2.03	1.52	3.05	3.05	3.81
0.25	2	0.05	0.15	0.08	0.23	0.18	0.51	0.25	0.76	0.51	1.52	0.64	1.91
	3.0	0.1	0.25	0.15	0.51	0.38	1.02	0.51	1.27	1.02	2.03	1.27	2.54
	4.0	0.2	0.64	0.38	1.14	0.76	1.52	1.02	2.03	2.03	3.05	2.54	3.81
0.35	2	0.05	0.15	0.1	0.25	0.18	0.51	0.38	1.02	0.64	1.78	0.76	2.03
	3.0	0.1	0.25	0.2	0.64	0.38	1.14	0.76	1.52	1.27	2.54	2.54	3.81
	4.0	0.2	0.64	0.38	1.02	0.89	1.78	1.52	2.54	2.54	3.56	3.81	4.57
0.45	2	0.08	0.23	0.13	0.38	0.25	0.76	0.38	1.14	0.89	1.78	1.14	2.54
	3.0	0.15	0.38	0.25	0.76	0.51	1.52	1.14	2.29	1.78	3.3	2.29	3.81
	4.0	0.25	0.76	0.51	1.02	1.02	2.03	2.29	3.05	3.05	3.81	3.81	4.57
0.55	2	0.08	0.23	0.18	0.51	0.25	0.76	0.64	1.91	1.02	2.54	1.27	3.05
	3.0	0.15	0.51	0.38	1.14	0.51	1.52	1.27	2.54	2.03	3.56	2.54	3.81
	4.0	0.25	0.76	0.76	1.52	1.14	2.29	2.54	3.81	3.56	4.57	4.06	5.08
0.65	2	0.1	0.25	0.23	0.76	0.38	1.02	0.76	2.54	1.27	3.05	1.52	3.81
	3.0	0.2	0.38	0.51	1.02	0.76	1.52	1.52	2.54	2.29	3.56	2.54	3.81
	4.0	0.38	0.89	1.02	2.03	1.52	2.54	2.54	3.81	3.56	4.57	4.06	5.08
0.7	2	0.13	0.38	0.25	0.76	0.51	1.52	1.02	2.54	1.52	3.05	1.78	3.81
	3.0	0.25	0.76	0.51	1.52	1.02	2.03	1.78	3.05	2.54	3.81	3.05	3.81
	4.0	0.51	1.14	1.02	2.03	1.52	2.54	2.54	3.81	3.81	4.57	4.32	5.59

Table 2.B.8.3—Amine Corrosion Estimated Corrosion Rate of Carbon Steel in MDEA (≤ 50 wt %), mpy

Acid Gas Loading (mol/mol)	HSAS (wt %)	Temperature (°F)											
		190		200		220		240		260		270	
		Velocity (ft/s)											
		≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20	≤ 20	> 20
< 0.1	0.5	1	3	1	3	3	10	5	15	10	25	15	40
	2.25	2	6	2	6	6	20	15	40	20	45	30	80
	4.0	5	10	5	15	15	40	30	60	40	90	60	120
		Velocity (ft/s)											
		≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	> 5	≤ 5	> 5
0.15	0.5	1	3	2	6	5	15	10	30	15	45	20	60
	2.25	2	6	4	12	10	30	20	60	30	90	40	80
	4.0	5	15	8	25	20	60	40	80	60	120	120	150
0.25	0.5	2	6	3	9	7	20	10	30	20	60	25	75
	2.25	4	10	6	20	15	40	20	50	40	80	50	100
	4.0	8	25	15	45	30	60	40	80	80	120	100	150
0.35	0.5	2	6	4	10	7	20	15	40	25	70	30	80
	2.25	4	10	8	25	15	45	30	60	50	100	100	150
	4.0	8	25	15	40	35	70	60	100	100	140	150	180
0.45	0.5	3	9	5	15	10	30	15	45	35	70	45	100
	2.25	6	15	10	30	20	60	45	90	70	130	90	150
	4.0	10	30	20	40	40	80	90	120	120	150	150	180
0.55	0.5	3	9	7	20	10	30	25	75	40	100	50	120
	2.25	6	20	15	45	20	60	50	100	80	140	100	150
	4.0	10	30	30	60	45	90	100	150	140	180	160	200
0.65	0.5	4	10	9	30	15	40	30	100	50	120	60	150
	2.25	8	15	20	40	30	60	60	100	90	140	100	150
	4.0	15	35	40	80	60	100	100	150	140	180	160	200
0.7	0.5	5	15	10	30	20	60	40	100	60	120	70	150
	2.25	10	30	20	60	40	80	70	120	100	150	120	150
	4.0	20	45	40	80	60	100	100	150	150	180	170	220

**Table 2.B.8.3M—Amine Corrosion Estimated Corrosion Rate
of Carbon Steel in MDEA (≤ 50 wt %), mm/yr**

Acid Gas Loading (mol/mol)	HSAS (wt %)	Temperature (°C)											
		88		93		104		116		127		132	
		Velocity (m/s)											
		≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1
< 0.1	0.5	0.03	0.08	0.03	0.08	0.08	0.25	0.13	0.38	0.25	0.64	0.38	1.02
	2.25	0.05	0.15	0.05	0.15	0.15	0.51	0.38	1.02	0.51	1.14	0.76	2.03
	4.0	0.13	0.25	0.13	0.38	0.38	1.02	0.76	1.52	1.02	2.29	1.52	3.05
		Velocity (m/s)											
		≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5	≤1.5	>1.5
0.15	0.5	0.03	0.08	0.05	0.15	0.13	0.38	0.25	0.76	0.38	1.14	0.51	1.52
	2.25	0.05	0.15	0.1	0.3	0.25	0.76	0.51	1.52	0.76	2.29	1.02	2.03
	4.0	0.13	0.38	0.2	0.64	0.51	1.52	1.02	2.03	1.52	3.05	3.05	3.81
0.25	0.5	0.05	0.15	0.08	0.23	0.18	0.51	0.25	0.76	0.51	1.52	0.64	1.91
	2.25	0.1	0.25	0.15	0.51	0.38	1.02	0.51	1.27	1.02	2.03	1.27	2.54
	4.0	0.2	0.64	0.38	1.14	0.76	1.52	1.02	2.03	2.03	3.05	2.54	3.81
0.35	0.5	0.05	0.15	0.1	0.25	0.18	0.51	0.38	1.02	0.64	1.78	0.76	2.03
	2.25	0.1	0.25	0.2	0.64	0.38	1.14	0.76	1.52	1.27	2.54	2.54	3.81
	4.0	0.2	0.64	0.38	1.02	0.89	1.78	1.52	2.54	2.54	3.56	3.81	4.57
0.45	0.5	0.08	0.23	0.13	0.38	0.25	0.76	0.38	1.14	0.89	1.78	1.14	2.54
	2.25	0.15	0.38	0.25	0.76	0.51	1.52	1.14	2.29	1.78	3.3	2.29	3.81
	4.0	0.25	0.76	0.51	1.02	1.02	2.03	2.29	3.05	3.05	3.81	3.81	4.57
0.55	0.5	0.08	0.23	0.18	0.51	0.25	0.76	0.64	1.91	1.02	2.54	1.27	3.05
	2.25	0.15	0.51	0.38	1.14	0.51	1.52	1.27	2.54	2.03	3.56	2.54	3.81
	4.0	0.25	0.76	0.76	1.52	1.14	2.29	2.54	3.81	3.56	4.57	4.06	5.08
0.65	0.5	0.1	0.25	0.23	0.76	0.38	1.02	0.76	2.54	1.27	3.05	1.52	3.81
	2.25	0.2	0.38	0.51	1.02	0.76	1.52	1.52	2.54	2.29	3.56	2.54	3.81
	4.0	0.38	0.89	1.02	2.03	1.52	2.54	2.54	3.81	3.56	4.57	4.06	5.08
0.7	0.5	0.13	0.38	0.25	0.76	0.51	1.52	1.02	2.54	1.52	3.05	1.78	3.81
	2.25	0.25	0.76	0.51	1.52	1.02	2.03	1.78	3.05	2.54	3.81	3.05	3.81
	4.0	0.51	1.14	1.02	2.03	1.52	2.54	2.54	3.81	3.81	4.57	4.32	5.59

Table 2.B.8.4—Amine Corrosion Rate Multiplier for High Amine Strengths

Type of Amine	Concentration (wt %)	Multiplier
MEA	≤ 20	1.0
	21 to 25	1.5
	> 25	2.0
DEA	≤ 30	1.0
	31 to 40	1.2
	> 40	1.5
MDEA	≤ 50	1.0

Table 2.B.8.5—Amine Corrosion Estimated Corrosion Rates for Stainless Steel for All Amines

Acid Gas Loading (mol/mol)	Temperature ≤ 300 °F (149 °C)	
	mm/yr	mpy
0.1	0.03	1
0.15	0.03	1
0.25	0.03	1
0.35	0.05	2
0.45	0.05	2
0.55	0.08	3
0.65	0.1	4
0.7	0.13	5

2.B.8.6 Figures

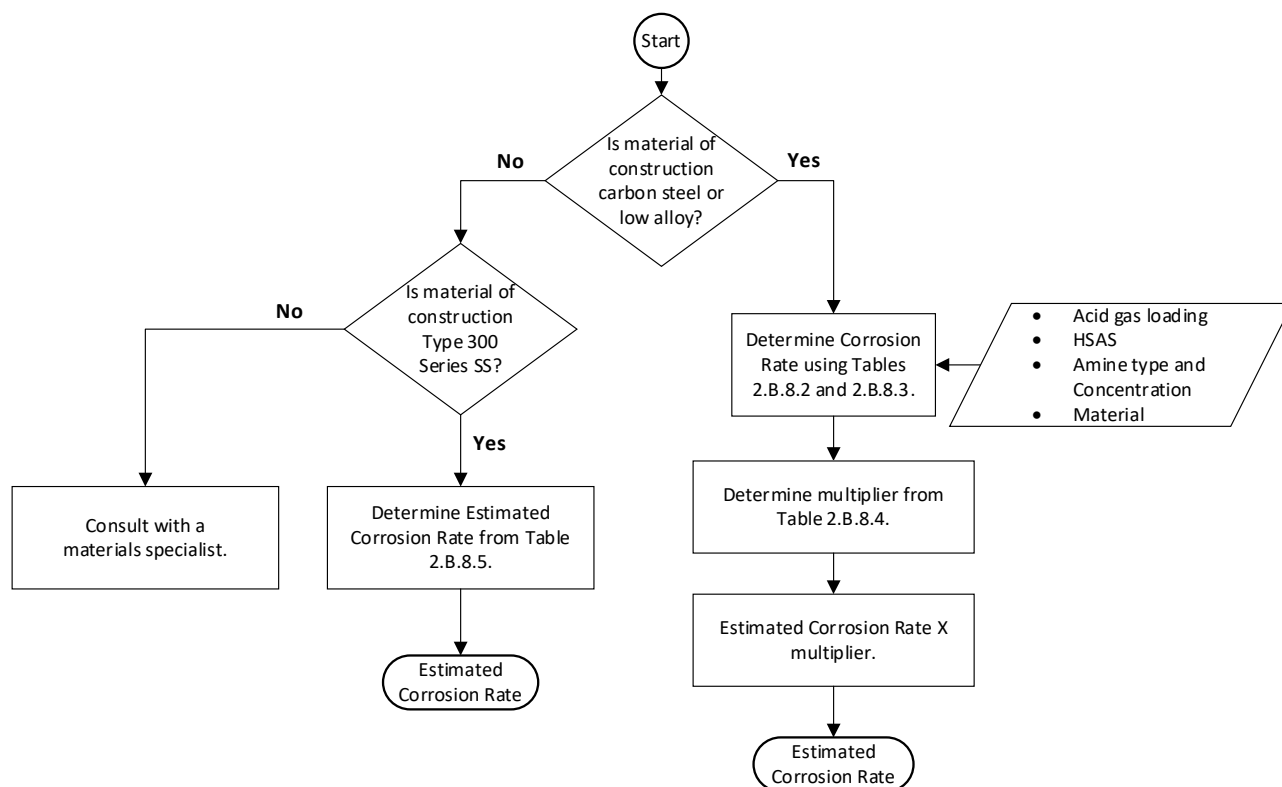


Figure 2.B.8.1—Amine Corrosion—Determination of Corrosion Rate

2.B.9 High-temperature Oxidation

2.B.9.1 Description of Damage

Corrosion due to high-temperature oxidation occurs at temperatures above about 900 °F (482 °C) for carbon steel and increasing higher temperatures for alloys. The metal loss occurs as a result of the reaction of metal with oxygen in the environment. Typically, at temperatures just above the temperature where oxidation begins to occur, a dense comparatively protective oxide forms on the surface that reduces the metal loss rate. The oxide scale tends to be significantly more protective as the chromium concentration in the metal increases.

2.B.9.2 Basic Data

The data listed in [Table 2.B.9.1](#) are required to determine the estimated corrosion rate for high-temperature oxidation service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.9.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.9.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.9.1](#) in conjunction with [Tables 2.B.9.2 through 2.B.9.3](#).

Table 2.B.9.2—High-temperature Oxidation—Estimated Corrosion Rate, mpy

Table 2.B.9.3—High-temperature Oxidation—Estimated Corrosion Rate, mpy

Material	Maximum Metal Temperature (°F)											
	1525	1575	1625	1675	1725	1775	1825	1875	1925	1975	2025	2075
CS	—	—	—	—	—	—	—	—	—	—	—	—
1 ¹ / ₄ Cr	—	—	—	—	—	—	—	—	—	—	—	—
2 ¹ / ₄ Cr	—	—	—	—	—	—	—	—	—	—	—	—
5Cr	—	—	—	—	—	—	—	—	—	—	—	—
7Cr	—	—	—	—	—	—	—	—	—	—	—	—
9Cr	60	—	—	—	—	—	—	—	—	—	—	—
12Cr	50	—	—	—	—	—	—	—	—	—	—	—
304 SS	6	9	13	18	25	35	48	—	—	—	—	—
309 SS	4	6	8	10	13	16	20	30	40	50	—	—
310 SS/HK	3	4	5	7	8	10	13	15	19	23	27	31
800 H/HP	3	4	6	8	10	13	17	21	27	33	41	50

Table 2.B.9.3M—High-temperature Oxidation—Estimated Corrosion Rate, mm/yr

Material	Maximum Metal Temperature (°C)											
	829	857	885	913	941	968	996	1024	1052	1079	1107	1135
CS	—	—	—	—	—	—	—	—	—	—	—	—
1 ¹ / ₄ Cr	—	—	—	—	—	—	—	—	—	—	—	—
2 ¹ / ₄ Cr	—	—	—	—	—	—	—	—	—	—	—	—
5Cr	—	—	—	—	—	—	—	—	—	—	—	—
7Cr	—	—	—	—	—	—	—	—	—	—	—	—
9Cr	1.52	—	—	—	—	—	—	—	—	—	—	—
12Cr	1.27	—	—	—	—	—	—	—	—	—	—	—
304 SS	0.15	0.23	0.33	0.46	0.64	0.89	1.22	—	—	—	—	—
309 SS	0.1	0.15	0.2	0.25	0.33	0.41	0.51	0.76	1.02	1.27	—	—
310 SS/HK	0.08	0.1	0.13	0.18	0.2	0.25	0.33	0.38	0.48	0.58	0.69	0.79
800 H/HP	0.08	0.1	0.15	0.2	0.25	0.33	0.43	0.53	0.69	0.84	1.04	1.27

2.B.9.5 Figures

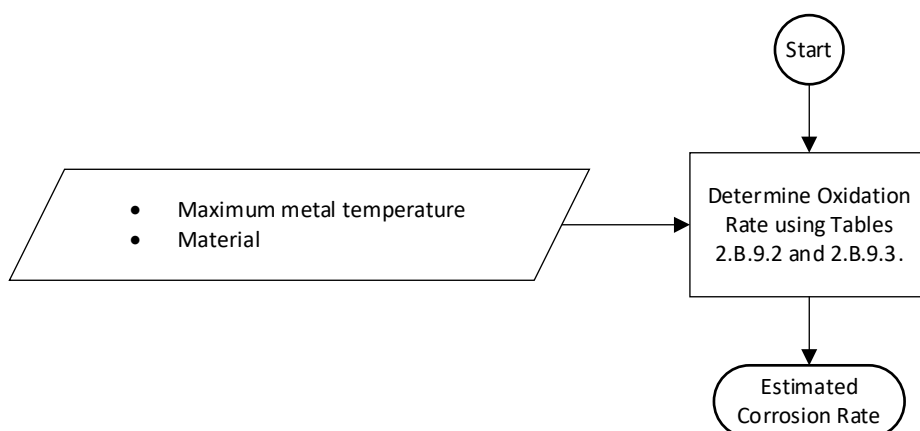


Figure 2.B.9.1—High-temperature Oxidation—Determination of Corrosion Rate

2.B.10 Acid Sour Water Corrosion

2.B.10.1 Description of Damage

2.B.10.1.1 Overview

Acid sour water is defined as water containing H_2S and with pH below neutral pH (7). The primary refining units or gas fractionator plants where acid sour water corrosion is a concern are sour distillation overhead systems in gas fractionation plants. Most other refining distillation units contain chlorides or ammonia and are covered in [Sections 2.B.2](#) and [2.B.7](#), respectively.

Corrosion damage from acid sour water is typically general thinning. Above pH of about 4.5, a protective thin iron sulfide layer limits the corrosion rate. In some instances at pH above 4.5, a thicker porous sulfide film layer can form. This can promote pitting under sulfide deposits, yet generally this does not affect the general corrosion rate. Sour water condensates in equilibrium with a vapor containing H_2S at a partial pressure below 1 atm will usually have a pH between 4.5 and 7. At H_2S partial pressures greater than 1 atm, a pH < 4.5 can be achieved and are outside the scope of this section.

2.B.10.1.2 Scope and Limitations

The scope of this section is to give guidance in determining a conservatively estimated corrosion rate driven by acid sour water, under the following conditions and assumptions.

- Primary corrosive is H_2S . Assuming no significant amounts of ammonia, carbon dioxide, chlorides, or cyanides are present.
- The corrosion mechanism is general corrosion, with some occurrence of pitting in the presence of oxygen.
- This section contains guidance for estimating corrosion rates of carbon steel. Copper alloys and nickel alloys (not containing chromium) can be used and are generally not susceptible to acid sour water corrosion in the refinery applications where acid sour water is found. Stainless steel can be used where the temperature is low enough that CISCC is not likely. Where the material of construction is other than carbon steel, it is assumed that the selected material is suitable for the service and that the corrosion rates will not exceed 0.05 mm/yr (2 mpy).

- d) Cracking is not considered. Wet H₂S cracking mechanisms are addressed elsewhere in this document.
- e) Presence of air or oxidants may increase the corrosion. It is assumed that the normal concentration of oxygen is less than 50 ppb.
- f) A high flow velocity can have an adverse effect on the corrosion. It is assumed that the effect is negligible for velocities less than 6 ft/s (1.83 m/s). When velocities exceed 6 ft/s (1.83 m/s), higher corrosion rates and possible localized corrosion should be considered.

The base corrosion rate is estimated from the pH level and temperature. An adjustment is made for oxygen content. Other factors, such as content of chlorides, cyanides, etc., are relevant but are considered less significant for the end result in this context. The result is a conservative value for the estimated corrosion rate.

2.B.10.2 Basic Data

The data listed in [Table 2.B.10.1](#) are required to estimate the rate of corrosion rate in acid sour water. If precise data has not been measured, a knowledgeable process specialist should be consulted.

2.B.10.3 Determination of Corrosion Rate

The corrosion rate is determined using [Equations \(2.B.1\)](#) through [Equation \(2.B.7\)](#) and shown in [Figure 2.B.10.1](#). If the pH is less than 4.5, then the corrosion rate shall be calculated using [Section 2.B.2](#). If the pH is greater than 7, then the corrosion rate is calculated using [Section 2.B.7](#). Otherwise, the corrosion rate of carbon steel exposed to acid sour water is computed using [Equation \(2.B.1\)](#).

$$CR = CR_{pH} \cdot F_O \cdot F_V \quad (2.B.1)$$

The base corrosion rate, CR_{pH} , of carbon steel exposed to acid sour water as a function of pH is provided in [Table 2.B.10.2](#). The corrosion rate can vary significantly with level of DO. The modification factor for the corrosion rate as a function of the oxygen content factor, F_O , is provided in [Table 2.B.10.3](#). The corrosion rate also varies with fluid velocity. The modification factor for fluid velocity is given by the following equations.

For SI units, use [Equations \(2.B.2\)](#) through [\(2.B.4\)](#):

$$F_V = 1.0 \quad \text{when velocity} < 1.83 \text{ m/s} \quad (2.B.2)$$

$$F_V = 0.82 \cdot \text{velocity} - 0.5 \quad \text{when } 1.83 \text{ m/s} \leq \text{velocity} \leq 6.10 \text{ m/s} \quad (2.B.3)$$

$$F_V = 5.0 \quad \text{when velocity} > 6.10 \text{ m/s} \quad (2.B.4)$$

For U.S. customary units, use [Equations \(2.B.5\)](#) through [\(2.B.7\)](#):

$$F_V = 1.0 \quad \text{when velocity} < 6 \text{ ft/s} \quad (2.B.5)$$

$$F_V = 0.25 \cdot \text{velocity} - 0.5 \quad \text{when } 6 \text{ ft/s} \leq \text{velocity} \leq 20 \text{ ft/s} \quad (2.B.6)$$

$$F_V = 5.0 \quad \text{when velocity} > 20 \text{ ft/s} \quad (2.B.7)$$

2.B.10.4 Nomenclature

CR	is the corrosion rate
CR_{pH}	is the base corrosion rate as a function of pH
F_o	is the corrosion rate correction for oxygen
F_v	is the corrosion rate correction for velocity
$velocity$	is the fluid velocity, m/s (ft/s)

2.B.10.5 References

See References [\[125\]](#), [\[126\]](#), [\[127\]](#), [\[128\]](#), and [\[129\]](#) in [Annex 2.G](#).

2.B.10.6 Tables

Table 2.B.10.1—Acid Sour Water Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping. Carbon and low-alloy steel (containing maximum 6 % alloys) assumed as default.
pH	Determine the lowest pH for the equipment/piping. The pH that is used should be of the separated acid phase within this equipment or nearest equipment downstream, e.g. the overhead accumulator boot water downstream of the overhead condenser.
Water temperature, °F (°C)	Determine the maximum temperature present in the equipment/piping. This may be the maximum process temperature, but local heating condition such as effect of the sun or heat tracing should be considered.
Air or oxidants present (Yes or No)	Presence of oxygen may increase the corrosion rates. Normal oxygen concentration is ≤ 50 ppb, and high is maximum > 50 ppb.
Chlorides present (Yes or No)	The present of chlorides in combination with a pH below 4.5 significantly affect the corrosion rate.
Flow velocity, ft/s (m/s)	Determine the maximum expected flow velocity.

Table 2.B.10.2—Acid Sour Water Corrosion Estimated Corrosion Rates for Carbon and Low-alloy Steel, mpy— CR_{pH}

pH	Temperature (°F)			
	100	125	175	200
4.75	1	3	5	7
5.25	0.7	2.0	3	4
5.75	0.4	1.5	2	3
6.25	0.3	1	1.5	2
6.75	0.2	0.5	0.7	1

Table 2.B.10.2M—Acid Sour Water Corrosion Estimated Corrosion Rates for Carbon and Low-alloy Steel, mm/yr— CR_{pH}

pH	Temperature (°C)			
	38	52	79	93
4.75	0.03	0.08	0.13	0.18
5.25	0.02	0.05	0.08	0.1
5.75	0.01	0.04	0.05	0.08
6.25	0.01	0.03	0.04	0.05
6.75	0.01	0.01	0.02	0.03

Table 2.B.10.3—Acid Sour Water Corrosion—Basic Data Required for Analysis

Oxygen Content	Adjustment Factor— F_o
Not significant (≤ 50 ppb)	1.0
High (> 50 ppb)	2.0

2.B.10.7 Figures

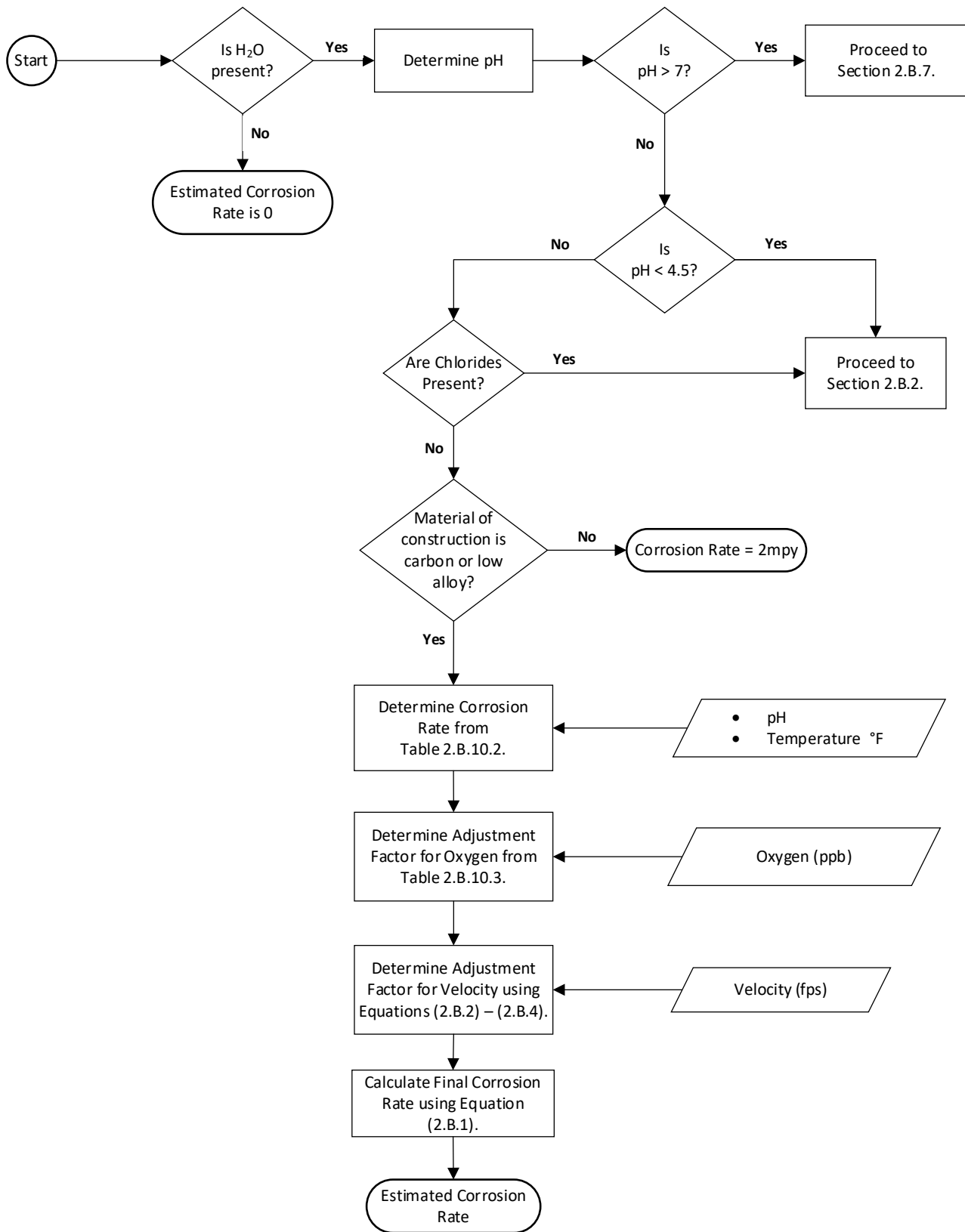


Figure 2.B.10.1—Acid Sour Water—Determination of Corrosion Rate

2.B.11 Cooling Water Corrosion

2.B.11.1 Description of Damage

2.B.11.1.1 Overview

The objective for this section is to describe a conservative approach for estimating corrosion rates of carbon steel components in cooling water systems. In freshwater systems, a model uses the Ryznar Stability Index (RSI), chloride content, temperature, and flow velocity to calculate a corrosion rate. For seawater systems, a simple correlation of corrosion rate and velocity is used. Many other factors influence corrosion of the typical modern cooling water system, and this section also describes qualitatively some of these considerations.

This section does not attempt to account for degradation of alloys other than carbon steel or to quantify the effectiveness of water treatment. Many other alloys are used in cooling water systems. Some of these alloys and the threats that they may face are described qualitatively, but corrosion rates of these alloys are assumed to be very low. While low-alloy steels are rarely used in cooling water systems, the corrosion rates given by this methodology would be reasonably accurate for low-alloy steels.

The best way to assess corrosion in cooling water systems is to use a variety of monitoring techniques, but detailed use of those techniques is not described here. Most cooling water corrosion monitoring begins with the use of corrosion coupons. Other techniques have been used to monitor cooling water corrosion in situ, but they are not described. Microbiologically induced corrosion (MIC) is another common degradation mechanism in cooling water systems, and coupons are not always a reliable way to monitor this corrosion or other corrosion where there are deposits or stagnant areas. Direct monitoring and control of the microorganisms is recommended.

2.B.11.1.2 Types of Cooling Water Systems

There are three types of cooling water systems typically found in industrial operations such as refineries, as follows.

- a) Once Through Cooling—Does not reuse the heated water, which normally is pumped from a fresh water or seawater source.
- b) Closed Recirculating Cooling—Continuously reuses water that is captive in the system. No makeup after the initial water charge (except to replace accidental leakage).
- c) Open Recirculating Cooling (Cooling Tower)—Reuses water from which the heat is rejected into a cooling reservoir (tower or pond), needs continual makeup water to compensate for evaporation, blowdown, windage, and drift losses, and needs a blowdown facility to limit the concentration of impurities that are typically introduced with the makeup water.

2.B.11.1.3 Once Through Systems

Usually, the water source must be presumed corrosive since the surface waters are open to the atmosphere and contain DO. In a general way, corrosion of iron and steel is proportional to the chloride content when DO is constant, and vice versa. For seawater in particular, the flow velocity has a significant impact on the corrosion rate.

Because once through cooling water is not reused, the volume of water circulated through such a system effectively precludes chemical inhibition from a cost-effective standpoint. In some cases, a small amount of scale inhibitor is added to the influent water. However, chlorination is usually necessary to control biological growth (e.g. bacteria, slime, marine organisms).

Both fresh and saline waters are sufficiently corrosive to carbon steel that more corrosion-resistant materials must be employed. In fresh water, galvanized steel is often adequate but brackish or salt water requires more

resistant materials [e.g., copper or nickel alloys; titanium; super-austenitic stainless steels (such as 6-Mo stainless steels); plastic; fiberglass reinforced plastic (FRP) or plastic-lined steel; concrete, etc.].

2.B.11.1.4 Closed Recirculated Systems

Recirculated cooling water systems are applied where water is in short supply or when the water chemistry must be rigorously controlled. Closed recirculated systems may be treated either by rendering them sterile and anaerobic or by use of inhibitors. The cost of treatment is minimal, including softening and pH control, if required or desirable. The heat is removed either in air-cooled heat exchangers or water-to-water exchangers cooled by an external cooling water system. Bactericidal treatment may be required, using nonoxidizing biocide, such as hexamethylene biguanide. If no treatment is applied, sulfate-reducing bacteria (SRB) would otherwise be a potential problem.

A successfully used strategy for preventing problems in the closed cooling water systems is to charge the system with condensate quality water and then add an effective corrosion inhibitor to prevent corrosion. Given the controlled environment, the material of construction is usually carbon steel, unless otherwise required for process reasons.

2.B.11.1.5 Open Recirculated Systems

These types of cooling systems involve constant air saturation as well as some concentration of water-borne solids in the circulating water. Such systems are corrosive to steel (unless suitably inhibited) and potentially scaling unless the hardness, pH, and alkalinity are also controlled.

In a cooling tower system, the total amount of water actually used is limited to that lost by evaporation plus the blowdown established to limit the buildup of salts and solids in the system. The extent of soluble salt concentration is expressed as cycles of concentration, which is the ratio of hardness in the blowdown to that in the makeup. Water treatment chemicals need only be replaced in accordance with the blowdown rate. In most systems (water chemistry permitting), the optimum balance between water savings and salt concentration is effected at four to six cycles of concentration. The additional water savings from a higher number of cycles are usually offset by the increasing difficulty of coping with higher dissolved salt and hardness concentrations.

Because of the warm temperature and constant air scrubbing in the tower, the water is not only corrosive but also a breeding ground for slime and algae introduced from air-borne spores. Unless corrosion-resistant materials are used, open recirculated systems must usually be corrosion inhibited, treated with biocides to control biological growths, and chemically treated to control scale and deposits. The cost of such treatment must be balanced against the obvious savings in water consumption. The choice between corrosion inhibition vs resistant materials of construction is one of economics and pollution abatement considerations.

Typical corrosion-resistant materials for components in freshwater-type open recirculated systems are stainless steel, copper alloys, nickel alloys, titanium, cement lined carbon steel, FRP lined or coated steel (for vessels), etc.

2.B.11.1.6 Factors Affecting Corrosion Rate

There are several factors that affect the rate of corrosion in cooling systems. Depending on the type of system and water source, the main concerns are related to the following.

- a) Impurities in Makeup Water—Calcium, chlorides, alkalinity, silica, etc.
- b) Scale Formation—When the process side temperature is greater than 140 °F (60 °C), a scaling potential exists. The scales are minerals formed by high concentration of specific impurities, e.g. calcite (CaCO_3) formed by calcium salts and dissolved CO_2 species. Temperature, pH, and alkalinity influence the solubility limit of most minerals found in cooling water systems. Unfortunately, high temperature reduces the solubility of many important minerals, causing scale most often to appear on the hottest surfaces in the

entire cooling system, which are the heat exchangers. Phosphates and zinc are two of the most common minerals used as corrosion inhibitors in water treatment programs and can form mineral scale if not properly controlled.

c) Deposits

- 1) Mud and Silt—Enters the cooling tower in makeup water or scrubbed from the air.
- 2) Corrosion Products (Iron Oxide)—Formed as a result of corrosion. Forms a porous deposit that is frequently the site for pitting corrosion.
- 3) Bio-mass—A mixture of bacterial slime and other material. Typically, mud and iron oxide accumulate in low flow regions, causing a favorable environment for microorganisms to form colonies on the surface that potentially can promote accelerated pitting corrosion. Process leaks of hydrocarbon can often accelerate bacterial growth and lead to rapid formation of bio-mass.

2.B.11.1.7 Types of Corrosion

Corrosion of carbon steel in cooling water systems is dominated by pitting. The following are other more common types of corrosion that can be seen.

- a) Under-deposit Corrosion—A form of pitting corrosion that occurs beneath deposits.
- b) Crevice Corrosion—Pitting and preferential attack at a crevice such as at the tube to tubesheet crevice, etc.
- c) Galvanic Corrosion—The enhanced corrosion of one metal in electrical contact with another kind of metal in an electrolyte. This form of corrosion depends on the metals having a dissimilar corrosion potential that causes one metal to be polarized into a potential region where it corrodes more quickly. As an example, copper alloy tubes in a carbon steel tubesheet may cause more rapid corrosion of the tubesheet.
- d) Dealloying—Corrosion process that appears to selectively dissolve one of the constituents of an alloy. When admiralty brass experiences dealloying, zinc is removed leaving copper (referred to as dezincification).
- e) MIC—MIC is a complex issue. Strictly speaking, MIC is not a specific type of corrosion. Rather, it consists of both direct and indirect effects on materials by bacteria, fungi, algae, and yeasts. Many types of bacteria can be implicated involved in MIC processes. Perhaps the best known type of MIC attack is the corrosion process involving SRB. These organisms are anaerobic (cannot tolerate oxygen) and thrive beneath deposits. They metabolize sulfate creating a highly acidic local environment that leads to metal corrosion. Other types of bacteria that contribute to MIC include slime forming bacteria, nitrifying bacteria, manganese-reducing bacteria, and iron-reducing bacteria.
- f) SCC—SCC mechanisms require the coming together of three things—a tensile stress, a susceptible alloy, and an environment that promotes SCC in that alloy. The tensile stress may be either applied or residual, and residual stresses from welding commonly contribute to SCC. Many alloys can be susceptible to SCC in at least one environment with 300 series SS and copper alloys being the most common susceptible materials used in cooling water systems. The environments most associated with SCC of these alloys are aqueous chloride environments for 300 series SS and ammonia for specific copper alloys.

2.B.11.1.8 Corrosion Monitoring and Control in Cooling Water Systems

The largest potential for problems in the cooling system is associated with scaling, deposition of suspended solids, and MIC. Usually, under conditions with controlled water treatment and operating parameters, only negligible corrosion is expected. However, even with these parameters in control, MIC or buildup of solids may cause unsuspected corrosion. This fact emphasizes the need for an effective corrosion monitoring program in addition to the water treatment and process control programs.

There are several strategies for controlling corrosion. These include:

- a) keep metal surfaces free from deposits,
- b) create and maintain an environment that is not conducive to corrosion,
- c) incorporate corrosion inhibitors into the treatment program,
- d) pre-passivate new and recently cleaned equipment.

In practice it is common to simultaneously employ several of the above strategies. For example, an effective treatment program frequently incorporates corrosion inhibitors, maintenance of a benign environment, and steps to keep metal surfaces clean by using dispersants and side-stream filtration.

Many variations of basic cooling water treatment programs are being practiced. In general, they all include fouling control, corrosion control and microbiological control. The most common method to control the microbiological population in a cooling system is to treat the system with one or more biocides. Biocides can be classified into oxidizing and nonoxidizing.

2.B.11.1.9 Indicators for Corrosion Issues and Their Deterrence

The following parameters might be used as indicators for potential issues in the cooling system, depending on the water treatment program in place.

- a) If process-side temperature is greater than 140 °F (60 °C), then a scaling potential exists. However, at the measured pH, one can calculate the temperature at which the water begins to scale, by solving for the value of C_2 in [Equation \(2.B.11\)](#) using the coefficients provided in [Table 2.B.11.3](#).
- b) Dissolved Solids—The higher the level of dissolved solids, typically an indicator of chlorides, the higher the corrosion rate.
- c) Velocity should be maintained at minimum 1 m/s (3 ft/s) through all parts of the system. For example, if cooling water is on the shell side of a shell-and-tube exchanger, some regions within the shell will have a low velocity.
- d) Iron levels greater than 5 ppm in the recirculating water could be an indication that the applied dispersants and flocculating agents are insufficient to keep the formation of deposits at an acceptable level. Other means of deposit control may be required.
- e) In open recirculated systems, suspended solids above 100 ppm will cause settlement in heat exchanger equipment and become a site for under-deposit corrosion.
- f) Chlorine content may be dissolved intentionally in water as a biocide. It has little effect on carbon steel if pH is maintained above 7 to suppress formation of acid hydrolysis products by $\text{Cl}_2 + \text{H}_2\text{O} \rightarrow \text{HClO} + \text{HCl}$. However, chlorine will attack copper alloys, even at higher pH, presumably by reaction with the Cu_2O surface film.

- g) Ammonia Content—Results primarily from contamination by process leaks. Could also be present if NH_4OH is used as an acid neutralizer; however, this is not recommended due to the volatility of ammonia and its use as a food source by microorganisms. It has little effect on iron and steel but has a strong effect on copper alloys. Ammonia forms complexes with copper that can cause rapid general corrosion and/or SCC of copper alloys. For example, admiralty brass is very susceptible to ammonia SCC and might experience SCC with only trace amount of ammonia present.

With fresh waters, corrosion of steel is governed by DO over a broad pH range (4.5 to 9.5) at relatively low temperatures. Below pH 4.5, the corrosion is controlled by hydrogen evolution under acid conditions. Above pH 9.5, an insoluble film of ferric hydroxide suppresses corrosion. In buffered solutions, where ionic concentrations are high without a corresponding drop in pH (as with carbonic and other weakly ionized acids), corrosion with hydrogen evolution may occur in the pH 5.0 to 5.5 range. In the intermediate pH range of 4.5 through 9.5, a loose, porous, ferrous-oxide deposit shelters the surface and maintains the steel surface pH at about 9.5. The corrosion rate remains nearly constant and is determined by uniform diffusion of DO through the deposit. At the metal surface under the deposit, oxygen is reduced cathodically. Cathodic reduction of DO produces a slightly alkaline surface condition, which precipitates calcium carbonate (CaCO_3). These precipitates in turn inhibit further cathodic reduction and corrosion.

The corrosive effect from the water in closed recirculating cooling water systems is easily mitigated. These systems may be treated either by rendering them sterile and anaerobic or by either oxidizing or nonoxidizing inhibitors.

Corrosion control in open recirculating cooling water systems can be achieved through the continuous use of treatment chemicals containing scale and corrosion inhibitors and polymeric dispersants. The regular use of broad spectrum microbiocides is typically used for controlling microbiological populations.

Once through cooling water systems present special problems because chemical treatment of the water may not be possible or practical. In addition, such systems often use seawater or other inherently corrosive water. Corrosion control in once through systems is principally achieved by proper alloy selection, CP, and/or the use of epoxy-phenolic coatings.

2.B.11.1.10 Assumptions

Cooling water systems can be very complex, and this RBI model does not attempt to address every issue that must be considered. For the purposes of this model, the following assumptions have been made.

- Low-alloy steels are rarely used in cooling water systems and will not be addressed in the remainder of this section. However, most of the content for carbon steel applies to low-alloy steels.
- This model does not consider degradation of alloys other than carbon steel. Beyond some general comments, SCC and pitting of stainless steels and dealloying of copper alloys are not considered.
- If coupon measurement results are available, these should be used instead of this model. As a rule of thumb for carbon steel, the pitting rate is a factor of 5 to 10 times the coupon general corrosion rate (calculated by weight loss).
- If corrosion inhibitors are being used, it is assumed that the program is designed and operated to adequately control corrosion of carbon steel and alloy materials.
- An effective microbiological control program is in place, and corrosion driven by MIC is negligible, i.e. can be set to < 5 mpy (0.13 mm/yr), pitting.
- Water pH is kept within the range 6.5 to 9.5. Outside this pH range, the corrosion is assumed caused by other means than what is covered in this section.

- g) In the event the RSI value is < 6 , it is assumed that corrosion is retarded by scale formation but can still be estimated on the basis of the chloride content, temperature, and flow velocity.
- h) There is no deposition and no local low flow areas.

2.B.11.1.1 Corrosion Rates for Copper Alloys Components

This section is not intended to cover material of construction other than carbon steel. The introduction of other materials such as stainless steel, copper, nickel, zinc, or aluminum-based alloys, etc. might introduce other types of degradation mechanisms. It is virtually impossible to model the complexity of the various materials and interrelation with various chemical and contaminants in the water. Thus, it has been assumed that, in general, the selection of appropriate alloy material combined with “correct” chemical treatment and process control will render a negligible corrosion rate in the cooling water system.

In general, copper and its alloys are the most reliable and cost effective alloys for many water services, although dezincification needs to be specifically inhibited for brasses containing more than 15 % zinc. Copper, red brass, inhibited admiralty brasses, aluminum brass, aluminum bronze, and cupronickels, in that order, are used for water of increasing salinity and/or velocity. In the presence of DO, soft waters can be highly corrosive to copper alloys. Also, copper can suffer pitting under some conditions, which for fresh waters can be described as three types of pitting:

- a) Type 1 pitting is apparently caused by residual carbonaceous films from the manufacturing process;
- b) Type 2 pitting is associated with hot soft waters [$> 140^{\circ}\text{F}$ (60°C)], and
- c) Type 3 pitting may occur in cold water or high pH and low salt concentrations, for unknown reasons.

Another issue related to copper alloys is cracking. Admiralty brass is very susceptible to ammonia SCC and might experience SCC with only a trace amount of ammonia present.

An important factor for copper-based alloys is maintaining operation within design velocity limits. Velocities under the lower limit can lead to increased deposition and under-deposit corrosion, and velocities exceeding the upper limit can cause damage to the protective surface film resulting in impingement attack.

2.B.11.2 Basic Data

2.B.11.2.1 Recirculating Cooling Water Systems

The data listed in [Table 2.B.11.1](#) are required for determining the estimated corrosion rate for recirculating cooling water service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.11.2.2 Once Through Cooling Water Systems

The data listed in [Table 2.B.11.2](#) are required for determining the estimated corrosion rate for once through cooling water service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.11.3 Determination of Corrosion Rate

2.B.11.3.1 Recirculating Cooling Water Systems

2.B.11.3.1.1 Corrosion Rate Equation

The steps required to determine the corrosion rate are shown in [Figure 2.B.11.1](#). The corrosion rate is calculated using [Equation \(2.B.8\)](#). In this equation, the base corrosion rate, CR_B , is adjusted for temperature and flow velocity for each component in the system to calculate a final representative corrosion rate.

$$CR = CR_B \cdot F_T \cdot F_V \quad (2.B.8)$$

The estimated corrosion rates need further adjustments in case construction material is other than carbon steel. This has not been addressed within this section.

2.B.11.3.1.2 Base Corrosion Rate

The base corrosion rate, CR_B , is an estimated corrosion rate that is determined from the water scale tendency, chloride concentration, and a threshold for flow velocity [i.e. higher or lower than 8 ft/s (2.44 m/s)].

The concept of RSI is used to predict whether water variables in the pH range of 6.5 to 9.5 will produce conditions that are scaling or corrosive to carbon steel. The expected tendencies are increased scaling conditions at higher temperatures, higher Ca hardness, and higher MO alkalinity and seeing corrosive conditions at lower temperatures, lower Ca hardness, or lower MO alkalinity. MO alkalinity refers to the methyl orange and the test used to measure the total alkalinity of water.

For given values of calcium hardness, MO alkalinity, and total dissolved salt concentration, a value of pH, pH_s , exists at which the water is in equilibrium with solid $CaCO_3$. The deposit of $CaCO_3$ is thermodynamically possible when the pH of water is higher than pH_s , i.e. higher than the pH at saturation of calcium carbonate. The difference between the actual pH, pH_a , of a sample of water and the pH for $CaCO_3$ saturated water, pH_s , is called the Langelier Saturation Index (LSI) and is computed using [Equation \(2.B.9\)](#).

$$LSI = pH_a - pH_s \quad (2.B.9)$$

The LSI is used to predict the tendency for $CaCO_3$ to either dissolve or precipitate and provide corrosion resistance in fresh water, under varying conditions.

While the concept of the LSI is correct and helpful; however, it should be emphasized that a positive value of the index can result from waters of totally different quality. As the pH increases, the Ca^{2+} concentration decreases drastically. The corrosion protection characteristics of the resulting $CaCO_3$ film differ accordingly. In other words, waters of different pH, Ca hardness, and MO alkalinity that give the same value of the index have different corrosivity.

The LSI alone cannot be used to do any quantitative assessment. However, when used along with the RSI determined using [Equation \(2.B.10\)](#), a relatively good prediction of the scaling or corrosive tendencies of a water is obtained.

$$RSI = 2 \cdot pH_s - pH_a \quad (2.B.10)$$

This RSI was developed based on actual operating results for waters with different saturation indexes and is used in practice for estimating corrosivity of water. The value of pH in [Equation \(2.B.10\)](#) is calculated using [Equation \(2.B.11\)](#) and the parameters in [Table 2.B.11.3](#).

$$pH_s = (9.3 + C_1 + C_2) - (C_3 + C_4) \quad (2.B.11)$$

All values of the RSI can be expected to be positive. At the value of 6, the CaCO_3 is in equilibrium. The deposition of CaCO_3 increases proportionally (increased tendency of forming scale) as the index drops to below 6, and corrosivity increases as the index rises above 6. Values of 10 or above indicate extreme corrosivity. Corrosion can still take place with < 6 RSI. However, in general, low corrosion rates are obtained in scale-forming waters.

Even though the RSI indicates that CaCO_3 precipitation takes place, the corrosion rate may remain high if the water contains colloidal silica or organic particles, such as algae, because CaCO_3 precipitates on them instead of on the steel surface. For waters high in dissolved salt (such as seawater) or at high temperature, the CaCO_3 film is less protective.

Once the RSI has been determined, the base corrosion rate is calculated based on the chloride concentration and flow velocity of the water using [Table 2.B.11.4](#). In case where the velocity is larger than 8 ft/s (2.44 m/s), the effect from scaling is assumed not protective against corrosion.

Corrosion of steel increases with chloride content of the water and reaches a maximum at approximately 6000 ppm. Above that level the chloride effect is offset by diminishing solubility of DO.

2.B.11.3.1.3 Temperature Factor

The corrosion rate of carbon steel has shown to increase almost linearly with temperature from 80 °F to 175 °F (27 °C to 79 °C). This classical correlation has been used to adjust the calculated corrosion rates. Therefore, to calculate the temperature adjustment, the ΔT is calculated by subtracting 75 °F (24 °C) from the actual metal temperature, T_{OP} , or:

$$\Delta T = T_{\text{OP}} - T_{\text{adjust}} \quad (2.B.12)$$

This ΔT is used to determine the temperature correction factor, F_T , using [Table 2.B.11.5](#). The F_T values are different between open and closed systems at high temperatures. In an open system, heating above room temperature initially increases corrosion rate for steel but also reduces solubility of DO, which allows oxygen to escape. Therefore, at temperatures of 175 °F (79 °C) and greater, the corrosion rate decreases. However, in a closed system, the corrosion rate increases with temperature because of retention of small amounts of DO under pressure.

2.B.11.3.1.4 Flow Velocity Factor

Velocity is one of the prime variables influencing waterside corrosion. At very low velocity, biofouling or deposit buildup can occur promoting under-deposit type of attack or MIC. Even if fouling deposits do not occur, low velocity encourages higher metal temperatures that results in an increase in the corrosion rate. For carbon steel, there is a range of flow velocities [see [Equation \(2.B.14\)](#)] where temperature does not have an effect on the corrosion rate. If flow velocities are outside these limits, the velocity factor may be determined from [Table 2.B.11.6](#) or calculated using the following equations where V_a is the actual velocity.

For SI units, use [Equations \(2.B.13\)](#) through [\(2.B.15\)](#):

$$F_V = 1 + 1.64 \cdot (0.914 - V_a) \quad \text{for } V_a < 0.914 \text{ m/s} \quad (2.B.13)$$

$$F_V = 1 \quad \text{for } 0.914 \text{ m/s} \leq V_a \leq 2.44 \text{ m/s} \quad (2.B.14)$$

$$F_V = 1 + 0.82 \cdot (V_a - 2.44) \quad \text{for } V_a > 2.44 \text{ m/s} \quad (2.B.15)$$

For U.S. customary units, use [Equations \(2.B.16\)](#) through [\(2.B.18\)](#):

$$F_V = 1 + 0.50 \cdot (3 - V_a) \quad \text{for } V_a < 3 \text{ ft/s} \quad (2.B.16)$$

$$F_V = 1 \quad \text{for } 3 \text{ ft/s} \leq V_a \leq 8 \text{ ft/s} \quad (2.B.17)$$

$$F_V = 1 + 0.25 \cdot (V_a - 8) \quad \text{for } V_a > 8 \text{ ft/s} \quad (2.B.18)$$

This represents a fairly coarse and conservative way of factoring in the velocity effect in the corrosion rate prediction model. In reality, this effect is a product of a much more sophisticated interrelation between temperature, DO, pH, and velocity. However, the trend shown in [Table 2.B.11.6](#) does comply with actual testing described in Reference [\[37\]](#) for velocities up to 7 ft/s (2.13 m/s). For carbon steel in seawater, the velocity is even more a governing factor for the corrosion rate.

2.B.11.3.2 Once Through Cooling Water Systems

2.B.11.3.2.1 Overview

The steps required to determine the corrosion rate are shown in [Figure 2.B.11.1](#). Once through cooling water systems are much less common in the U.S. refinery industry than recirculation systems. Once through systems may be economical where there is an abundance of surface water, but the effects of thermal pollution may be too great to allow their use in some locations. Chemical treatment is normally environmentally unacceptable and/or uneconomical. These systems rarely use anything but chlorination, which controls biological growth.

It is assumed in this section that chemical treatment is not applied and that the material of construction is carbon steel. In practice, the materials of construction in once through systems may be copper alloys, titanium alloys, stainless steels, polyvinyl chloride (PVC), cement-lined or coated (organic) steel, or even galvanized carbon steel where the supply source is known to be fairly clean fresh water.

The main concern for a once through cooling water system is the quality of the supply water, i.e. type of water (sea or salt, brackish or fresh water) and level of contaminants (such as solids, phosphates, iron, ammonia, bugs, and bacteria, etc.). In total there are a large number of factors that ultimately affect damage to the equipment in a once through cooling water system.

For simplicity of this corrosion model for once through systems, these systems are considered either as seawater systems or freshwater systems, and the corrosion rates are determined as a function of temperature, water flow velocity, DO, and content of chlorides.

2.B.11.3.2.2 Fresh Water Once Through System

Fresh water comprises natural surface water with chloride content less than 1000 ppm. The corrosion rate is estimated in the same manner as an open recirculating system, with no chemical treatment or corrosion inhibition, except for biocide.

2.B.11.3.2.3 Seawater Once Through Systems

Seawater comprises brackish or seawater with a chloride content of more than 1000 ppm. The salts found in seawater do not appreciably alter the pH value when dissolved in water. The main type of dissolved salt in seawater is sodium chloride (NaCl).

Seawater typically contains about 3 % sodium chloride with approximately 19,000 ppm chloride ion (and 11,000 ppm sodium). The chloride ions comprise about 55 % of the total dissolved solids (TDS). DO is typically present at normal saturated values of 6 to 8 ppm at 75 °F to 85 °F (24 °C to 29 °C). The pH of seawater is usually 7.7 to 8.3 in surface waters [\[29\]](#). Seawater always contains SRB and a level of sulfate ion

concentration (2 ppm to 3,000 ppm) conducive to SRB growth under anaerobic conditions. Anaerobic conditions will exist under deposits (organic or inorganic), in crevices, and under the influence of biological oxygen demand (BOD) or chemical oxygen demand (COD). One of the most important properties of seawater is its ratios of concentrations of the major constituents are remarkably constant worldwide, including the level of chloride and oxygen.

The temperatures encountered in once through seawater systems usually preclude scale formation by inverse solubility effects, which normally would initiate at about 190 °F (88 °C). Obviously, deposits can occur under extreme conditions of temperature in condensers, but this is an exceptional circumstance. Deposition of sand and silt is primarily controlled by establishing a minimum flow and by mechanical cleaning as required. Biofouling can be caused by soft organisms (slimes, algae, and hydroids) and hard organisms (barnacles, mussels, oysters, tubeworms, and sea squirts). The degree of fouling depends to some extent on the material of construction. Metals and alloys that produce toxic salts (e.g. copper, lead, and zinc) are more resistant. Both fouling and bacterial effects are controlled largely by chlorination.

Corrosion of carbon steel in seawater is controlled by the availability of oxygen to the metal surface. Under static conditions (zero velocity), carbon steel corrodes at rates between 4 and 8 mpy (0.10 and 0.20 mm/yr), depending on the local oxygen and temperature variations. As the velocity causes a mass flow of oxygen to the metal surface, corrosion is very dependent on flow rate and can increase by a factor of 100 in moving from static condition to a velocity of about 130 ft/s (39.6 m/s). Galvanizing confers only limited benefit under flow conditions, as corrosion of zinc also increases with velocity. For the thickness normally used in seawater piping, it will extend the life of the pipe for about 6 months only.

Thus, velocity is the most important single factor influencing design of carbon steel components in seawater systems. The chosen design velocity controls the dimensions of many components, such as piping and valves. When the corrosion rate is subject to mass transfer control, flow velocity at the metal surface becomes the rate-determining factor.

Based on test results reported [30] [35] [36], Equations (2.B.19) and (2.B.20) may be used to calculate the corrosion rates on carbon steel in seawater systems as a function of the velocity, V_a . Values for the corrosion rate as a function of velocity using this equation are shown in Table 2.B.11.7.

For SI units, use Equation (2.B.19):

$$CR = 0.1318 + 0.3108 \cdot V_a - 0.0579 \cdot V_a^2 + 0.01208 \cdot V_a^{2.5} \quad (2.B.19)$$

For U.S. customary units, use Equation (2.B.20):

$$CR = 5.1885 + 3.7293 \cdot V_a - 0.21181 \cdot V_a^2 + 0.02439 \cdot V_a^{2.5} \quad (2.B.20)$$

Equations (2.B.19) and (2.B.20) were developed based on the data specified in Reference [35], assuming seawater temperature of about 70 °F (21 °C) and an oxygen concentration of 6 ppm to 8 ppm.

With high flow rates, the corrosion rate increases up to around 40 ft/s (12.2 m/s), where the attack changes to erosion-corrosion. However, it is assumed that cooling water systems in the refining industry will not experience water flow velocities in excess of 20 ft/s (6.1 m/s).

2.B.11.3.3 Groundwater

Groundwater is not specifically addressed in this section. However, the following can be a quick guideline for determining the level of corrosivity for such waters. The assessment needs to be made by a competent person for water corrosivity issues.

Groundwater may contain well water, geothermal springs, or produced water (i.e. waters of brines co-produced with oil or gas). Although groundwaters can be considered one category, they might vary largely

in chemistry. Groundwaters are often characterized in terms of total key species (TKS), which is a sum of chloride, sulfate, dissolved CO₂, bicarbonate, carbonate, sulfide, and ammonia concentrations. TKS is a measure of corrosivity. Depending on the TKS value, the corrosivity towards steel can be rated as follows.

- a) Low [< 1 mpy (0.03 mm/yr)] corrosion rate.
- b) Medium [1 to 10 mpy (0.03 to 0.25 mm/yr)].
- c) High [10 to 50 mpy (0.25 to 1.27 mm/yr)].
- d) Very High [> 50 mpy (1.27 mm/yr)].

The subject of specific TKS values vs corrosivity has not been addressed in this section.

2.B.11.4 Nomenclature

$C_1 \rightarrow C_4$	are the pH_s calculation parameters
CR	is the corrosion rate, mpy (mm/yr)
CR_B	is the base corrosion rate, mpy (mm/yr)
F_T	is the corrosion rate temperature correction
F_V	is the corrosion rate velocity correction
LSI	is the Langelier Saturation Index
pH_a	is the actual pH
pH_s	is the pH of the sample
RSI	is the Ryznar Stability Index
T_{adjust}	is used to calculate the temperature adjustment = 75 °F (24 °C)
T_{op}	is the corrosion operating temperature, °F (°C)
V_a	is the actual velocity, ft/s (m/s)
ΔT	is the temperature difference, °F (°C)

2.B.11.5 References

See References [\[130\]](#), [\[131\]](#), [\[132\]](#), [\[133\]](#), [\[134\]](#), [\[135\]](#), [\[136\]](#), [\[137\]](#), and [\[138\]](#) in [Annex 2.G](#).

2.B.11.6 Tables**Table 2.B.11.1—Cooling Water Corrosion—Basic Data Required for Analysis: Recirculating Cooling Water Systems and Once Through Cooling Water System with Fresh Water**

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping. Only carbon steel components are covered.
Actual corrosion rates	Corrosion coupon data on this system or similar systems or actual rates at the facility. Caution is warranted when using corrosion rates as determined from corrosion coupons or actual measured rates from system measurements. These measurements may not be representative or indicators of worst case. Example would be coupons placed in flowing streams that could not provide data on for deposits or no flow areas.
Metal temperature of cooling or condenser surfaces, °F (°C)	Determine the estimated metal temperature exposed to the cooling water, i.e. water-side metal surface temperature.
pH_a	Experimentally measured pH of the water.
pH_s	pH value at which the water is in equilibrium with solid calcium carbonate ($CaCO_3$).
TDS (mg/L)	Determine if TDS is in the range of: a) 50 to 400 mg/L, or b) 401 to 1000 mg/L. Determine to what degree the TDS consist of salts (including ammonia), phosphates, Cu, etc. that potentially effect under-deposit corrosion.
Ca (mg/L) as $CaCO_3$	Determine calcium hardness as calcium carbonate ($CaCO_3$).
MO alkalinity (mg/L) as $CaCO_3$	Corresponds to the concentration of bicarbonate (HCO_3^-), commonly expressed as parts per million or mg/L of $CaCO_3$ (calcium carbonate).
Flow velocity, ft/s (m/s)	Determine the maximum and minimum expected water velocities.
Chlorides (ppm Cl^-)	Determine parts per million of chlorides.
MIC observed or suspected? (Yes or No)	Indicate if MIC has been observed in the cooling water system, or if MIC is considered likely.
DO (ppm O_2)	Dissolved oxygen.

Table 2.B.11.2—Cooling Water Corrosion—Basic Data Required for Analysis: Once Through Cooling Water System with Salt Water

Basic Data	Comments
Material of construction	Determine the material of construction of the equipment/piping. Only carbon steel components are covered.
Actual corrosion rates	Corrosion coupon data on this system or similar systems or actual rates at the facility.
Flow velocity, ft/s (m/s)	Determine the maximum and minimum expected water velocities.

Table 2.B.11.3—pH Calculation Parameters

C_1 Factor			C_3 Factor		C_4 Factor	
Total Solids (mg/L)	C_1		Calcium Hardness (mg/L CaCO_3)	C_3	MO Alkalinity (mg/L CaCO_3)	C_4
50 to 400	0.1		10.5	0.6	10.5	1.0
> 400 to 1000	0.2		12.5	0.7	12.5	1.1
C_2 Factor			15.5	0.8	15.5	1.2
			20	0.9	20	1.3
Temperature (°C)	Temperature (°F)	C_2	25	1.0	25	1.4
			31	1.1	31	1.5
1	33	2.6	39	1.2	40	1.6
4	39	2.5	49.5	1.3	50	1.7
8	46	2.4	62.5	1.4	62.5	1.8
12	53	2.3	78.5	1.5	79	1.9
16	60	2.2	99	1.6	99.5	2.0
19	67	2.1	124.5	1.7	125	2.1
24	76	2.0	156.5	1.8	158	2.2
29	85	1.9	197.5	1.9	197.5	2.3
34	94	1.8	250	2.0	250	2.4
41	105	1.7	310	2.1	315	2.5
47	117	1.6	390	2.2	400	2.6
53	128	1.5	495	2.3	500	2.7
60	140	1.4	625	2.4	625	2.8
68	154	1.3	785	2.5	790	2.9
77	170	1.2	940	2.6	945	3.0

Table 2.B.11.4— CR_B Base Corrosion Rate Calculation

Chloride Content (ppm)	Base Corrosion Rate, CR_B (mpy)	
	RSI > 6 or Velocity > 8 ft/s	RSI ≤ 6 and Velocity ≤ 8 ft/s
5	1	0.3
10	2	0.6
50	4	1.4
100	6	2
250	9	3
500	13	4.3
750	15	5
1,000	17	5.7
2,000	17	5.6
3,000	16	5.4
5,000	15	4.9
10,000	13	4.3
NOTE 1 RSI < 4—Heavy scale forming, nonaggressive.		
NOTE 2 RSI 5 to 6—Slightly scale forming and mildly aggressive.		
NOTE 3 RSI 6 to 6.5—Balanced or at CaCO_3 saturation.		
NOTE 4 RSI 6.5 to 7—Non-scaling and slightly aggressive.		
NOTE 5 RSI > 8—Under-saturated, very aggressive.		

Table 2.B.11.4M— CR_B Base Corrosion Rate Calculation

Chloride Content (ppm)	Base Corrosion Rate, CR_B (mm/yr)	
	RSI > 6 and Velocity > 2.4 m/s	RSI > 6 and Velocity ≤ 2.4 m/s
5	0.03	0.01
10	0.05	0.02
50	0.1	0.04
100	0.15	0.05
250	0.23	0.08
500	0.33	0.11
750	0.38	0.13
1,000	0.43	0.14
2,000	0.43	0.14
3,000	0.41	0.14
5,000	0.38	0.12
10,000	0.33	0.11
NOTE 1 RSI < 4—Heavy scale forming, nonaggressive.		
NOTE 2 RSI 5 to 6—Slightly scale forming and mildly aggressive.		
NOTE 3 RSI 6 to 6.5—Balanced or at CaCO_3 saturation.		
NOTE 4 RSI 6.5 to 7—Non-scaling and slightly aggressive.		
NOTE 5 RSI > 8—Under-saturated, very aggressive.		

Table 2.B.11.5—Temperature Adjustment Factor, F_T , as a Function of ΔT

Operating Temperature		F_T for Closed Systems	F_T for Open Systems
°C	°F		
24	75	0.1	0.1
27	80	0.3	0.3
29	85	0.4	0.4
32	90	0.6	0.6
35	95	0.8	0.8
38	100	0.9	0.9
41	105	1.1	1.1
43	110	1.2	1.2
46	115	1.4	1.4
49	120	1.6	1.6
52	125	1.7	1.7
54	130	1.9	1.9
57	135	2.1	2.1
60	140	2.2	2.2
63	145	2.4	2.4
66	150	2.5	2.5
68	155	2.7	2.7
71	160	2.9	2.9
74	165	3.0	3.0
77	170	3.2	3.2
79	175	3.4	3.3
82	180	3.5	3.3
85	185	3.7	3.3
88	190	3.8	3.3
91	195	4.0	3.1
93	200	4.2	2.9
96	205	4.3	2.5
99	210	4.5	1.7

Table 2.B.11.6—Flow Velocity Adjustment Factor (F_V) as a Function of the Flow Velocity

Flow Velocity		Flow Velocity Factor, F_V
m/s	ft/s	
0.15	0.5	2.25
0.3	1	2
0.61	2	1.5
0.91	3	1
1.22	4	1
1.52	5	1
1.83	6	1
2.13	7	1
2.44	8	1
2.74	9	1.25
3.05	10	1.5
3.35	11	1.75
3.66	12	2
3.96	13	2.25
4.27	14	2.5
4.57	15	2.75
4.88	16	3
5.18	17	3.25
5.49	18	3.5
5.79	19	3.75
6.1	20	4

Table 2.B.11.7—Cooling Water Corrosion Estimated Corrosion Rate for Carbon and Low-alloy Steels in Seawater as a Function of Flow Velocity

Flow Velocity (ft/s)	Corrosion Rate (mpy)
0	5.2
1	8.7
2	11.9
3	14.9
4	17.5
5	19.9
6	22.1
7	24.1
8	25.9
9	27.5
10	29.0
11	30.4
12	31.6
13	32.7
14	33.8
15	34.7
16	35.6
17	36.4
18	37.2
19	38.0

Table 2.B.11.7M—Cooling Water Corrosion Estimated Corrosion Rate for Carbon and Low-alloy Steels in Seawater as a Function of Flow Velocity

Flow Velocity (m/s)	Corrosion Rate (mm/yr)
0	0.13
0.3	0.22
0.61	0.3
0.91	0.38
1.22	0.44
1.52	0.51
1.83	0.56
2.13	0.61
2.44	0.66
2.74	0.7
3.05	0.74
3.35	0.77
3.66	0.8
3.96	0.83
4.27	0.86
4.57	0.88
4.88	0.9
5.18	0.92
5.49	0.94
5.79	0.97

2.B.11.7 Figures

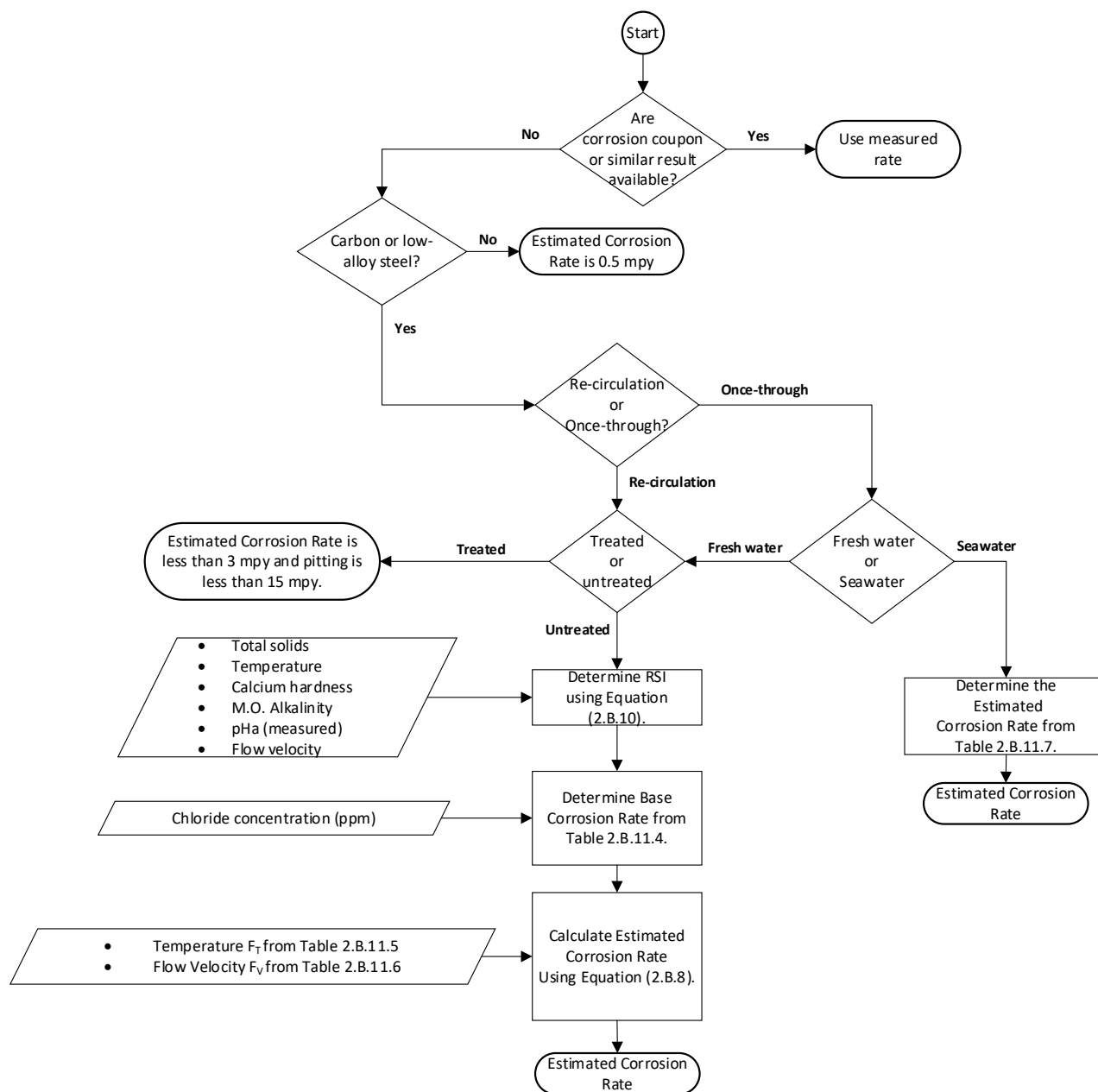


Figure 2.B.11.1—Cooling Water—Determination of Corrosion Rate

2.B.12 Soil-side Corrosion

2.B.12.1 Description of Damage

2.B.12.1.1 Overview

The objective for this supplement is to give a conservative approach for assessing the potential for soil corrosion and determining appropriate mitigation measures, while taking the most significant factors for soil corrosion into account.

This supplement pertains to any carbon steel equipment or structure having surface metal exposed to soil, with the exception of the soil side of aboveground storage tanks, which are covered in [Section 2.B.14](#). The most typical equipment exposed to soil corrosion is buried or partly buried carbon steel vessels/drums and piping, with some type of coating.

The method described in this section may be used to establish an estimate of the corrosion rate that would be expected in a given environment. If actual corrosion rates are known for particular pieces of equipment or other similar equipment in similar service, that data may be used in lieu of this method.

2.B.12.1.2 Soil Corrosivity

The damage to the exterior of metals exposed to soils is usually referred to as soil corrosion and is often attributed to soil characteristics. Soils having high moisture content, high dissolved salt concentrations, and high acidity are expected to be the most corrosive. However, soil composition alone has been found to have little correlation with soil corrosivity.

There is no single easily measured soil parameter that can be used to determine soil corrosivity. Instead, a number of characteristics must be combined to estimate the corrosion that may be expected on a steel structure from a particular soil. According to ASTM STP741, soil corrosivity classes can be characterized by total acidity, resistivity, conductivity, drainage (soil texture), and aeration (water–air permeability). The most significant causes for soil corrosion are described in [Section 2.B.12.2](#).

Soils frequently have characteristics of which some indicate that the soil is corrosive and others indicate just the opposite. By virtue of water and related water-soluble salts being present, soil becomes an effective electrolyte for completing the corrosion circuit between anode and cathode. This can be true even if the soil is fairly dry and nonconductive (high resistivity). The water content in the soils relates to drainage, which is defined as the ability to allow water percolation. In the long term, the residence time for water or moisture on the metal surface will control the degree of corrosion in soil. Measuring this residence time is difficult or impossible in practice. Therefore, it becomes necessary to use more easily measured soil characteristics, which have a less certain correlation with soil corrosivity. The parameters usually considered include soil resistivity, pH, chloride content, redox potential, and type of soil.

Soil resistivity is frequently used to estimate soil corrosivity, mainly because it is easy to measure (commonly measured by the four-pin Wenner technique as described in ASTM G57, or electromagnetic non-contacting methods, Geonics). In practice, the conditions around the equipment surface are likely to be different than in the surrounding native soil, due to different compaction and possibly also different soil type and texture (especially where sand is used for backfill). Furthermore, the conditions probably vary along the equipment surface as well. These variations will cause local effects that are not easily predicted by bulk resistivity measurements, and these local effects again make a direct correlation solely between soil resistivity and soil corrosivity of questionable value.

2.B.12.1.3 Preventing Soil Corrosion

The common prevention methods for soil corrosion of carbon steel equipment are special backfill, coating, and CP. The most effective corrosion protection is achieved by a combination of a corrosion-resistant coating and an effective CP system. With an effective CP system in place, the corrosion rate can be maintained at a level close to zero. However, maintaining and managing an effective CP system can be complex and should involve personnel competent in this field. An effective CP system will normally be maintained in compliance with a recognized standard, such as NACE SP0169.

Partially buried equipment must be handled in three ways. The portion under the soil will be treated as a piece of buried equipment. The portion exposed to air will be treated as any other outdoor equipment and often requires little attention. The soil-to-air interface is unique for the location and alloy, and soil-to-air interface corrosion may present a higher corrosion concern than underground corrosion.

Equipment that is fully encased in concrete is not normally in need of additional corrosion protection provided that a chloride-free concrete mix is used and moisture content is stable, and it is not subject to chloride intrusion.

2.B.12.2 Description of Damage

The soil corrosion damage morphology is generally expected to be localized external corrosion, i.e. pitting at the anode. The severity of corrosion depends on the local soil conditions and changes in the immediate environment along the equipment metal surface. The following are the main theoretical causes of soil and underground corrosion.

- a) **Equipment Temperature**—For a moist environment containing DO, an increase in the equipment temperature (operating temperature for piping or pipelines) can significantly increase the external corrosion rate. Theoretically, corrosion by oxygen (oxidation) ceases when all the DO is consumed. Oxygen can be replenished by drain water or from the air (especially at the soil-to-air interface). The corrosion reaction is primarily controlled by diffusion of oxygen to the corroding surface. Any process that slows oxygen diffusion slows the reaction and ultimately reduces the corrosion rate. As corrosion products accumulate on the corroding surface, oxygen diffusion is slowed. Corrosion due to oxidation of steel doubles for every 20 °C to 30 °C (35 °F to 55 °F) rise in temperature, beginning at room temperature. Corrosion is nearly proportional to temperature up to about 80 °C (180 °F) when oxygen is replenished unrestricted to the corroding surface. With the increase in temperature, DO is driven from the water solution, resulting in a decrease in the rate of corrosion by oxygen.
- b) **Galvanic Corrosion (Dissimilar Metal Corrosion)**—This occurs when two different metals are joined in the soil, such as steel and copper. Electrical current will flow from the steel into the soil and back into the copper, resulting in corrosion of the steel. A less recognized but similar phenomenon occurs when new steel is connected to old steel in the soil, such as when replacing a section of corroded pipe. The new steel that is not cathodically protected will frequently experience a higher corrosion rate.
- c) **Corrosion Resulting from Dissimilar Soils**—In much the same manner as dissimilar metals, a structure that contacts two or more different types of soil will have different electrical potentials between the metal and each respective soil. Hence, variations in soil density and porosity can be a common cause of corrosion in buried equipment, with more dense soil areas promoting an anodic reaction and lighter soil cover promoting a cathodic reaction. The resultant pitting at the anode can lead to swift penetration of the wall. The phenomena can occur even over long distances. For example, on a buried pipeline, the anodic areas and cathodic areas may be considerable distances apart, e.g. where a pipeline crosses a marshy area near a river and then runs through much drier sandy soil. The differences in the native pipe-to-soil potential can be sufficient to set up a corrosion cell with anode and cathode many hundreds of yards apart.
- d) **Corrosion by Stray Current Drainage**—This corrosion differs from other corrosion damage types in that the current, which causes the corrosion, has a source external to the affected structure. The stray current source can be AC power lines, telephone lines, adjacent CP systems, or any electrically driven equipment, most notably rail systems. Stray currents flow from an external source onto a pipeline or structure and then flow along it to some other area(s) where they leave to reenter the earth causing localized corrosion. Where stray current corrosion is a factor, CP may not be the best method of controlling corrosion. The majority of stray current corrosion problems result from the interacting CP systems where nearby equipment provides the low-resistance paths for the current from the impressed-current CP system to pass before returning to the protected equipment. This disturbance in current distribution makes the CP system incomplete and causes localized corrosion on the interfering equipment. One solution to stray current problems is electrical bonding of nearby equipment. However, the appropriate solution needs to be evaluated on a case-by-case basis.
- e) **Differential Aeration Corrosion Cells**—Local differences in the packing of the soil and in its moisture content may develop oxygen concentration cells where the area with the least oxygen is anodic to the area in which oxygen is more readily available. Aeration corrosion cells are similar to the corrosion cells that produce pitting in waters, when one area of the metal has more ready access to oxygen than other areas. The areas with less access to oxygen will corrode preferentially. This sometimes occurs when a pipe passes beneath a roadbed or crosses deep underneath a river.

- f) MIC—Microbacterial action can also promote local corrosion. Corrosion enhanced by SRB is well documented. These microbes reduce the commonly available sulfate ions in the soil to produce hydrogen sulfide. This, in turn, results in increased acidity and acceleration of anodic dissolution. Coating types, age, and condition are significant factors in preventing microbiologically influenced corrosion.

2.B.12.3 Basic Data

The data listed in [Table 2.B.12.1](#) are required to determine the estimated corrosion rate for soil-side corrosion. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.12.4 Determination of Corrosion Rate

2.B.12.4.1 Corrosion Rate Equation

The steps required to determine the corrosion rate are shown in [Figure 2.B.12.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.12.1](#) in conjunction with [Equation. \(2.B.21\)](#):

$$CR = CR_B \cdot F_{SR} \cdot F_T \cdot F_{CP} \cdot F_{CE} \quad (2.B.21)$$

In this equation, the base corrosion rate, CR_B , is adjusted for soil resistivity, F_{SR} , temperature, F_T , cathodic protection, F_{CP} , and coating effectiveness, F_{CE} . Determination of the base corrosion rate and each of these factors is discussed in the following sections.

2.B.12.4.2 Establishing the Base Corrosion Rate

The base corrosion rate is the expected or observed corrosion rate for the buried equipment or structure. Estimating a corrosion rate based on soil properties is difficult without extensive physical and chemical analyses. Corrosion rates will be estimated based on rather easily established general characteristics, as shown in [Table 2.B.12.2](#). There are numerous possible combinations of these variables, with possible offsetting or compounding effects on the expected corrosion rate. The user should use a corrosion rate that is based on the actual conditions of the soil in contact with the structure. Corrosion rates should be extrapolated between those values shown in the table to account for the expected effects of the various factors. For example, if a soil had all the characteristics of those in row 2 of the table, then a corrosion rate of 5 mpy (0.13 mm/yr) would be estimated. If, however, the soil was primarily clay, in an industrial setting (moderate chemical contaminants), with a mixture of some other soil types and sizes and the soil is normally saturated, a corrosion rate between 5 and 10 mpy (0.13 and 0.25 mm/yr), or as an average 7 mpy (0.178 mm/yr), would be estimated. If actual corrosion rates are known for the particular piece of equipment or other similar equipment in similar service, that data should be used.

2.B.12.4.3 Adjustment Factor for Soil Resistivity (Optional)

The soil resistivity factor might be considered as input information when estimating the base corrosion and as such discarded as an adjustment factor. However, for a couple of cases, the soil resistivity factor should be included as an adjustment factor for the base corrosion rate, i.e. where:

- a) estimation of the base corrosion rate is determined by intuitive settings for the sub-factors in [Table 2.B.12.2](#), and
- b) regular measurements of soil resistivity are part of the inspection program and variation in soil resistivity might be the only indicative variable for monitoring changes in the soil characteristics (an example would be monitoring soil resistivity around a cooling tower basin with adjacent chemical treating facilities).

Soil resistivity gives a composite measure of moisture content of soil and dissolved electrolytes in the soil water, i.e. an indication for soil condition. Soil resistivity has often been used as a broad indicator of soil corrosivity. Because ionic current flow is associated with soil corrosion reactions, high resistivity will arguably

slow down corrosion reactions although a high soil resistivity alone will not guarantee absence of serious corrosion. Soil resistivity generally decreases with increasing water content and concentration of ionic species. Variations in soil resistivity along the length of the structure are highly undesirable, as this will lead to the formation of macro corrosion cells. Thus, the merit of a corrosion risk classification based on an absolute value of soil resistivity is limited.

Resistivity of native undisturbed earth and the soil adjacent to the pipe (looser) may be very different. However, over time the less compacted and possibly higher resistivity soil near the structure will assume the characteristics of the native soil, i.e. the high resistivity soil might become contaminated by capillary action. While the soil resistivity against the pipe or structure cannot be measured accurately, bulk measurements can be taken for soil resistivity in the vicinity of the buried equipment. Given the above theory and assuming several measurements will be taken, these resistivity measurements can be considered representative for the soil adjacent to the structure.

Normal soil resistivity is 3,000 to 5,000 Ω -cm, although 20,000 Ω -cm is not uncommon. Corrosion rate adjustment factors for soil resistivities are provided in [Table 2.B.12.3](#). The ranges in this table are consistent with API 651 (general classification of resistivity, based on NACE 51011). API 570 (1997) only stipulates three ranges (< 2,000; 2,000 to 10,000; >10,000) for determining the recommended inspection frequencies of 5, 10, and 15 years, respectively, for buried piping without CP.

2.B.12.4.4 Adjustment Factor for Temperature

The base corrosion rate is adjusted for the operating temperature in accordance with [Table 2.B.12.4](#). See *ASM Handbook 13* (Corrosion) for temperature effect on external corrosion.

2.B.12.4.5 Adjustment Factor for CP and Stray Current Drainage

CP is the primary method used to avoid corrosion of buried structures from the soil corrosion. However, the system must be installed and maintained properly. In [Table 2.B.12.5](#), corrosion rate adjustment factors are given for CP system coverage and expected efficiency of protection. “Hot spot” protection is the practice of installing sacrificial anodes (aluminum, zinc, or magnesium) at locations of suspected anodic activity, as determined by surveys of structure-to-soil potential. Complete protection is achieved by installation of sacrificial anodes or impressed current protection systems sufficient to cover the entire surface of the buried equipment. Anodic protection is not an applicable method for protection of buried equipment. NACE SP0169 establishes three criteria for protection. One common reference level is a structure-to-soil potential measurement of -0.85 volts with reference to a copper/copper sulfate reference electrode. This criterion is considered less effective than the other two criteria commonly known as 100 mV polarization and -0.85 volt polarized structure-to-soil potential.

As discussed earlier, stray current can originate from various external sources such as power lines, electrically driven equipment, and impressed current CP systems in the environs. Except for the few cases where AC stray current is present from inductively coupled situations such as paralleling high tension lines, stray current would not occur if electrical systems were entirely insulated from earth. At the same time, proper grounding of electrical power circuits is necessary to reduce electric shock hazards. Hence the stray current corrosion problem will probably never be eliminated.

A low-level, steady state current may be controlled with CP systems. But a larger stray current that may be dynamic would require special analysis and corrective measures. The corrosion potential from these larger stray current problems is of a much higher magnitude than the other corrosion causes discussed. Therefore, they should be addressed first before considering any other effects on the corrosion potential of the equipment or structure being addressed. An effective CP system will include testing and mitigating the effect of stray currents on a routine basis.

Adjustment factors for CP systems, based on the effectiveness of the system, are provided in [Table 2.B.12.5](#). It shall be noted that the effectiveness of the CP system depends on the continuity of operation of impressed current sources, the system complies to NACE RP0169 and managed by NACE certified personal.

For structures which are only partly protected by a CP system, the unprotected areas will have corrosion rates that are determined by the prevailing conditions.

2.B.12.4.6 Adjustment Factor for Coating Effectiveness

The primary effect that a coating has on the corrosion rate is related to the potential for the coating to shield the CP current in the event that the coating becomes disbonded from the structure. This is a complicated relationship between many factors but is primarily related to how well coating adheres to the pipe and how age, temperature extremes, and maintenance practices affect the dielectric properties of the coating. Each factor is considered to be independent of each other. All of multiplying factors that apply to the coating in question should be used to determine the total coating effectiveness factor, F_{CE} .

Table 2.B.12.6 is used for calculating the adjustment factor for a coating. When the multiplying factors criterion does not apply, substitute factor with 1.0. For example, for a mill applied polyethelene (PE) tape that is 30 years old, has been occasionally subjected to temperatures over the maximum, and there is never any coating inspection or maintenance, the total coating effectiveness factor would be:

$$F_{CE} = 1.5 \cdot 1.2 \cdot 3.0 \cdot 1.5 = 13.5 \quad (2.B.22)$$

For a bare pipe or structure, $F_{CE} = 1.0$. For a pipe that does not have CP, the coating effectiveness factors should still be used since holidays in the coating may allow concentrated corrosion to occur in the damaged area.

2.B.12.5 Nomenclature

CR	is the corrosion rate
CR_B	is the base corrosion rate
F_{CE}	is the corrosion rate correction factor for coating effectiveness
F_{CP}	is the corrosion rate correction factor for CP
F_{SR}	is the corrosion rate correction factor for soil resistivity
F_T	is the corrosion rate correction factor for temperature

2.B.12.6 References

See References [134], [138], [139], [140], [141], [142], [143], and [144] in Annex 2.G.

2.B.12.7 Tables

Table 2.B.12.1—Soil-side Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Base corrosion rate, mpy (mm/yr)	The expected or observed corrosion rate for the buried structure, or a “similar” structure under “similar” service and conditions.
Equipment temperature, °F (°C)	Equipment temperature (operating temperature for piping and pipelines).
Soil resistivity, Ω -cm	Soil characteristics in the vicinity of the buried structure.
CP	Specify whether or not a CP system is installed and how effective it is.
Coating	Type of coating, age, temperature abuse, and inspection and maintenance history, if a coating is installed.
Equipment age, years	The time since installation of the buried equipment—used to determine accumulated corrosion over time since buried.

Table 2.B.12.2—Base Corrosion Rate

Factors Affecting Base Corrosion Rate				Base Corrosion Rate	
Primary Soil Type	Level of Chemical Contaminants	Particle Size and Uniformity	Moisture Level	mm/yr	mpy
Sand	Low chlorides (inland, nonindustrial)	Homogeneous, fine silt or sand	Dry, desert-like	0.03	1
Silt	Moderate (industrial)	Mixed	Variable moisture	0.13	5
Clay	High chlorides (coastal areas)	> 50 % gravel	Normally saturated	0.25	10

Table 2.B.12.3—Soil Resistivity Adjustment

Resistivity (Ω -cm)	Corrosiveness	Multiplying Factor
< 500	Very corrosive	1.50
500 to 1,000	Corrosive	1.25
1,000 to 2,000	Moderately corrosive	1.00
2,000 to 10,000	Mildly corrosive	0.83
> 10,000	Progressively less corrosive	0.60

Table 2.B.12.4—Equipment Temperature Adjustment

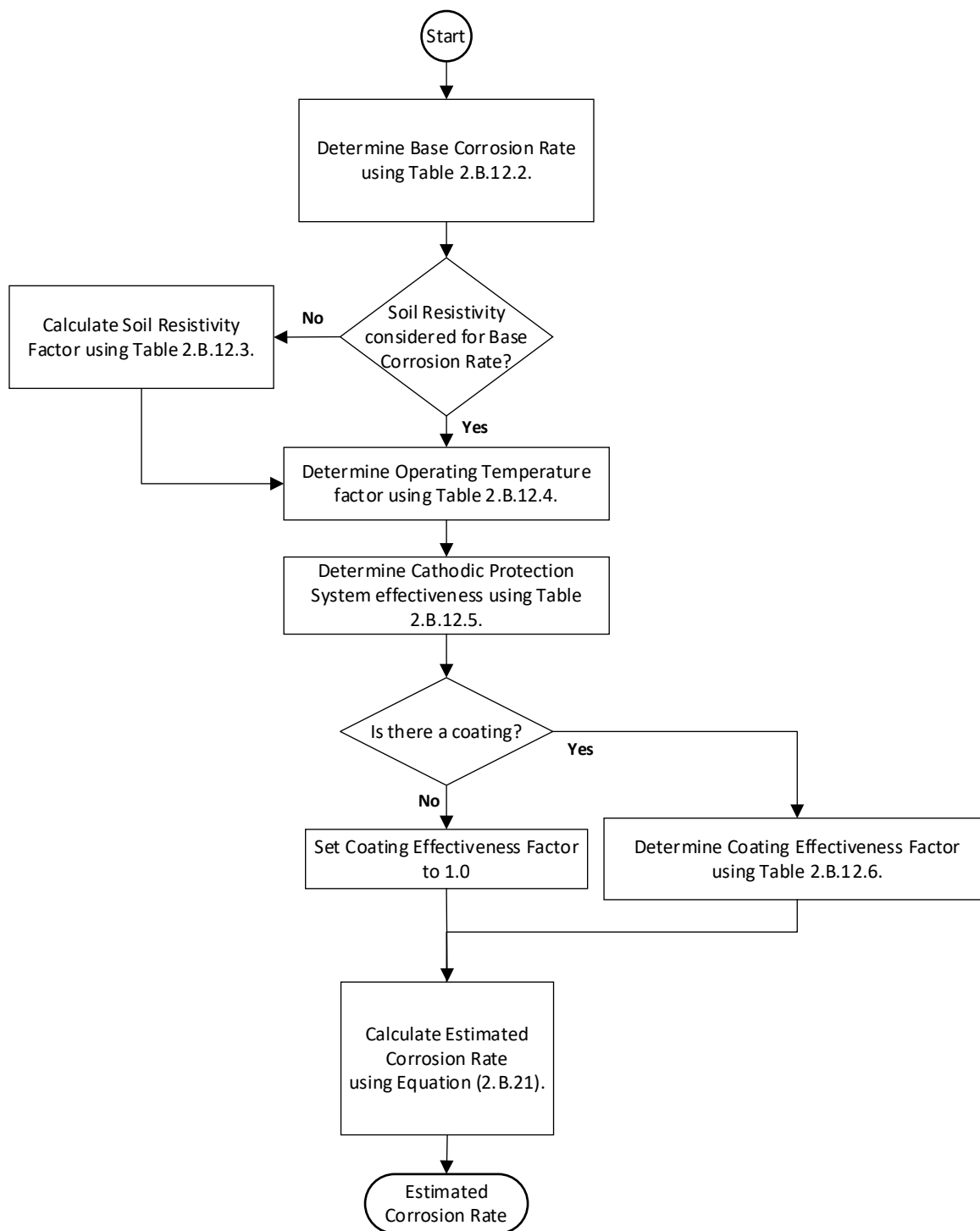
Temperature		Multiplying Factor
°C	°F	
< 49	< 120	1.00
49 to 104	120 to 220	2.00
> 104	> 220	1.00

Table 2.B.12.5—CP Effectiveness Factors

CP Measurement Practices	Multiplying Factor
No CP on structure (or CP exists but is not regularly tested per NACE SP0169) and CP on an adjacent structure could cause stray current corrosion	10.0
No CP	1.0
CP exists, but is not tested each year or part of the structure is not in accordance with any NACE RP0169 criteria	0.8
CP is tested annually and is in accordance with NACE RP0169 “on” potential criteria over entire structure	0.4
CP is tested annually and is in accordance with NACE RP0169 polarized or “instant-off” potential criteria over entire structure	0.05

Table 2.B.12.6—Calculating the Total Coating Effectiveness Factor

Coating Type	Base Factor for Coating Type	Multiplying Factors		
		Age > 20 years	Maximum Rated Temperature is Occasionally Exceeded	Coating Maintenance is Rare or None
Fusion bonded epoxy	1.0	1.1	1.5	1.1
Liquid epoxy				
Asphalt enamel				
Asphalt mastic				
Coal tar enamel	1.0	1.2	2.0	1.5
Extruded PE with mastic or rubber	1.0	1.2	3.0	1.5
Mill applied PE tape with mastic	1.5	1.2	3.0	1.5
Field applied PE tape with mastic	2.0	2.0	3.0	1.5
Three-layer PE or polypropylene (PP)	1.0	1.2	2.0	1.2

2.B.12.8 Figures**Figure 2.B.12.1—Soil-side Corrosion—Determination of Corrosion Rate**

2.B.13 CO₂ Corrosion

2.B.13.1 Description of Damage

Carbon dioxide is a weakly acidic gas. In streams with carbon dioxide and free water, the CO₂ dissolves in water producing carbonic acid (H₂CO₃). The carbonic acid then dissolves the steel producing iron carbonate and hydrogen (Fe+H₂CO₃→FeCO₃+H₂). Despite being a weak acid, carbonic acid can be extremely corrosive to carbon steel. CO₂ is commonly found in upstream sections before treatment. CO₂ corrosion requires the presence of free water in order to produce the carbonic acid. The primary variables that influence CO₂ corrosion rates are the CO₂ concentration, operating pressure, operating temperature, application of inhibitors, flow rate, and presence of hydrocarbon fluids and contaminants in the system.

Aqueous CO₂ corrosion of carbon and low-alloy steels is an electrochemical process involving the anodic dissolution of iron and the cathodic evolution of hydrogen. The electrochemical reactions are often accompanied by the formation of films of FeCO₃ (and/or Fe₃O₄), which can be protective or non-protective depending on the conditions under which these are formed.

NORSOK Standard M-506 has been used as the main reference for the developing the corrosion rate calculation model described in this section.

2.B.13.2 Basic Data

The data listed in [Table 2.B.13.1](#) are required to determine the estimated corrosion rate for carbonic acid service. If precise data have not been measured, a knowledgeable process specialist should be consulted. Entering only the data marked required will result in a conservative estimate of the corrosion rate. The calculation for the corrosion rate is more refined as more optional data are entered.

2.B.13.3 Determination of Corrosion Rate

2.B.13.3.1 Calculation of the Corrosion Rate

The steps required to determine the corrosion rate are shown in [Figure 2.B.13.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.13.1](#) in conjunction with [Equation \(2.B.23\)](#).

$$CR = CR_B \cdot \min[F_{\text{glycol}}, F_{\text{inhib}}] \quad (2.B.23)$$

The calculation of the base corrosion rate, CR_B , is most complex; it depends on the temperature, the partial pressure of CO₂, the fluid flow velocity, and the pH of the fluid. The following sections detail how these can be estimated for RBI purposes for some simple mixtures of crude oil, water, and natural gas mixtures. In order to estimate corrosion rates for situations outside this simple mixture, the analyst should refer to NORSOK Standard M-506. In cases where the equipment is not associated with upstream production, the analyst should also be prepared to adjust or estimate corrosion rates for fluids that are not mixtures of crude oil, water, and natural gas.

2.B.13.3.2 Relative Humidity

In order for corrosion to occur, there must be liquid water present in the equipment. In a system transporting gas, liquid water exists only if the temperature is below the dew point and the relative humidity (RH) in the stream is greater than 100 %. When a mixture of water vapor and natural gas behaves approximately as ideal gases, the RH in a gas is 100 % when the partial pressure of the water vapor is equal to the saturation pressure. This results in the simplified formula for the RH,

$$RH = \left(\frac{x \cdot P}{P_{\text{sat}}(T)} \right) \left(\frac{1}{0.622 + x} \right) \quad (2.B.24)$$

In Equation (2.B.24), x is the ratio of the mass of water to the mass of dry gas, or $\%w/(100 - \%w)$, where $\%w$ is the percent water by weight in the stream. The parameter P is the pressure and $P_{\text{sat}}(T)$ is the saturation pressure for water at temperature, T , which can be obtained from steam tables. The 0.622 is the ratio of the MW of water (≈ 18) to the average MW of air (≈ 29). Using Equation (2.B.24) and standard steam tables, an approximate equation for the dew point temperature T_d ($^{\circ}\text{F}$) can be derived; see Equation (2.B.25):

$$\log_{10} T_d = 2.0866 + 0.2088 \cdot \log_{10} \left[\frac{\%w}{100} \right] + 0.2242 \cdot \log_{10} [P] \quad (2.B.25)$$

In Equation (2.B.25), P is the pressure in psia, and $\%w$ is the percent water by weight in the stream (lbm/100 lbm), between 0 and 30.

2.B.13.3.3 Base Corrosion Rate

The base corrosion rate in mm/yr is calculated from Equation (2.B.26). To obtain mpy, multiply the result in mm/yr by 39.4.

$$CR_{\text{base}} = f(T, pH) \cdot f_{\text{CO}_2}^{0.62} \cdot \left(\frac{S}{19} \right)^{0.146 + 0.0324 f_{\text{CO}_2}} \quad (2.B.26)$$

In Equation (2.B.26), $f(T, pH)$ is the temperature-pH function that is tabulated in Table 2.B.13.2. This tabulated function was calculated by combining the M-506 temperature and temperature-dependent function pH function into a single quantity. It should be noted that the $f(T, pH)$ function jumps sharply between 176 $^{\circ}\text{F}$ and 194 $^{\circ}\text{F}$ (80 $^{\circ}\text{C}$ and 90 $^{\circ}\text{C}$).

The CO_2 fugacity, f_{CO_2} , in bar, pH, and the shear stress from the flow S in Pa needed to calculate the basic corrosion rate are discussed in the following sections.

2.B.13.3.4 Determining the pH

For RBI purposes, the pH term in temperature-pH function tabulated in Table 2.B.13.2 may be calculated using one of the following approximations. For condensation:

$$pH = 2.8686 + 0.7931 \cdot \log_{10} [T] - 0.57 \cdot \log_{10} [p_{\text{CO}_2}] \quad (2.B.27)$$

for Fe^{++} saturated water:

$$pH = 2.5907 + 0.8668 \cdot \log_{10} [T] - 0.49 \cdot \log_{10} [p_{\text{CO}_2}] \quad (2.B.28)$$

and for water with salinity slightly greater than seawater (salinity = 46 g/L):

$$pH = 2.7137 + 0.8002 \cdot \log_{10}[T] - 0.57 \cdot \log_{10}[p_{\text{CO}_2}] \quad (2.B.29)$$

In Equations (2.B.27), (2.B.28), and (2.B.29), T is the temperature in °F, and p_{CO_2} is the CO_2 partial pressure in psi. These approximations were developed from Monte Carlo simulations. These simulation studies used the equilibrium equations recommended and by M-506 to calculate the concentration of hydrogen cation and then the pH for a wide range of temperatures, pressures, and CO_2 mole fractions.

Equations (2.B.27), (2.B.28), and (2.B.29) apply to water, seawater, and Fe^{++} saturated water and do not account for the buffering action of bicarbonate ions or for the increase acidity caused by salinity levels higher than 45 g/L. In cases where these factors are significant, the analyst should consider using an alternative analysis such as direct application of the provisions in M-506 for salinity and dissolved bicarbonate.

2.B.13.3.5 Determining the CO_2 Fugacity

Fugacity has units of pressure. It is used in place of the pressure—or partial pressure—in calculations concerning the equilibrium of real gas mixtures. When the fugacity is used in place of the pressure, real gases can be modeled using the equations for ideal gases. M-506 uses the following equation for modeling the fugacity, f_{CO_2} .

$$\log_{10}[f_{\text{CO}_2}] = \log_{10}[p_{\text{CO}_2}] + \min[250, p_{\text{CO}_2}] \cdot \left(0.0031 - \frac{1.4}{T + 273} \right) \quad (2.B.30)$$

$$\log_{10}[f_{\text{CO}_2}] = \log_{10}[p_{\text{CO}_2}] + \log_{10}[a] \quad (2.B.31)$$

In Equations (2.B.30) and (2.B.31), p_{CO_2} is the CO_2 partial pressure in bar and T is the temperature in °C.

NOTE The fugacity coefficient, a , is the ratio between CO_2 fugacity and the partial pressure, or:

$$f_{\text{CO}_2} = p_{\text{CO}_2} \cdot a \quad (2.B.32)$$

2.B.13.3.6 Determining the Flow Velocity

M-506 uses the fluid flow shear stress to model the effect of flow velocity on the base corrosion rate. M-506 recommends the Equation (2.B.33) to calculate the stress, S , in units of Pa. In the calculation for the corrosion rate, the shear stress need not exceed 150 Pa.

$$S = \frac{f \cdot \rho_m \cdot u_m^2}{2} \quad (2.B.33)$$

In Equation (2.B.33), f is the friction factor, u_m is the mixture flow velocity in m/s, and ρ_m is the mixture mass density in kg/m^3 . The friction coefficient may be approximated for turbulent flow ($Re > 2300$) by using Equation (2.B.34):

$$f = 0.001375 \left[1 + \left(20,000 \left(\frac{e}{D} \right) + \frac{10^6}{Re} \right)^{0.33} \right] \quad (2.B.34)$$

The term e/D is the relative roughness and Re is the Reynolds Number of the mixture given by Equation (2.B.35):

$$Re = \frac{D\rho_m u_m}{\mu_m} = \frac{\dot{m}D}{A\mu_m} \quad (2.B.35)$$

In Equation (2.B.35), D is the diameter in meters, and μ_m is viscosity of the mixture in Pa·s (0.001cP = Pa·s). This equation also shows that the Reynolds number can be calculated using the mass flux, $\dot{m}$, and the cross-sectional area, A .

M-506 gives some guidance on the calculation of the two-phase viscosity, density, and fluid velocity. These factors depend on the volumetric ratio of the liquid flow to the flow, sometimes known as the liquid holdup, the amount of water in the liquid fraction, and the gas water and oil viscosities at the temperature and pressure. These calculations are complex and go beyond the scope of an RBI study. If required, the analyst can refer to the recommendations in NORSOK or use the software provided by NORSOK to perform the calculations recommended in M-506 to approximate the two-phase flow characteristics. While M-506 provides some guidelines for the calculation of bulk fluid properties, they do not explicitly account for the solubility of natural gas in oil, which can also affect the all of these properties.

2.B.13.3.7 Adjustment for Inhibitors or Glycol

The addition of glycol reduces the CO₂ corrosion rate. M-506 accounts for this by simply reducing the corrosion rate by applying a factor of the form:

$$\log_{10}[F_{\text{glycol}}] = 1.6 \cdot (\log[100 - G] - 2) \quad (2.B.36)$$

In Equation (2.B.36), G is the percent weight of glycol as a percent of water in the system. F_{glycol} is limited to a minimum value of 0.008. The base corrosion rate is multiplied by the factor F_{glycol} to account for the corrosion reduction due to glycol.

For other types of corrosion inhibitors added to the stream, M-506 requires that its effectiveness must be independently determined and used directly as a reduction factor, F_{inhib} . If both glycol and an inhibitor are used, the minimum of F_{inhib} and F_{glycol} should be used as shown in Equation (2.B.23).

2.B.13.4 Nomenclature

A	is the pipe cross-sectional area, ft ² (m ²)
a	is the fugacity coefficient
CR	is the corrosion rate
CR_B	is the base corrosion rate
D	is the pipe diameter, ft (m)
e/D	is the relative roughness
F_{glycol}	is the corrosion rate correction factor for glycol
F_{inhib}	is the corrosion rate correction factor for the inhibitor
f	is the fraction factor
f_{CO_2}	is the CO ₂ fugacity, bar
$f(T, pH)$	is the temperature-pH function
G	is the percent weight of glycol as a percent of water in the system
$\dot{m}$	is the calculated using the mass flux, lb/(ft ² -s) (kg/(m ² -s))
P	is the pressure, psia
$P_{\text{sat}}(T)$	is the saturation pressure for water at temperature T , psia
p_{CO_2}	is the CO ₂ partial pressure, psi (bar)
Re	is the Reynolds Number
RH	is the relative humidity
S	is the shear stress, Pa
T	is the temperature, °F (°C)
T_d	is dew point temperature, °F (°C)
u_m	is the mixture flow velocity, m/s
% _w	is the percent water by weight in the stream
x	is the ratio of the mass of water to the mass of dry gas
μ_m	is the viscosity of the mixture, cP
ρ_m	is the mixture mass density, kg/m ³

2.B.13.5 Tables

Table 2.B.13.1—CO₂ Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Temperature—required	The corrosion phenomenon is highly temperature dependent. The maximum temperature of the process is required. Temperatures above 284 °F (140 °C) are not considered.
Pressure—required	Total pressure of the system. The total pressure of the gas is a big contributor in the corrosion rate up to about 250 psig.
CO ₂ concentration (mole %)—required	Determine the CO ₂ partial pressure (p_{CO_2}) = (mol fraction of CO ₂ × total pressure), a maximum 580 psi (4 MPa) partial CO ₂ pressure is considered.
p_{CO_2} —required, if CO ₂ concentration is not given	CO ₂ partial pressure, which is converted to CO ₂ fugacity to account for nonideal behavior.
Material of construction—required	Determine the material of construction of equipment/piping. Stainless steels and copper alloys are assumed to be resistant to CO ₂ corrosion.
pH—required	If known explicitly, the pH of the stream should be used; otherwise, Equations (2.B.27) , (2.B.28) , and (2.B.29) can be used to estimate the pH based on the CO ₂ partial pressure, whether the water in the stream is Fe ⁺⁺ saturated or water with salinity slightly larger than seawater.
Stream properties: bulk density, ρ_m , viscosity, μ_m , gas-to-liquid ratios—required	Guidance with respect to typical values properties expected in natural gas–oil mixtures (i.e. reservoir fluids) is provided. Estimation of densities can be made on the basis of the oil density (°API), gas–oil ratio (GOR), pressure, P , and temperature, T . For other streams, a process engineer should assess these parameters.
For systems with liquids: water cut—optional	Determine the percentage of water in the system. The default for this field is 30 %.
For gas systems: relative humidity, RH or the dew point temperature, T_d —optional	Determine the dew point temperature, T_d , based on the water content. Equation (2.B.25) is provided for guidance, but should not be assumed to be accurate within ± 10 °F. If not provided, the gas stream temperature is assumed to be below the dew point.
Glycol/water mix—Optional	Water content of glycol/water mix in %weight (%water in the total glycol/water mix). The default value would assume no glycol added in the system.
Inhibition efficiency—Optional	Requires %efficiency of the inhibitor. No inhibitor injected as a default value.

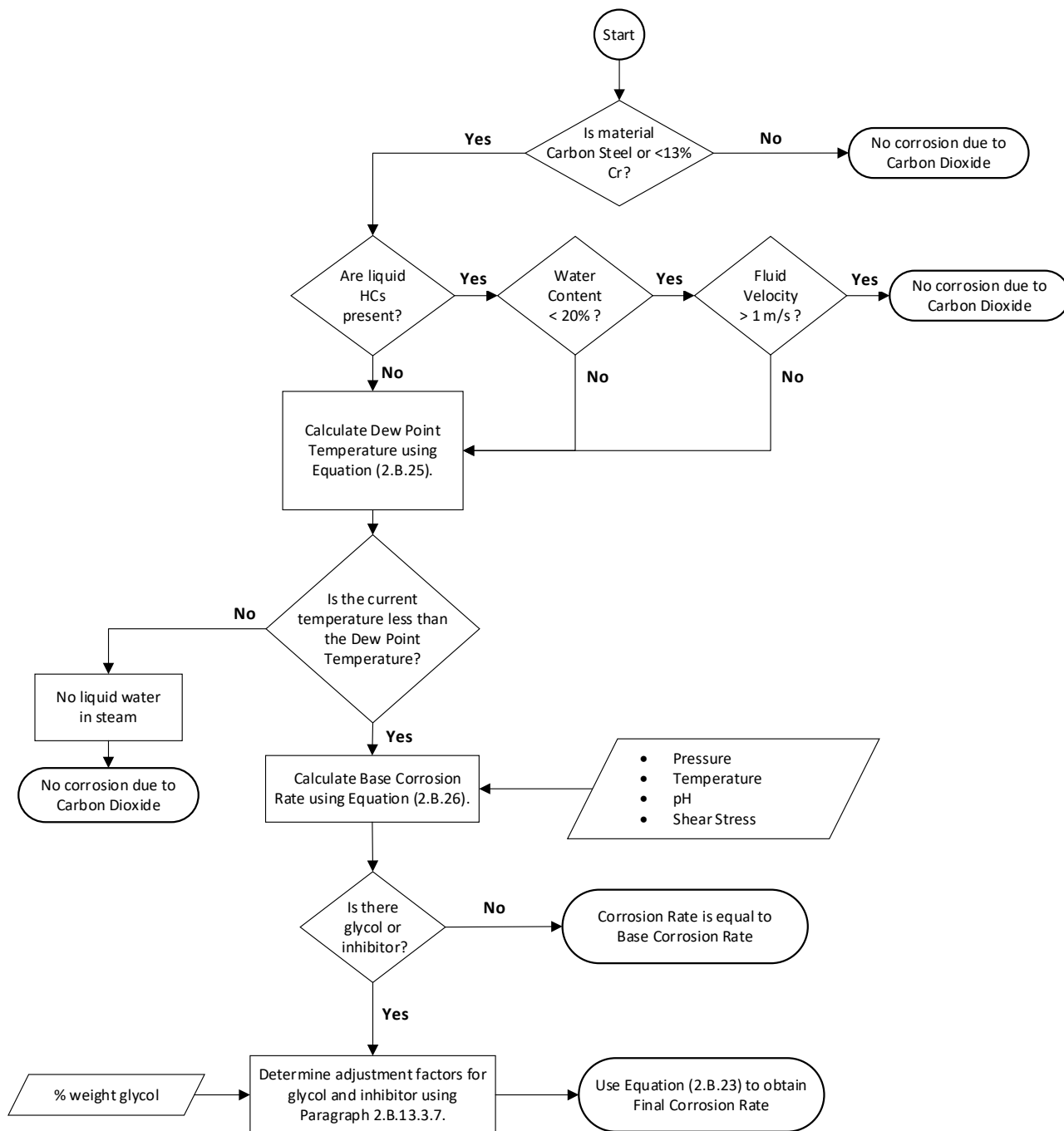
Table 2.B.13.2—pH Temperature Function

Temperature (°F)	pH						
	3.5	4.0	4.5	5.0	5.5	6.0	6.5
68	6.00	5.45	4.9	3.72	2.55	1.55	0.72
86	8.52	7.77	7.02	5.16	3.40	2.00	0.91
104	10.98	10.06	9.13	6.49	4.08	2.30	1.02
122	11.92	10.96	10.01	6.86	4.10	2.20	0.94
140	12.83	11.86	10.89	7.18	4.05	2.03	0.84
158	13.42	12.01	10.6	6.58	3.61	1.86	0.87
176	13.93	12.12	10.31	6.01	3.20	1.70	0.90
194	9.37	7.91	6.45	2.44	0.82	0.49	0.32
212	9.23	8.04	6.38	2.19	0.94	0.62	0.42
230	8.96	8.09	6.22	1.87	1.07	0.77	0.53
248	8.55	8.06	5.98	1.48	1.20	0.92	0.65
266	7.38	6.39	3.98	0.96	0.80	0.63	0.47
284	6.26	4.91	2.31	0.53	0.46	0.39	0.32
302	5.20	3.62	0.98	0.19	0.19	0.19	0.19

Table 2.B.13.2M—pH Temperature Function

Temperature (°C)	pH						
	3.5	4.0	4.5	5.0	5.5	6.0	6.5
20	6.00	5.45	4.9	3.72	2.55	1.55	0.72
30	8.52	7.77	7.02	5.16	3.40	2.00	0.91
40	10.98	10.06	9.13	6.49	4.08	2.30	1.02
50	11.92	10.96	10.01	6.86	4.10	2.20	0.94
60	12.83	11.86	10.89	7.18	4.05	2.03	0.84
70	13.42	12.01	10.6	6.58	3.61	1.86	0.87
80	13.93	12.12	10.31	6.01	3.20	1.70	0.90
90	9.37	7.91	6.45	2.44	0.82	0.49	0.32
100	9.23	8.04	6.38	2.19	0.94	0.62	0.42
110	8.96	8.09	6.22	1.87	1.07	0.77	0.53
120	8.55	8.06	5.98	1.48	1.20	0.92	0.65
130	7.38	6.39	3.98	0.96	0.80	0.63	0.47
140	6.26	4.91	2.31	0.53	0.46	0.39	0.32
150	5.20	3.62	0.98	0.19	0.19	0.19	0.19

2.B.13.6 Figures

Figure 2.B.13.1—CO₂ Corrosion—Determination of Corrosion Rate

2.B.14 Storage Tank Bottom Corrosion

2.B.14.1 Description of Damage

Corrosion occurs from the product side (internal corrosion) and soil side (external corrosion) of storage tank bottoms constructed of carbon steel. Product-side corrosion can result in general or localized thinning. Factors affecting product-side corrosion are the stored product corrosivity characteristics, operating temperature, steam coil practices, and the presence of water in the storage tank. Soil-side corrosion results in localized thinning. Factors affecting soil-side corrosion are soil type, pad type, water draining, CP, storage tank bottom design, and operating temperature of the process stored.

2.B.14.2 Basic Data

2.B.14.2.1 Soil-side Corrosion Rate Equation

The data listed in [Table 2.B.14.1](#) are required to determine the estimated corrosion rate for soil-side service. If precise data have not been measured, a knowledgeable corrosion specialist should be consulted.

2.B.14.2.2 Product-side Corrosion Rate Equation

The data listed in [Table 2.B.14.2](#) are required to determine the estimated corrosion rate for product-side service. If precise data have not been measured, a knowledgeable process specialist should be consulted.

2.B.14.3 Determination of Corrosion Rate

2.B.14.3.1 Soil-side Corrosion Rate Equation

The steps required to determine the corrosion rate are shown in [Figure 2.B.14.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.14.1](#) in conjunction with [Equation \(2.B.37\)](#).

$$CR_S = CR_{SB} \cdot F_{SR} \cdot F_{PA} \cdot F_{TD} \cdot F_{CP} \cdot F_{TB} \cdot F_{ST} \quad (2.B.37)$$

The base soil-side base corrosion rate, CR_{SB} , should be determined based on actual inspection data. If these data are not available, then the base soil-side corrosion rate may be assumed to be 5 mpy (0.13 mm/yr). This base corrosion rate is the expected or observed corrosion rate for a typical storage tank under average conditions (see [Table 2.B.14.3](#)), neither highly susceptible to corrosion nor especially resistant to corrosion.

The adjustment factors in [Equation \(2.B.37\)](#) are determined as described below.

- a) Adjustment Factor for Soil Conditions, F_{SR} —The corrosion rate adjustment factor is given in [Table 2.B.14.4](#). The resistivity of the native soil beneath the storage tank pad can affect the corrosion rate of the storage tank bottom. The resistivity of the storage tank pad material may be higher than the existing surrounding soil. However, corrosive soil beneath the high resistivity storage tank pad material may contaminate the storage tank pad fill by capillary action (see API 651, 1997, Section 5.3.1). Therefore, resistivity of the surrounding native soil may be used to determine the likelihood of corrosion on the storage tank bottom. A common method of measuring soil resistivity is described in ASTM G57. If the soil resistivity is not known, then assume moderately corrosive soil (adjustment factor equals 1).

NOTE An adjustment factor of 1 is used for storage tanks with release prevention barriers (RPBs), since RPBs effectively prevent the contamination of the storage tank pad material by the native soil.

- b) Adjustment Factor for Storage Tank Pad, F_{PA} —The corrosion rate adjustment factor is given in [Table 2.B.14.5](#). The type of pad or foundation that the storage tank rests upon will influence the corrosion rate. The adjustment factors are assigned in a similar manner to those for the native soil beneath the storage tank pad.

- c) Adjustment Factor for Drainage, F_{TD} —The corrosion rate adjustment factor is given in [Table 2.B.14.6](#). Rainwater collecting around the base of the storage tank can greatly increase corrosion. The adjustment is made so that storm water collecting around a storage tank will cause the base corrosion rate to increase by a factor of 2. If the drainage is so poor that more than one-third of the circumference of the bottom edge of the storage tank is underwater for extended periods of time, then the base corrosion rate is increased by a factor of 3. Good drainage is considered normal, so the multiplier is set to 1 if water does not normally collect around the base of the storage tank.
- d) Adjust for CP, F_{CP} —The corrosion rate adjustment factor is given in [Table 2.B.14.7](#). CP is one of the primary methods used to avoid corrosion of AST bottoms from the soil side. However, the system must be installed and maintained properly. The factor is established so that the most credit is given for a properly functioning CP system in accordance with API 651, but no penalty is assessed for lack of CP. This assumes that the base corrosion rate is for systems without CP. Unless a high-level inspection can verify that the CP system is effective (verified by inspection in compliance with NACE SP0169 or equivalent), no credit is obtained for the CP system.
- e) Adjust for Storage Tank Bottom Type, F_{TB} —The corrosion rate adjustment factor is given in [Table 2.B.14.8](#). ASTs with properly installed RPBs tend to have bottom corrosion rates comparable to those with a single bottom.
- f) Adjustment for Operating Temperature, F_{ST} —The corrosion rate adjustment factor is given in [Table 2.B.14.9](#). The operating temperature of the storage tank may influence external corrosion.

2.B.14.3.2 Product-side Corrosion Rate Equation

The steps required to determine the corrosion rate are shown in [Figure 2.B.14.1](#). The corrosion rate may be determined using the basic data in [Table 2.B.14.2](#) in conjunction with [Equation \(2.B.38\)](#).

$$CR_P = CR_{PB} \cdot F_{PC} \cdot F_{PT} \cdot F_{SC} \cdot F_{WD} \quad (2.B.38)$$

The product-side base corrosion rate, CR_{PB} , should be determined based on actual inspection data. If these data are not available, then the base product-side corrosion rate may be assumed to be 2 mpy (0.05 mm/yr). The base corrosion rate is founded on the conditions stated in [Table 2.B.14.10](#).

The adjustment factors in [Equation \(2.B.38\)](#) are determined as described below.

- a) Adjustment for Product Condition, F_{PC} —The corrosion rate adjustment factor is given in [Table 2.B.14.11](#). Wet conditions should be used if significant bottom sediments and water are present.
- b) Adjustment for Operating temperature, F_{PT} —The corrosion rate adjustment factor is given in [Table 2.B.14.12](#).
- c) Adjustment for Steam Coil, F_{SC} —The corrosion rate adjustment factor is given in [Table 2.B.14.13](#). If a steam coil heater is present, the internal corrosion rate is adjusted upwards slightly due to extra heat and the possibility of steam leaks from the internal coil.
- d) Adjustment for Water Draw-off, F_{WD} —The corrosion rate adjustment factor is given in [Table 2.B.14.14](#). Water draws, when consistently used, can greatly reduce the damaging effects of water at the bottom of the AST. To receive the full benefit, water must be drawn weekly or after every receipt.

2.B.14.3.3 Combined Storage Tank Floor Corrosion Rate

The internal and external corrosion rates are estimated by multiplying the base corrosion rate by the respective adjustment factors. This will produce two separate corrosion rates that are combined as described below. It is assumed that the soil-side corrosion will be localized in nature while the product-side corrosion will

be either generalized or localized. To avoid understating the risk, it is recommended that the combined corrosion rate should not be set lower than 2 mils per year.

- a) Option 1—If the internal corrosion is generalized in nature, the corrosion areas will likely overlap such that the bottom thickness is simultaneously reduced by both internal and external influences. In this case, the internal and external rates are additive.
- b) Option 2—For pitting and localized corrosion, the chances are low that internal and external rates can combine to produce an additive effect on wall loss. In this case, the user chooses the greater of the two corrosion rates as the governing rate for the proceeding step.

2.B.14.4 Nomenclature

CR_P	is the product-side corrosion rate
CR_{PB}	is the product-side base corrosion rate
CR_S	is the soil-side corrosion rate
CR_{SB}	is the soil-side base corrosion rate
F_{CP}	is the soil-side corrosion rate correction factor for CP
F_{PA}	is the soil-side corrosion rate correction factor for storage tank pad type
F_{PC}	is the product-side corrosion rate correction factor for product condition
F_{PT}	is the product-side corrosion rate correction factor for temperature
F_{SC}	is the soil-side corrosion rate correction factor for temperature
F_{SR}	is the soil-side corrosion rate correction factor for soil conditions
F_{ST}	is the product-side corrosion rate correction factor for temperature
F_{TB}	is the soil-side corrosion rate correction factor for storage tank bottom type
F_{TD}	is the soil-side corrosion rate correction factor for drainage
F_{WD}	is the product-side corrosion rate correction factor for water draw-off

2.B.14.5 Tables

Table 2.B.14.1—Soil-side Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Measured or estimated corrosion rate, mpy (mm/yr)	If measured or estimated soil-side corrosion rate is available, it should be used and substituted for the base soil-side corrosion rate of 5 mpy (0.13 mm/yr).
Soil condition (Ω -cm)	Soil resistivity of native soil underneath and around the storage tank or dike area. A common method of measuring soil resistivity is described in ASTM G57.
Storage tank pad	The type of storage tank pad material (soil, sand, etc.) upon which the tank rests. In the case of a storage tank supported on a ring wall, it is the material used for filling inside the wall.
Storage tank drainage	The effectiveness with which rainwater is drained away from the storage tank and prevented from collecting under the storage tank bottom.
CP	The existence of a CP system for the storage tank bottom, and the proper installation and operation of such a system, based on API 651.
Bottom type	Single bottom or bottom with RPB. The RPB can be a textile or plastic type barrier, or a second floor.
Operating temperature, °F (°C)	The highest operating temperature expected during operation (considering both normal and unusual operating conditions).

Table 2.B.14.2—Product-side Corrosion—Basic Data Required for Analysis

Basic Data	Comments
Measured or estimated corrosion rate, mpy (mm/yr)	If measured or estimated soil-side corrosion rate is available, it should be used and substituted for the base soil-side corrosion rate of 2 mpy (0.05 mm/yr).
Product-side condition	Dry or wet, wet conditions should be used if significant bottom sediments and water are present.
Operating temperature (°F)	The highest operating temperature expected during operation (considering both normal and unusual operating conditions).
Storage tank steam coil heater	Yes or No. If a steam coil heater is utilized, the internal corrosion is adjusted upwards slightly due to extra heat and the possibility of steam leaks.
Water draws	Water draws when consistently used can greatly reduce the damaging effects of water at the bottom of the storage tank.

Table 2.B.14.3—Summary of Conditions for Soil-side Base Corrosion Rate

Factor	Base Corrosion Rate Conditions
Soil resistivity	Moderately corrosive (1000 to 2000 Ω -cm)
Storage tank pad material	Continuous asphalt or concrete
Storage tank drainage	Storm water does not collect around base of storage tank
CP	None or not functioning
Bottom type	Single bottom
Bulk fluid temperature	Below 75 °F (24 °C)

Table 2.B.14.4—Soil-side Soil Resistivity Adjustment Factor

Resistivity (Ω -cm)	Potential Corrosion Activity	Multiplying Factor— F_{SR}
< 500	Very corrosive	1.5
500 to 1,000	Corrosive	1.25
1,000 to 2,000	Moderately corrosive	1.0
2,000 to 10,000	Mildly corrosive	0.83
> 10,000	Progressively less corrosive	0.66
Storage tank with RPB		1.0

Table 2.B.14.5—Soil-side Storage Tank Pad Adjustment Factor

Storage Tank Pad Type	Multiplying Factor— F_{PA}
Soil with high salt	1.5
Crushed limestone	1.4
Native soil	1.3
Construction grade sand	1.15
Continuous asphalt	1.0
Continuous concrete	1.0
Oil sand	0.7
High resistivity low chloride sand	0.7

Table 2.B.14.6—Soil-side Storage Tank Drainage Adjustment Factor

AST Drainage Type	Multiplying Factor— F_{TD}
One-third frequently underwater	3
Storm water collects at storage tank base	2
Storm water does not collect at storage tank base	1

Table 2.B.14.7—Soil-side CP Adjustment Factor

CP Type	Multiplying Factor— F_{CP}
None	1.0
Yes not per API 651	0.66
Yes per API 651	0.33

Table 2.B.14.8—Soil-side AST Bottom Type Adjustment

Storage Tank Pad Type	Multiplying Factor— F_{TB}
RPB not per API 650	1.4
RPB per API 650	1.0
Single bottom	1.0

Table 2.B.14.9—Soil-side Temperature Adjustment

Soil-side Temperature		Multiplying Factor— F_{ST}
°C	°F	
Temp ≤ 24	Temp ≤ 75	1.0
$24 < \text{Temp} \leq 66$	$75 < \text{Temp} \leq 150$	1.1
$66 < \text{Temp} \leq 93$	$150 < \text{Temp} \leq 200$	1.3
$93 < \text{Temp} \leq 121$	$200 < \text{Temp} \leq 250$	1.4
> 121	> 250	1.0

Table 2.B.14.10—Summary of Conditions for Product-side Base Corrosion Rate

Factor	Base Corrosion Rate Conditions
Internal coating	Internal coating not needed for corrosion protection and none applied
Bulk fluid temperature	Below 75 °F (24 °C)
Steam coil heater	No
Water draws	No (water draws conducted neither weekly nor after every receipt)

Table 2.B.14.11—Product-side Product Condition Adjustment

Product-side Condition	Multiplying Factor— F_{PC}
Wet	2.5
Dry	1.0

Table 2.B.14.12—Product-side Temperature Adjustment

Product-side Temperature		Multiplying Factor— F_{PT}
°C	°F	
Temp ≤ 24	Temp ≤ 75	1.0
$24 < \text{Temp} \leq 66$	$75 < \text{Temp} \leq 150$	1.1
$66 < \text{Temp} \leq 93$	$150 < \text{Temp} \leq 200$	1.3
$93 < \text{Temp} \leq 121$	$200 < \text{Temp} \leq 250$	1.4
> 121	> 250	1.0

Table 2.B.14.13—Product-side Steam Coil Adjustment

Steam Coil	Multiplying Factor— F_{SC}
No	1.0
Yes	1.15

Table 2.B.14.14—Product-side Water Draw-off Adjustment

Water Draw-off	Multiplying Factor— F_{WD}
No	1.0
Yes	0.7

2.B.14.6 Figures

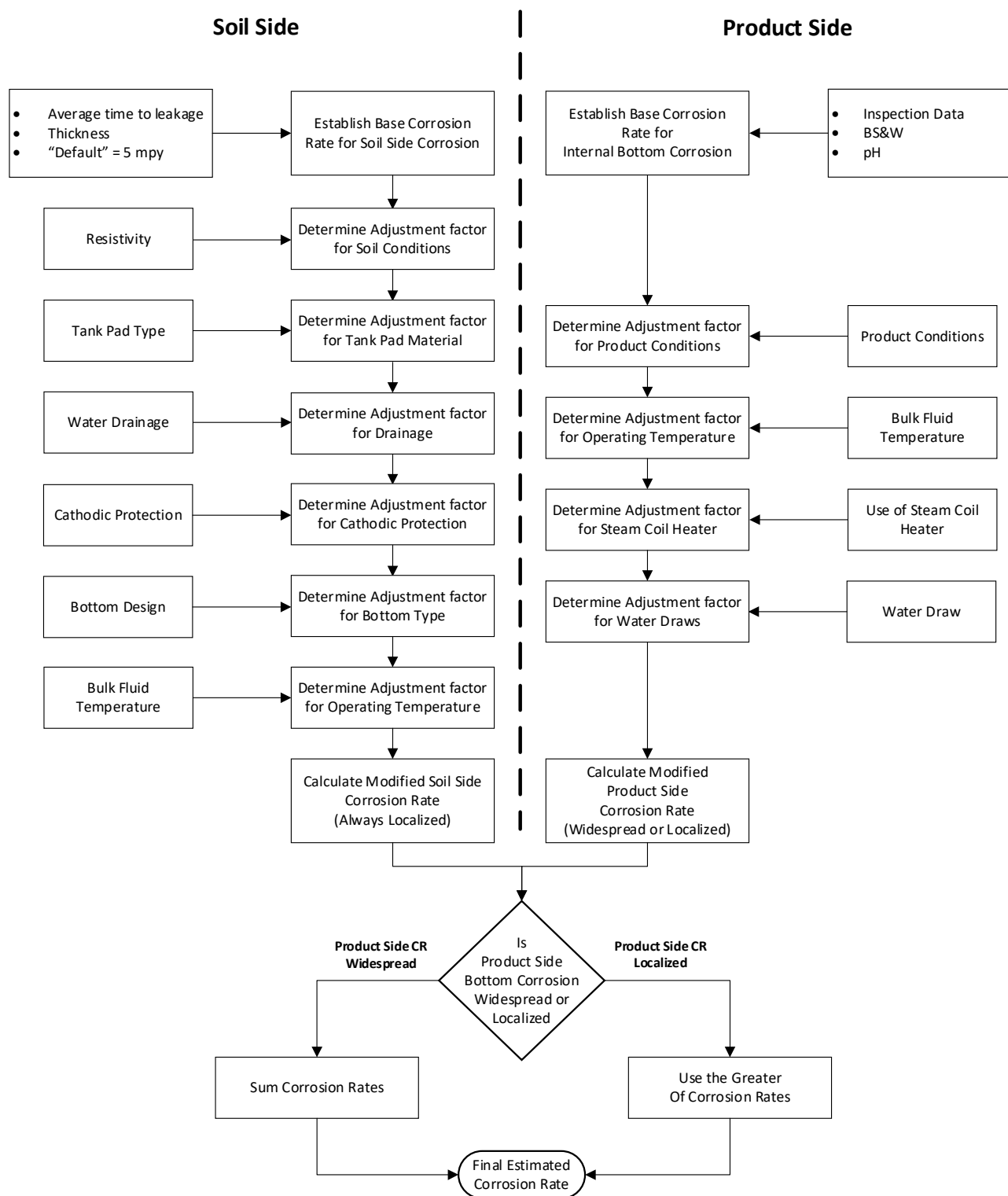


Figure 2.B.14.1—Storage Tank Bottom Corrosion—Determination of Soil-side and Product-side Corrosion Rates

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Risk-based Inspection Methodology
Part 2—Probability of Failure Methodology
Annex 2.C—Determination of Internal Stress Corrosion Cracking Susceptibilities

2.C.1 Overview

2.C.1.1 Determination of SCC Susceptibilities

SCC susceptibilities should be based on assignments for each potential cracking mechanism using this document or as estimated by a corrosion specialist.

Screening questions are used to determine which of the cracking mechanism sections may apply. The applicable sections are used to determine conservative estimated cracking susceptibilities for potential cracking mechanisms. The screening questions listed in [Table 2.C.1.1](#) are used to select the applicable thinning mechanism.

2.C.1.2 Tables

Table 2.C.1.1—Screening Questions for SCC Damage

Screening Questions	Action
ACSCC Cracking 1. Carbon or low-alloy steel? 2. Is free water present in the process stream (including initial condensing condition)? 3. Is the pH > 7.5?	If Yes to all, proceed to Section 2.C.2
Amine Cracking 1. Carbon or low-alloy steel? 2. Is the operating temperature > 100 °F (51 °C)? 3. Is equipment exposed to acid gas treating amines (MEA, DEA, DIPA, or MDEA)?	If Yes to all, proceed to Section 2.C.3
Caustic SCC 1. Carbon or low-alloy steel? 2. Process containing caustic? 3. Is the operating temperature > 100 °F (51 °C)?	If Yes to all, proceed to Section 2.C.4
CISCC 1. Austenitic stainless steel or nickel-based alloy? 2. Is free water present containing chlorides in the process stream (including initial condensing condition)? 3. Temperature between 75 °F (23.90 °C) and 345 °F (173.90 °C) and a pH > 2.5 and < 10.5?	If Yes to all, proceed to Section 2.C.5
Hydrofluoric Acid—HIC/SOHIC-HF 1. Carbon or low-alloy steel? 2. Process containing HF?	If Yes to both, proceed to Section 2.C.6
Hydrofluoric Acid—HSC 1. Carbon or low-alloy steel? 2. Process containing HF?	If Yes to both, proceed to Section 2.C.7
PASCC 1. Austenitic stainless steel or nickel-based alloy? 2. Process exposed to sulfur bearing compounds?	If Yes to both, proceed to Section 2.C.8
Wet H₂S—HIC/SOHIC-H₂S 1. Carbon or low-alloy steel? 2. Process containing H ₂ S? 3. Pressure > 0.05 psia (0.3 MPa)? 4. Is free water present (including consideration for dew point condensation)?	If Yes to all, proceed to Section 2.C.9
Wet H₂S—Sulfide Stress Cracking (SSC) 1. Carbon or low-alloy steel? 2. Process containing H ₂ S? 3. Pressure > 0.05 psia (0.3 MPa)? 4. Is free water present (including consideration for dew point condensation)?	If Yes to all, proceed to Section 2.C.10

Table 2.C.1.2—Severity Index—All SCC Mechanisms

Susceptibility	ACSCC	Amine SCC	Caustic SCC	CISCC	HSC	HIC/SOHIC-HF	PASCC	HIC/SOHIC-H ₂ S	SSC	Other
High	1000	1000	5000	5000	100	100	5000	100	100	5000
Medium	100	100	500	500	10	10	500	10	10	500
Low	10	10	50	50	1	1	50	1	1	50
None	0	0	0	0	0	0	0	0	0	0

Table 2.C.1.3—SCC DFs—All SCC Mechanisms

S_{VI}	Inspection Effectiveness												
	E	1 Inspection				2 Inspections				3 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	8	3	1	1	6	2	1	1	4	1	1	1
50	50	40	17	5	3	30	10	2	1	20	5	1	1
100	100	80	33	10	5	60	20	4	1	40	10	2	1
500	500	400	170	50	25	300	100	20	5	200	50	8	1
1000	1000	800	330	100	50	600	200	40	10	400	100	16	2
5000	5000	4000	1670	500	250	3000	1000	250	50	2000	500	80	10

S_{VI}	Inspection Effectiveness												
	E	4 Inspections				5 Inspections				6 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	2	1	1	1	1	1	1	1	1	1	1	1
50	50	10	2	1	1	5	1	1	1	1	1	1	1
100	100	20	5	1	1	10	2	1	1	5	1	1	1
500	500	100	25	2	1	50	10	1	1	25	5	1	1
1000	1000	200	50	5	1	100	25	2	1	50	10	1	1
5000	5000	1000	250	25	2	500	125	5	1	250	50	2	1

2.C.2 SCC DF—Alkaline Carbonate Stress Corrosion Cracking (ACSCC)

2.C.2.1 Scope

The DF calculation for components subject to ACSCC is covered in this section.

2.C.2.2 Description of Damage

ACSCC is the common term applied to surface breaking cracks that occur at or near carbon and low-alloy steel welds under the combined action of tensile stress and in the presence of alkaline water containing moderate to high concentrations of carbonate ions (CO_3^{2-}).

On a macroscopic level, ACSCC typically propagates parallel to the weld in the adjacent base material but can also occur in the weld deposit or heat-affected zones (HAZs).

At times surface inspection results of ACSCC may be mistaken for SSC or SOHIC, but further review will show that ACSCC is usually located further from the toe of the weld into the residual stress field of the base material and can contain multiple parallel cracks. When cracking is in the weld metal, the pattern of cracking observed on the steel surface is sometimes described as a “spider web” of small cracks, which often initiate at or interconnect with weld-related flaws that serve as local stress risers. Finally, from the microscopic perspective, the cracking is characterized by predominantly intergranular, oxide-filled cracks similar in appearance to ACSCC found in caustic and amine services.

Historically, ACSCC has been most prevalent in fluid catalytic cracking unit (FCCU) main fractionator overhead condensing and reflux systems, the downstream wet gas compression system, and the sour water systems emanating from these areas. Based upon recent survey results, sour water strippers with side pumparound (P/A) designs, CO_2 removal facilities for hydrogen manufacturing units, and delayed coker light ends units have been added to the list of affected units. There have also been cases of ACSCC in non-refining industries. In all instances, both piping and vessels are affected.

Assuming the presence of an alkaline water phase containing H_2S , three key parameters are used to assess the susceptibility of steel fabrications to ACSCC: pH of the water, carbonate ion concentration of the water, and the residual stress level of the exposed carbon or low-alloy steel.

- a) pH—Typically, pHs are greater than 7.5 and process streams that are lower in H_2S or higher in NH_3 causing higher pHs will be more susceptible to this form of ACSCC. Although H_2S is often present, no threshold level has been established; no evidence exists to indicate cyanides or polysulfides have an impact.
- b) Carbonates—Plants that generate more carbonate ions in the water will be more susceptible to ACSCC.
- c) Residual Stresses—ACSCC appears to be very susceptible to residual stress levels so that welded structures and cold-worked structures will be susceptible.

Studies have concluded that the electrochemical potential of the water can be used to assess the likelihood of ACSCC. However, accurate measurement in a field environment is difficult. Therefore, further discussion of the electrochemical potential is outside the scope of this document.

With regard to mitigation techniques, the application of a post-fabrication stress-relieving heat treatment [e.g. postweld heat treatment (PWHT)] is the most commonly used method of preventing ACSCC in carbon and low-alloy steels. A heat treatment of about 1200 °F to 1225 °F (649 °C to 663 °C) in accordance with WRC 452 or AWS D1010 is considered effective to minimize residual stresses. The heat treatment requirements apply to all exposed welds as well as any external welds with HAZs in contact with the service environment. Other mitigation techniques include: process barriers (either organic or metallic), alloy upgrades

(solid or clad 300 series, Alloy 400 or other corrosion-resistant alloys), effective water washing, and inhibitor injection.

2.C.2.3 Screening Criteria

If the component's material of construction is carbon or low-alloy steel and the process environment contains water at $\text{pH} > 7.5$ in any concentration, then the component should be considered for evaluation for susceptibility to ACSCC. Another trigger would be changes in FCCU feed sulfur and nitrogen contents, particularly when feed changes have reduced sulfur (low sulfur feeds or hydroprocessed feeds) or increased nitrogen [44].

2.C.2.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the ACSCC DF are provided in [Table 2.C.2.1](#).

2.C.2.5 Basic Assumptions

The main assumption in determining the DF for ACSCC is that the damage can be characterized by a susceptibility parameter that is designated as High, Medium, or Low based on process environment, material of construction, and component fabrication variables (i.e. cold work, welding, and heat treatment). A severity index is assigned based on the susceptibility parameter

If cracks are detected in the component during an inspection, the susceptibility is designated as High, and this will result in the maximum value for the severity index. Cracks that are found during an inspection should be evaluated using FFS methods in API 579-1/ASME FFS-1 [10].

2.C.2.6 Determination of the DF

2.C.2.6.1 Overview

A flow chart of the steps required to determine the DF for ACSCC is shown in [Figure 2.C.2.1](#). The following sections provide additional information and the calculation procedure.

2.C.2.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting for ACSCC. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.8.2](#).

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.C.2.6.3 Calculation of the DF

The following procedure may be used to determine the DF for ACSCC; see [Figure 2.C.2.1](#).

- 1) Step 1—Determine the susceptibility for cracking using [Figure 2.C.2.1](#) and [Table 2.C.2.2](#) based on the pH of the water, and CO_3 concentration, and knowledge of whether the component has been PWHT'd.

NOTE A High susceptibility should be used if cracking is confirmed to be present.

- 2) Step 2—Based on the susceptibility in Step 1, determine the severity index, S_{VI} , from [Table 2.C.1.2](#).

- 3) Step 3—Determine the time in service, *age*, since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- 4) Step 4—Determine the number of inspections and the corresponding inspection effectiveness category using [2.C.2.6.2](#) for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using [Part 2, Section 3.4.3](#).
- 5) Step 5—Determine the base DF for ACSCC, D_{fB}^{ACSCC} , using [Table 2.C.1.3](#) based on the number of inspections and the highest inspection effectiveness determined in Step 4 and the severity index, S_{VI} , from Step 2.
- 6) Step 6—Calculate the escalation in the DF based on the time in service since the last inspection using the *age* from Step 3 and [Equation \(2.C.1\)](#). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

$$D_f^{ACSCC} = \min \left(D_{fB}^{ACSCC} \cdot (\max(\text{age}, 1.0))^{1.1}, 5000 \right) \quad (2.C.1)$$

2.C.2.7 Nomenclature

<i>age</i>	is the component in-service time since the last cracking inspection or service start date
D_f^{ACSCC}	is the DF for ACSCC
D_{fB}^{ACSCC}	is the base value of the DF for ACSCC
S_{VI}	is the severity index

2.C.2.8 References

See References [\[10\]](#), [\[13\]](#), [\[34\]](#), [\[36\]](#), [\[39\]](#), [\[40\]](#), [\[41\]](#), [\[42\]](#) (see Appendix D), [\[43\]](#), [\[44\]](#), and [\[45\]](#) in [Annex 2.G](#).

2.C.2.9 Tables

Table 2.C.2.1—Data Required for Determination of the DF—ACSCC

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section. This type of cracking may be sporadic and may grow rapidly depending on subtle changes in the process conditions. Periodic monitoring of process pH and CO_3^{2-} in FCC alkaline waters should be done to determine cracking susceptibility.
Presence of water (Yes or No)	Determine whether free water is present in the component. Consider not only normal operating conditions but also start-up, shutdown, process upsets, etc.
Presence of H_2S in the water (Yes or No)	Determine whether H_2S is present in the water phase in this component. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
pH of water	Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
CO_3^{2-} concentration in water	Determine the carbonate ion concentration of the water phase present in this component. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Age (years)	Use inspection history to determine the time since the last SCC inspection.
PWHT	Effective heat treatment to minimize residual stresses of carbon and low-alloy steel weldments.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

Table 2.C.2.2—Susceptibility to Cracking—ACSCC

pH	Susceptibility to Cracking as a Function of Residual Stress and CO_3^{2-} Concentration in Water ¹				
	Effective PWHT	Unknown or Ineffective PWHT and/or Possible Cold Working			
	$\text{CO}_3^{2-} < 10,000 \text{ ppm}$ ²	$\text{CO}_3^{2-} < 10 \text{ ppm}$	$10 < \text{CO}_3^{2-} < 100 \text{ ppm}$	$100 < \text{CO}_3^{2-} < 1,000 \text{ ppm}$	$\text{CO}_3^{2-} > 1,000 \text{ ppm}$ ²
< 7.5	None	None	None	None	None
7.5 to 8.0	None	None	None	Low	Low
8.0 to 8.5	None	None	Low	Medium	High
8.5 to 9.0	None	Low	Medium	High	High
9.0 to 9.5	None	Medium	High	High	High
> 9.5	None	High	High	High	High

NOTE 1 Traditional alkalinity titration methods (e.g., phenolphthalein or methyl orange indicator alkalinity) are not effective for measurement of CO_3^{2-} in sour water.

NOTE 2 In refinery processes, the concentration of CO_3^{2-} is typically less than 10,000 ppm.

NOTE 3 These values were developed based upon an industry survey that did not include a standardized means of determining the carbonate ion concentration. The owner–operator and corrosion specialist should exercise caution when selecting these values.

2.C.2.10 Figures

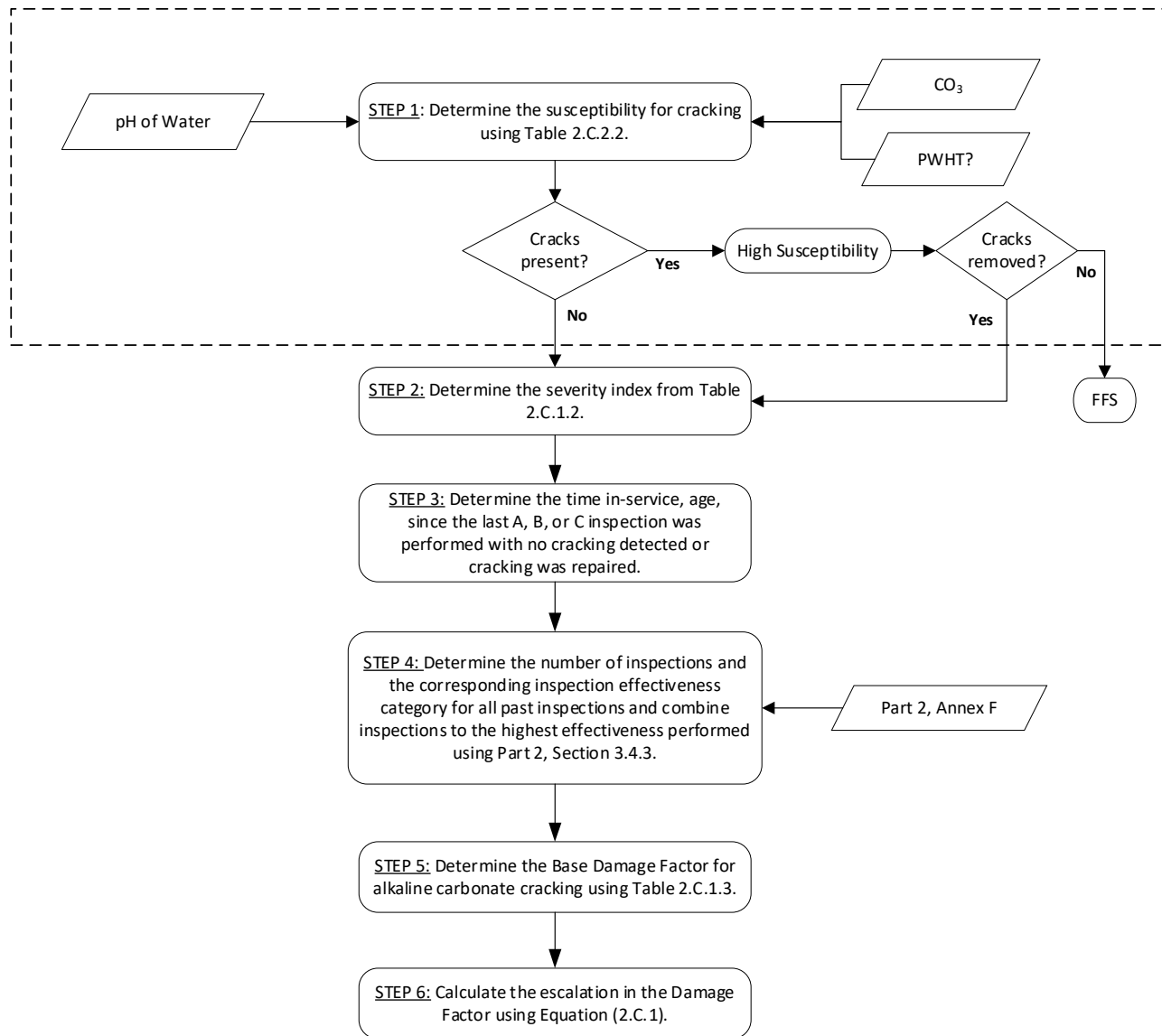


Figure 2.C.2.1—Determination of the ACSCC DF

2.C.3 SCC DF—Amine Cracking

2.C.3.1 Scope

The DF calculation for components subject to amine cracking is covered in this section.

2.C.3.2 Description of Damage

Amine cracking is defined as cracking of a metal under the combined action of tensile stress and corrosion in the presence of an aqueous alkanolamine solution at elevated temperature. The cracking is predominately intergranular in nature and typically occurs in carbon steels as a network of very fine, corrosion-product-filled cracks. Low-alloy ferritic steels are also susceptible to amine cracking. Amine cracking is typically observed in amine treating units that use aqueous alkanolamine solutions for removal of acid gases such as H_2S and CO_2 from various gas or liquid hydrocarbon streams.

Four available parameters are used to assess the susceptibility of steel fabrications to amine cracking. They are the type of amine, amine solution composition, metal temperature, and level of tensile stress.

Results of a NACE survey indicate that amine cracking is most prevalent in MEA and DIPA units and to a somewhat lesser extent in DEA units. Cracking is much less prevalent in MDEA, sulfinol, and diglycolamine (DGA) units.

Studies have concluded that the cracking occurs in a narrow range of electrochemical potential, which is very dependent upon the amine solution composition. Carbonate is a critical solution contaminant, and other contaminants such as chlorides, cyanides, etc. have been shown to affect cracking susceptibility. Despite this mechanistic understanding, the electrochemical potential of in-service components may not be readily available. Amine concentration is a factor in cracking susceptibility in MEA solutions, where cracking susceptibility has been shown to be higher in the 15 % to 35 % concentration range. There is not sufficient understanding of this relationship in other amine solutions, but it is noteworthy that cracking susceptibility is lower in MDEA and sulfinol units that typically utilize higher concentration amine solutions.

With regard to the amine solution composition, cracking typically occurs in the lean alkanolamine solution that is alkaline and contains very low levels of acid gases. Amine cracking does not occur in fresh amine solutions (i.e. those that have not been exposed to acid gases). Amine cracking is not likely to occur in rich alkanolamine solutions, which contain high levels of acid gases. In rich amine solutions, other forms of cracking are far more prevalent.

Amine cracking susceptibility is generally higher at elevated temperatures. A key consideration is the actual metal temperature and not just the normal process temperature. Cracking has occurred in components that normally operate at low temperatures but were heat traced or steamed out prior to water washing to remove residual amine solution.

As-welded or cold-worked carbon and low-alloy steel fabrications are susceptible to amine cracking because of the high level of residual stress remaining after fabrication by these methods. Application of a post-fabrication stress-relieving heat treatment (e.g. PWHT) is a proven method of preventing amine cracking. A heat treatment of about 1150 °F (621 °C) for 1 hour per inch of thickness (1 hour minimum) is considered an effective stress-relieving heat treatment to prevent amine cracking of carbon steel.

It should be noted that other forms of cracking have been reported in amine units. In most cases, cracking occurred in components exposed to rich alkanolamine solutions and have typically been forms of hydrogen damage such as SSC, HIC, and SOHIC. These are not included here but are dealt with in other sections of [Part 2](#).

2.C.3.3 Screening Criteria

If the component's material of construction is carbon or low-alloy steel and the process environment contains acid gas treating amines (MEA, DEA, DIPA, MDEA, etc.) in any concentration, then the component should be evaluated for susceptibility to amine cracking.

2.C.3.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the amine cracking DF are provided in [Table 2.C.3.1](#).

2.C.3.5 Basic Assumptions

The main assumption in determining the DF for amine cracking is that the damage can be characterized by a susceptibility parameter that is designated as High, Medium, or Low based on process environment, material of construction, and component fabrication variables (i.e. heat treatment). Based on the susceptibility parameter, a severity index is assigned that is a measure of the component susceptibility to cracking (or the probability of initiating cracks) and the probability that the crack will result in a leak.

If cracking is detected in the component during an inspection, the susceptibility is designated as High, and this will result in the maximum value for the severity index. Cracks or arrays of cracks that are found during an inspection should be evaluated using FFS methods in API 579-1/ASME FFS-1 [\[10\]](#).

2.C.3.6 Determination of the DF

2.C.3.6.1 Overview

A flow chart of the steps required to determine the DF for amine cracking is shown in [Figure 2.C.3.1](#). The following sections provide additional information and the calculation procedure.

2.C.3.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting amine cracking. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.8.1](#).

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.C.3.6.3 Calculation of the DF

The following procedure may be used to determine the DF for amine cracking; see [Figure 2.C.3.1](#).

- a) Step 1—Determine the susceptibility for cracking using [Figure 2.C.3.1](#).

NOTE A High susceptibility should be used if cracking is confirmed to be present.

- b) Step 2—Based on the susceptibility in Step 3, determine the severity index, S_{VI} , from [Table 2.C.1.2](#).
- c) Step 3—Determine the time in service, *age*, since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- d) Step 4—Determine the number of inspections and the corresponding inspection effectiveness category using [2.C.3.6.2](#) for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using [Part 2, Section 3.4.3](#).

- e) Step 5—Determine the base DF for amine cracking, D_{fB}^{amine} , using [Table 2.C.1.3](#) based on the number of inspections and the highest inspection effectiveness determined in Step 4 and the severity index, S_{VI} , from Step 2.
- f) Step 6—Calculate the escalation in the DF based on the time in service since the last inspection using the *age* from Step 3 and [Equation \(2.C.2\)](#). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

$$D_f^{amine} = \min \left(D_{fB}^{amine} \cdot (\max(age, 1.0))^{1.1}, 5000 \right) \quad (2.C.2)$$

2.C.3.7 Nomenclature

<i>age</i>	is the component in-service time since the last cracking inspection or service start date
D_f^{amine}	is the DF for amine cracking
D_{fB}^{amine}	is the base value of the DF for amine cracking
S_{VI}	is the severity index

2.C.3.8 References

See References [\[23\]](#), [\[24\]](#), [\[25\]](#), [\[26\]](#), [\[27\]](#), [\[28\]](#), and [\[29\]](#) in [Annex 2.G](#).

2.C.3.9 Tables

Table 2.C.3.1—Data Required for Determination of the DF—Amine Cracking

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section.
Amine solution composition	Determine what amine solution composition is being handled in this component. Fresh amine has not been exposed to H ₂ S or CO ₂ . Lean amine contains low levels of H ₂ S or CO ₂ . Rich amine contains high levels of H ₂ S or CO ₂ . For components exposed to both lean and rich amine solutions (i.e. amine contactors and regenerators), indicate lean.
Maximum process temperature, °F (°C)	Determine the maximum process temperature in this component.
Steam out? (Yes or No)	Determine whether the component has been steamed out prior to water flushing to remove residual amine.
Age (years)	Use inspection history to determine the time since the last SCC inspection.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

2.C.3.10 Figures

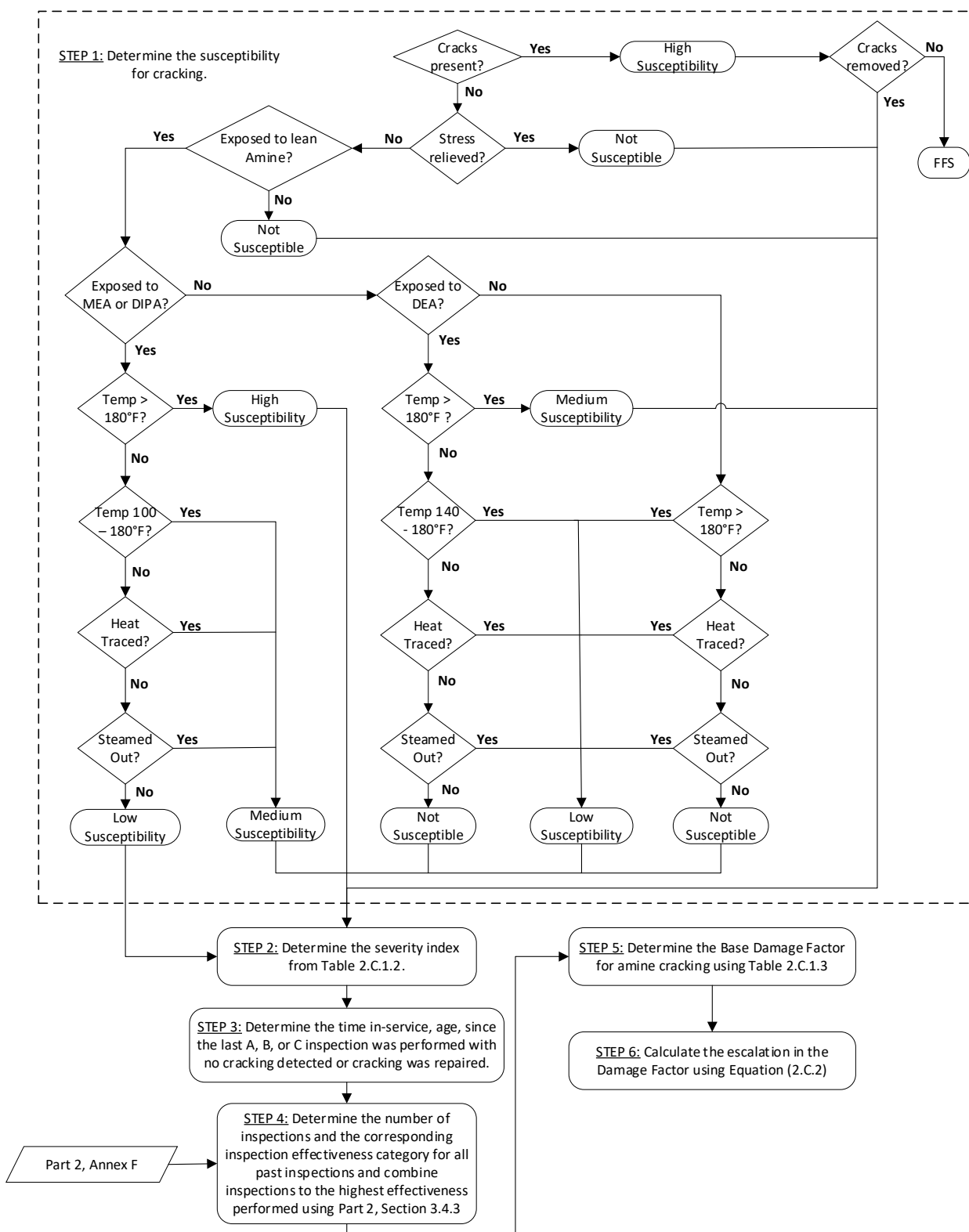


Figure 2.C.3.1—Determination of the Amine Cracking DF

2.C.4 SCC DF—Caustic Cracking

2.C.4.1 Scope

The DF calculation for components subject to caustic cracking is covered in this section.

2.C.4.2 Description of Damage

Caustic cracking is defined as the cracking of a material under the combined action of tensile stress and corrosion in the presence of sodium hydroxide (NaOH) at elevated temperature. The cracking is predominantly intergranular in nature and typically occurs as a network of fine cracks in carbon steels. Low-alloy ferritic steels have similar cracking susceptibility.

There are three key parameters that determine susceptibility of steel fabrications to caustic cracking. They are caustic concentration, metal temperature, and level of tensile stress. Industry experience indicates that some caustic cracking failures occur in a few days, while many require prolonged exposure of one or more years.

Increasing the caustic concentration or metal temperature accelerates the cracking rate. The susceptibility to caustic cracking of carbon steel is shown in [Figure 2.C.4.1](#). Caustic cracking of carbon steel is not anticipated at metal temperatures less than about 115 °F (46 °C). In the 115 °F to 180 °F (46 °C to 82 °C) range, cracking susceptibility is a function of the caustic concentration. Above 180 °F (82 °C), cracking susceptibility is a function of the caustic concentration. Above 180 °F (82 °C), cracking is highly likely for all concentrations above about 5 wt %. Although cracking susceptibility is significantly lower in caustic solutions with less than 5 % concentration, presence of high temperatures (approaching boiling) can cause locally higher concentrations that would increase cracking susceptibility. Notable case histories of this phenomenon include caustic cracking of distillation columns when caustic is added to the column for pH control, and caustic cracking of boiler feed water (BFW) components or piping bolts when gasket leaks expose the bolts to feed water.

With regard to temperature, the key consideration is the actual metal temperature and not just the normal process temperature. There are many case histories of caustic cracking of components operating at ambient temperature that were heat traced or subject to a steam out while still containing caustic. As-welded or as-bent carbon and low-alloy steel assemblies are susceptible to caustic cracking because of the high level of residual stress remaining after fabrication by these methods.

Application of a post-fabrication stress-relieving heat treatment (e.g. PWHT) is a proven method of preventing caustic cracking. A heat treatment of about 1150 °F (621 °C) for 1 hour per inch of thickness (1 hour minimum) is considered an effective stress-relieving heat treatment to prevent caustic cracking of carbon steel.

2.C.4.3 Screening Criteria

If the component's material of construction is carbon or low-alloy steel and the process environment contains caustic in any concentration, then the component should be evaluated for susceptibility to caustic cracking.

2.C.4.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the caustic cracking DF are provided in [Table 2.C.4.1](#).

2.C.4.5 Basic Assumptions

The main assumption in determining the DF for caustic cracking is that the damage can be characterized by a susceptibility parameter that is designated as High, Medium, or Low based on process environment, material of construction, and component fabrication variables (i.e. heat treatment). Based on the susceptibility parameter, a severity index is assigned that is a measure of the susceptibility of the component to cracking (or the probability of initiating cracks) and the probability that the crack will result in a leak.

A high susceptibility should be assigned if cracking was detected during a previous inspection whether the crack was repaired or left in place based upon FFS evaluation. The high susceptibility should be maintained until subsequent inspections of adequate effectiveness reveal no cracking detected. Cracking susceptibility can then be reassigned by a corrosion specialist. Cracks or arrays of cracks that are found during an inspection should be evaluated using FFS methods in API 579-1/ASME FFS-1 [10].

2.C.4.6 Determination of the DF

2.C.4.6.1 Overview

A flow chart of the steps required to determine the DF for caustic cracking is shown in [Figure 2.C.4.2](#). The following sections provide additional information and the calculation procedure.

2.C.4.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting caustic cracking.

Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.8.3](#). The number and category of the highest effective inspection will be used to determine the DF.

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.C.4.6.3 Calculation of the DF

The following procedure may be used to determine the DF for caustic cracking; see [Figure 2.C.4.2](#).

- a) Step 1—Determine the susceptibility for cracking using [Figure 2.C.4.2](#).

NOTE High susceptibility should be used if cracking is confirmed to be present.

- b) Step 2—Based on the susceptibility in Step 1, determine the severity index, S_{VI} , from [Table 2.C.1.2](#).
- c) Step 3—Determine the time in service, *age*, since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- d) Step 4—Determine the number of inspections and the corresponding inspection effectiveness category using [2.C.4.6.2](#) for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using [Part 2, Section 3.4.3](#).
- e) Step 5—Determine the base DF for caustic cracking, $D_{fB}^{caustic}$, using [Table 2.C.1.3](#) based on the number of inspections and the highest inspection effectiveness determined in Step 4 and the severity index, S_{VI} , from Step 2.
- f) Step 6—Calculate the escalation in the DF based on the time in service since the last inspection using the *age* from Step 3 and [Equation \(2.C.3\)](#). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

$$D_f^{caustic} = \min \left(D_{fB}^{caustic} \cdot (\max(age, 1.0))^{1.1}, 5000 \right) \quad (2.C.3)$$

2.C.4.7 Nomenclature

age is the component in-service time since the last cracking inspection or service start date

$DF_f^{caustic}$ is the DF for caustic cracking

$DF_{fB}^{caustic}$ is the base value of the DF for caustic cracking

S_{VI} is the severity index

2.C.4.8 References

See References [19], [20] (pp. 583–587), [21], and [22] in Annex 2.G.

2.C.4.9 Tables

Table 2.C.4.1—Data Required for Determination of the DF—Caustic Cracking

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section.
NaOH concentration (%)	Determine the concentration of the caustic solution being handled in this component. Take into account whether heating or flashing of water produces higher concentration.
Maximum process temperature, °F (°C)	Determine the maximum process temperature in this component. Consider local heating due to mixing if at a caustic injection point.
Steam out? (Yes or No)	Determine whether the component has been steamed out prior to water flushing to remove residual caustic.
Time since last SCC inspection (years)	Use inspection history to determine years since the last SCC inspection.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

2.C.4.10 Figures

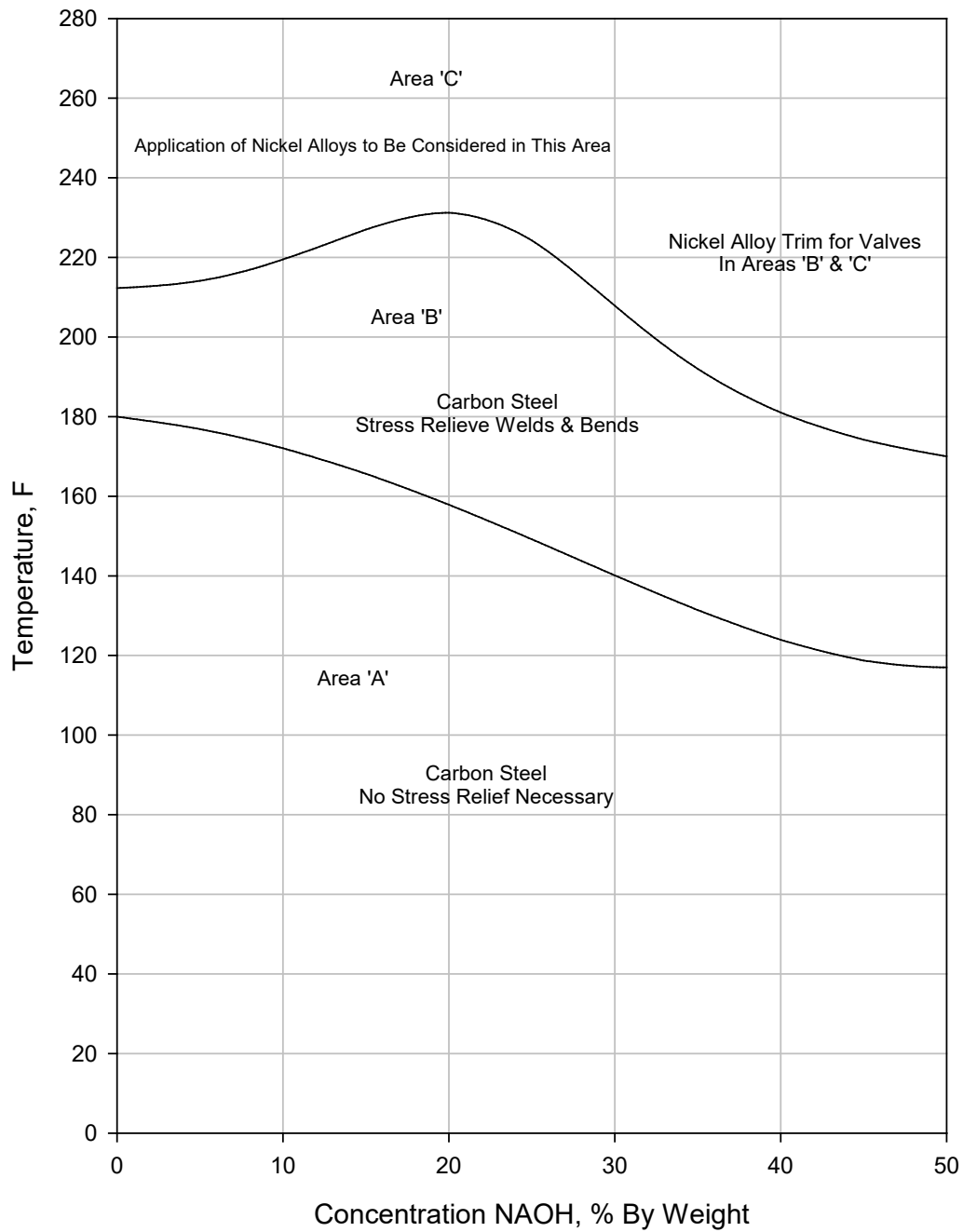


Figure 2.C.4.1—Susceptibility of Caustic Cracking in Carbon Steel

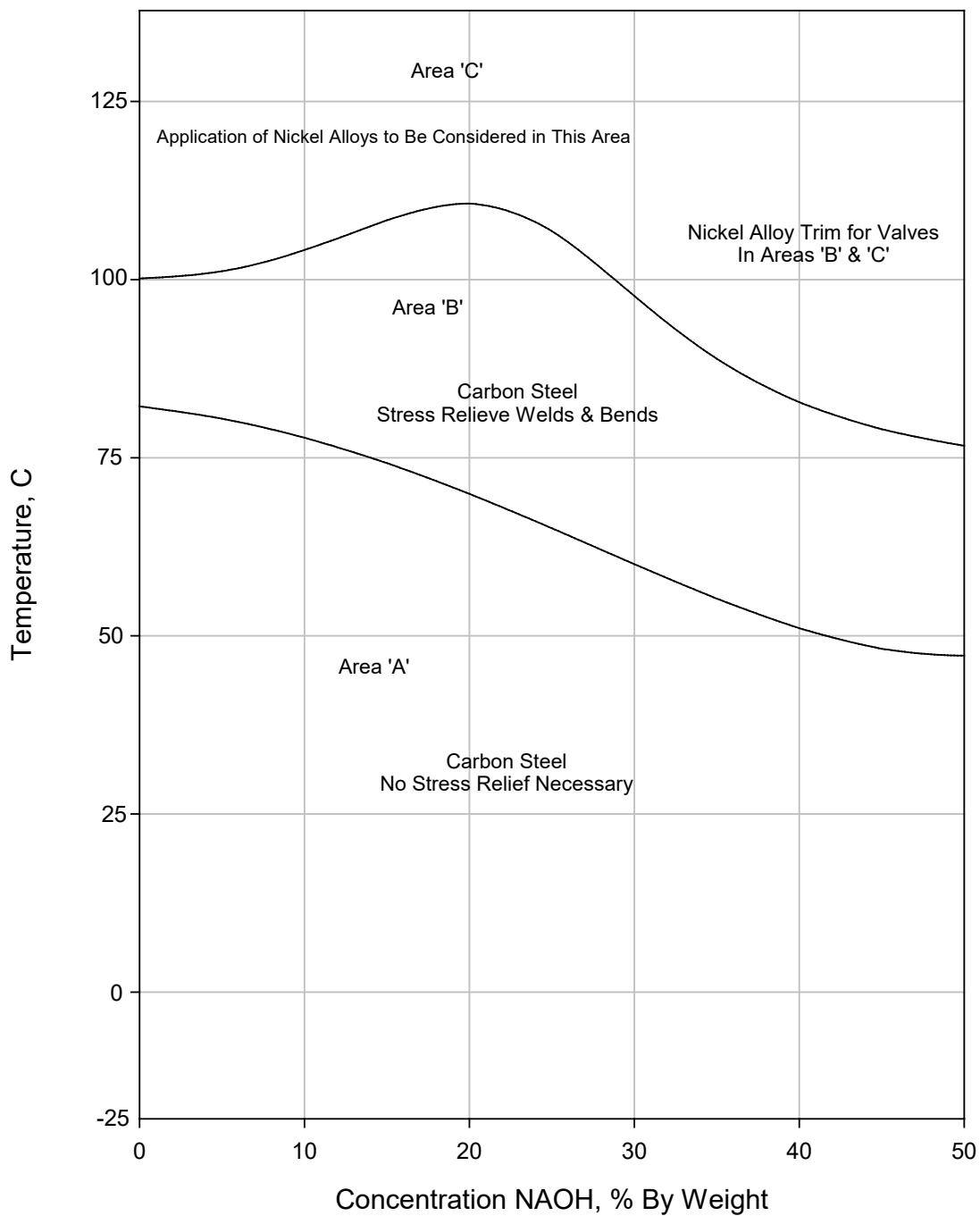


Figure 2.C.4.1M—Susceptibility of Caustic Cracking in Carbon Steel

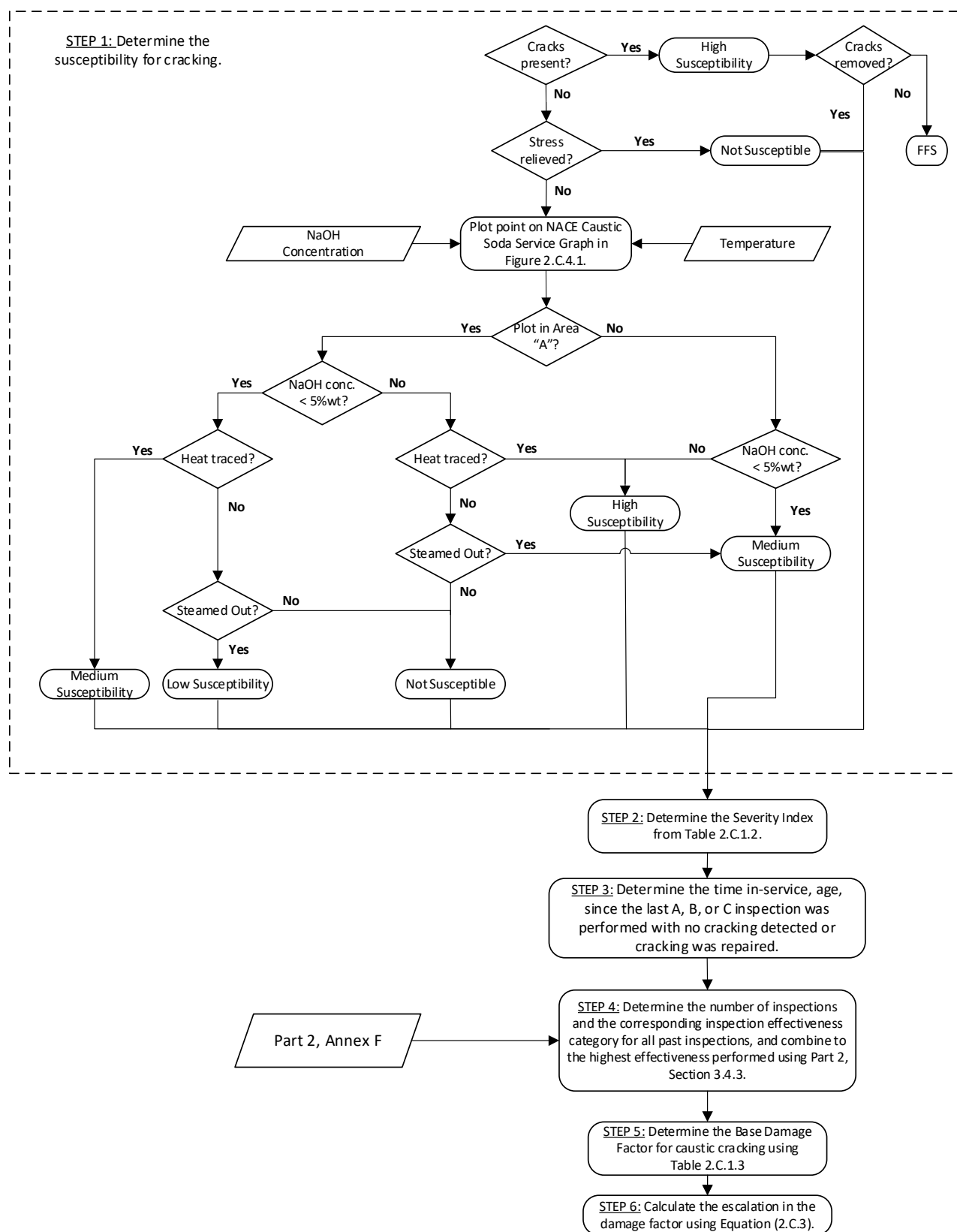


Figure 2.C.4.2—Determination of the Caustic Cracking DF

2.C.5 SCC DF—Chloride Stress Corrosion Cracking (CISCC)

2.C.5.1 Scope

The DF calculation for components subject to CISCC is covered in this section.

2.C.5.2 Description of Damage

CISCC of austenitic stainless steels can occur in a chloride-containing aqueous environment. The susceptibility to CISCC is dependent on the concentration of the chloride ions, the temperature, and other factors outlined in the basic data in [Table 2.C.5.1](#). It should be emphasized that the chloride concentration in water within wetting and drying conditions can be higher than the concentration measured in the bulk solution due to partial water vaporization. Such vaporization can increase CISCC susceptibility. CISCC is more likely to occur at metal temperatures above 66 °C (150 °F).

Chlorides are found in many processes. The following factors are major influences on the probability of chloride-containing solutions to cause CISCC.

- a) Aqueous conditions are present.
- b) pH and temperature are the most influential factors in CISCC.
- c) Below a temperature of 77 °F (25 °C), cracking is virtually unknown. But extremes of Cl concentration, stress, and/or pH can cause cracking.
- d) CISCC is more likely to occur at metal temperatures above 140 °F (60 °C).
- e) Above 302 °F (150 °C), it has been generally accepted that liquid water is not present unless the system is under pressure.
- f) Below a pH of 2.5, the material corrodes/pits rather than cracking as the cause of failure.
- g) Above a pH of 10.5, only extremely high Cl concentrations in the presence of oxidizers and elevated stress and temperature may experience cracking. In these conditions, cracking may be better characterized as caustic cracking.
- h) In industrial processes, chlorides may concentrate even in low bulk process Cl ppm concentrations.
- i) In laboratory tests, concentrations of 10 ppm Cl are sufficient to influence cracking in higher temperature solutions at pH of 6 and below. Oxidizers may also increase the susceptibility to CISCC in these regions.
- j) Higher chloride content can influence the tendency toward cracking in the less extreme regions of pH and temperature.
- k) In the High susceptibility region of pH and temperature, a very low concentrations of chlorides may result in Cl cracking. Austenitic stainless steels should not be used in this region.

Examples of common sources of chlorides in refineries and petrochemical plants are as follows.

- 1) Chloride salts from crude oil, produced water, and ballast water.
- 2) Water condensed from a process stream (process water).
- 3) BFW and stripping system.
- 4) Catalyst.

- 5) Insulation.
- 6) Residue from hydrotest water and other manufacturing operations.
- 7) Fumes from chemicals containing either organic or inorganic chlorides.

CISCC may occur during in-service or shutdown periods, if chloride-containing solutions are present at temperatures greater than 140 °F (60 °C). In addition, internal CISCC may occur as a result of exposure to wash water or fire water.

CISCC is typically transgranular and branched. The greatest susceptibility to CISCC is exhibited by austenitic stainless steels with an 8 % Ni content (300 series SS). Greater resistance to CISCC is experienced in material with lower or higher 8 % Ni contents. Duplex stainless steels with low nickel contents are more resistant to CISCC, as are alloys with greater than 42 % Ni.

2.C.5.3 Screening Criteria

If all of the following are true, then the component should be evaluated for susceptibility to CISCC.

- a) The component's material of construction is an austenitic stainless steel.
- b) The component is exposed or potentially exposed to chlorides and water. Also consider upsets, hydrotest water remaining in component, and cooling tower drift (consider both under insulation and process conditions).
- c) The presence of aqueous conditions.
- d) The operating temperature is between 75 °F (23.90 °C) and 345 °F (173.90 °C) and a pH > 2.5 and < 10.5 (if pH is < 2.5, go to HCl corrosion for damage rate determination).

2.C.5.4 Required Data

The basic component data required for analysis are given in [Table 2.C.1.1](#), and the specific data required for determination of the CISCC DF are provided in [Table 2.C.5.1](#).

2.C.5.5 Basic Assumptions

The main assumption in determining the DF for CISCC is that the damage can be characterized by a susceptibility parameter that is designated as High, Medium, or Low based on process environment, material of construction, and component fabrication variables (i.e. heat treatment). Based on the susceptibility parameter, a severity index is assigned that is a measure of the component susceptibility to cracking (or the probability of initiating cracks) and the probability that the crack will result in a leak.

If cracks are detected in the component during an inspection, the susceptibility is designated as High, and this will result in the maximum value for the severity index. Cracks that are found during an inspection should be evaluated using FFS methods in API 579-1/ASME FFS-1 [\[10\]](#).

2.C.5.6 Determination of the DF

2.C.5.6.1 Overview

A flow chart of the steps required to determine the DF for CISCC is shown in [Figure 2.C.5.1](#). The following sections provide additional information and the calculation procedure.

2.C.5.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting for CISCC.

Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.8.4](#).

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.C.5.6.3 Calculation of the DF

The following procedure may be used to determine the DF for CISC; see [Figure 2.C.5.2](#).

- a) Step 1—Determine the susceptibility for cracking using [Figure 2.C.5.1](#) and [Table 2.C.5.2](#). If cracking is confirmed to be present, set the susceptibility to High and skip to Step 4. If cracking is present and was not removed, a FFS evaluation is recommended to ensure that the component is suitable for continued service.
- b) Step 2—Determine the susceptibility using [Table 2.C.5.2](#) or [Figure 2.C.5.1](#).
- c) Step 3—Modify the base susceptibility in Step 2 with the susceptibility modifier from [Table 2.C.5.3](#).
- d) Step 4—Determine the severity index, S_{VI} , from [Table 2.C.1.2](#) using susceptibility from Step 1 (if cracking is present) or Step 3.
- e) Step 5—Determine the time in service, *age*, since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- f) Step 6—Determine the number of inspections and the corresponding inspection effectiveness category using [2.C.5.6.2](#) for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using [Part 2, Section 3.4.3](#).
- g) Step 7—Determine the base DF for CISC, D_{fB}^{CISC} , using [Table 2.C.1.3](#) based on the number of inspections and the highest inspection effectiveness determined in Step 6 and the severity index, S_{VI} , from Step 4.
- h) Step 8—Calculate the escalation in the DF based on the time in service since the last inspection using the *age* from Step 5 and [Equation \(2.C.4\)](#). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

$$D_f^{CISC} = \min \left(D_{fB}^{CISC} \cdot (\max(\text{age}, 1.0))^{1.1}, 5000 \right) \quad (2.C.4)$$

2.C.5.7 Nomenclature

<i>age</i>	is the component in-service time since the last cracking inspection or service start date
D_f^{CISC}	is the DF for CISC
D_{fB}^{CISC}	is the base value of the DF for CISC
S_{VI}	is the severity index

2.C.5.8 References

See References [\[10\]](#), [\[58\]](#), [\[59\]](#), [\[60\]](#), [\[61\]](#), [\[62\]](#), [\[63\]](#), and [\[64\]](#) in [Annex 2.G](#).

2.C.5.9 Tables

Table 2.C.5.1—Data Required for Determination of the DF—CISCC

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section.
Cl ⁻ concentration of process water (ppm)	Determine the bulk Cl ⁻ concentration of the water phase. If unknown, the default value for ppm is > 1000. Consider Cl ⁻ content of any water present in system (i.e. hydrotest, boiler feed, steam). Also, consider the possibility of concentration of Cl ⁻ by evaporation or upset conditions.
Operating temperature, °F (°C)	Determine the highest operating temperature expected during operation (consider normal and non-normal operating conditions).
pH of process water	Determine pH of the process water. High pH solutions with high chlorides generally are not as susceptible to cracking as low pH solution with chlorides.
Age (years)	Use inspection history to determine the time since the last SCC inspection.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

Table 2.C.5.2—Susceptibility to CISCC

Temperature (°F)	Susceptibility to Cracking as a Function of pH																		
	< 2.5 ⁵	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9.5	10.0	10.5	> 11.0
< 30	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
30 to 52.5	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
52.5 to 75	None	Low	Low	Low	Low	None	None	None	None	None	None	None	None	None	None	None	None	None	None
75 to 97.5	None	Medium	Medium	Medium	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	None	None	None	None
97.5 to 120	None	High	High	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Low	Low	Low	Low	Low	None	None	None
120 to 142.5	None	High	High	High	High	High	High	High	Medium	Medium	Medium	Medium	Low	Low	Low	Low	Low	Low	None
142.5 to 165	None	High	High	High	High	High	High	High	High	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Low	None
165 to 187.5	None	High	High	High	High	High	High	High	High	High	High	High	High	High	High	High	Low	Low	None
187.5 to 210	None	High	High	High	High	High	High	High	High	High	High	High	High	High	High	High	Low	Low	None
210 to 232.5	None	High	High	High	High	High	High	High	High	High	High	High	High	High	High	High	Low	Low	None
232.5 to 255	None	High	High	High	High	High	High	High	High	High	High	High	High	High	High	High	Low	Low	None
255 to 277.5	None	High	High	High	High	High	High	High	High	High	High	High	High	High	High	High	Low	Low	None
277.5 to 300	None	High	High	High	High	High	High	High	High	High	High	High	High	High	High	High	Low	Low	None
300 to 322.5	None	High	High	High	High	High	High	High	High	High	High	High	High	High	High	High	Low	Low	None
322.5 to 345	None	High	High	High	High	High	High	High	High	High	High	High	High	High	High	High	Low	Low	None
> 345	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
NOTE 1 Decrease one susceptibility category if chloride concentration is < 10 ppm.																			
NOTE 2 Decrease one susceptibility category if oxygen concentration is < 90 ppb.																			
NOTE 3 Increase one susceptibility category if chloride concentration is > 100 ppm.																			
NOTE 4 Increase one susceptibility category if deposits are present where chlorides may concentrate.																			
NOTE 5 No cracking susceptibility, go to HCl corrosion to determine corrosion rate.																			

Table 2.C.5.2M—Susceptibility to CISCC

[illegible]

NOTE 1 Decrease one susceptibility category if chloride concentration is < 10 ppm.

NOTE 2 Decrease one susceptibility category if oxygen concentration is < 90 ppb.

NOTE 3 Increase one susceptibility category if chloride concentration is > 100 ppm.

NOTE 4 Increase one susceptibility category if deposits are present where chlorides may concentrate.

NOTE 5 No cracking susceptibility, go to HCl corrosion to determine corrosion rate.

Table 2.C.5.3—Determination of the Susceptibility Modifier for CISCC

Environmental Variable	Susceptibility Modifier
Cl < 10 ppm	–1
Oxygen < 90 ppb	–1
Cl > 100 ppm	+1
Deposits	+1
NOTE CISCC susceptibility value is determined by adjusting the base susceptibility with the susceptibility modifiers.	

2.C.5.10 Figures

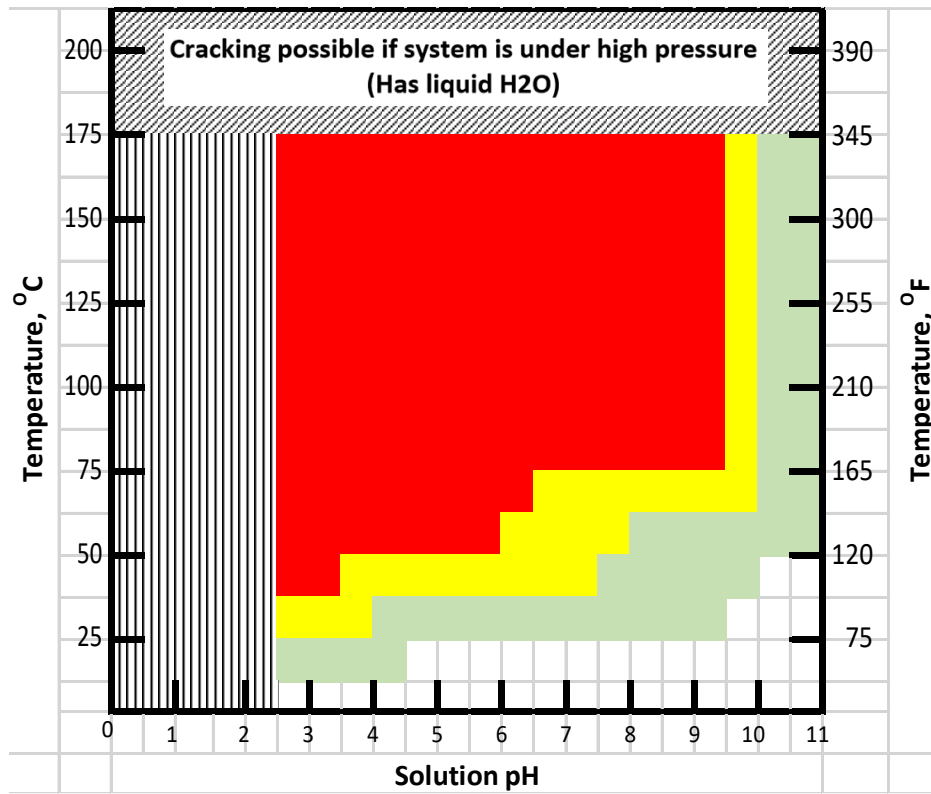


Chart Key	
Base Susceptibility for CISC	
None	
Low	
Medium	
High	
Pitting Corrosion - Go to HCl corrosion	

Figure 2.C.5.1—Determination of CISC Susceptibility

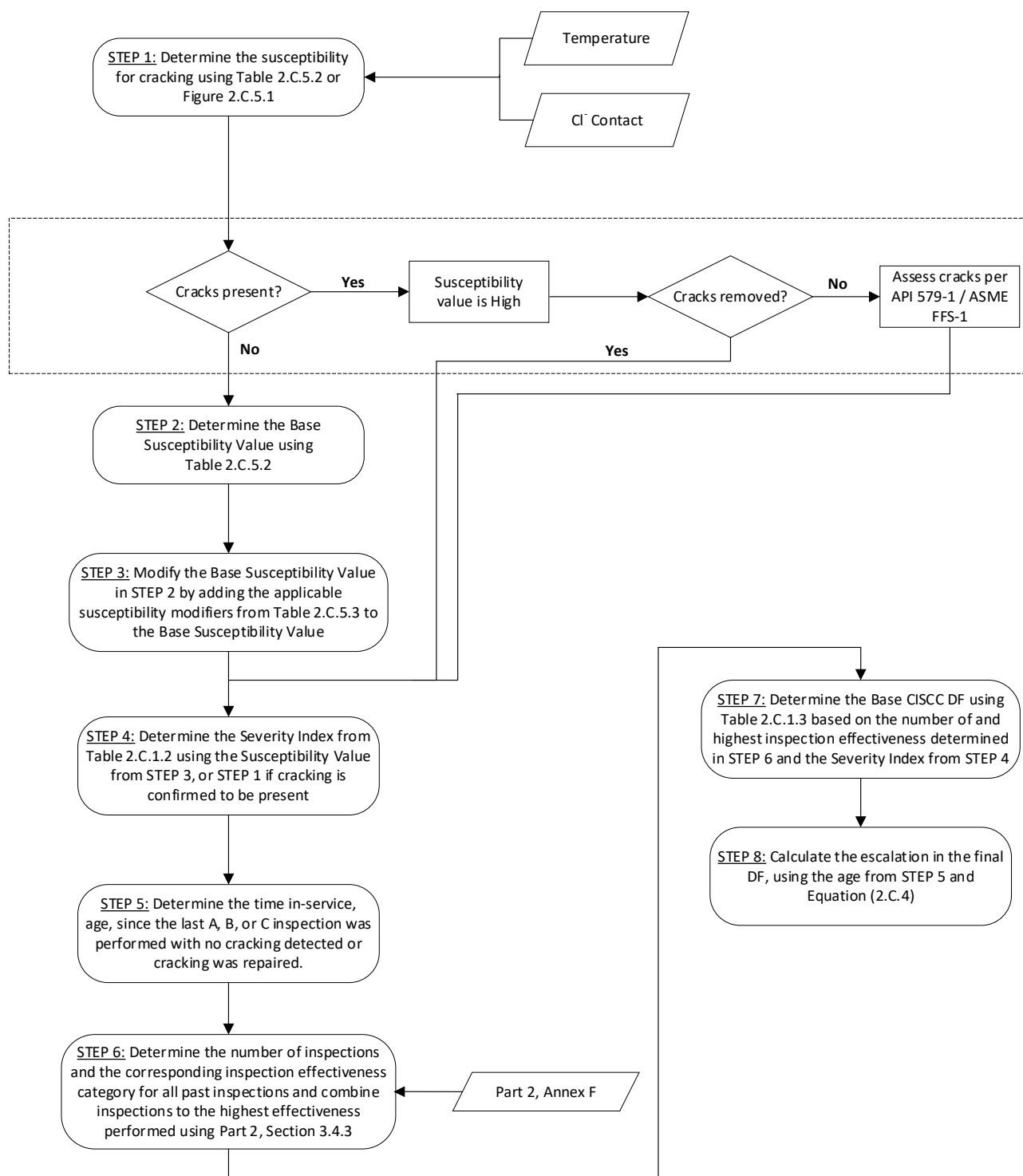


Figure 2.C.5.2—Determination of the CISCC DF

2.C.6 SCC DF—Hydrogen-induced Cracking and Stress-oriented Hydrogen-induced Cracking in Hydrofluoric Acid Services (HIC/SOHIC-HF)

2.C.6.1 Scope

The DF calculation for components subject to HIC/SOHIC-HF is covered in this section.

2.C.6.2 Description of Damage

HIC is defined as stepwise internal cracks that connect adjacent hydrogen blisters on different planes in the metal or to the metal surface. No externally applied stress is needed for the formation of HIC. The driving force for the cracking is high stress at the circumference of the hydrogen blisters caused by buildup of internal pressure in the blisters. Interaction between these high stress fields tends to cause cracks to develop that link blisters on different planes in the steel.

The source of hydrogen in the steel is the corrosion reaction with either wet hydrogen sulfide (covered in [Section 2.C.9](#)) or HF. HF is used in HF alkylation units at concentrations in the range 96 % to 99 % and greater concentration of HF in water. Exposure of carbon steel to aqueous or anhydrous HF may result in HIC/SOHIC.

Hydrogen blisters are planar hydrogen-filled cavities formed at discontinuities in the steel (i.e. voids, inclusions, laminations, sulfide inclusions). Blisters most often occur in rolled plate steels with a banded microstructure resulting from elongated sulfide inclusions. Susceptibility to hydrogen blistering, and therefore HIC, is primarily related to the quality of the plate steel (i.e. the number, size, and shape of the discontinuities). In this regard, the sulfur content of the steel is a primary material parameter. Reducing the sulfur content of the steel reduces the susceptibility to blistering and HIC. Addition of calcium or rare earth minerals (REMs) for sulfide inclusion shape control is generally beneficial.

SOHIC is defined as a stacked array of blisters joined by HIC that is aligned in the through-thickness direction of the steel as a result of high localized tensile stresses. SOHIC is a special form of HIC that usually occurs in the base material adjacent to the HAZ of a weld, where there are high residual stresses from welding. As with HIC, plate steel quality is a key parameter of SOHIC susceptibility. In addition, reduction of residual stresses by PWHT can reduce, but may not eliminate, the occurrence and severity of SOHIC.

2.C.6.3 Screening Criteria

If the component's material of construction is carbon or low-alloy steel and the component is exposed to HF in any concentration, then the component should be evaluated for susceptibility to HIC/SOHIC-HF.

2.C.6.4 Required Data

The basic component data required for analysis are given in [Table 2.C.1.1](#), and the specific data required for determination of the HIC/SOHIC-HF DF are provided in [Table 2.C.6.1](#).

2.C.6.5 Basic Assumptions

The main assumption in determining the DF for HIC/SOHIC-HF is that the damage can be characterized by a susceptibility parameter that is designated as High, Medium, or Low based on process environment, material of construction, and component fabrication variables (i.e. heat treatment). Based on the susceptibility parameter, a severity index is assigned that is a measure of the component susceptibility to cracking (or the probability of initiating cracks) and the probability that the crack will result in a leak.

Piping fabricated from wrought components of conventional steels [i.e. A53, A106, API 5L (not including 5LX), A234, A105, etc.] should be considered to have a low susceptibility to HIC/SOHIC-HF. For components fabricated from rolled and welded plate steel, the susceptibility should be determined using [Table 2.C.6.2](#). The

susceptibility of the steel to blistering is directly related to the cleanliness of the steel. It should be recognized that blistering is not a damage mechanism that will lead to a leak path unless it is accompanied by HIC leading to the surface. Blistering does pose a danger to mechanical integrity particularly when it approaches a weld that contains sufficient residual stresses to drive the HIC to the surfaces. It is this last case, the most severe situation that is considered when determining the susceptibility to HIC/SOHIC-HF.

If cracks are detected in the component during an inspection, the susceptibility is designated as High, and this will result in the maximum value for the severity index. Cracks that are found during an inspection should be evaluated using FFS methods in API 579-1/ASME FFS-1 [10].

2.C.6.6 Determination of the DF

2.C.6.6.1 Overview

A flow chart of the steps required to determine the DF for HIC/SOHIC-HF is shown in [Figure 2.C.6.1](#). The following sections provide additional information and the calculation procedure.

2.C.6.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting for HIC/SOHIC-HF. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.8.9](#).

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.C.6.6.3 Adjustment for Online Monitoring

In addition to inspection, online monitoring using hydrogen probes and/or key process variables provides a better understanding of HIC/SOHIC-HF susceptibility. The advantage of online monitoring is that process changes affecting SCC susceptibility can be detected before significant cracking occurs. This earlier detection could permit more timely action to decrease the POF. For HIC/SOHIC-HF, an online monitoring factor of 2 is applied if either hydrogen probes or monitoring of key process variables are used. If both hydrogen probes and monitoring of key process variables are used, an online monitoring factor of 4 is applied.

2.C.6.6.4 Calculation of the DF

The following procedure may be used to determine the DF for HIC/SOHIC-HF; see [Figure 2.C.6.1](#).

- a) Step 1—Determine the susceptibility for cracking using [Figure 2.C.6.1](#) and [Table 2.C.6.2](#) based on the material of construction and knowledge of whether the component was subject to PWHT.

NOTE A High susceptibility should be used if cracking is confirmed to be present.

- b) Step 2—Based on the susceptibility in Step 1, determine the severity index, S_{VI} , from [Table 2.C.1.2](#). In determining the susceptibility, it should be noted that if HF is present in any concentration, then the component is potentially susceptible to HIC/SOHIC-HF.
- c) Step 3—Determine the time in service, *age*, since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- d) Step 4—Determine the number of inspections and the corresponding inspection effectiveness category using [2.C.6.6.2](#) for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using [Part 2, Section 3.4.3](#).

- e) Step 5—Determine the base DF for HIC/SOHIC-HF, $D_{fB}^{HIC/SOHIC-HF}$, using [Table 2.C.1.3](#) based on the number of inspections and the highest inspection effectiveness determined in Step 4 and the severity index, S_{VI} , from Step 2.
- f) Step 6—Determine the online adjustment factor, F_{OM} , from [Table 2.C.6.3](#).
- g) Step 7—Calculate the final DF accounting for escalation based on the time in service since the last inspection using the *age* from Step 3 and [Equation \(2.C.5\)](#). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. The equation also applies the adjustment factor for online monitoring.

$$D_f^{HIC/SOHIC-HF} = \min \left(\frac{D_{fB}^{HIC/SOHIC-HF} \cdot (\max(age, 1.0))^{1.1}}{F_{OM}}, 5000 \right) \quad (2.C.5)$$

2.C.6.7 Nomenclature

<i>age</i>	is the component in-service time since the last cracking inspection or service start date
$D_f^{HIC/SOHIC-HF}$	is the DF for HIC/SOHIC-HF
$D_{fB}^{HIC/SOHIC-HF}$	is the base value of the DF for HIC/SOHIC-HF
F_{OM}	is the online monitoring adjustment factor
S_{VI}	is the severity index

2.C.6.8 References

See References [\[10\]](#), [\[81\]](#), and [\[82\]](#) in [Annex 2.G](#).

2.C.6.9 Tables

Table 2.C.6.1—Data Required for Determination of the DF—HIC/SOHIC-HF

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section.
Presence of HF (Yes or No)	Determine whether HF may be present in the component. Consider not only normal operating conditions but also upset conditions that may allow carryover of HF from other components.
Sulfur content of plate steel	Determine the sulfur content of the plate steel used to fabricate the component. This information should be available on the material test report (MTR) in the equipment files. If not available, it can be estimated from the ASTM or ASME specification of the steel listed on the U-1 form in consultation with a materials engineer.
Steel product form (plate or pipe)	Determine what product form of steel was used to fabricate the component. Most components are fabricated from rolled and welded steel plates (e.g. A285, A515, A516, etc.), but some small-diameter components is fabricated from steel pipe and piping components. Most small-diameter piping is fabricated from steel pipe (e.g. A106, A53, API 5L, etc.) and piping components (e.g. A105, A234, etc.), but most large-diameter piping (above approximately NPS 16 diameter) is fabricated from rolled and welded plate steel.
Age (years)	Use inspection history to determine the time since the last SCC inspection.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Online monitoring (hydrogen probes, process variables, or combination)	The type of proactive corrosion monitoring methods or tools employed such as hydrogen probes and/or process variable monitoring.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

Table 2.C.6.2—Susceptibility to Cracking—HIC/SOHIC-HF

Weld Condition	Susceptibility to Cracking as a Function of Steel Sulfur Content		
	High Sulfur Steel ^a > 0.01 % S	Low Sulfur Steel ≤ 0.01 % S	Product Form—Seamless/Extruded Pipe
Non-PWHT	High	High	Low
PWHT	High	Medium	Low

^a Typically includes A70, A201, A212, A285, A515, and most A516 before about 1990.

Table 2.C.6.3—Online Monitoring Adjustment Factors for HIC/SOHIC-HF

Online Monitoring Method	Adjustment Factors as a Function of Online Monitoring— F_{OM}
Key process variables	2
Hydrogen probes	2
Key process variables and hydrogen probes	4

NOTE The adjustment factors shown above are estimates providing a measure of the relative effectiveness of various online monitoring methods. Factors based on the user's experience can be used as a substitute for the values presented in this table.

2.C.6.10 Figures

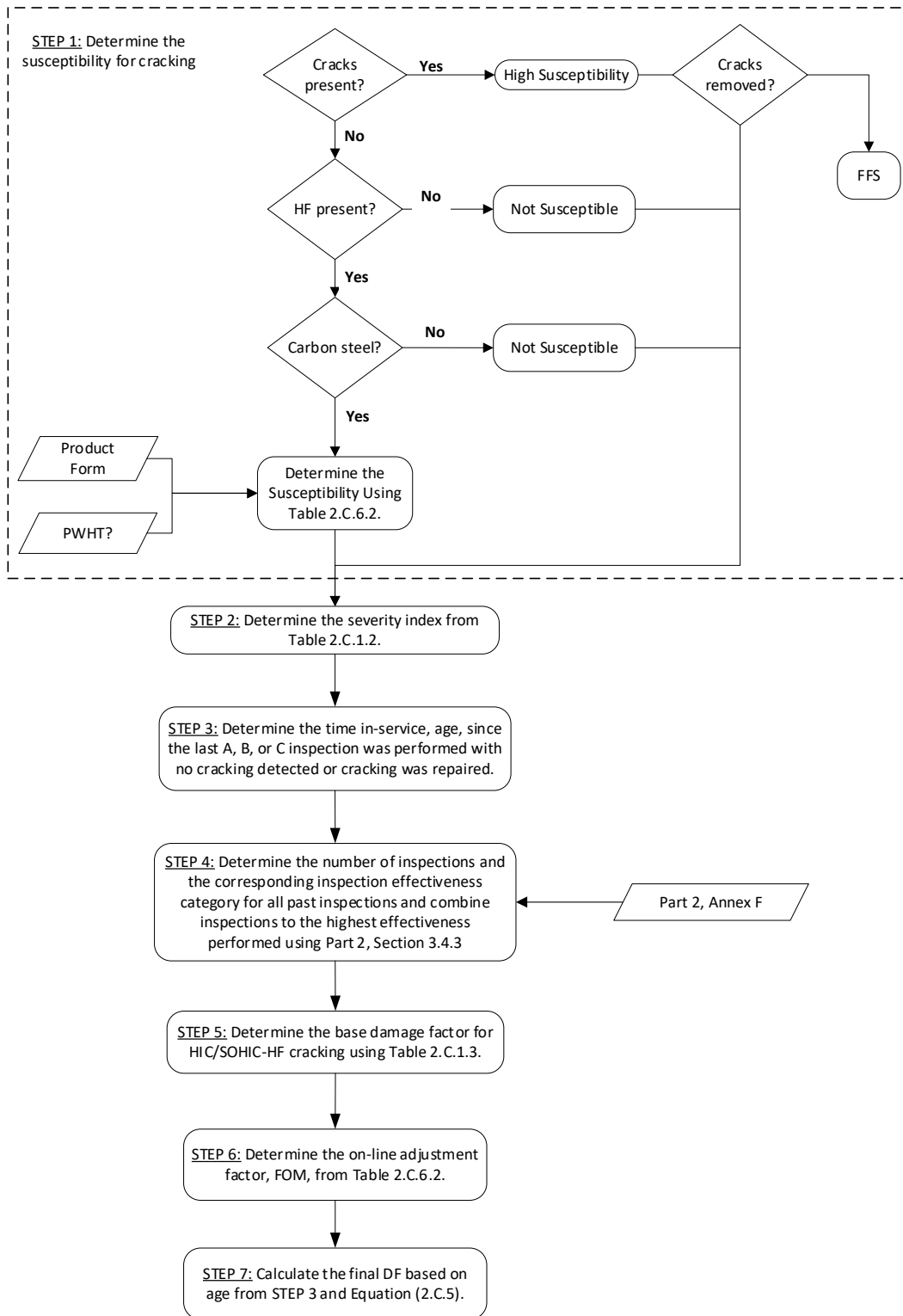


Figure 2.C.6.1—Determination of the HIC/SOHIC-HF Cracking DF

2.C.7 SCC DF—Hydrogen Stress Cracking in Hydrofluoric Acid (HSC-HF)

2.C.7.1 Scope

The DF calculation for components subject to HSC-HF covered in this section.

2.C.7.2 Description of Damage

HSC is defined as cracking of a metal under the combined action of tensile stress and a corrosion mechanism that produces hydrogen that may diffuse into the metal. HSC may result from exposure to hydrogen sulfide (see [Section 2.C.10](#)) or from exposure to HF. HSC-HF occurs in high-strength (high hardness) steels or in hard weld deposits or hard HAZs of lower-strength steels. In addition, HSC-HF may occur in stressed Alloy 400 if oxygen or other oxidizers are present in the HF.

Concentrated HF is used as the acid catalyst in HF alkylation units. The usual HF-in-water concentrations are 96 % to 99+ %, and the temperatures are generally below 66 °C (150 °F). Under these conditions, a fully killed (deoxidized), low sulfur, clean soft carbon steel is the material of choice for most equipment except where close tolerances are required for operation (i.e. pumps, valves, instruments).

Where close tolerances are required and at temperatures over 150 °F (66 °C) to approximately 350 °F (178 °C), Alloy 400 is used. Corrosion in 80 % and stronger HF-in-water solutions is equivalent to corrosion in AHF (< 200 ppm H₂O) and reference to corrosion in AHF implies an HF-in-water concentration as low as 80 %. HF acid with a concentration lower than 80 % HF in water is considered aqueous. Both aqueous and anhydrous HF can cause hydrogen embrittlement of hardened carbon and alloy steels. To prevent hydrogen embrittlement in welded steel structures, the requirements of NACE RP0472 should be followed. Welds produced by all welding methods should be hardness tested.

Alloy steel fasteners have been a source of many failures in anhydrous HF service. ASTM A193/A193M Grade B7 chromium molybdenum steel bolts are hard and will crack in the presence of HF. Grade B7M, the same steel tempered to a lower hardness of 201 to 235 Brinnell, may be a better choice if contact by HF cannot be avoided. However, B7M bolts will also crack if stressed beyond their yield point in an HF environment. Bolt torque may be difficult to control in field flange makeup. In this case, B7 bolts may be specified and replacement of any bolt that may have contacted HF as a result of flange leaks would be required.

2.C.7.3 Screening Criteria

If the component's material of construction is carbon or low-alloy steel and the component is exposed to HF in any concentration, then the component should be evaluated for susceptibility to HSC-HF.

2.C.7.4 Required Data

The basic component data required for analysis are given in [Table 2.C.1.1](#), and the specific data required for determination of the HSC-HF DF are provided in [Table 2.C.7.1](#).

2.C.7.5 Basic Assumptions

The main assumption in determining the DF for HSC-HF is that the damage can be characterized by a susceptibility parameter that is designated as High, Medium, or Low based on process environment, material of construction, and component fabrication variables (i.e. heat treatment). Based on the susceptibility parameter, a severity index is assigned that is a measure of the component susceptibility to cracking (or the probability of initiating cracks) and the probability that the crack will result in a leak.

If cracks are detected in the component during an inspection, the susceptibility is designated as High, and this will result in the maximum value for the severity index. Cracks that are found during an inspection should be evaluated using FFS methods in API 579-1/ASME FFS-1 [10].

2.C.7.6 Determination of the DF

2.C.7.6. Overview

A flow chart of the steps required to determine the DF for HSC-HF is shown in Figure 2.C.7.1. The following sections provide additional information and the calculation procedure.

2.C.7.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting for HSC. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally), are provided in Annex 2.F, Table 2.F.8.8.

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with Part 2, Section 3.4.3.

2.C.7.6.3 Calculation of the DF

The following procedure may be used to determine the DF for HSC-HF; see Figure 2.C.7.1.

- a) Step 1—Determine the susceptibility for cracking using Figure 2.C.7.1 and Table 2.C.7.2 based on the maximum Brinnell hardness of weldments and knowledge of whether the component was subject to PWHT.

NOTE A High susceptibility should be used if cracking is confirmed to be present.

- b) Step 2—Based on the susceptibility in Step 1, determine the severity index, S_{VI} , from Table 2.C.1.2.
- c) Step 3—Determine the time in service, age , since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- d) Step 4—Determine the number of inspections and the corresponding inspection effectiveness category using 2.C.7.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Part 2, Section 3.4.3.
- e) Step 5—Determine the base DF for HSC-HF, D_{fB}^{HSC-HF} , using Table 2.C.1.3 based on the number of inspections and the highest inspection effectiveness determined in Step 4 and the severity index, S_{VI} , from Step 2.
- f) Step 6—Calculate the escalation in the DF based on the time in service since the last inspection using the age from Step 3 and Equation (2.C.6). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

$$D_f^{HSC-HF} = \min \left(D_{fB}^{HSC-HF} \cdot (\max(age, 1.0))^{1.1}, 5000 \right) \quad (2.C.6)$$

2.C.7.7 Nomenclature

age is the component in-service time since the last cracking inspection or service start date

D_f^{HSC-HF} is the DF for HSC-HF

D_{fB}^{HSC-HF} is the base value of the DF for HSC-HF

S_{VI} is the severity index

2.C.7.8 References

See References [10], [81], and [82] in Annex 2.G.

2.C.7.9 Tables

Table 2.C.7.1—Data Required for Determination of the DF—HSC-HF

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section.
Presence of HF (Yes or No)	Determine whether HF may be present in the component. Consider not only normal operating conditions but also upset conditions that may allow carryover of HF from other components.
Brinnell hardness of steel weldments	Determine the maximum Brinnell hardness actually measured at the weldments of the steel component. Readings should be made and reported using Brinnell scale, not converted from micro-hardness techniques (e.g. Vicker, Knoop, etc.). If actual readings are not available, use the maximum allowable hardness permitted by the fabrication specification.
Age (years)	Use inspection history to determine the time since the last SCC inspection.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

Table 2.C.7.2—Susceptibility to Cracking—HSC-HF

As-welded Max Brinnell Hardness			PWHT Max Brinnell Hardness		
< 200	200 to 237	> 237	< 200	200 to 237	> 237
Low	Medium	High	None	Low	High

2.C.7.10 Figures

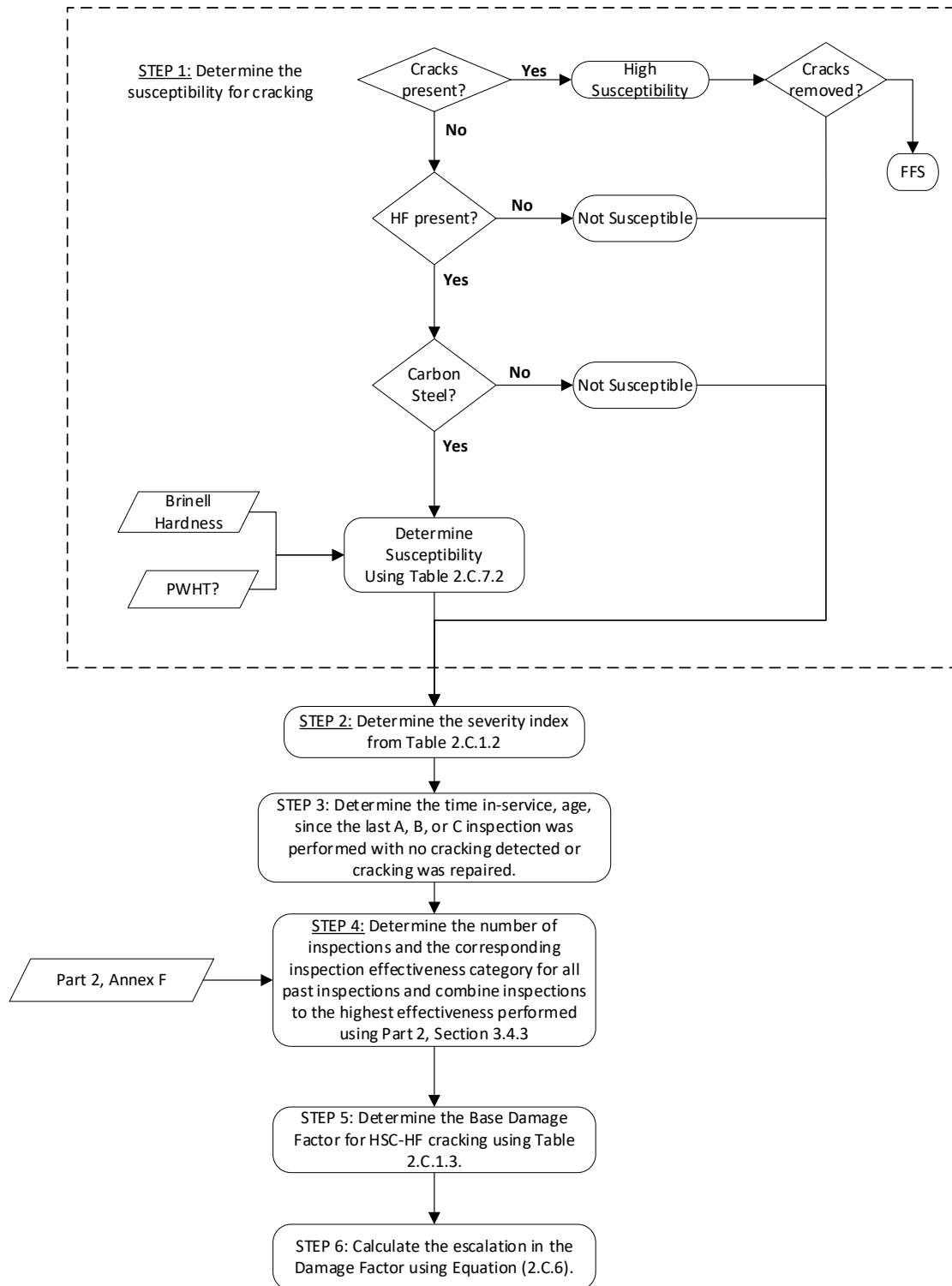


Figure 2.C.7.1—Determination of the HSC-HF Cracking DF

2.C.8 SCC DF—Polythionic Acid Stress Corrosion Cracking (PASCC)

2.C.8.1 Scope

The DF calculation for components subject to PASCC is covered in this section.

2.C.8.2 Description of Damage

PTA and sulfurous acid are major considerations in the petroleum-refining industry, particularly in catalytic cracking, desulfurizer, hydrocracker, and catalytic reforming processes. These complex acids typically form in sulfide containing deposits during shutdown (or ambient) conditions when the component is exposed to air and moisture. The acid environment, combined with susceptible materials of construction in the sensitized or as-welded condition, results in rapid intergranular corrosion and cracking. Preventive measures to reduce or eliminate PASCC include flushing the component with alkaline or soda ash solution to neutralize sulfides immediately after shutdown and exposure to air or purging with dry nitrogen during the shutdown to prevent air exposure, according to recommended practices established by NACE (RP0170).

PTA and sulfurous acid will cause SCC in sensitized austenitic stainless steels and nickel base alloys. Cracking is always intergranular and requires relatively low tensile stresses for initiation and propagation. As-welded, regular, and high carbon grade stainless steels, such as Types 304/304H and 316/316H, are particularly susceptible to SCC in the weld HAZ. Low-carbon steels (i.e. $C < 0.03\%$) are less susceptible at temperatures less than 800 °F (427 °C). Chemically stabilized stainless steel grades, such as Types 321 and 347, are less susceptible to PASCC, particularly if they are thermally stabilized. Susceptibility of alloys and chemically or thermally stabilized materials to PASCC can be determined by laboratory corrosion testing according to ASTM G35.

2.C.8.3 Screening Criteria

If the component's material of construction is an austenitic stainless steel or nickel-based alloy and the component is exposed to sulfur bearing compounds, then the component should be evaluated for susceptibility to PASCC.

2.C.8.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the PASCC DF are provided in [Table 2.C.8.1](#).

2.C.8.5 Basic Assumptions

The main assumption in determining the DF for PASCC is that the damage can be characterized by a susceptibility parameter that is designated as High, Medium, or Low based on process environment, material of construction, and component fabrication variables (i.e. heat treatment). Based on the susceptibility parameter, a severity index is assigned that is a measure of the component susceptibility to cracking (or the probability of initiating cracks) and the probability that the crack will result in a leak.

If cracks are detected in the component during an inspection, the susceptibility is designated as High, and this will result in the maximum value for the severity index. Cracks that are found during an inspection should be evaluated using FFS methods in API 579-1/ASME FFS-1 [\[10\]](#).

2.C.8.6 Determination of the DF

2.C.8.6.1 Overview

A flow chart of the steps required to determine the DF for PASCC is shown in [Figure 2.C.8.1](#). The following sections provide additional information and the calculation procedure.

2.C.8.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting for PASCC. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.8.5](#).

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.C.8.6.3 Calculation of the DF

The following procedure may be used to determine the DF for PASCC; see [Figure 2.C.8.1](#).

- a) Step 1—Determine the susceptibility for cracking using [Figure 2.C.8.1](#) and [Table 2.C.8.2](#) based on the operating temperature and material of construction.

NOTE A High susceptibility should be used if cracking is confirmed to be present.

- b) Step 2—Based on the susceptibility in Step 1, determine the severity index, S_{VI} , from [Table 2.C.1.2](#).
- c) Step 3—Determine the time in service, *age*, since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- d) Step 4—Determine the number of inspections and the corresponding inspection effectiveness category using [2.C.8.6.2](#) for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using [Part 2, Section 3.4.3](#).
- e) Step 5—Determine the base DF for PASCC, D_{fB}^{PASCC} , using [Table 2.C.1.3](#) based on the number of inspections and the highest inspection effectiveness determined in Step 4 and the severity index, S_{VI} , from Step 2.
- f) Step 6—Calculate the final DF using [Equation \(2.C.7\)](#).

$$D_f^{PASCC} = \min(D_{fB}^{PASCC}, 5000) \quad (2.C.7)$$

NOTE Escalation of the DF with time is not applicable for PASCC.

2.C.8.7 Nomenclature

<i>age</i>	is the component in-service time since the last cracking inspection or service start date
D_f^{PASCC}	is the DF for PASCC cracking
D_{fB}^{PASCC}	is the base value of the DF for PASCC cracking
S_{VI}	is the severity index

2.C.8.8 References

See References [\[10\]](#), [\[46\]](#), [\[47\]](#), [\[48\]](#), [\[49\]](#), [\[50\]](#), [\[51\]](#), [\[52\]](#), [\[53\]](#), [\[54\]](#), [\[55\]](#), [\[56\]](#), and [\[57\]](#) in [Annex 2.G](#).

2.C.8.9 Tables

Table 2.C.8.1—Data Required for Determination of the DF—PASCC

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section.
Thermal history (solution annealed, stabilized before welding, stabilized after welding)	Determine the thermal history of the material. Consider especially whether thermal stabilization heat treatment was performed after all welding.
Maximum operating temperature, °F (°C)	Determine the maximum operating temperature (TMO) of the component. Consider any high temperature exposure such as during decoking.
Presence of sulfides, moisture, and oxygen: during operation? (Yes or No) during shutdown? (Yes or No)	Determine whether these constituents are present in the component. If uncertain, consult with a process engineer. Consider whether high-temperature component in sulfidic service is opened to environment during shutdown.
Downtime protection used? (Yes or No)	Determine whether downtime protection for PASCC has been provided per NACE RP0170. This may include soda ash washing, nitrogen blanketing, or dehumidification.
Age (years)	Use inspection history to determine the time since the last SCC inspection.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

Table 2.C.8.2—Susceptibility to Cracking—PASCC

Operating Temperatures < 800 °F (427 °C)			
Material	Susceptibility to Cracking as a Function of Heat Treatment		
	Solution Annealed (default)	Stabilized Before Welding	Stabilized After Welding
All regular 300 series SS and Alloys 600 and 800	Medium	—	—
H Grade 300 series SS	High	—	—
L Grade 300 series SS	Low	—	—
321 SS	Medium	Medium	Low
347 SS, Alloy 20, Alloy 625, all austenitic weld overlay	Low	Low	Low
Operating Temperatures ≥ 800 °F (427 °C)			
Material	Susceptibility to Cracking as a Function of Heat Treatment		
	Solution Annealed (default)	Stabilized Before Welding	Stabilized After Welding
All regular 300 series SS and Alloys 600 and 800	High	—	—
H Grade 300 series SS	High	—	—
L Grade 300 series SS	Medium	—	—
321 SS	High	High	Low
347 SS, Alloy 20, Alloy 625, all austenitic weld overlay	Medium	Low	Low
NOTE If the process operating temperature is less than 800 °F (427 °C), then sensitization is present in the as-welded condition only. If the process operating temperature is greater than or equal to 800 °F (427 °C), then sensitization can occur during operation.			

2.C.8.10 Figures

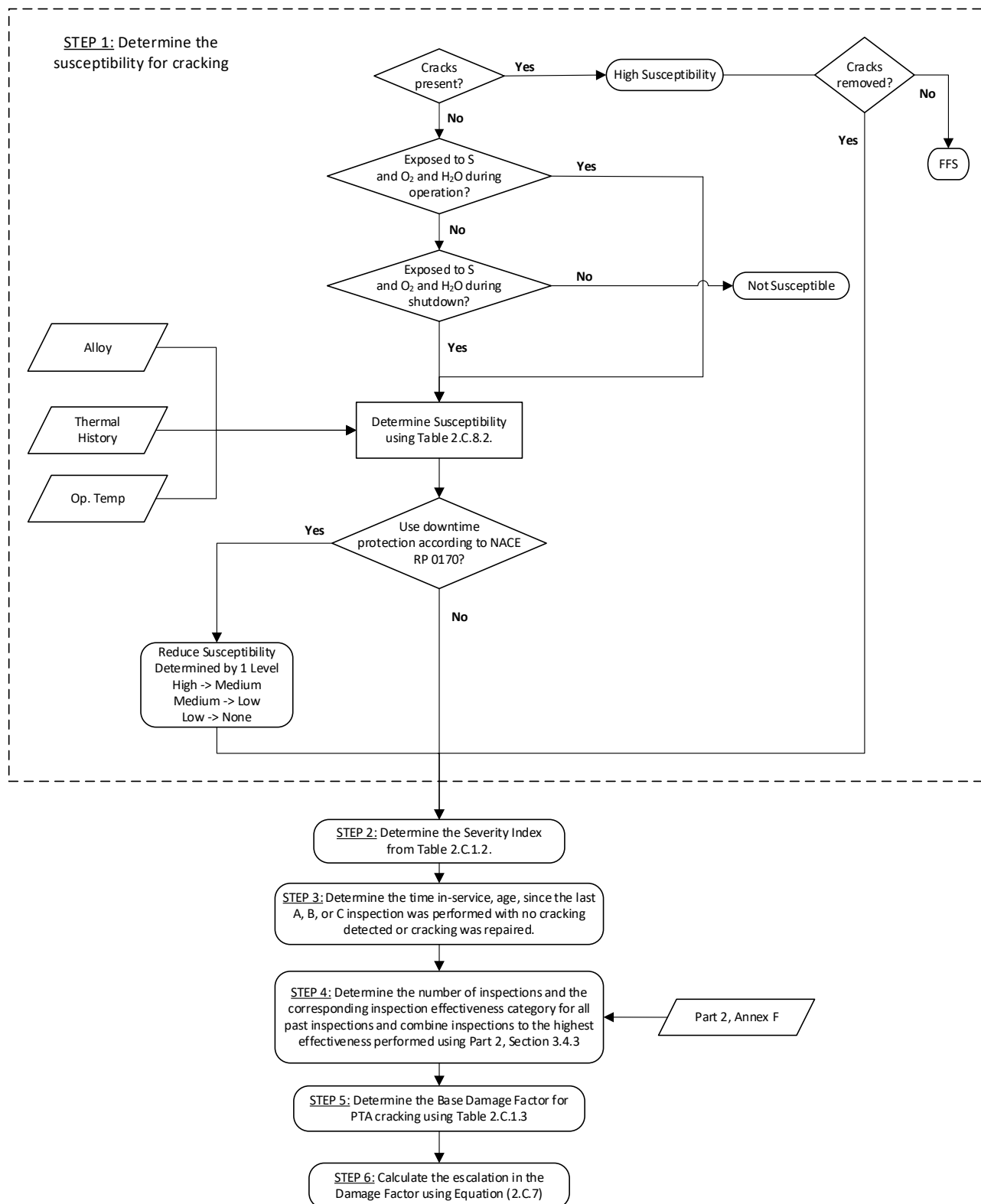


Figure 2.C.8.1—Determination of the PASCC DF

2.C.9 SCC DF—Wet H₂S Hydrogen-induced Cracking and Stress-oriented Hydrogen-induced Cracking (HIC/SOHIC-H₂S)

2.C.9.1 Scope

The DF calculation for components subject to HIC/SOHIC-H₂S is covered in this section.

2.C.9.2 Description of Damage

HIC is defined as stepwise internal cracks that connect adjacent hydrogen blisters on different planes in the metal or to the metal surface. An externally applied stress is not required for the formation of HIC. The driving force for the cracking is high stresses at the circumference of the hydrogen blisters caused by buildup of internal pressure in the blisters. Interactions between these high stress fields tend to cause cracks to develop that link blisters on different planes in the steel.

The buildup of pressure in the blisters is related to the hydrogen permeation flux in the steel. The source of the hydrogen in the steel is the corrosion reaction with wet hydrogen sulfide. Water must be present for this corrosion reaction to occur, and the resultant hydrogen flux is primarily associated with two environmental parameters, pH and the H₂S content of the water. Typically, the hydrogen flux in steels has been found to be lowest in near neutral pH solutions, with increasing flux at both lower and higher pH values. Corrosion at low pH values is caused by H₂S, whereas corrosion at high pH values is caused by high concentrations of the bisulfide ion. The presence of cyanides at elevated pH can further aggravate the hydrogen penetration into the steel. Hydrogen permeation is known to increase with H₂S content, e.g. H₂S partial pressure in the gas phase or H₂S content of the water phase. The presence of 50 ppm of H₂S in the water has been sufficient to cause HIC.

Hydrogen blisters are planar hydrogen-filled cavities formed at discontinuities in the steel (e.g. voids, inclusions, laminations, sulfide inclusions). Blisters most often occur in rolled plate steels, especially those with a banded microstructure resulting from elongated sulfide inclusions. Susceptibility to hydrogen blistering, and therefore HIC, is primarily related to the quality of the plate steel (i.e. the number, size, and shape of the discontinuities). In this regard, the sulfur content of the steel is a key material parameter. Reducing the sulfur content of the steel reduces the susceptibility to blistering and HIC. Additions of calcium or REMs that control sulfide inclusion shape control are generally beneficial.

The susceptibility of the steel to blistering is directly related to the cleanliness of the steel, which is measured by sulfur content. It should be recognized that blistering is not a damage mechanism that will lead to a leak path unless it is accompanied by HIC leading to the surface. Blistering does pose a danger to mechanical integrity when it approaches a weld that contains sufficient residual stresses to drive the HIC to the surfaces. It is in this last case, the most severe situation that is considered when determining the susceptibility to HIC/SOHIC-H₂S.

SOHIC is defined as a stacked array of blisters joined by HIC that is aligned in the through-thickness direction of the steel as a result of high localized tensile stresses. SOHIC is a special form of HIC that usually occurs in the base material, adjacent to the HAZ of a weld, where stresses are highest due to the additive effect of applied stress (from internal pressure) and the residual stresses from welding. As with HIC, plate steel quality is a key parameter for SOHIC susceptibility. In addition, reduction of residual stresses by PWHT can reduce, but may not eliminate, the occurrence and severity of SOHIC.

The level of applied stress also influences the occurrence and severity of SOHIC. Although HIC/SOHIC is much more prominent in plate steel fabrications, it has been observed to a limited extent in steel pipe fabrications, usually in the more severe hydrogen charging environments.

Environmental conditions known to cause HIC/SOHIC-H₂S damage are carbon and low-alloy steels in process environments containing an aqueous phase (liquid water) and any of the following, as outlined ANSI/NACE MR0103/ISO 17945 [144]:

- a) > 50 ppmw total sulfide content in the aqueous phase;
- b) ≥ 1 ppmw total sulfide content in the aqueous phase and $\text{pH} < 4$;
- c) ≥ 1 ppmw total sulfide content and ≥ 20 ppmw free cyanide in the aqueous phase, and $\text{pH} > 7.6$;
- d) > 0.3 kPa absolute (0.05 psia) partial pressure H₂S in the gas phase associated with the aqueous phase (including liquid water condensation from streams shown as 100 % vapor when at or close to saturation).
- e) rich and lean aqueous H₂S removal solvent (amine, e.g.) services when the gas or liquid being treated contains H₂S.

All sustained operation conditions should be considered when assigning service severity level. Start-up, shutdown, or other anomalous transient conditions do not need to be considered. Condensation of vapor streams should be considered when the vapor phase is close to saturation, along with process upset events that are known to have sustained conditions.

2.C.9.3 Screening Criteria

If the component's material of construction is carbon or low-alloy steel and the process environment contains water and H₂S in any concentration, then the component should be evaluated for susceptibility to HIC/SOHIC-H₂S cracking.

2.C.9.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the HIC/SOHIC-H₂S cracking DF are provided in [Table 2.C.9.1](#).

2.C.9.5 Basic Assumptions

The main assumption in determining the DF for HIC/SOHIC-H₂S cracking is that the damage can be characterized by a susceptibility parameter that is designated as High, Medium, or Low based on process environment, material of construction, and component fabrication variables (i.e. heat treatment). Based on the susceptibility parameter, a severity index is assigned that is a measure of the component susceptibility to cracking (or the probability of initiating cracks) and the probability that the crack will result in a leak.

If SOHIC is detected in the component during an inspection, the susceptibility is designated as High, and this will result in the maximum value for the severity index. Known blisters or cracks that are found during an inspection should be evaluated using FFS methods in API 579-1/ASME FFS-1 [10].

2.C.9.6 Determination of the DF

2.C.9.6.1 Overview

A flow chart of the steps required to determine the DF for HIC/SOHIC-H₂S cracking is shown in [Figure 2.C.9.1](#). The following sections provide additional information and the calculation procedure.

2.C.9.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting for HIC/SOHIC-H₂S. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.8.7](#).

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.C.9.6.3 Adjustment for Online Monitoring

In addition to inspection, online monitoring using hydrogen probes and/or key process variables provides a better understanding of HIC/SOHIC-H₂S susceptibility. The advantage of online monitoring is that process changes affecting SCC susceptibility can be detected before significant cracking occurs. This earlier detection could permit more timely action to decrease the POF. For HIC/SOHIC-H₂S, an online monitoring factor of 2 is applied if either hydrogen probes or monitoring of key process variables are used. If both hydrogen probes and monitoring of key process variables are used, an online monitoring factor of 4 is applied.

2.C.9.6.4 Calculation of the DF

The following procedure may be used to determine the DF for HIC/SOHIC-H₂S cracking; see [Figure 2.C.9.1](#).

- a) Step 1—Determine the environmental severity (potential level of hydrogen flux) for cracking based on the H₂S content of the water and its pH using [Table 2.C.9.2](#).

NOTE A High environmental severity should be used if cracking is confirmed to be present.

- b) Step 2—Determine the susceptibility for cracking using [Figure 2.C.9.1](#) and [Table 2.C.9.3](#) based on the environmental severity from Step 1, the sulfur content of the carbon steel, product form, and knowledge of whether the component was subject to PWHT.
- c) Step 3—Based on the susceptibility in Step 2, determine the severity index, S_{VI} , from [Table 2.C.1.2](#).
- d) Step 4—Determine the time in service, *age*, since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- e) Step 5—Determine the number of inspections and the corresponding inspection effectiveness category using [2.C.9.6.2](#) for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using [Part 2, Section 3.4.3](#).
- f) Step 6—Determine the base DF for HIC/SOHIC-H₂S cracking, $D_{fB}^{HIC/SOHIC-H_2S}$, using [Table 2.C.1.3](#) based on the number of inspections and the highest inspection effectiveness determined in Step 5 and the severity index, S_{VI} , from Step 3.
- g) Step 7—Determine the online adjustment factor, F_{OM} , from [Table 2.C.9.4](#).

- h) Step 8—Calculate the final DF accounting for escalation based on the time in service since the last inspection using the *age* from Step 4 and [Equation \(C.2.8\)](#). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. The equation also applies the adjustment factor for online monitoring.

$$D_f^{\text{HIC/SOHIC-H}_2\text{S}} = \min \left(\frac{D_{\text{fB}}^{\text{HIC/SOHIC-H}_2\text{S}} \cdot (\max(\text{age}, 1.0))^{1.1}}{F_{\text{OM}}}, 5000 \right) \quad (\text{C.2.8})$$

2.C.9.7 Nomenclature

<i>age</i>	is the component in-service time since the last cracking inspection or service start date
$D_f^{\text{HIC/SOHIC-H}_2\text{S}}$	is the DF for HIC/SOHIC-H ₂ S cracking
$D_{\text{fB}}^{\text{HIC/SOHIC-H}_2\text{S}}$	is the base value of the DF for HIC/SOHIC-H ₂ S cracking
F_{OM}	is the online monitoring adjustment factor
S_{VI}	is the severity index

2.C.9.8 References

See References [\[30\]](#), [\[31\]](#), [\[32\]](#), [\[33\]](#), [\[34\]](#), [\[35\]](#), [\[36\]](#), [\[37\]](#), [\[38\]](#), and [\[144\]](#) in [Annex 2.G](#).

2.C.9.9 Tables

Table 2.C.9.1—Data Required for Determination of the DF—HIC/SOHIC-H₂S Cracking

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section.
Presence of water (Yes or No)	Determine whether free water is present in the component. Consider not only normal operating conditions but also start-up, shutdown, process upsets, etc.
H ₂ S content of water	Determine the H ₂ S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore [30].
pH of water	Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Presence of cyanides (Yes or No)	Determine the presence of cyanide through sampling and/or field analysis. Consider primarily normal and upset operations but also start-up and shutdown conditions.
Sulfur content of plate steel	Determine the sulfur content of the steel used to fabricate the component. This information should be available on MTRs in equipment files. If not available, it can be estimated from the ASTM or ASME specification of the steel listed on the U-1 form in consultation with materials engineer.
Steel product form (plate or pipe)	Determine what product form of steel was used to fabricate the component. Most components are fabricated from rolled and welded steel plates (e.g. A285, A515, A516, etc.), but some small-diameter components is fabricated from steel pipe and piping components. Most small-diameter piping is fabricated from steel pipe (e.g. A106, A53, API 5L, etc.) and piping components (e.g. A105, A234, etc.), but most large-diameter piping (above approximately NPS 16 diameter) is fabricated from rolled and welded plate steel.
Age (years)	Use inspection history to determine the time since the last SCC inspection.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Online monitoring (hydrogen probes, process variables, or combination)	The type of proactive corrosion monitoring methods or tools employed such as hydrogen probes and/or process variable monitoring.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

Table 2.C.9.2—Environmental Severity—HIC/SOHIC-H₂S Cracking

pH of Water	Environmental Severity as a Function of H ₂ S Content of Water				
	< 0.05 psia	> 0.05 psia Partial Pressure H ₂ S			
	All ppm H ₂ S	1 to 50 ppm	> 50 to 1,000 ppm	> 1,000 to 10,000 ppm	> 10,000 ppm
< 3.5	None	Low	Low	Moderate	High
3.5 to 4.5	None	Low	Low	Moderate	High
4.5 to 5.5	None	None	Low	Low	Moderate
5.5 to 6.5	None	None	Low	Low	Moderate
6.5 to 7.6	None	None	Low	Low	Moderate
7.6 to 8.3	None	None (see Note)	Moderate (see Note)	Moderate (see Note)	Moderate (see Note)
8.4 to 8.9	None	None (see Note)	Moderate (see Note)	Moderate (see Note)	High
> 9.0	None	None (see Note)	Moderate (see Note)	Moderate (see Note)	High

NOTE If > 20 ppmw free cyanides are present, increase the susceptibility to HIC/SOHIC-H₂S one category for pH > 7.6 and H₂S concentrations greater than 1 ppm.

Table 2.C.9.3—Susceptibility to Cracking—HIC/SOHIC-H₂S

Environmental Severity	Susceptibility to Cracking as a Function of Steel Sulfur Content					
	High Sulfur Steel ^a > 0.01 % S		Low Sulfur Steel ≤ 0.01 % S		Product Form—Seamless/Extruded Pipe	
	As-welded	PWHT	As-welded	PWHT	As-welded	PWHT
High	High	High	High	Medium	Medium	Low
Moderate	High	Medium	Medium	Low	Low	Low
Low	Medium	Low	Low	Low	Low	Low

^a Typically includes A70, A201, A212, A285, A515, and most A516 before about 1990.

Table 2.C.9.4—Online Monitoring Adjustment Factors for HIC/SOHIC-H₂S

Online Monitoring Method	Adjustment Factors as a Function of Online Monitoring— F_{OM}
Key process variables	2
Hydrogen probes	2

2.C.9.10 Figures

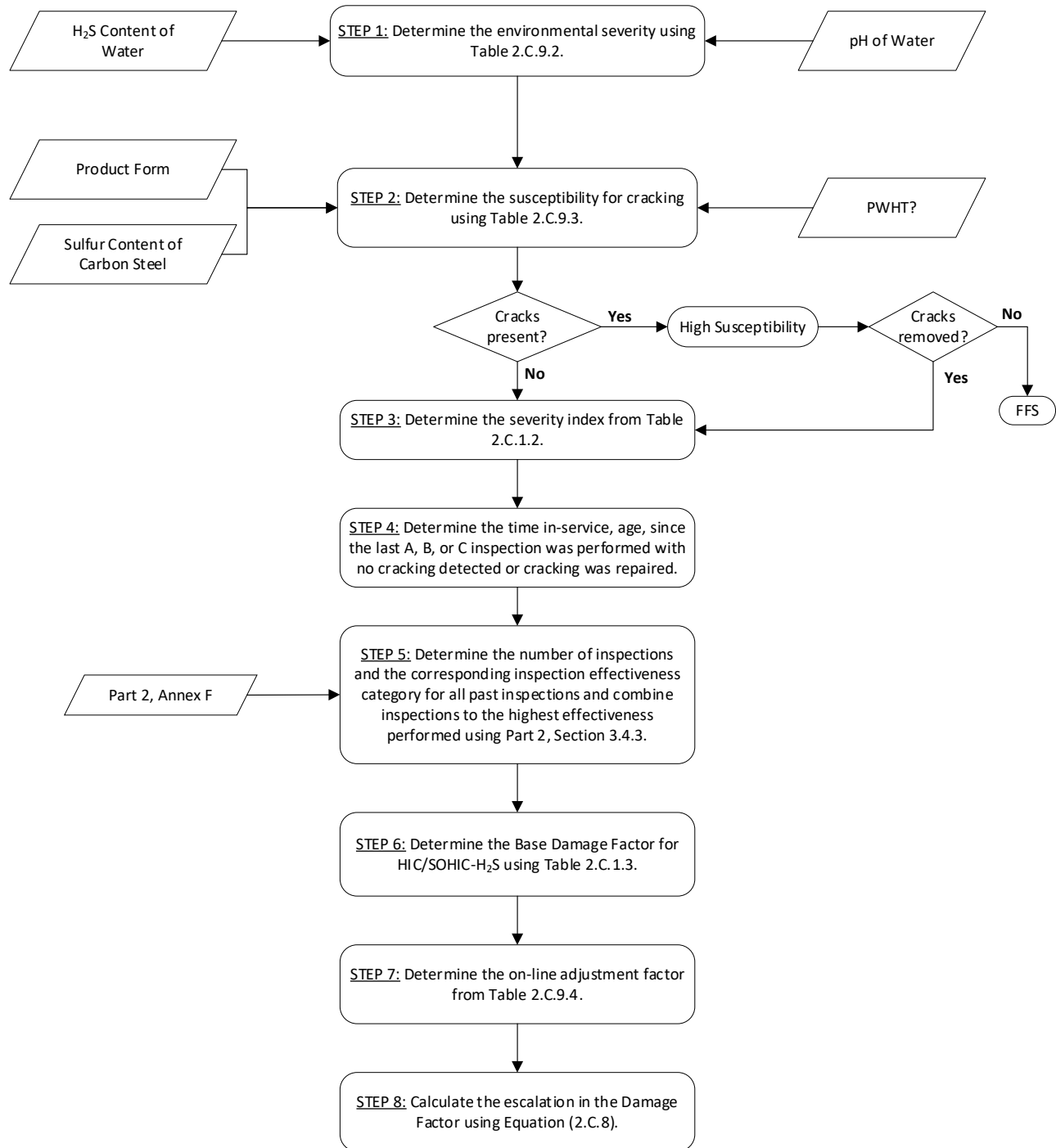


Figure 2.C.9.1—Determination of the HIC/SOHIC-H₂S DF

2.C.10 SCC DF—Sulfide Stress Cracking (SSC)

2.C.10.1 Scope

The DF calculation for components subject to SSC is covered in this section.

2.C.10.2 Description of Damage

SSC is defined as cracking of a metal under the combined action of tensile stress and corrosion in the presence of water and hydrogen sulfide. SSC is a form of HSC resulting from absorption of atomic hydrogen that is produced by the sulfide corrosion process on the metal surface. SSC usually occurs more readily in high-strength (high hardness) steels in hard weld deposits or hard HAZs of lower-strength steels. Susceptibility to SSC is related to the hydrogen permeation flux in the steel, which is primarily associated with two environmental parameters, pH and H_2S content of the water. Typically, the hydrogen flux in steels has been found to be lowest in near neutral pH solutions, with increasing flux at both lower and higher pH values. Corrosion at low pH values is caused by H_2S , whereas corrosion at high pH values is caused by high concentrations of the bisulfide ion. The presence of cyanides at elevated pH can further aggravate the hydrogen penetration into the steel. SSC susceptibility is known to increase with H_2S content, e.g. H_2S partial pressure in the gas phase or H_2S content of the water phase. The presence of as little as 1 ppm of H_2S in the water has been found to be sufficient to cause SSC.

Susceptibility to SSC is primarily related to two material parameters, hardness and stress level. High hardness of the steel increases its susceptibility to SSC. SSC has not generally been a concern for carbon steel base materials typically used for refinery pressure vessels and piping in wet hydrogen sulfide service because these steels have sufficiently low strength (hardness) levels. However, weld deposits and HAZs may contain zones of high hardness and high residual stresses from welding. High residual tensile stresses associated with welds increases susceptibility to SSC. PWHT significantly reduces residual stresses and also tempers (softens) weld deposits and HAZs. A PWHT of about 621 °C (1150 °F) for 1 hour per inch of thickness (1 hour minimum) is considered effective for carbon steel. Somewhat higher temperatures are required for low-alloy steels. Control of hardness and reduction of residual stresses are recognized methods for preventing SSC as outlined in NACE RP0472.

Environmental conditions known to cause SSC damage are carbon and low-alloy steels in process environments containing an aqueous phase (liquid water) and any of the following, as outlined in ANSI/NACE MR0103/ISO 17945 ^[144]:

- a) > 50 ppmw total sulfide content in the aqueous phase;
- b) ≥ 1 ppmw total sulfide content in the aqueous phase and $pH < 4$;
- c) ≥ 1 ppmw total sulfide content and ≥ 20 ppmw free cyanide in the aqueous phase, and $pH > 7.6$;
- d) > 0.3 kPa absolute (0.05 psia) partial pressure H_2S in the gas phase associated with the aqueous phase (including liquid water condensation from streams shown as 100 % vapor when at or close to saturation).
- e) rich and lean aqueous H_2S removal solvent (amine, e.g.) services when the gas or liquid being treated contains H_2S .

All sustained operation conditions should be considered when assigning service severity level. Start-up, shutdown, or other anomalous transient conditions do not need to be considered. Condensation of vapor streams should be considered when the vapor phase is close to saturation, along with process upset events that are known to have sustained conditions.

2.C.10.3 Screening Criteria

If the component's material of construction is carbon or low-alloy steel and the process environment contains water and H_2S in any concentration, then the component should be evaluated for susceptibility to SSC.

2.C.10.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the SSC DF are provided in [Table 2.C.10.1](#).

2.C.10.5 Basic Assumptions

The main assumption in determining the DF for SSC is that the damage can be characterized by a susceptibility parameter that is designated as High, Medium, or Low based on process environment, material of construction, and component fabrication variables (i.e. heat treatment). Based on the susceptibility parameter, a severity index is assigned that is a measure of the component susceptibility to cracking (or the probability of initiating cracks) and the probability that the crack will result in a loss of containment.

If cracking is detected in the component during an inspection, the susceptibility is designated as High, and this will result in the maximum value for the severity index. Cracks or arrays of cracks that are found during an inspection should be evaluated using FFS methods in API 579-1/ASME FFS-1 [\[10\]](#).

2.C.10.6 Determination of the DF

2.C.10.6.1 Overview

A flow chart of the steps required to determine the DF for SSC is shown in [Figure 2.C.10.1](#). The following sections provide additional information and the calculation procedure.

2.C.10.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting SSC. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.8.6](#).

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.C.10.6.3 Calculation of the DF

The following procedure may be used to determine the DF for SCC; see [Figure 2.C.10.1](#).

- a) Step 1—Determine the environmental severity (potential level of hydrogen flux) for cracking based on the H_2S content of the water and its pH using [Table 2.C.10.2](#).
- b) Step 2—Determine the susceptibility for cracking using [Figure 2.C.10.1](#) and [Table 2.C.10.3](#) based on the environmental severity from Step 1, the maximum Brinnell hardness of weldments, and knowledge of whether the component was subject to PWHT.

NOTE A High susceptibility should be used if cracking is confirmed to be present.

- c) Step 3—Based on the susceptibility in Step 2, determine the severity index, S_{VI} , from [Table 2.C.1.2](#).

- d) Step 4—Determine the time in service, *age*, since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- e) Step 5—Determine the number of inspections and the corresponding inspection effectiveness category using 2.C.10.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Part 2, Section 3.4.3.
- f) Step 6—Determine the base DF for SCC, D_{fB}^{SSC} , using Table 2.C.1.3 based on the number of inspections and the highest inspection effectiveness determined in Step 5 and the severity index, S_{VI} , from Step 3.
- g) Step 7—Calculate the escalation in the DF based on the time in service since the last inspection using the *age* from Step 4 and Equation (2.C.9). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

$$D_f^{SSC} = \min \left(D_{fB}^{SSC} \cdot (\max(\text{age}, 1.0))^{1.1}, 5000 \right) \quad (2.C.9)$$

2.C.10.7 Nomenclature

<i>age</i>	is the component in-service time since the last cracking inspection or service start date
D_f^{SSC}	is the DF for SSC
D_{fB}^{SSC}	is the base value of the DF for SSC
S_{VI}	is the severity index

2.C.10.8 References

See References [14], [19] (pp. 541–559), [29], [30], [31], [32], and [144] in Annex 2.G.

2.C.10.9 Tables

Table 2.C.10.1—Data Required for Determination of the DF—SSC

Required Data	Comments
Susceptibility (Low, Medium, High)	The susceptibility is determined by expert advice or using the procedures in this section.
Presence of water (Yes or No)	Determine whether free water is present in the component. Consider not only normal operating conditions but also start-up, shutdown, process upsets, etc.
H ₂ S content of water	Determine the H ₂ S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore [30].
pH of water	Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Presence of cyanides (Yes or No)	Determine the presence of cyanide through sampling and/or field analysis. Consider primarily normal and upset operations but also start-up and shutdown conditions.
Max Brinnell hardness	Determine the maximum Brinnell hardness actually measured at the weldments of the steel components. Report readings actually taken as Brinnell, not converted from finer techniques (e.g. Vickers, Knoop, etc.). If actual readings are not available, use the maximum allowable hardness permitted by the fabrication specification.
Age (years)	Use inspection history to determine the time since the last SCC inspection.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.

Table 2.C.10.2—Environmental Severity—SSC

pH of Water	Environmental Severity as a Function of H ₂ S Content of Water				
	< 0.05 psia	> 0.05 psia Partial Pressure H ₂ S			
	All ppm H ₂ S	> 1 to 50 ppm	> 50 to 1,000 ppm	> 1,000 to 10,000 ppm	> 10,000 ppm
< 3.5	None	Low	Low	Moderate	High
3.5 to 4.5	None	Low	Low	Moderate	High
4.5 to 5.5	None	None	Low	Low	Moderate
5.5 to 6.5	None	None	Low	Low	Moderate
6.5 to 7.6	None	None	Low	Low	Moderate
7.6 to 8.3	None	None (see Note)	Moderate (see Note)	Moderate (see Note)	Moderate (see Note)
8.4 to 8.9	None	None (see Note)	Moderate (see Note)	Moderate (see Note)	High
> 9.0	None	None (see Note)	Moderate (see Note)	Moderate (see Note)	High

NOTE If > 20 ppmw free cyanides are present, increase the susceptibility to SSC one category for pH > 7.6 and H₂S concentrations greater than 1 ppm.

Table 2.C.10.3—Susceptibility to SSC—SSC

Environmental Severity	Susceptibility to SSC as a Function of Heat Treatment					
	As-welded Max Brinnell Hardness Moderate (see Note)			PWHT Max Brinnell Hardness (see Note)		
	< 200	200 to 237	> 237	< 200	200 to 237	> 237
High	Low	Medium	High	None	Low	Medium
Moderate	Low	Medium	High	None	None	Low
Low	Low	Low	Medium	None	None	Not

NOTE Actually tested as Brinnell, not converted from finer techniques, e.g. Vickers, Knoop, etc.

2.C.10.10 Figures

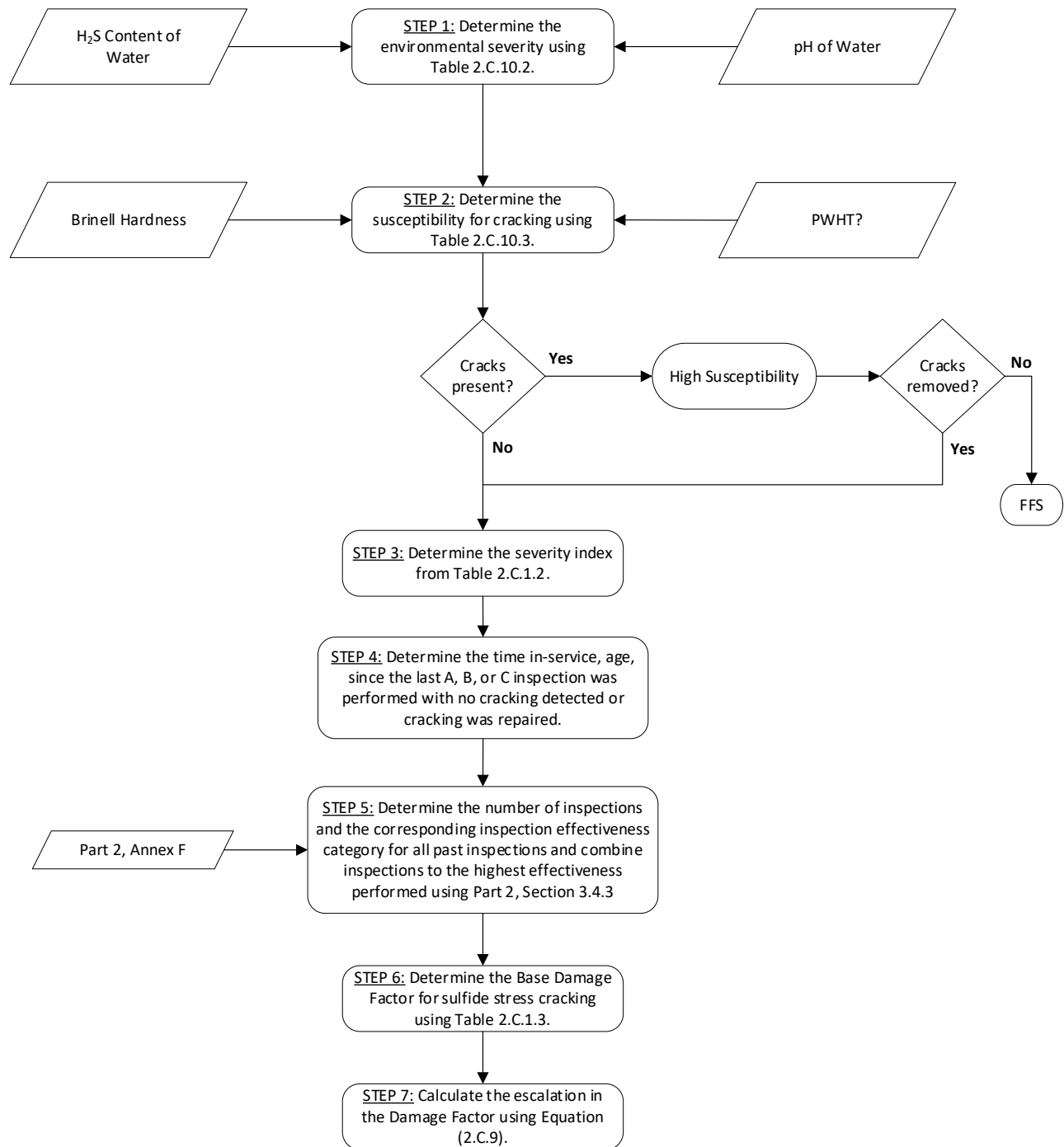


Figure 2.C.10.1—Determination of the SSC DF

Part 2, Annex 2.D—Determination of External Damage Susceptibilities

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2.D.3	Corrosion Under Insulation (CUI) DF—Ferritic Component	13
2.D.4	External Chloride Stress Corrosion Cracking (ExtCISCC) DF— Austenitic Component	26
2.D.5	External CUI CISCC DF—Austenitic Component	31

Risk-based Inspection Methodology
Part 2—Probability of Failure Methodology
Annex 2.D—Determination of External Damage Susceptibilities

2.D.1 Overview

2.D.1.1 Determination of External Damage Susceptibilities

External damage susceptibilities should be based on assignments for each potential mechanism using this document or as estimated by a corrosion specialist.

Screening questions are used to determine which of the external damage mechanism sections may apply. The applicable sections are used to determine conservative estimated corrosion rates or cracking susceptibilities for potential external damage mechanisms. The screening questions listed in [Table 2.D.1.1](#) are used to select the applicable external damage mechanism.

2.D.1.2 Tables

Table 2.D.1.1—Screening Questions for External Damage

Screening Questions	Action
External Corrosion—Ferritic Component 1. Carbon or low-alloy steel? 2. Is the operating temperature between 10 °F and 250 °F (–12 °C to 121 °C)? 3. Is component uninsulated?	If Yes to all, proceed to Section 2.D.2
Corrosion Under Insulation (CUI)—Ferritic Component 1. Carbon or low-alloy steel? 2. Is the operating temperature between 10 °F and 350 °F (–12 °C to 177 °C)? 3. Is component insulated?	If Yes to all, proceed to Section 2.D.3
External Chloride SCC (ExtCISCC)—Austenitic Component 1. Austenitic stainless steel? 2. Is component uninsulated? 3. Is the operating temperature between 120 °F and 300 °F (50 °C to 150 °C)?	If Yes to all, proceed to Section 2.D.4
External CUI Chloride SCC (CUI CISCC)—Austenitic Component 1. Austenitic stainless steel? 2. Is component insulated? 3. Is the operating temperature between 120 °F and 300 °F (50 °C to 150 °C)?	If Yes to all, proceed to Section 2.D.5

Table 2.D.1.2—Severity Index—External SCC Mechanisms

Susceptibility	External CISCC	CUI CISCC
High	50	50
Medium	10	10
Low	1	1
None	0	0

2.D.2 External Corrosion DF—Ferritic Component

2.D.2.1 Scope

The DF calculation for ferritic components subject to external corrosion is covered in this section.

2.D.2.2 Description of Damage

As a general rule, plants located in areas with high annual rainfalls, in warm humid climates, and in marine locations are more prone to external corrosion than plants located in cooler, drier, mid-continent locations. Variables that can affect external corrosion rates include annual rainfall, humidity, chloride levels in rainfall, proximity to ocean spray, and levels of various industrial pollutants. Corrosion rates can also vary by location within a facility. For example, units located near cooling towers and steam vents are highly susceptible to external corrosion, as are units whose operating temperatures cycle through the dew point on a regular basis.

Mitigation of external corrosion is accomplished through proper painting. A regular program of inspection for paint deterioration and repainting will prevent most occurrences of external corrosion.

2.D.2.3 Screening Criteria

If the component is uninsulated and subject to any of the following, then the component should be evaluated for external damage from corrosion.

- a) Areas exposed to mist overspray from cooling towers.
- b) Areas exposed to steam vents.
- c) Areas exposed to deluge systems.
- d) Areas subject to process spills, ingress of moisture, or acid vapors.
- e) Carbon steel systems, operating between 10 °F and 250 °F (–12 °C and 121 °C). External corrosion is particularly aggressive where operating temperatures cause frequent or continuous condensation and reevaporation of atmospheric moisture.
- f) Systems that do not normally operate between 10 °F and 250 °F (–12 °C and 121 °C) but cool or heat into this range intermittently or are subjected to frequent outages.
- g) Systems with deteriorated coating and/or wrappings.
- h) Cold service equipment consistently operating below the atmospheric dew point.
- i) Uninsulated nozzles or other protrusions components of insulated equipment in cold service conditions.

2.D.2.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for external corrosion are provided in [Table 2.C.2.1](#).

2.D.2.5 Basic Assumption

The DF for external corrosion is based on the method for general thinning covered in [Part 2, Section 4](#).

2.D.2.6 Determination of the DF

2.D.2.6.1 Overview

A flow chart of the steps required to determine the DF for external corrosion is shown in [Figure 2.D.2.1](#). The following sections provide additional information and the calculation procedure.

2.D.2.6.2 Drivers

External corrosion rates are affected by the operating temperature, weather conditions based on the equipment location (such as coastal conditions and proximity to cooling water towers or steam vents), and the equipment surface condition (external coating or paint, insulation type and condition, and weatherproofing). The driver selected for the base corrosion rate, C_{rB} , should be the best match of the external corrosion rates experienced at that location. The following are examples of conditions that may give corrosion rates similar to the respective categories.

- a) Severe—High wetting (e.g. > 60 % of time); very high rainfall [e.g. > 100 in./yr (2250 mm/yr)]; frequent deluge testing; highly corrosive industrial atmosphere; in a coastal zone with very high atmospheric chloride content (e.g. > 1500 mg/m²/day).
- b) Moderate—Frequently wet (e.g. 30 % to 60 % of time); downwind of a cooling tower; high rainfall [e.g. 60 to 100 in./yr (1524 to 2250 mm/yr)]; corrosive industrial atmosphere; near the coast with high chloride content in rainwater (e.g. 300 to 1500 mg/m²/day).
- c) Mild—Occasionally wet (e.g. < 30 % of time); moderate rainfall [e.g. 20 to 60 in./yr (762 to 1524 mm/yr)]; low chloride content in rainwater (e.g. 60 to 300 mg/m²/day).
- d) Dry—Very dry or cold zone with very low pollution and time of wetness; low rainfall [e.g. < 20 in./yr (508 mm/yr)]; inside building (operating above dew point); low chloride content in rainwater (e.g. < 60 mg/m²/day).

2.D.2.6.3 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting the specific damage mechanism. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.9.1](#).

The number and effectiveness categories for inspection history will be used to determine the DF.

2.D.2.6.4 Calculation of the DF

The following procedure may be used to determine the DF for external corrosion; see [Figure 2.D.2.1](#).

- a) Step 1—Determine the furnished thickness, t , and age, age , for the component from the installation date.
- b) Step 2—If the corrosion rate is determined based on inspection history or assigned by a knowledgeable specialist, use the assigned corrosion rate and go to Step 5.

- c) Step 3—Determine the base corrosion rate, C_{rB} , based on the driver and operating temperature using [Table 2.C.2.2](#).

Corrosion rates can be higher than predicted in cyclic or intermittent service. [Table 2.C.2.2](#) can be used to help estimate a more representative corrosion rate; with adjustments made for factors such as:

- the complete temperature range the equipment will see, including idle or out of service;
- time spent at each temperature range;
- wet/dry cycling if going through the dew point range;
- potential for higher concentration of contaminants;
- frequency of temperature cycles.

- d) Step 4—Calculate the final corrosion rate, C_r , using [Equation \(2.D.1\)](#).

$$C_r = C_{rB} \cdot \max[F_{EQ}, F_{IF}] \quad (2.D.1)$$

The adjustment factors are determined as follows.

- 1) Adjustment for Equipment Design or Fabrication, F_{EQ} —If the equipment has a design that allows water to pool and increase metal loss rates, such as piping supported directly on beams, vessel stiffening rings or insulation supports, or other such configuration that does not allow water egress and/or does not allow for proper coating maintenance, then $F_{EQ} = 2$; otherwise, $F_{EQ} = 1$.
 - 2) Adjustment for Interface, F_{IF} —If the piping has an interface where it enters either soil or water, then $F_{IF} = 2$; otherwise, $F_{IF} = 1$.
- e) Step 5—Determine the time in service, age_{tke} , since the last known inspection thickness, t_{rde} (see [Part 2, Section 4.5.5](#)). The t_{rde} is the starting thickness with respect to wall loss associated with external corrosion. If no measured thickness is available, set $t_{rde} = t$ and $age_{tke} = age$. The measured wall loss due to external corrosion, L_e , may be used to calculate t_{rde} using [Equation \(2.D.2\)](#).

$$t_{rde} = t - L_e \quad (2.D.2)$$

NOTE When using [Equation \(2.D.2\)](#), age_{tke} , is the time in service since L_e was measured.

- f) Step 6—Determine the in-service time, age_{coat} , since the coating has been installed using [Equation \(2.D.3\)](#).

$$age_{coat} = \text{Calculation Date} - \text{Coating Installation Date} \quad (2.D.3)$$

- g) Step 7—Determine the expected coating age, C_{age} , based on coating type, quality of application, and service conditions. C_{age} should be 0 years for no coating or poorly applied coatings. Lower quality coatings will typically have a C_{age} of 5 years or less. High-quality coatings or coatings in less harsh external environments may have a C_{age} of 15 or more years. C_{age} may be adjusted based on an evaluation of the coating condition during a high-quality inspection.

h) Step 8—Determine coating adjustment, $Coat_{adj}$, using Equations (2.D.4) through (2.D.5).

If $age_{tke} \geq age_{coat}$:

$$Coat_{adj} = \min(C_{age, age_{coat}})$$

If $age_{tke} < age_{coat}$:

1) If the coating has failed at the time of inspection when age_{tke} was established, then:

$$Coat_{adj} = 0$$

2) If the coating has not failed at the time of inspection when age_{tke} was established, use Equation (2.36) to calculate $Coat_{adj}$.

$$Coat_{adj} = \min(C_{age, age_{coat}}) - \min(C_{age, age_{coat} - age_{tke}}) \quad (2.D.4)$$

i) Step 9—Determine the in-service time, age , over which external corrosion may have occurred using Equation (2.D.5).

$$age = age_{tke} - Coat_{adj} \quad (2.D.5)$$

j) Step 10—Determine the allowable stress, S , weld joint efficiency, E , and minimum required thickness, t_{min} , per the original construction code or API 579-1/ASME FFS-1 [10]. In cases where components are constructed of uncommon shapes or where the component's minimum structural thickness, t_c , may govern, the user may use the t_c in lieu of t_{min} where pressure does not govern the minimum required thickness criteria.

k) Step 11—Determine the A_{rt} parameter using Equation (2.D.6) based on the age and t_{rde} from Step 5 and C_r from Step 4.

$$A_{rt} = \frac{C_r \cdot age}{t_{rde}} \quad (2.D.6)$$

l) Step 12—Calculate the flow stress, $FS^{extcorr}$, using S from Step 9 and Equation (2.D.7).

$$FS^{extcorr} = \frac{(YS + TS)}{2} \cdot E \cdot 1.1 \quad (2.D.7)$$

NOTE Use flow stress (FS^{Thin}) at design temperature for conservative results, using the appropriate Equation (2.40) or Equation (2.41).

m) Step 13—Calculate the strength ratio parameter, SR_p^{extcorr} , using Equation (2.D.8) or (2.D.9).

- 1) Use Equation (2.D.8) with t_{rde} from Step 4, $t_{\min}$ or t_c , S , and E from Step 10, and FS^{extcorr} from Step 12.

$$SR_p^{\text{extcorr}} = \frac{S \cdot E}{FS^{\text{extcorr}}} \cdot \frac{\max(t_{\min}, t_c)}{t_{rde}} \quad (2.D.8)$$

NOTE The $t_{\min}$ is based on a design calculation that includes evaluation for internal pressure hoop stress, external pressure and/or structural considerations, as appropriate. The minimum required thickness calculation is the design code $t_{\min}$. Consideration for internal pressure hoop stress alone may not be sufficient. t_c as defined in Step 5 may be used when appropriate.

- 2) Using Equation (2.D.9) with t_{rde} from Step 5 and FS^{extcorr} from Step 12.

$$SR_p^{\text{extcorr}} = \frac{P \cdot D}{\alpha \cdot FS^{\text{extcorr}} \cdot t_{rde}} \quad (2.D.9)$$

where α is the shape factor for the component type. $\alpha = 2$ for a cylinder, 4 for a sphere, 1.13 for a head.

NOTE This strength ratio parameter is based on internal pressure hoop stress only. It is not appropriate where external pressure and/or structural considerations dominate. When t_c dominates or if the $t_{\min}$ is calculated using another method, Equation (2.D.8) should be used.

- n) Step 14—Determine the number of inspections, N_A^{extcorr} , N_B^{extcorr} , N_C^{extcorr} , and N_D^{extcorr} , and the corresponding inspection effectiveness category using Section 2.D.2.6.2 for past inspections performed during the in-service time (see Part 2, Section 4.5.5).
- o) Step 15—Determine the inspection effectiveness factors, I_1^{extcorr} , I_2^{extcorr} , and I_3^{extcorr} , using Equation (2.D.10), prior probabilities, Pr_{p1}^{extcorr} , Pr_{p2}^{extcorr} , and Pr_{p3}^{extcorr} , from Part 2, Table 4.5, conditional probabilities (for each inspection effectiveness level), Co_{p1}^{extcorr} , Co_{p2}^{extcorr} , and Co_{p3}^{extcorr} , from Part 2, Table 4.6, and the number of inspections, N_A^{extcorr} , N_B^{extcorr} , N_C^{extcorr} , and N_D^{extcorr} , in each effectiveness level obtained from Step 14.

$$\begin{aligned} I_1^{\text{extcorr}} &= Pr_{p1}^{\text{extcorr}} \left(Co_{p1}^{\text{extcorrA}} \right)^{N_A^{\text{extcorr}}} \left(Co_{p1}^{\text{extcorrB}} \right)^{N_B^{\text{extcorr}}} \left(Co_{p1}^{\text{extcorrC}} \right)^{N_C^{\text{extcorr}}} \left(Co_{p1}^{\text{extcorrD}} \right)^{N_D^{\text{extcorr}}} \\ I_2^{\text{extcorr}} &= Pr_{p2}^{\text{extcorr}} \left(Co_{p2}^{\text{extcorrA}} \right)^{N_A^{\text{extcorr}}} \left(Co_{p2}^{\text{extcorrB}} \right)^{N_B^{\text{extcorr}}} \left(Co_{p2}^{\text{extcorrC}} \right)^{N_C^{\text{extcorr}}} \left(Co_{p2}^{\text{extcorrD}} \right)^{N_D^{\text{extcorr}}} \\ I_3^{\text{extcorr}} &= Pr_{p3}^{\text{extcorr}} \left(Co_{p3}^{\text{extcorrA}} \right)^{N_A^{\text{extcorr}}} \left(Co_{p3}^{\text{extcorrB}} \right)^{N_B^{\text{extcorr}}} \left(Co_{p3}^{\text{extcorrC}} \right)^{N_C^{\text{extcorr}}} \left(Co_{p3}^{\text{extcorrD}} \right)^{N_D^{\text{extcorr}}} \end{aligned} \quad (2.D.10)$$

- p) Step 16—Calculate the posterior probabilities, $Po_{p1}^{extcorr}$, $Po_{p2}^{extcorr}$, and $Po_{p3}^{extcorr}$, using Equation (2.D.11) with $I_1^{extcorr}$, $I_2^{extcorr}$, and $I_3^{extcorr}$ in Step 14.

$$\begin{aligned} Po_{p1}^{extcorr} &= \frac{I_1^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}} \\ Po_{p2}^{extcorr} &= \frac{I_2^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}} \\ Po_{p3}^{extcorr} &= \frac{I_3^{extcorr}}{I_1^{extcorr} + I_2^{extcorr} + I_3^{extcorr}} \end{aligned} \quad (2.D.11)$$

- q) Step 17—Calculate the parameters, $\beta_1^{extcorr}$, $\beta_2^{extcorr}$, and $\beta_3^{extcorr}$, using Equation (2.D.12) and assigning $COV_{dt} = 0.20$, $COV_{Sf} = 0.20$, and $COV_p = 0.05$.

$$\begin{aligned} \beta_1^{extcorr} &= \frac{1 - D_{S1} \cdot A_{rt} - SR_p^{extcorr}}{\sqrt{D_{S1}^2 \cdot A_{rt}^2 \cdot COV_{dt}^2 + (1 - D_{S1} \cdot A_{rt})^2 \cdot COV_{Sf}^2 + (SR_p^{extcorr})^2 \cdot COV_p^2}}, \\ \beta_2^{extcorr} &= \frac{1 - D_{S2} \cdot A_{rt} - SR_p^{extcorr}}{\sqrt{D_{S2}^2 \cdot A_{rt}^2 \cdot COV_{dt}^2 + (1 - D_{S2} \cdot A_{rt})^2 \cdot COV_{Sf}^2 + (SR_p^{extcorr})^2 \cdot COV_p^2}}, \\ \beta_3^{extcorr} &= \frac{1 - D_{S3} \cdot A_{rt} - SR_p^{extcorr}}{\sqrt{D_{S3}^2 \cdot A_{rt}^2 \cdot COV_{dt}^2 + (1 - D_{S3} \cdot A_{rt})^2 \cdot COV_{Sf}^2 + (SR_p^{extcorr})^2 \cdot COV_p^2}}. \end{aligned} \quad (2.D.12)$$

where $D_{S1} = 1$, $D_{S2} = 2$, and $D_{S3} = 4$. These are the corrosion rate factors for damage states 1, 2, and 3 as discussed in Part 2, Section 4.5.3 [17].

NOTE The DF calculation is very sensitive to the value used for the coefficient of variance for thickness, COV_{dt} . The COV_{dt} is in the range $0.10 \leq COV_{dt} \leq 0.20$, with a recommended conservative value of $COV_{dt} = 0.20$.

- r) Step 18—Calculate $D_f^{extcorr}$ using Equation (2.D.13).

$$D_f^{extcorr} = \left[\frac{(Po_{p1}^{extcorr} \Phi(-\beta_1^{extcorr})) + (Po_{p2}^{extcorr} \Phi(-\beta_2^{extcorr})) + (Po_{p3}^{extcorr} \Phi(-\beta_3^{extcorr}))}{1.56E-04} \right] \quad (2.D.13)$$

where Φ is the standard normal cumulative distribution function (NORMSDIST in Excel).

2.D.2.7 Nomenclature

A_{rt}	is the expected metal loss fraction since last inspection
age	is the in-service time that damage is applied, years
age_{coat}	is the in-service time since the coating installation, years

age_{tke}	is the component in-service time since the last inspection thickness measurement with respect to wall loss associated with external corrosion or service start date, years
C_{age}	is the total anticipated coating life from the time of installation
C_r	is the corrosion rate, in./yr (mm/yr)
C_{rB}	is the base value of the corrosion rate, in./yr (mm/yr)
$Co_{p1}^{extcorr}$	is the conditional probability of inspection history inspection effectiveness for damage state 1
$Co_{p2}^{extcorr}$	is the conditional probability of inspection history inspection effectiveness for damage state 2
$Co_{p3}^{extcorr}$	is the conditional probability of inspection history inspection effectiveness for damage state 3
$Coat_{adj}$	is the coating adjustment, years
COV_p	is the pressure variance
COV_{Sf}	is the flow stress variance
$COV_{\Delta t}$	is the thinning variance
D	is the component inside diameter, in. (mm)
$D_f^{extcorr}$	is the DF for external corrosion
D_{S1}	is the corrosion rate factor for damage state 1
D_{S2}	is the corrosion rate factor for damage state 2
D_{S3}	is the corrosion rate factor for damage state 3
E	is the weld joint efficiency or quality code from the original construction code
F_{EQ}	is the adjustment factor for equipment design/fabrication detail
F_{IF}	is the corrosion rate adjustment factor for interface for soil and water
$FS^{extcorr}$	is the flow stress
$I_1^{extcorr}$	is the first order inspection effectiveness factor

I_2^{extcorr}	is the second order inspection effectiveness factor
I_3^{extcorr}	is the third order inspection effectiveness factor
L_e	is the measured wall loss from external corrosion, in. (mm)
N_A^{extcorr}	is the number of A level inspections
N_B^{extcorr}	is the number of B level inspections
N_C^{extcorr}	is the number of C level inspections
N_D^{extcorr}	is the number of D level inspections
P	is the pressure (operating, design, PRD overpressure, etc.), psi (MPa)
Po_{p1}^{extcorr}	is the posterior probability for damage state 1
Po_{p2}^{extcorr}	is the posterior probability for damage state 2
Po_{p3}^{extcorr}	is the posterior probability for damage state 3
Pr_{p1}^{extcorr}	is the prior probability of corrosion rate data reliability for damage state 1
Pr_{p2}^{extcorr}	is the prior probability of corrosion rate data reliability for damage state 2
Pr_{p3}^{extcorr}	is the prior probability of corrosion rate data reliability for damage state 3
S	is the allowable stress, psi (MPa)
SR_p^{extcorr}	is the strength ratio parameter defined as the ratio of hoop stress to flow stress
TS	is the tensile strength, psi (MPa)
t	is the furnished thickness of the component calculated as the sum of the base material and cladding/weld overlay thickness, as applicable, in. (mm)
t_c	is the minimum structural thickness of the component base material, in. (mm)
$t_{\min}$	is the minimum required thickness, in. (mm)
t_{rde}	is the measured thickness reading from previous inspection with respect to wall loss associated with external corrosion, in. (mm)
YS	is the yield strength, psi (MPa)
α	is the component geometry shape factor

- β_1^{Thin} is the β reliability indices for damage state 1
- β_2^{Thin} is the β reliability indices for damage state 2
- β_3^{Thin} is the β reliability indices for damage state 3
- Φ is the standard normal cumulative distribution function

2.D.2.8 References

None.

2.D.2.9 Tables

Table 2.D.2.1—Data Required for Determination of the DF—External Corrosion

Required Data	Comments
Driver	The drivers for external corrosion. See 2.D.2.6.2 for driver descriptions and selection.
Corrosion rate, mpy (mm/yr)	Corrosion rate for external corrosion. Based on temperature, and driver, or user input.
Coating installation date	The date the coating was installed.
Coating quality	Relates to the type of coating applied, for example: None—no coating or primer only; Medium—single coat epoxy; High—multi-coat epoxy or filled epoxy.
Equipment design or fabrication allowing water to pool	If equipment has a design or fabrication detail that allows water to pool and increase metal loss rates, such as piping supported directly on beams, vessel external stiffening rings or insulation supports, or other such configuration that does not allow for water egress and/or does not allow for proper coating maintenance, external metal loss can be more severe.
Interface penalty (Yes/No)	If the piping has an interface where it enters either soil or water, this area is subject to increased corrosion.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.
Thickness reading	The thickness used for the DF calculation is either the furnished thickness or the measured thickness (see Part 2, Section 4.5.5).
Thickness reading date	The date at which the thickness measurement used in the calculation was obtained. If no acceptable inspection has been conducted, the installation date should be used.

Table 2.D.2.2—Corrosion Rates for Calculation of the DF—External Corrosion

Operating Temperature (°F)	Corrosion Rate as a Function of Driver ¹ (mpy)			
	Severe	Moderate	Mild	Dry
10	0	0	0	0
18	3	1	0	0
43	10	5	3	1
90	10	5	3	1
160	10	5	2	1
225	2	1	0	0
250	0	0	0	0

NOTE 1 Driver is defined as the atmospheric condition causing the corrosion rate. See 2.D.2.6.2 for explanation of drivers.

NOTE 2 Interpolation may be used for intermediate values of temperature.

Table 2.D.2.2M—Corrosion Rates for Calculation of the DF—External Corrosion

Operating Temperature (°C)	Corrosion Rate as a Function of Driver ¹ (mm/y)			
	Severe	Moderate	Mild	Dry
−12	0	0	0	0
−8	0.076	0.025	0	0
6	0.254	0.127	0.076	0.025
32	0.254	0.127	0.076	0.025
71	0.254	0.127	0.051	0.025
107	0.051	0.025	0	0
121	0	0	0	0

NOTE 1 Driver is defined as the atmospheric condition causing the corrosion rate. See 2.D.2.6.2 for explanation of drivers.

NOTE 2 Interpolation may be used for intermediate values of temperature.

2.D.2.10 Figures

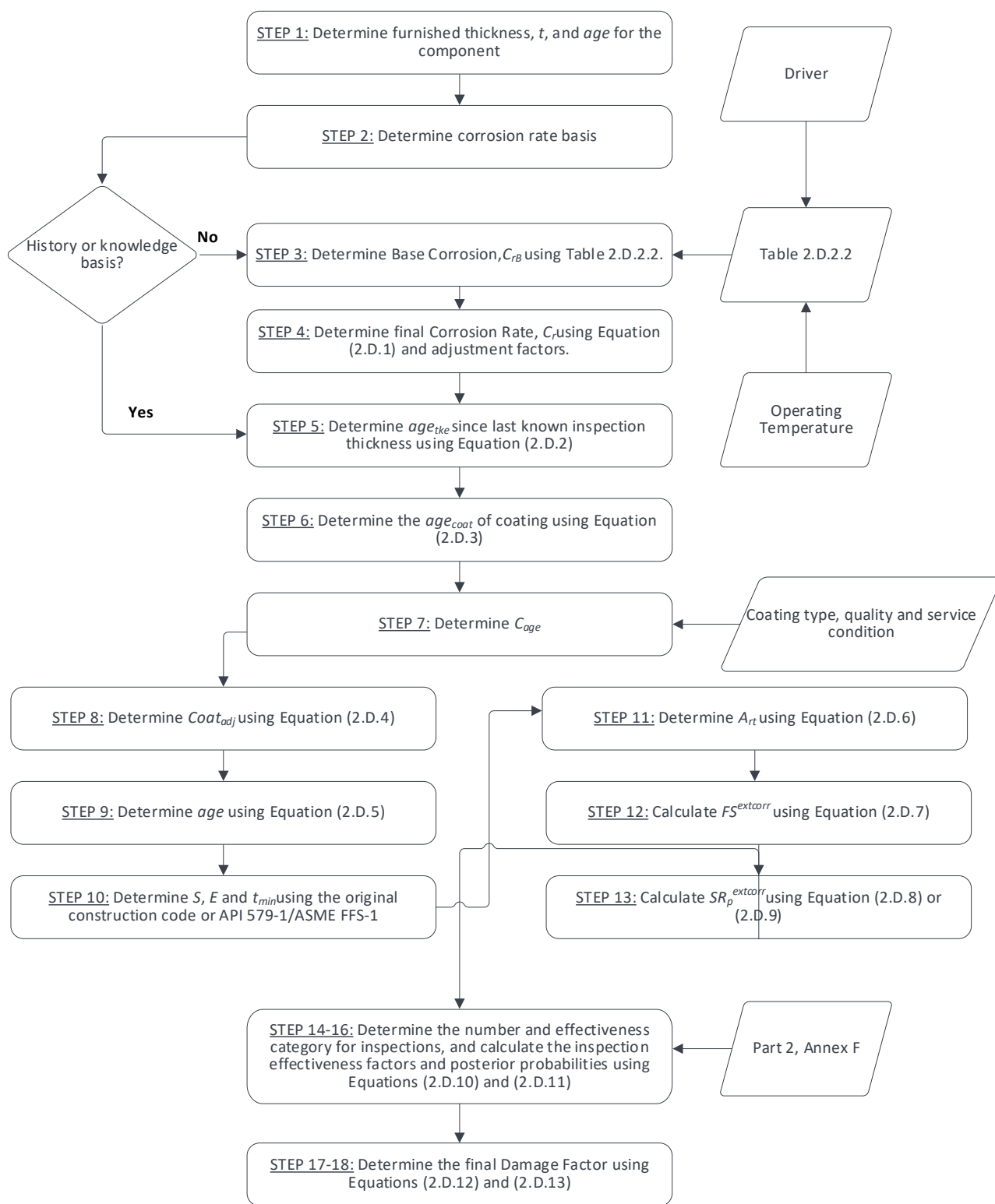


Figure 2.D.2.1—Determination of the External Corrosion DF

2.D.3 Corrosion Under Insulation (CUI) DF—Ferritic Component

2.D.3.1 Scope

The DF calculation for ferritic components subject to CUI is covered in this section.

2.D.3.2 Description of Damage

CUI results from the collection of water in the vapor space (or annulus space) between the insulation and the metal surface. Sources of water may include rain, water leaks, condensation, cooling water tower drift, deluge systems, and steam tracing leaks. CUI causes wall loss in the form of localized corrosion. CUI generally occurs in the temperature range between 10 °F and 350 °F (–12 °C and 175 °C), with the temperature range of 170 °F to 230 °F (77 °C to 110 °C) being the most severe environment.

As a general rule, plants located in areas with high annual rainfall, in warm humid climates, or in marine locations are more prone to CUI than plants located in cooler, drier, mid-continent locations. Variables that can affect CUI corrosion rates include annual rainfall, humidity, chloride levels in rainfall, proximity to ocean spray, and levels of various industrial pollutants. Corrosion rates can also vary by location within the facility. For example, units located near cooling towers and steam vents are highly susceptible to CUI, as are units whose operating temperatures cycle through the dew point on a regular basis. External inspection of insulated systems should include a review of the integrity of the insulation system for conditions that could lead to CUI and for signs of ongoing CUI, i.e. rust stains or bulging. However, external indicators of CUI are not always present.

Mitigation of CUI is accomplished through good insulation practices and proper coatings. Proper installation and maintenance of insulation simply prevents ingress of large quantities of water. In recent years, a coating system is frequently specified for component operating in the CUI temperature range and where CUI has been a problem. A high-quality immersion grade coating, like those used in hot water tanks, is recommended. For guidance, refer to NACE 6H189. A good coating system should last a minimum of 15 years.

2.D.3.3 Screening Criteria

Specific locations and/or systems, such as penetrations and visually damaged insulation areas, are highly suspect and should be considered during inspection program development. Examples of highly suspect areas include, but are not limited to, the following.

- a) Penetrations.
 - 1) All penetrations or breaches in the insulation jacketing systems, such as dead-legs (vents, drains, and other similar items), hangers and other supports, valves and fittings, bolted-on pipe shoes, ladders, and platforms.
 - 2) Steam tracer tubing penetrations.
 - 3) Termination of insulation at flanges and other components.
 - 4) Poorly designed insulation support rings.
 - 5) Stiffener rings.
- b) Damaged Insulation Areas.
 - 1) Damaged or missing insulation jacketing.
 - 2) Termination of insulation in a vertical pipe or piece of equipment.
 - 3) Caulking that has hardened, has separated, or is missing.

- 4) Bulges, staining of the jacketing system, or missing bands (bulges may indicate corrosion product buildup).
- 5) Low points in systems that have a known breach in the insulation system, including low points in long unsupported piping runs.
- 6) Carbon or low-alloy steel flanges, bolting, and other components under insulation in high-alloy piping.

The following are some examples of other suspect areas that should be considered when performing inspection for CUI.

- 1) Areas exposed to mist overspray from cooling towers.
- 2) Areas exposed to steam vents.
- 3) Areas exposed to deluge systems.
- 4) Areas subject to process spills, ingress of moisture, or acid vapors.
- 5) Insulation jacketing seams located on top of horizontal vessels or improperly lapped or sealed insulation systems,
- 6) Carbon steel systems, including those insulated for personnel protection, operating between -12°C and 175°C (10°F and 350°F). CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and reevaporation of atmospheric moisture.
- 7) Carbon steel systems that normally operate in services above 350°F (175°C) but are in intermittent service or are subjected to frequent outages.
- 8) Dead-legs and attachments that protrude from the insulation and operate at a different temperature than the operating temperature of the active line, i.e. insulation support rings, piping/platform attachments.
- 9) Systems in which vibration has a tendency to inflict damage to insulation jacketing providing paths for water ingress.
- 10) Steam traced systems experiencing tracing leaks, especially at tubing fittings beneath the insulation.
- 11) Systems with deteriorated coating and/or wrappings.
- 12) Cold service equipment consistently operating below the atmospheric dew point.
- 13) Inspection ports or plugs that are removed to permit thickness measurements on insulated systems represent a major contributor to possible leaks in insulated systems. Special attention should be paid to these locations. Promptly replacing and resealing of these plugs is imperative.

2.D.3.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for CUI are provided in [Table 2.D.3.1](#).

2.D.3.5 Basic Assumption

The DF for CUI is based on the method for general thinning covered in [Part 2, Section 4](#).

2.D.3.6 Determination of the DF

2.D.3.6.1 Overview

A flow chart of the steps required to determine the DF for CUI is shown in [Figure 2.D.3.1](#). The following sections provide additional information and the calculation procedure.

2.D.3.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting the specific damage mechanism. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F](#), [Table 2.F.9.3](#).

The number and category of the highest effective inspection will be used to determine the DF.

2.D.3.6.3 Calculation of the DF

The following procedure may be used to determine the DF for CUI; see [Figure 2.D.3.1](#).

- a) Step 1—Determine the furnished thickness, t , and age, age , for the component from the installation date.
- b) Step 2—If the corrosion rate is determined based on inspection history or assigned by a knowledgeable specialist, use the assigned value and skip to Step 5.
- c) Step 3—Determine the base corrosion rate, C_{rB} , based on the driver and operating temperature using [Table 2.D.3.2](#).

Corrosion rates can be higher than predicted in cyclic or intermittent service. [Table 2.D.3.2](#) can be used to help estimate a more representative corrosion rate; with adjustments made for factors such as:

- 1) the complete temperature range the equipment will see, including idle or out of service,
 - 2) time spent at each temperature range,
 - 3) wet/dry cycling if going through the dew point range,
 - 4) potential for higher concentration of contaminants,
 - 5) frequency of temperature cycles.
- d) Step 4—Calculate the final corrosion rate using [Equation \(2.D.14\)](#).

$$C_r = C_{rB} \cdot F_{INS} \cdot F_{CM} \cdot F_{IC} \cdot \max[F_{EQ}, F_{IF}] \quad (2.D.14)$$

The adjustment factors are determined as follows.

- 1) Adjustment for Insulation Type, F_{INS} —Based on [Table 2.D.3.3](#).
- 2) Adjustment for Complexity, F_{CM} —Established based on the following criteria.
 - If the complexity is Below Average, then $F_{CM} = 0.75$.
 - If the complexity is Average, then $F_{CM} = 1.0$.
 - If the complexity is Above Average, then $F_{CM} = 1.25$.

- 3) Adjustment for Insulation Condition, F_{IC} —Established based on the following criteria.
- If the insulation condition is Below Average, then $F_{IC} = 1.25$.
 - If the insulation condition is Average, then $F_{IC} = 1.0$.
 - If the insulation condition is Above Average, then $F_{IC} = 0.75$.
- 4) Adjustment for Equipment Design or Fabrication, F_{EQ} —If equipment has a design that allows water to pool and increase metal loss rates, such as piping supported directly on beams, vessel external stiffening rings or insulation supports, or other such configuration that does not allow water egress and/or does not allow for proper coating maintenance, then $F_{EQ} = 2$; otherwise, $F_{EQ} = 1$.
- 5) Adjustment for Interface, F_{IF} —If the piping has an interface where it enters either soil or water, then $F_{IF} = 2$; otherwise, $F_{IF} = 1$.
- e) Step 5—Determine the time in service, age_{tke} , since the last known thickness, t_{rde} (see [Part 2, Section 4.5.5](#)). The t_{rde} is the starting thickness with respect to wall loss associated with external corrosion (see [Part 2, Section 4.5.5](#)). If no measured thickness is available, set $t_{rde} = t$ and $age_{tke} = age$. The measured wall loss from CUI, L_e , may be used to calculate t_{rde} using [Equation \(2.D.15\)](#).

$$t_{rde} = t - L_e \quad (2.D.15)$$

NOTE 1 When using [Equation \(2.D.15\)](#), age_{tke} is the time in service since L_e was measured.

- f) Step 6—Determine the in-service time, age_{coat} , since the coating has been installed using [Equation \(2.D.16\)](#).

$$age_{coat} = \text{Calculation Date} - \text{Coating Installation Date} \quad (2.D.16)$$

- g) Step 7— Determine the expected coating age, C_{age} , based on coating type, quality of application, and service conditions. C_{age} should be 0 years for no coating or poorly applied coatings. Lower quality coatings will typically have a C_{age} of 5 years or less. High-quality coatings or coatings in less harsh external environments may have a C_{age} of 15 or more years. C_{age} may be adjusted based on an evaluation of the coating condition during a high-quality inspection.
- h) Step 8—Determine the coating adjustment, $Coat_{adj}$, using [Equations \(2.D.17\)](#) and [\(2.D.18\)](#).

If $age_{tke} \geq age_{coat}$:

$$Coat_{adj} = \min(C_{age}, age_{coat}) \quad (2.D.17)$$

If $age_{tke} < age_{coat}$:

- 1) If the coating has failed at the time of inspection when age_{tke} was established, then

$$Coat_{adj} = 0$$

- 2) If the coating has not failed at the time of inspection when age_{tke} was established, use Equation (2.D.18) to calculate $Coat_{adj}$.

$$Coat_{adj} = \min(C_{age, age_{coat}}) - \min(C_{age, age_{coat} - age_{tke}}) \quad (2.D.18)$$

- i) Step 9—Determine the in-service time, age , over which CUI may have occurred using Equation (2.D.19).

$$age = age_{tke} - Coat_{adj} \quad (2.D.19)$$

- j) Step 10—Determine the allowable stress, S , weld joint efficiency, E , and minimum required thickness, t_{min} , per the original construction code or API 579-1/ASME FFS-1 [10]. In cases where components are constructed of uncommon shapes or where the component's minimum structural thickness, t_c , may govern, the user may use the t_c in lieu of t_{min} where pressure does not govern the minimum required thickness criteria.
- k) Step 11—Determine the A_{rt} parameter using Equation (2.D.20) based on the age and t_{rde} from Step 5, C_r from Step 3.

$$A_{rt} = \frac{C_r \cdot age}{t_{rde}} \quad (2.D.20)$$

- l) Step 12—Calculate the flow stress, FS^{CUIF} , using E from Step 10 and Equation (2.D.21).

$$FS^{CUIF} = \frac{(YS + TS)}{2} \cdot E \cdot 1.1 \quad (2.D.21)$$

NOTE 2 Use flow stress (FS^{Thin}) at design temperature for conservative results, using the appropriate Equation (2.D.20) or Equation (2.D.21).

- m) Step 13—Calculate strength ratio parameter, SR_p^{CUIF} , using Equation (2.D.22) or Equation (2.D.23).

- 1) Use Equation (2.D.22) with t_{rde} from Step 5, S , E , and t_{min} or t_c from Step 10, and flow stress FS^{CUIF} from Step 11.

$$SR_p^{CUIF} = \frac{S \cdot E}{FS^{CUIF}} \cdot \frac{\max(t_{min}, t_c)}{t_{rde}} \quad (2.D.22)$$

NOTE 3 The t_{min} is based on a design calculation that includes evaluation for internal pressure hoop stress, external pressure, and/or structural considerations, as appropriate. The minimum required thickness calculation is the design code t_{min} . Consideration for internal pressure hoop stress alone may not be sufficient. t_c as defined in Step 5 may be used when appropriate.

- 2) Use Equation (2.D.23) with t_{rde} from Step 4 and flow stress FS^{CUIF} from Step 12.

$$SR_p^{CUIF} = \frac{P \cdot D}{\alpha \cdot FS^{CUIF} \cdot t_{rde}} \quad (2.D.23)$$

where α is the shape factor for the component type. $\alpha = 2$ for a cylinder, 4 for a sphere, 1.13 for a head.

NOTE 4 This strength ratio parameter is based on internal pressure hoop stress only. It is not appropriate where external pressure and/or structural considerations dominate. When t_c dominates or if the t_{min} is calculated using another method, Equation (2.D.22) should be used.

- n) Step 14—Determine the number of inspections, N_A^{CUIF} , N_B^{CUIF} , N_C^{CUIF} , and N_D^{CUIF} , and the corresponding inspection effectiveness category using Section 2.D.3.6.2 for all past inspections.
- o) Step 15—Determine the inspection effectiveness factors, I_1^{CUIF} , I_2^{CUIF} , and I_3^{CUIF} , using Equation (2.D.24), prior probabilities, Pr_{p1}^{CUIF} , Pr_{p2}^{CUIF} , and Pr_{p3}^{CUIF} , from Part 2, Table 4.5, conditional probabilities (for each inspection effectiveness level), Co_{p1}^{CUIF} , Co_{p2}^{CUIF} , and Co_{p3}^{CUIF} , from Part 2, Table 4.6, and the number of inspections, N_A^{CUIF} , N_B^{CUIF} , N_C^{CUIF} , and N_D^{CUIF} , in each effectiveness level obtained from Step 13.

$$\begin{aligned} I_1^{CUIF} &= Pr_{p1}^{CUIF} \left(Co_{p1}^{CUIFA} \right)^{N_A^{CUIF}} \left(Co_{p1}^{CUIFB} \right)^{N_B^{CUIF}} \left(Co_{p1}^{CUIFC} \right)^{N_C^{CUIF}} \left(Co_{p1}^{CUIFD} \right)^{N_D^{CUIF}} \\ I_2^{CUIF} &= Pr_{p2}^{CUIF} \left(Co_{p2}^{CUIFA} \right)^{N_A^{CUIF}} \left(Co_{p2}^{CUIFB} \right)^{N_B^{CUIF}} \left(Co_{p2}^{CUIFC} \right)^{N_C^{CUIF}} \left(Co_{p2}^{CUIFD} \right)^{N_D^{CUIF}} \\ I_3^{CUIF} &= Pr_{p3}^{CUIF} \left(Co_{p3}^{CUIFA} \right)^{N_A^{CUIF}} \left(Co_{p3}^{CUIFB} \right)^{N_B^{CUIF}} \left(Co_{p3}^{CUIFC} \right)^{N_C^{CUIF}} \left(Co_{p3}^{CUIFD} \right)^{N_D^{CUIF}} \end{aligned} \quad (2.D.24)$$

- n) Step 16—Calculate the posterior probabilities, Po_{p1}^{CUIF} , Po_{p2}^{CUIF} , and Po_{p3}^{CUIF} , using Equation (2.D.25) with I_1^{CUIF} , I_2^{CUIF} , and I_3^{CUIF} in Step 13.

$$\begin{aligned} Po_{p1}^{CUIF} &= \frac{I_1^{CUIF}}{I_1^{CUIF} + I_2^{CUIF} + I_3^{CUIF}} \\ Po_{p2}^{CUIF} &= \frac{I_2^{CUIF}}{I_1^{CUIF} + I_2^{CUIF} + I_3^{CUIF}} \\ Po_{p3}^{CUIF} &= \frac{I_3^{CUIF}}{I_1^{CUIF} + I_2^{CUIF} + I_3^{CUIF}} \end{aligned} \quad (2.D.25)$$

- o) Step 17—Calculate the parameters, β_1^{CUIF} , β_2^{CUIF} , and β_3^{CUIF} , using Equation (2.D.26) and assigning $COV_{\Delta t} = 0.20$, $COV_{S_f} = 0.20$, and $COV_p = 0.05$.

$$\begin{aligned}\beta_1^{\text{CUIF}} &= \frac{1 - D_{S_1} \cdot A_{rt} - SR_p^{\text{CUIF}}}{\sqrt{D_{S_1}^2 \cdot A_{rt}^2 \cdot COV_{\Delta t}^2 + (1 - D_{S_1} \cdot A_{rt})^2 \cdot COV_{S_f}^2 + (SR_p^{\text{CUIF}})^2 \cdot COV_p^2}}, \\ \beta_2^{\text{CUIF}} &= \frac{1 - D_{S_2} \cdot A_{rt} - SR_p^{\text{CUIF}}}{\sqrt{D_{S_2}^2 \cdot A_{rt}^2 \cdot COV_{\Delta t}^2 + (1 - D_{S_2} \cdot A_{rt})^2 \cdot COV_{S_f}^2 + (SR_p^{\text{CUIF}})^2 \cdot COV_p^2}}, \\ \beta_3^{\text{CUIF}} &= \frac{1 - D_{S_3} \cdot A_{rt} - SR_p^{\text{CUIF}}}{\sqrt{D_{S_3}^2 \cdot A_{rt}^2 \cdot COV_{\Delta t}^2 + (1 - D_{S_3} \cdot A_{rt})^2 \cdot COV_{S_f}^2 + (SR_p^{\text{CUIF}})^2 \cdot COV_p^2}}.\end{aligned}\tag{2.D.26}$$

where $D_{S_1} = 1$, $D_{S_2} = 2$, and $D_{S_3} = 4$. These are the corrosion rate factors for damage states 1, 2, and 3 as discussed in Part 2, Section 4.5.3 [17].

NOTE 5 The DF calculation is very sensitive to the value used for the coefficient of variance for thickness, $COV_{\Delta t}$. The $COV_{\Delta t}$ is in the range $0.10 \leq COV_{\Delta t} \leq 0.20$, with a recommended conservative value of $COV_{\Delta t} = 0.20$.

- p) Step 18—Calculate D_f^{CUIF} using Equation (2.D.27).

$$D_f^{\text{CUIF}} = \left[\frac{(P_{o_{p1}}^{\text{CUIF}} \Phi(-\beta_1^{\text{CUIF}})) + (P_{o_{p2}}^{\text{CUIF}} \Phi(-\beta_2^{\text{CUIF}})) + (P_{o_{p3}}^{\text{CUIF}} \Phi(-\beta_3^{\text{CUIF}}))}{1.56\text{E-}04} \right]\tag{2.D.27}$$

where Φ is the standard normal cumulative distribution function (NORMSDIST in Excel).

2.D.3.7 Nomenclature

A_{rt}	is the expected metal loss fraction since last inspection
age	is the in-service time that damage is applied, years
age_{coat}	is the in-service time since the coating installation, years
age_{tke}	is the component in-service time since the last inspection thickness measurement with respect to wall loss associated with CUI or service start date, years
C_{age}	is the total anticipated coating life from the time of installation, years
C_r	is the corrosion rate, mpy (mm/yr)
C_{rB}	is the base value of the corrosion rate, mpy (mm/yr)
Co_{p1}^{CUIF}	is the conditional probability of inspection history inspection effectiveness for damage state 1

Co_{p2}^{CUIF}	is the conditional probability of inspection history inspection effectiveness for damage state 2
Co_{p3}^{CUIF}	is the conditional probability of inspection history inspection effectiveness for damage state 3
$Coat_{adj}$	is the coating adjustment, year
COV_p	is the pressure variance
COV_{Sf}	is the flow stress variance
$COV_{\Delta t}$	is the thinning variance
D	is the component inside diameter, in. (mm)
D_f^{CUIF}	is the DF for CUI for ferritic components
D_{S1}	is the corrosion rate factor for damage state 1
D_{S2}	is the corrosion rate factor for damage state 2
D_{S3}	is the corrosion rate factor for damage state 3
E	is the weld joint efficiency or quality code from the original construction code
F_{CM}	is the corrosion rate adjustment factor for insulation complexity
F_{EQ}	is an adjustment factor for equipment design detail
F_{IC}	is the corrosion rate adjustment factor for insulation condition
F_{IF}	is the corrosion rate adjustment factor for interface for soil and water
F_{INS}	the corrosion rate adjustment factor for insulation type
FS^{CUIF}	is the flow stress, psi (MPa)
I_1^{CUIF}	is the first order inspection effectiveness factor
I_2^{CUIF}	is the second order inspection effectiveness factor
I_3^{CUIF}	is the third order inspection effectiveness factor
L_e	is the measured wall loss due to CUI, in. (mm)
N_A^{CUIF}	is the number of A level inspections
N_B^{CUIF}	is the number of B level inspections

N_C^{CUIF}	is the number of C level inspections
N_D^{CUIF}	is the number of D level inspections
P	is the pressure (operating, design, PRD overpressure, etc.) used to calculate the limit state function for POF
Po_{p1}^{CUIF}	is the posterior probability posterior for damage state 1
Po_{p2}^{CUIF}	is the posterior probability posterior for damage state 2
Po_{p3}^{CUIF}	is the posterior probability posterior for damage state 3
Pr_{p1}^{CUIF}	is the prior probability of corrosion rate data reliability for damage state 1
Pr_{p2}^{CUIF}	is the prior probability of corrosion rate data reliability for damage state 2
Pr_{p3}^{CUIF}	is the prior probability of corrosion rate data reliability for damage state 3
S	is the allowable stress
SR_p^{CUIF}	is the strength ratio parameter defined as the ratio of hoop stress to flow stress
TS	is the tensile strength
t	is the furnished thickness of the component calculated as the sum of the base material and cladding/weld overlay thickness, as applicable
t_c	is the minimum structural thickness of the component base material
t_{min}	is the minimum required thickness based on the applicable construction code
t_{rde}	is the measured thickness reading from previous inspection with respect to wall loss associated with CUI
YS	is the yield strength
α	is the component geometry shape factor
β_1^{CUIF}	is the β reliability indices for damage state 1
β_2^{CUIF}	is the β reliability indices for damage state 2
β_2^{CUIF}	is the β reliability indices for damage state 3
ϕ	is the standard normal cumulative distribution function

2.D.3.8 References

See Reference [83] in [Annex 2.G](#).

2.D.3.9 Tables

Table 2.D.3.1—Data Required for Determination of the DF—CUI

Required Data	Comments
Insulation type	Type of insulation per Table 2.D.3.3 .
Driver	The drivers for external CUI corrosion. See 2.D.2.6.2 for driver descriptions and selection.
Corrosion rate, mpy (mm/y)	Corrosion rate for external CUI corrosion. Based on temperature, and driver (see below), or user input.
Coating installation date	The date the coating was installed.
Coating quality	Relates to the type of coating applied under the insulation, for example: None—no coating or primer only; Medium—single coat epoxy; High—multi-coat epoxy or filled epoxy.
Equipment design/fabrication penalty (Yes/No)	If the equipment has a design or fabrication detail that allows water to pool and increase metal loss rates, such as piping supported directly on beams, vessel external stiffener rings or insulation supports, or other such configuration that does not allow water egress and/or does not allow for proper coating maintenance, external metal loss can be more severe.
Complexity	The number of protrusions such as branch connections, nozzles, pipe supports, poorly designed insulation support rings, etc., and any design feature that would promote the retention and/or collection of moisture. The complexity is defined as follows: Below Average—penetrations in the insulation system do not exist; Average—some penetrations in the insulation systems, or the insulation system is slightly complex do to some appurtenances or multiple branches in a piping system; Above Average—many penetrations in the insulation systems, or the insulation system is very complex do to many appurtenances or multiple branches in a piping system.
Insulation condition? (Above Average, Average, or Below Average)	Determine the insulation condition based on external visual inspection of jacketing condition. Above Average insulation will show no signs of damage (i.e. punctured, torn, or missing waterproofing, and missing caulking) or standing water (i.e. brown, green, or black stains). Take careful note of areas where water can enter into the insulation system, such as inspection ports and areas where the insulation is penetrated (i.e. nozzles, ring supports, and clips). Horizontal areas also accumulate water. Average insulation condition will have good jacketing with some areas of failed weatherproofing or small damaged areas. NOTE The corrosion rates for CUI represent average/typical insulation systems found in most plants. This should be considered when determining if any adjustment or penalty multipliers apply.
Pipe support penalty? (Yes/No)	If piping is supported directly on beams or other such configuration that does not allow for proper coating maintenance, CUI can be more severe.
Interface penalty? (Yes/No)	If the piping has an interface where it enters either soil or water, this area is subject to increased corrosion.

Required Data	Comments
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.
Thickness reading	The thickness used for the DF calculation is either the furnished thickness or the measured thickness (see Part 2, Section 4.5.5).
Thickness reading date	The date at which the thickness measurement used in the calculation was obtained. If no acceptable inspection has been conducted, the installation date should be used.

Table 2.D.3.2—Corrosion Rates for Calculation of the DF—CUI

Operating Temperature (°F)	Corrosion Rate as a Function of Driver ¹ (mpy)			
	Severe	Moderate	Mild	Dry
10	0	0	0	0
18	3	1	0	0
43	10	5	3	1
90	10	5	3	1
160	20	10	5	2
225	10	5	1	1
275	10	2	1	0
325	5	1	0	0
350	0	0	0	0

NOTE 1 Driver is defined as the CUI condition causing the corrosion rate. See [2.D.2.6.2](#) for explanation of drivers.

NOTE 2 Interpolation may be used for intermediate values of temperature.

Table 2.D.3.2M—Corrosion Rates for Calculation of the DF—CUI

Operating Temperature (°C)	Corrosion Rate as a Function of Driver ¹ (mm/y)			
	Severe	Moderate	Mild	Dry
−12	0	0	0	0
−8	0.076	0.025	0	0
6	0.254	0.127	0.076	0.025
32	0.254	0.127	0.076	0.025
71	0.508	0.254	0.127	0.051
107	0.254	0.127	0.025	0.025
135	0.254	0.051	0.025	0
162	0.127	0.025	0	0
176	0	0	0	0

NOTE 1 Driver is defined as the CUI condition causing the corrosion rate. See [2.D.2.6.2](#) for explanation of drivers.

NOTE 2 Interpolation may be used for intermediate values of temperature.

Table 2.D.3.3—Corrosion Rate Adjustment Factor for Insulation Type

Insulation Type	Adjustment Factor, F_{INS}
Unknown/unspecified	1.5
Asbestos	1.5
Cellular glass	0.75
Expanded perlite ²	1.0
Fiberglass	1.25
Type E fiberglass ²	1.25
Mineral wool	1.5
Mineral wool (water resistant)	1.25
Calcium silicate ²	1.25
Flexible aerogel ²	1.25
Microporous blanket	1.0
Intumescent coating	0.75
Cementitious coating	1.0
NOTE 1 The values in this table are suggested values. NOTE 2 The use of F_{INS} 0.75 for any insulation complying with mass loss corrosion rate (MLCR) less than deionized (DI) water values calculated as per ASTM C1617.	

2.D.3.10 Figures



Figure 2.D.3.1—Determination of the CUI DF

2.D.4 External Chloride Stress Corrosion Cracking (ExtCISCC) DF—Austenitic Component

2.D.4.1 Scope

The DF calculation for uninsulated austenitic stainless steel components subject to ExtCISCC is covered in this section.

2.D.4.2 Description of Damage

Uninsulated austenitic stainless steel components located in process plants may be subject to ExtCISCC as a result chloride accumulation resulting from local atmospheric conditions that include chlorides. Cracking generally occurs at metal temperatures above about 140 °F (60 °C), although exceptions can be found at lower temperatures. The operating range where damage may occur is between 120 °F to 300 °F (50 °C to 150 °C). Heating and/or cooling intermittently into this range will present an opportunity for CISCC to occur.

Mitigation of ExtCISCC is best accomplished by preventing chloride accumulation on the stainless steel surface. On uninsulated surfaces, chloride-containing fluids, mists, or solids should be prevented from contacting the surface. Markers, dyes, tape, etc. used on stainless steels should be certified suitable for such applications. In rare cases, uninsulated stainless steels could be protected externally by a coating. If intermittent conditions exist, then both normal operating and intermittent temperatures should be considered.

2.D.4.3 Screening Criteria

If all of the following are true, then the component should be evaluated for susceptibility to ExtCISCC.

- a) The component's material of construction is an austenitic stainless steel.
- b) The component external surface is exposed to chloride-containing fluids, mists, or solids.
- c) The operating temperature is between 120 °F and 300 °F (50 °C and 150 °C) or the system heats or cools into this range intermittently.

2.D.4.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for ExtCISCC are provided in [Table 2.D.4.1](#).

2.D.4.5 Basic Assumption

The DF for ExtCISCC is based on the method in [Section 2.C.2.5](#).

2.D.4.6 Determination of the DF

2.D.4.6.1 Overview

A flow chart of the steps required to determine the DF for ExtCISCC is shown in [Figure 2.D.4.1](#). The following sections provide additional information and the calculation procedure.

2.D.4.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting the specific damage mechanism. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.9.2](#).

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.D.4.6.3 Calculation of the DF

The following procedure may be used to determine the DF for ExtCISCC; see [Figure 2.D.4.1](#).

- a) Step 1—Determine the susceptibility using [Table 2.D.4.2](#) based on the driver and the operating temperature.

NOTE A High susceptibility should be used if cracking is confirmed to be present.

- b) Step 2—Determine the severity index, S_{VI} , using [Table 2.D.1.2](#) based on the susceptibility from Step 1.
- c) Step 3—Determine the in-service time, age_{crack} , since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- d) Step 4—Determine the in-service time, age_{coat} , since the coating has been installed using [Equation \(2.D.28\)](#).

$$age_{coat} = \text{Calculation Date} - \text{Coating Installation Date} \quad (2.D.28)$$

- e) Step 5—Determine the expected coating age, C_{age} , based on coating type, quality of application, and service conditions. C_{age} should be 0 years for no coating or poorly applied coating. Lower quality coatings will typically have a C_{age} of 5 years or less. High-quality coatings or coatings in less harsh external environments may have a C_{age} of 15 or more years. C_{age} may be adjusted based on an evaluation of the coating condition during a high-quality inspection.
- f) Step 6—Determine the coating adjustment, $Coat_{adj}$, using [Equations \(2.D.29\) through \(2.D.30\)](#).

If $age_{crack} \geq age_{coat}$:

$$Coat_{adj} = \min(C_{age}, age_{coat}) \quad (2.D.29)$$

If $age_{crack} < age_{coat}$:

- 1) If the coating has failed at the time of inspection when age_{tke} was established, then

$$Coat_{adj} = 0$$

- 2) If the coating has not failed at the time of inspection when age_{tke} was established, use [Equation \(2.36\)](#) to calculate $Coat_{adj}$.

$$Coat_{adj} = \min(C_{age}, age_{coat}) - \min(C_{age}, age_{coat} - age_{tke}) \quad (2.D.30)$$

- g) Step 7—Determine the in-service time, age , over which ExtCISCC may have occurred using [Equation \(2.D.31\)](#).

$$age = age_{crack} - Coat_{adj} \quad (2.D.31)$$

- h) Step 8—Determine the number of inspections performed with no cracking detected or cracking was repaired and the corresponding inspection effectiveness category using [Section 2.D.6.2](#) for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using [Part 2, Section 3.4.3](#). Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- i) Step 9—Determine the base DF for ExtCISCC, $D_{fB}^{\text{ext-CISCC}}$, using [Table 2.C.1.3](#) based on the number of inspections and the highest inspection effectiveness determined in Step 8 and the severity index, S_{VI} , from Step 2.
- j) Step 10—Calculate the escalation in the DF based on the time in service since the last inspection using the *age* from Step 7 and [Equation \(2.D.32\)](#). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

$$D_f^{\text{ext-CISCC}} = \min \left(D_{fB}^{\text{ext-CISCC}} \cdot (\max(\text{age}, 1.0))^{1.1}, 5000 \right) \quad (2.D.32)$$

2.D.4.7 Nomenclature

<i>age</i>	is the component in-service time since the last cracking inspection or service start date
<i>age</i> _{coat}	is the in-service time since the coating installation
<i>age</i> _{crack}	is the in-service time since the last CISCC inspection
<i>C</i> _{age}	is the total anticipated coating life from the time of installation
<i>Coat</i> _{adj}	is the coating adjustment
$D_f^{\text{ext-CISCC}}$	is the DF for ExtCISCC
$D_{fB}^{\text{ext-CISCC}}$	is the base value of the DF for ExtCISCC
<i>S</i> _{VI}	is the severity index

2.D.4.8 References

None.

2.D.4.9 Tables

Table 2.D.4.1—Data Required for Determination of the DF—External CISCC

Required Data	Comments
Driver	The drivers for ExtCISCC. See 2.D.2.6.2 for driver descriptions and selection.
Crack severity	Crack severity based on susceptibility (temperature and weather; see below).
Date	The date the component was installed or the date of the last inspection where no damage was found.
Coating quality	Relates to the type of coating applied, for example: None—no coating or primer only; Medium—single coat epoxy; High—multi-coat epoxy or filled epoxy.
Coating date	Determine the age of the coating.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Number of inspections	The number of inspections in each effectiveness category that have been performed.
Operating temperature, °F (°C)	Determine the expected operating temperature (consider normal and non-normal operating conditions).

Table 2.D.4.2—SCC Susceptibility—External CISCC

Operating Temperature		SCC Susceptibility as a Function of Driver (See Note)			
°C	°F	Severe	Moderate	Mild	Dry
< 49	120	None	None	None	None
49 to 93	120 to 200	High	Medium	Low	None
93 to 149	200 to 300	Medium	Low	Low	None
> 149	> 300	None	None	None	None
NOTE Driver is defined as the atmospheric condition causing the SCC.					

2.D.4.10 Figures

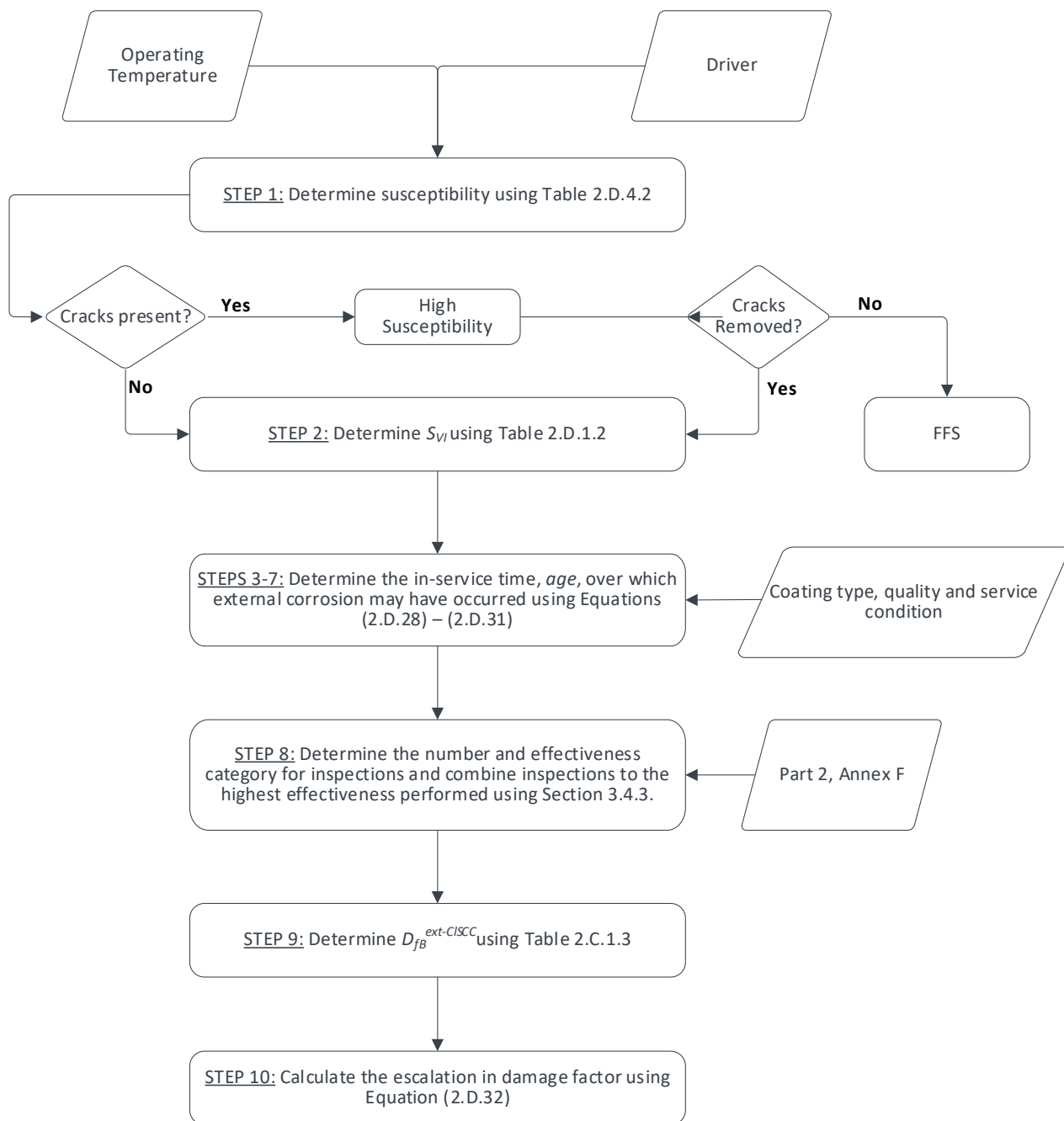


Figure 2.D.4.1—Determination of the External CISC DF

2.D.5 External CUI CISCC DF—Austenitic Component

2.D.5.1 Scope

The DF calculation for insulated austenitic stainless steel components subject to CUI CISCC is covered in this section.

2.D.5.2 Description of Damage

Insulation can be a source of chlorides and/or cause the retention of water and chloride concentrating under the insulation. CUI CISCC can be caused by the spray from sea water and cooling water towers carried by the prevailing winds. The spray soaks the insulation over the austenitic stainless steel components, the chloride concentrates by evaporation, and cracking occurs in the areas with residual stresses (e.g. weld and bends). Other cases of cracking under insulation have resulted from water dripping on insulated pipe and leaching chlorides from insulation. Mitigation of CUI CISCC is best accomplished by preventing chloride accumulation on the stainless steel surface. This is best accomplished by maintaining the integrity of the insulation and by preventing chloride ions from contacting the stainless steel surface with a protective coating. An immersion grade coating suitable for stainless steel is the most practical and proven method of protection. However, wrapping of the stainless steel with aluminum foil that serves as both a barrier coating and a CP anode has also proven to be effective.

CUI damage in austenitic stainless steels occurs at temperatures between 120 °F and 350 °F (50 °C and 175 °C) although exceptions have been reported at lower temperatures.

- a) Below 120 °F (50 °C), it is difficult to concentrate significant amounts of chlorides.
- b) Above 350 °F (175 °C), water is normally not present and CUI damage is infrequent.
- c) Austenitic stainless steel piping that normally operates above 500 °F (260 °C) can also suffer severe ExtCISCC during start-up if the insulation is soaked from deluge system testing or rain during downtime.

Heating and/or cooling intermittently into this range creates the conditions for CUI CISCC to occur.

2.D.5.3 Screening Criteria

If all of the following are true, then the component should be evaluated for susceptibility to CUI CISCC.

- a) The component's material of construction is an austenitic stainless steel.
- b) The component is insulated.
- c) The component's external surface is exposed to chloride-containing fluids, mists, or solids.
- d) The operating temperature is between 120 °F and 300 °F (50 °C and 150 °C) or intermittently operated in this range.

2.D.5.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for CUI CISCC are provided in [Table 2.D.5.1](#).

2.D.5.5 Basic Assumption

The DF for external CUI CISCC is based on the method in [Section 2.C.2.5](#).

2.D.5.6 Determination of the DF

2.D.5.6.1 Overview

A flow chart of the steps required to determine the DF for external CUI CISCC is shown in [Figure 2.D.5.1](#). The following sections provide additional information and the calculation procedure.

2.D.5.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting the specific damage mechanism. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in [Annex 2.F, Table 2.F.9.4](#).

If multiple inspections of a lower effectiveness have been conducted during the designated time period, they can be equated to an equivalent higher effectiveness inspection in accordance with [Part 2, Section 3.4.3](#).

2.D.5.6.3 Calculation of the DF

The following procedure may be used to determine the DF for CUI CISCC; see [Figure 2.D.5.1](#).

NOTE A High susceptibility should be used if cracking is known to be present.

- a) Step 1—Determine the susceptibility using [Table 2.D.5.2](#) based on the driver and the operating temperature and the following adjustment factors.
 - 1) Adjustments for Piping Complexity—If the piping complexity is Below Average, then decrease susceptibility one level (e.g. Medium to Low). If the piping complexity is Above Average, then increase susceptibility one level (e.g. Medium to High). If the piping complexity is Average, then there is no change in the susceptibility.
 - 2) Adjustments for Insulation Condition—If the insulation condition is Above Average, then decrease susceptibility one level (e.g. Medium to Low). If the insulation condition is Below Average, then increase susceptibility one level (e.g. Medium to High). If the insulation condition is Average, then there is no change in the susceptibility.
 - 3) Adjustments for Chloride-free Insulation—If the insulation contains chlorides, then there is no change in the susceptibility. If the insulation is chloride free, then decrease the susceptibility one level (e.g. Medium to Low).

NOTE A High susceptibility should be used if cracking is confirmed to be present.

- b) Step 2—Determine the severity index, S_{VI} , using [Table 2.D.1.2](#), based on the susceptibility from Step 1.
- c) Step 3—Determine the in-service time, age_{crack} , since the last Level A, B, or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- d) Step 4—Determine the in-service time, age_{coat} , since the coating has been installed using [Equation \(2.D.33\)](#).

$$age_{coat} = \text{Calculation Date} - \text{Coating Installation Date} \quad (2.D.33)$$

- e) Step 5—Determine the expected coating age, C_{age} , based on coating type, quality of application, and service conditions. C_{age} should be 0 years for no coating or poorly applied coating. Lower quality coatings will typically have a C_{age} of 5 years or less. High-quality coatings or coatings in less harsh external environments may have a C_{age} of 15 or more years. C_{age} may be adjusted based on an evaluation of the coating condition during a high-quality inspection.
- f) Step 6—Determine the coating adjustment, $Coat_{adj}$, using [Equations \(2.D.34\) and \(2.D.35\)](#).

If $age_{crack} \geq age_{coat}$:

$$Coat_{adj} = \min(C_{age}, age_{coat}) \quad (2.D.34)$$

If $age_{crack} < age_{coat}$:

- 3) If the coating has failed at the time of inspection when age_{tke} was established, then

$$Coat_{adj} = 0$$

- 4) If the coating has not failed at the time of inspection when age_{tke} was established, use [Equation \(2.36\)](#) to calculate $Coat_{adj}$:

$$Coat_{adj} = \min(C_{age}, age_{coat}) - \min(C_{age}, age_{coat} - age_{tke}) \quad (2.D.35)$$

- g) Step 7—Determine the in-service time, age , over which external CUI CISCC may have occurred using [Equation \(2.D.36\)](#).

$$age = age_{crack} - Coat_{adj} \quad (2.D.36)$$

- h) Step 8—Determine the number of inspections performed with no cracking detected or cracking was repaired and the corresponding inspection effectiveness category using [Table 2.F.9.2](#) for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using [Part 2, Section 3.4.3](#). Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
- i) Step 9—Determine the base DF for CUI CISCC, $D_{fB}^{CUI-CISCC}$, using [Table 2.C.1.3](#) based on the number of inspections and the highest inspection effectiveness determined in Step 8 and the severity index, S_{VI} , from Step 2.
- j) Step 10—Calculate the escalation in the DF based on the time in service since the last inspection using the age from Step 7 and [Equation \(2.D.37\)](#). In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

$$D_f^{CUI-CISCC} = \min\left(D_{fB}^{CUI-CISCC} \cdot (\max[age, 1.0])^{1.1}, 5000\right) \quad (2.D.37)$$

2.D.5.7 Nomenclature

age	is the component in-service time since the last cracking inspection or service start date
age_{coat}	is the in-service time since the coating installation
age_{crack}	is the in-service time since the last CISCC inspection
C_{age}	is the total anticipated coating life from the time of installation
$Coat_{adj}$	is the coating adjustment
$D_f^{CUI-CISCC}$	is the DF for CUI CISCC
$D_{fB}^{CUI-CISCC}$	is the base value of the DF for CUI CISCC
S_{VI}	is the severity index

2.D.5.8 References

See Reference [\[83\]](#) in [Annex 2.G](#).

2.D.5.9 Tables

Table 2.D.5.1—Data Required for Determination of the DF—CUI CISCC

Required Data	Comments
Driver	The drivers for CUI CISCC. See Section 2.D.2.6.2 for driver descriptions and selection.
Crack severity	Crack severity based on susceptibility (temperature and weather; see below).
Date	The date the insulation was installed or the date of the last inspection where no damage was found.
Coating quality	Relates to the type of coating applied under the insulation, for example: None—no coating or primer only; Medium—single coat epoxy; High—multi-coat epoxy or filled epoxy.
Coating date	Determine the age of the coating.
Inspection effectiveness category	The effectiveness category that has been performed on the component.
Insulation condition (Above Average, Average, or Below Average)	Determine insulation condition (Below Average, Average, or Above Average) based on external visual inspection of jacketing condition. Above average insulation will show no signs of damage (i.e. punctured, torn, or missing waterproofing, and missing caulking) or standing water (i.e. brown, green, or black stains). Take careful note of areas where water can enter into the insulation system, such as inspection ports and areas where the insulation is penetrated (i.e. nozzles, ring supports, and clips). Horizontal areas also accumulate water. Average insulation condition will have good jacketing with some areas of failed weatherproofing or small damaged areas. NOTE The susceptibilities represent susceptibilities for CUI for average/typical insulation systems found in most plants. This should be considered when determining if any adjustments apply.
Complexity	The number of protrusions such as branch connections, nozzles, pipe supports, poorly designed insulation support rings, etc., and any design feature that would promote the retention and/or collection of moisture. The complexity is defined as follows: Below Average—penetrations in the insulation system do not exist; Average—some penetrations in the insulation systems, or the insulation system is slightly complex do to some appurtenances or multiple branches in a piping system; Above Average—many penetrations in the insulation systems, or the insulation system is very complex do to many appurtenances or multiple branches in a piping system.
Number of inspections	The number of inspections in each effectiveness category that have been performed.
Operating Temperature, °F (°C)	Determine the highest operating temperature expected during operation (consider normal and non-normal operating conditions).

Table 2.D.5.2—SCC Susceptibility—CUI CISCC

Operating Temperature		SCC Susceptibility as a Function of Driver (See Note)			
°C	°F	Severe	Moderate	Mild	Dry
< 49	< 120	None	None	None	None
49 to 93	120 to 200	High	High	Medium	Low
93 to 149	200 to 300	High	Medium	Low	None
> 149	> 300	None	None	None	None
NOTE Driver is defined as the atmospheric condition causing the SCC.					

2.D.5.10 Figures

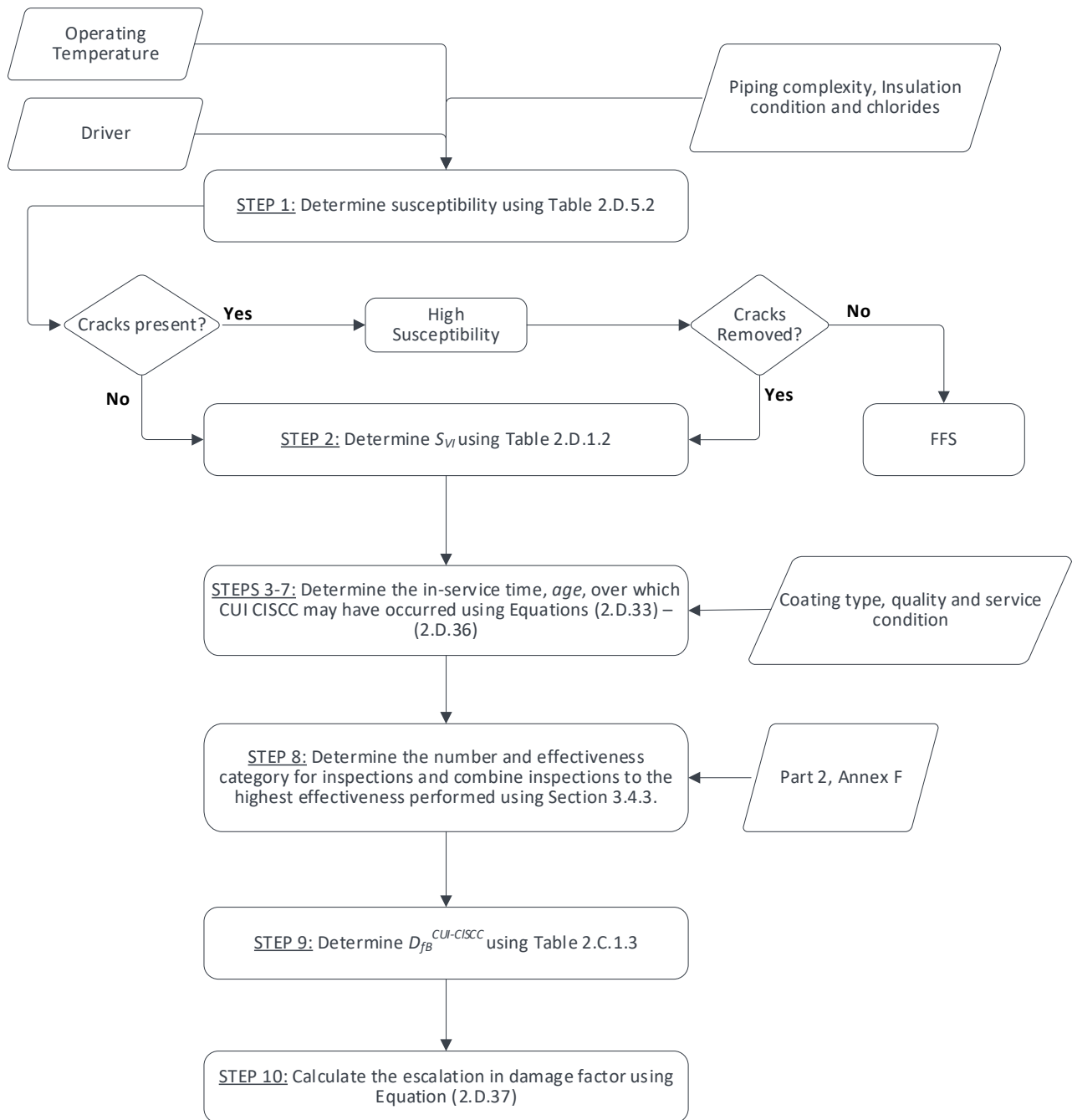


Figure 2.D.5.1—Determination of the CUI CISC DF

Part 2, Annex 2.E—Mechanical and Metallurgical Damage Mechanisms

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Risk-based Inspection Methodology

Part 2—Probability of Failure Methodology

Annex 2.E—Mechanical and Metallurgical Damage Mechanisms

2.E.1 Overview

2.E.1.1 Determination of Mechanical and Metallurgical Damage Susceptibilities

Mechanical and metallurgical damage susceptibilities should be based on assignments for each potential mechanism using this document or as estimated by a corrosion specialist.

Screening questions are used to determine if the mechanical and metallurgical damage mechanism sections apply. The applicable sections are used to determine conservative susceptibilities for potential damage mechanisms. The screening questions listed in [Table 2.E.1.1](#) are used to select the applicable mechanisms.

2.E.1.2 Tables

Table 2.E.1.1—Screening Questions for Mechanical and Metallurgical Damage

Screening Questions	Action
HTHA 1. Carbon steel, C- $\frac{1}{2}$ Mo, or a Cr-Mo low-alloy steel (such as $\frac{1}{2}$ Cr- $\frac{1}{2}$ Mo, 1 Cr- $\frac{1}{2}$ Mo, $\frac{1}{4}$ Cr- $\frac{1}{2}$ Mo, $\frac{2}{4}$ Cr-1 Mo, 3Cr-1 Mo, 5Cr- $\frac{1}{2}$ Mo, 7Cr-1 Mo, and 9Cr-1 Mo)? 2. Operating temperature > 350 °F (177 °C)? 3. Operating hydrogen partial pressure > 50 psia (0.345 MPa)?	If Yes to all, proceed to Section 2.E.2
Brittle Fracture 1. Carbon or low-alloy steel? 2. Minimum design metal temperature or minimum allowable temperature is unknown or below operating or upset temperature?	If Yes to both, proceed to Section 2.E.3
Low-alloy Steel Embrittlement 1. 1Cr-0.5Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, or 3Cr-1 Mo low-alloy steel? 2. Operating temperature between 650 °F and 1070 °F (343 °C and 577 °C)?	If Yes to both, proceed to Section 2.E.4
885 °F Embrittlement 1. High chromium (> 12 % Cr) ferritic steel? 2. Operating temperature between 700 °F and 1050 °F (371° C and 566 °C)?	If Yes to both, proceed to Section 2.E.5
Sigma Phase Embrittlement 1. Austenitic stainless steel? 2. Operating temperature between 1100 °F and 1700 °F (593 °C and 927 °C)?	If Yes to both, proceed to Section 2.E.6
Mechanical Fatigue (Piping) 1. Component piping? 2. History of fatigue failures, visible/audible shaking or a source of cyclic vibration (continuous or intermittent) within approximately 50 ft (15.24 m) that is connected (directly or indirectly via structure)?	If Yes to both, proceed to Section 2.E.7

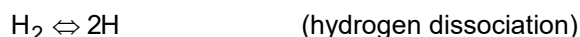
2.E.2 HTHA DF

2.E.2.1 Scope

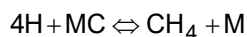
The DF calculation for carbon steel, C-1/2 Mo, and Cr-Mo low-alloy steel components subject to HTHA is covered in this section.

2.E.2.2 Description of Damage

HTHA occurs in carbon steel, C-1/2 Mo, and Cr-Mo low-alloy steels exposed to a high partial pressure of hydrogen at elevated temperatures. It is the result of atomic hydrogen diffusing through the steel and reacting with carbides in the microstructure. There are two reactions associated with HTHA. First the hydrogen molecule, H₂, must dissociate to form atomic hydrogen, H, which can diffuse through steel.



The reaction to form atomic hydrogen occurs more readily at higher temperatures and higher hydrogen partial pressures. As a result, as both the temperature and hydrogen partial pressure are increased, the driving force for HTHA increases. The second reaction that occurs is between atomic hydrogen and the metal carbides.



Damage due to the HTHA can possess two forms:

- 1) internal decarburization and fissuring from the accumulation of methane gas at the carbide matrix interface;
- 2) surface decarburization from the reaction of the atomic hydrogen with carbides at or near the surface where the methane gas can escape without causing fissures.

Internal fissuring is more typically observed in carbon steel, C-1/2 Mo steels, and in Cr-Mo low-alloy steels at higher hydrogen partial pressures, while surface decarburization is more commonly observed in Cr-Mo steels at higher temperatures and lower hydrogen partial pressures.

HTHA can be mitigated by increasing the alloy content of the steel and thereby increasing the stability of the carbides in the presence of hydrogen. As a result, carbon steel that only contains Fe₃C carbides has significantly less HTHA resistance than any of the Cr-Mo low-alloy steels that contain Cr and Mo carbides that are more stable and resistant to HTHA.

Historically, HTHA resistance has been predicted based on industry experience that has been plotted on a series of curves for carbon steel and Cr-Mo low-alloy steels showing the temperature and hydrogen partial pressure regime in which these steels have been successfully used without damage due to HTHA. These curves, which are commonly referred to as the Nelson curves, are maintained based on industry experience in API 941.

2.E.2.3 Current Status of HTHA Investigations and Inspection

In 2010, an incident within the refining industry led to an investigation where HTHA was identified as the damage mechanism that led to the failure of a heat exchanger. The refining industry has been examining the findings published in the Chemical & Safety Board report, along with new information from the industry concerning HTHA damage.

At the time of API 581, Third Edition release, API Recommended Practice 941, Seventh Edition—*Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*—has been published and a review of this module will be done in the future. Technology for

investigating HTHA susceptibility and inspection methods for detection and assessment of HTHA damage is being developed. The Third Edition of API 581 includes a conservative screening criterion that allows the owner–operator to flag components potentially affected by HTHA (see [Section 2.E.2.4](#)) until a more quantitative risk assessment is developed based on a later edition of API 941. Additionally, the most current edition of API 941 should be consulted for guidance on investigation, inspection, and replacement.

This document does not:

- a) prescribe changes in materials of construction for components that exceed limits defined in [Section 2.E.2.4](#);
- b) provide guidance for assessing HTHA damage.

This document provides a screening criteria to identify potentially susceptible components for a thorough investigation. It is the owner–operator's responsibility to:

- a) review, investigate, and determine the actual status regarding HTHA, including documenting the procedures, assessment results, and conclusions;
- b) conduct a thorough investigation and evaluate options for continued operation or replacement if HTHA is detected in the component during an inspection.

2.E.2.4 Screening Criteria for Carbon and C- $\frac{1}{2}$ Mo and Cr-Mo Low-alloy Steels

If all of the following are true, then the component should be evaluated for susceptibility to HTHA.

- a) The material is carbon steel, C- $\frac{1}{2}$ Mo, or a Cr-Mo low-alloy steel (such as Mn-0.5 Mo, $\frac{1}{2}$ Cr- $\frac{1}{2}$ Mo, 1 Cr- $\frac{1}{2}$ Mo, $1\frac{1}{4}$ Cr- $\frac{1}{2}$ Mo, $1\frac{1}{4}$ Cr- $\frac{1}{2}$ Mo-V, $2\frac{1}{4}$ Cr-1 Mo, 3 Cr-1 Mo, 5 Cr- $\frac{1}{2}$ Mo).
- b) The operating temperature is greater than 350 °F (177 °C).
- c) The operating hydrogen partial pressure is greater than 50 psia (0.345 MPa).

2.E.2.5 Required Data

The basic data required for analysis are provided in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for HTHA are provided in [Table 2.E.2.1](#).

2.E.2.6 Determination of the DF

2.E.2.6.1 Overview

A flow chart of the steps required to determine the DF for HTHA is shown in [Figure 2.E.2.2](#). The following sections provide additional information and the calculation procedure.

2.E.2.6.2 Inspection Effectiveness

Currently there is no level of inspection effectiveness (LoIE) for HTHA damage.

2.E.2.6.3 Calculation of the DF

The following procedure may be used to determine the DF for HTHA; see [Figure 2.E.2.2](#).

- a) Step 1—Determine the material of construction, exposure temperature, T , and the exposure hydrogen partial pressure, P_{H_2} .

- b) Step 2—Has HTHA damage historically been observed in the component?
- If yes and component has not been replaced, assign susceptibility to Damage Observed and skip to Step 4.
 - If yes and the component has been replaced in kind, assign susceptibility to High and skip to Step 4.
 - If a component has been replaced with an upgrade in the materials of construction, the component shall be reevaluated in Step 1 for the susceptibility based on the new material of construction.
- c) Step 3—Assign component susceptibility to HTHA as outlined below.
- 1) For Carbon and C-¹/₂ .Mo Alloy Steels.
 - a) If the exposure temperature is > 350 °F (177 °C) and the exposure hydrogen partial pressure is > 50 psia (0.345 MPa), assign a High susceptibility to HTHA.
 - b) If exposure temperature is ≤ 350 °F (177 °C) and the exposure hydrogen partial pressure is ≤ 50 psia (0.345 MPa), assign HTHA susceptibility to None.
 - 2) For All Other Cr-Mo Low-alloy Steels.

If the exposure temperature is > 350 °F (177 °C) and exposure hydrogen partial pressure is > 50 psia (0.345 MPa), calculate ΔT proximity to the API 941 curve using T and P_{H_2} from Step 1. Assign HTHA susceptibility using [Figure 2.E.2.1](#).

NOTE The approach used in [Figure 2.E.2.1](#) is an example guideline using 50 °F (27.7 °C) increments. The 50 °F (27.7 °C) increments were used to represent relative changes in susceptibility. It is the owner–operator’s responsibility to customize the values to represent their practice for determining HTHA susceptibility.
- d) Step 4—Determine the DF for HTHA, D_f^{HTHA} , using [Table 2.E.2.2](#) based on the susceptibility from Step 2 or Step 3.

2.E.2.6.4 Consideration of Susceptibility

The time in service of component significantly affects susceptibility to HTHA and should be considered during the HTHA review. Additionally, steels fabricated prior to 1970 may contain impurities and/or inclusions that were introduced during fabrication. As these steels age, they may become more susceptible to HTHA for similar process conditions compared to steels fabricated in 1980 or later. As a result, the owner–operator may choose more conservative guidelines by increasing the susceptibilities in [Table 2.E.2.2](#).

2.E.2.7 Nomenclature

D_f^{HTHA}	is the DF for HTHA
P_{H_2}	is the hydrogen partial pressure, MPa (psia)
T	is the operating temperature, °F (°C)

2.E.2.8 References

None.

2.E.2.9 Tables

Table 2.E.2.1—Data Required for Determination of Susceptibility to HTHA

Required Data	Comments
Material of construction	The component generic construction material (e.g. carbon steel, C- ¹ / ₂ Mo, 2 ¹ / ₄ Cr-1 Mo).
Hydrogen partial pressure, MPa (psia)	Determine the hydrogen partial pressure, which is equal to the product of the mole fraction of hydrogen and the total pressure (absolute).
Temperature, °F (°C)	The temperature of exposure.

Table 2.E.2.2—DF—HTHA

Susceptibility	DF
Damage Observed	5000
High Susceptibility	5000
Medium Susceptibility	2000
Low Susceptibility	100
No Susceptibility	0

2.E.2.10 Figures

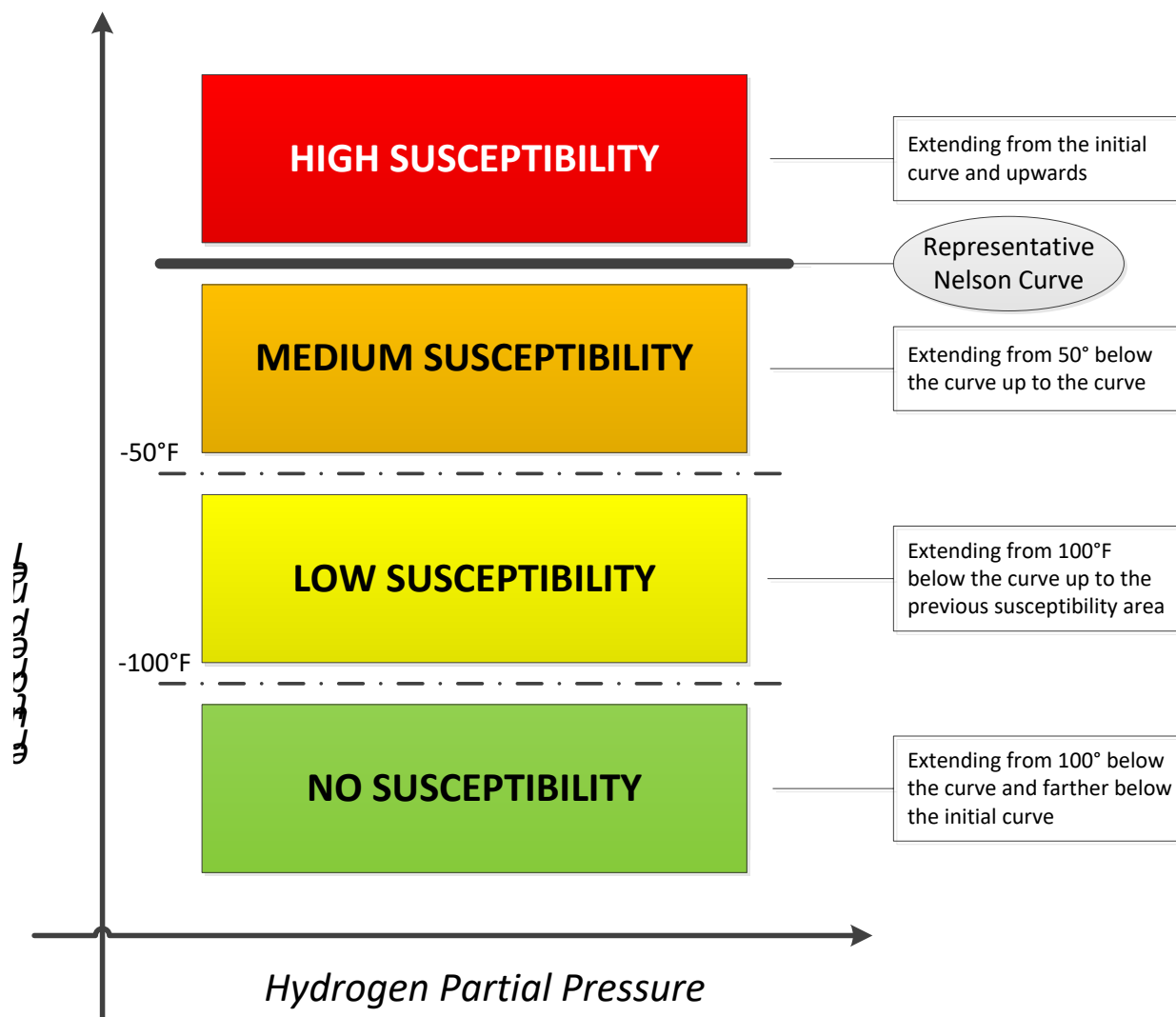


Figure 2.E.2.1—Example of HTHA Susceptibility Rankings for Cr-Mo Low-alloy Steels

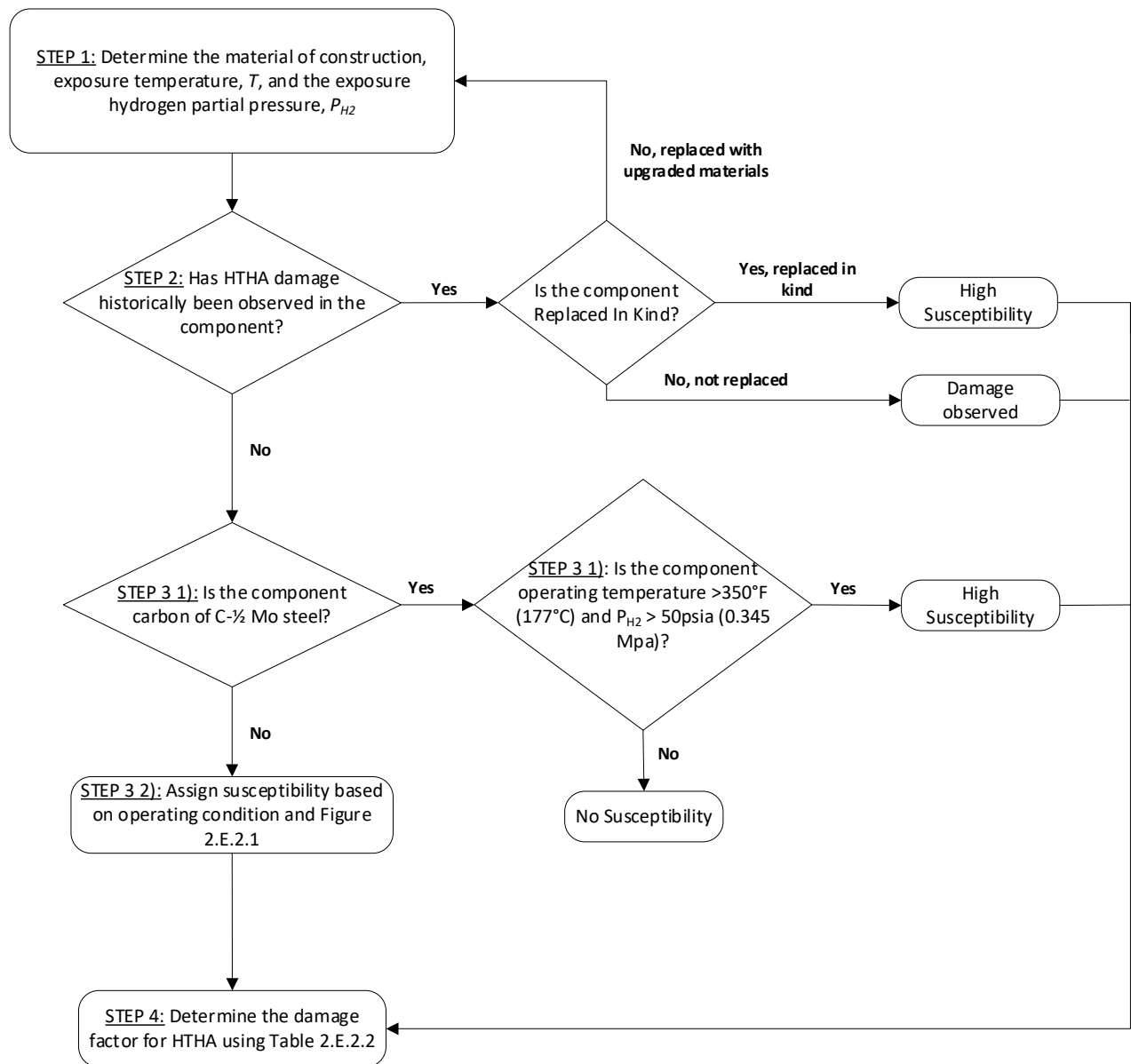


Figure 2.E.2.2—Determination of the HTHA DF

2.E.3 Brittle Fracture DF

2.E.3.1 Scope

The DF calculation for ferritic components subject to brittle fracture due to low-temperature operation is covered in this section. Low-alloy steels subject to embrittlement at relatively high temperature are not part of the scope in this section and are covered in [Section 2.E.4](#).

2.E.3.2 Description of Damage

Brittle fracture due to low temperature operation or relatively low toughness is the sudden failure of a structural component, usually initiated at a crack or defect. This is an unusual occurrence because design stresses are normally low enough to prevent such an occurrence. However, some older equipment with thick walls, equipment that might see low temperatures due to an upset, or equipment that has been modified could be susceptible to varying degrees.

Low temperature/low toughness fracture of steel is affected by the following.

- a) The applied loads. Brittle fracture is less likely at low applied loads.
- b) The material specification. Some materials are manufactured to have good fracture properties or toughness properties. Materials are often “qualified” for use by performing an impact test. This test measures the energy needed to break a notched specimen.
- c) Temperature. Many materials (especially ferritic steels) become brittle below some temperature called the brittle-ductile transition temperature or reference temperature. Brittle fracture is typically not a concern above 300 °F (149 °C).
- d) Weld residual stresses and PWHT.
- e) Thickness of the component.

The goal of the low temperature/low toughness fracture assessment is to rank components by their relative POF with respect to fracture. This assessment will take into account the thickness, the material type, the PWHT, and temperatures.

2.E.3.3 Screening Criteria

If both of the following are true, then the component should be evaluated for susceptibility to brittle fracture.

- 1) The material is carbon steel or a low-alloy steel; see [Table 2.E.3.1](#).
- 2) If minimum design metal temperature (MDMT), T_{MDMT} , or minimum allowable temperature (MAT), T_{MAT} , is unknown, or the component is known to operate at or below the MDMT or MAT under normal or upset conditions.

2.E.3.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for brittle fracture are provided in [Table 2.E.3.2](#).

2.E.3.5 Basic Assumption

Brittle fracture requires the coincident presence of a crack-like defect, application of sufficient stress, and a susceptible material. The susceptibility to failure by brittle fracture can change due to in-service conditions.

2.E.3.6 Determination of the DF

2.E.3.6.1 Overview

A flow chart of the steps required to determine the DF for brittle fracture is shown in [Figure 2.E.3.1](#). The following sections provide additional information and the calculation procedure.

2.E.3.6.2 Inspection Effectiveness

Low temperature/low toughness fracture is prevented by a combination of appropriate design and operating procedures. When low temperature/low toughness fracture does occur, it almost invariably initiates at some preexisting crack-like defect. From the initiation point, a crack will grow unstable, resulting in a serious leak or sometimes complete catastrophic rupture of the component. Theoretically, an inspection to locate and remove such preexisting defects would reduce the POF. However, the initiating defect can be very small and need not be exposed to the surface where it could be found. For this reason, inspection for such defects is generally not considered to be an effective method for prevention of brittle fracture.

If existing records of a component do not indicate if it is constructed of normalized plate, then a metallurgical examination may help resolve this. In some cases, it may be possible to remove samples of the material large enough for testing to determine the toughness, which can also improve the accuracy of the prediction of low temperature/low toughness fracture likelihood.

For this damage mechanism, credit is not given for inspection. However, the results of metallurgical testing together with impact testing can be used to update the inputs to the DF calculation that may result in a change in this value.

2.E.3.6.3 Calculation of the DF

The following procedure may be used to determine the DF for brittle fracture; see [Figure 2.E.3.1](#).

- a) Step 1—Determine if administrative or process controls exist that will prevent the component from being fully pressurized below some temperature. If so, use this temperature for critical exposure temperature, CET , and go to Step 3.
- b) Step 2—Determine the CET that the component may be subjected to during operation, using the guidance of API 579-1/ASME FFS-1, Part 3.
- c) Step 3—Determine the reference temperature, T_{ref} , using the material yield strength, YS , from [Table 2.E.3.3](#) and ASME Exemption Curve from [Table 2.E.3.1](#), in accordance with API 579-1/ASME FFS-1 [10].
- d) Step 4—Determine $CET - T_{ref}$ from Step 1 or Step 2, as applicable; T_{ref} is from Step 3.
- e) Step 5—Determine the base DF, D_{fb}^{brit} , using the component thickness, t , and [Table 2.E.3.4](#) or [Table 2.E.3.5](#) based on the component PWHT condition and $CET - T_{ref}$ from Step 4.
- f) Step 6—Determine the DF, D_f^{brit} , using [Equation \(2.E.1\)](#).

$$D_f^{brit} = D_{fb}^{brit} \cdot F_{SE} \quad (2.E.1)$$

In general, the adjustment factor for service experience is 1 or $F_{SE} = 1.00$. However, this factor is reduced to $F_{SE} = 0.01$ if the component under assessment has a thickness less than or equal to 0.5 in. (12.7 mm) or meets all of the following criteria.

- 1) It is fabricated from P-1 and P-3 steels where the design temperature is less than or equal to 650 °F (343 °C).
- 2) The equipment satisfied all requirements of a recognized code or standard at the time of fabrication.
- 3) The nominal operating conditions have been essentially the same and consistent with the specified design conditions for a significant period of time and more severe conditions (i.e. lower temperature and/or higher stress) are not expected in the future.
- 4) The CET at the MAWP is greater than or equal to -20 °F (-29 °C) if it is a pressure vessel or -155 °F (-104 °C) if it is a piping circuit.
- 5) The nominal uncorroded thickness is not greater than 2 in. (50.8 mm).
- 6) Cyclic service, fatigue, or vibration service is not a design requirement per design code.
- 7) The equipment or circuit is not subject to environmental cracking.
- 8) The equipment or circuit is not subject to shock chilling (see API 579-1/ASME FFS-1 for a definition of shock chilling).

This adjustment is based on the grandfathering concept permitted in API 579-1/ASME FFS-1, Part 3, Level 2, Method C.

2.E.3.7 Nomenclature

CET	is the critical exposure temperature as defined in API 579-1/ASME FFS-1, °F (°C)
D_f^{brit}	is the DF for brittle fracture
D_{fB}^{brit}	is the base DF for brittle fracture
F_{SE}	is the DF adjustment for service experience
T_{MAT}	is the MAT as defined in API 579-1/ASME FFS-1, °F (°C)
T_{MDMT}	is the MDMT as defined by construction code, °F (°C)
T_{ref}	is the reference temperature as defined in API 579-1/ASME FFS-1, °F (°C)
t	is the component thickness, in. (mm)
YS	is the material yield strength, ksi (MPa)

2.E.3.8 References

None.

2.E.3.9 Tables

Table 2.E.3.1—Assignment of Materials to the Material Temperature Exemption Curves

Curve	Material ^{1, 2, 6}
A	- All carbon and all low-alloy steel plates, structural shapes, and bars not listed in Curves B, C, and D below. - SA-216 Grades WCB and WCC if normalized and tempered or water-quenched and tempered; SA-217 Grade WC6 if normalized and tempered or water-quenched and tempered. - The following specifications for obsolete materials: A7, A10, A30, A70, A113, A149, A150.³ - The following specifications for obsolete materials from the 1934 edition of the ASME Code, Section VIII: S1, S2, S25, S26, and S27.⁴ - A201 and A212 unless it can be established that the steel was produced by a fine-grain practice.⁵
B	- SA-216 Grade WCA if normalized and tempered or water-quenched and tempered. SA-216 Grades WCB and WCC for thicknesses not exceeding 2 in. if produced to a fine-grain practice and water-quenched and tempered. SA -217 Grade WC9 if normalized and tempered. SA-285 Grades A and B. SA-414 Grade A. SA-442 Grade 55 > 1 in. if not to fine-grain practice and normalized. SA-442 Grade 60 if not to fine-grain practice and normalized. SA-515 Grades 55 and 60. SA-516 Grades 65 and 70 if not normalized. SA-612 if not normalized. SA-662 Grade B if not normalized. - Except for cast steels, all materials of Curve A if produced to fine-grain practice and normalized that are not listed for Curves C and D below. - All pipe, fittings, forgings, and tubing not listed for Curves C and D below. - Parts permitted from paragraph UG-11 of the ASME Code, Section VIII, Division 1, shall be included in Curve B even when fabricated from plate that otherwise would be assigned to a different curve. - A201 and A212 if it can be established that the steel was produced by a fine-grain practice.
C	- SA-182 Grades 21 and 22 if normalized and tempered. SA-302 Grades C and D. SA-336 Grades F21 and F22 if normalized and tempered. SA-387 Grades 21 and 22 if normalized and tempered. SA-442 Grade 55 < 1 in. if not to fine-grain practice and normalized. SA-516 Grades 55 and 60 if not normalized. SA-533 Grades B and C. SA-662 Grade A. - All material of Curve B if produced to fine-grain practice and normalized and not listed for Curve D below.

Curve	Material ^{1, 2, 6}
D	SA-203. SA-442 if to fine-grain practice and normalized. SA-508 Class 1. SA-516 if normalized. SA-524 Classes 1 and 2. SA-537 Classes 1 and 2. SA-612 if normalized. SA-662 if normalized. SA-738 Grade A.
NOTE 1 When a material class or grade is not shown, all classes or grades are included. NOTE 2 The following apply to all material assignment notes. a. Cooling rates faster than those obtained in air, followed by tempering, as permitted by the material specification, are considered equivalent to normalizing and tempering heat treatments. b. Fine-grain practice is defined as the procedures necessary to obtain a fine austenitic grain size as described in SA-20. NOTE 3 The first edition of the <i>API Code for Unfired Pressure Vessels</i> (discontinued in 1956) included these ASTM carbon steel plate specifications. These specifications were variously designated for structural steel for bridges, locomotives, and rail cars or for boilers and firebox steel for locomotives and stationary service. ASTM A149 and A150 were applicable to high-tensile-strength carbon steel plates for pressure vessels. NOTE 4 The 1934 edition of Section VIII of the ASME <i>Code</i> listed a series of ASME steel specifications, including S1 and S2 for forge welding; S26 and S27 for carbon steel plates; and S25 for open-hearth iron. The titles of some of these specifications are similar to the ASTM specifications listed in the 1934 edition of the <i>API Code for Unfired Pressure Vessels</i>. NOTE 5 These two steels were replaced in strength grades by the four grades specified in ASTM A515 and the four grades specified in ASTM A516. Steel in accordance with ASTM A212 was made only in strength grades the same as Grades 65 and 70 and has accounted for several known brittle failures. Steels in conformance with ASTM A201 and A212 should be assigned to Curve A unless it can be established that the steel was produced by fine-grain practice, which may have enhanced the toughness properties. NOTE 6 No attempt has been made to make a list of obsolete specifications for tubes, pipes, forgings, bars, and castings. Unless specific information to the contrary is available, all of these product forms should be assigned to Curve A.	

Table 2.E.3.2—Data Required for Determination of the DF—Brittle Fracture

Required Data	Comments
Administrative controls for upset management (Yes/No)	Are there controls and or awareness training to prevent the coincident occurrence of low temperatures (upset) at or near design pressures?
Minimum operating temperature under normal or upset conditions, °F (°C)	Can be entered by the user. The temperature may be set to the atmospheric boiling point of the fluid in the component if the fluid is a liquid.
Service life of equipment (years)	How long has the equipment been in the specified service?
Inspection and testing history accuracy factor	Accuracy and attainability of previous inspection history. Frequency of inspections, data points available. Previous metallurgical analysis and mechanical testing (impact test).

Table 2.E.3.3—Reference Temperature

Carbon Steels—20 joule or 15 ft-lb Transition Temperature for Each ASME Exemption Curve				
Minimum Yield Strength (ksi)	ASME Exemption (°F)			
	Curve A	Curve B	Curve C	Curve D
30	104	66	28	2
32	97	59	21	−5
34	91	53	15	−11
36	86	48	10	−16
38	81	43	5	−21
40	78	40	2	−24
42	74	36	−2	−28
44	71	33	−5	−31
46	68	30	−8	−34
48	66	28	−10	−36
50	63	25	−13	−39
Low-alloy Steels—27 joule or 20 ft-lb Transition Temperature for Each ASME Exemption Curve				
Minimum Yield Strength (ksi)	ASME Exemption (°F)			
	Curve A	Curve B	Curve C	Curve D
30	124	86	48	22
32	115	77	39	13
34	107	69	31	5
36	101	63	25	−1
38	96	58	20	−6
40	92	54	16	−10
42	88	50	12	−14
44	85	47	9	−17
46	81	43	5	−21
48	79	41	3	−23
50	76	38	0	−26
52	73	35	−3	−29
54	71	33	−5	−31
56	69	31	−7	−33
58	67	29	−9	−35
60	65	27	−11	−37
62	63	25	−13	−39
64	62	24	−14	−40
66	60	22	−16	−42
68	58	20	−18	−44
70	57	19	−19	−45
72	56	18	−20	−46
74	54	16	−22	−48
76	53	15	−23	−49
78	52	14	−24	−50
80	51	13	−25	−51

Table 2.E.3.3M—Reference Temperature

Carbon Steels—20 joule or 15 ft-lb Transition Temperature for Each ASME Exemption Curve				
Minimum Yield Strength (MPa)	ASME Exemption (°C)			
	Curve A	Curve B	Curve C	Curve D
200	42	21	0	−15
210	38	17	−4	−18
220	36	15	−7	−21
230	33	1	−9	−23
240	31	10	−11	−26
260	27	6	−15	−29
280	24	3	−18	−32
300	22	1	−21	−35
320	19	−2	−23	−37
340	17	−4	−25	−39
360	15	−6	−27	−41
Low-alloy Steels—27 joule or 20 ft-lb Transition Temperature for Each ASME Exemption Curve				
Minimum Yield Strength (MPa)	ASME Exemption (°C)			
	Curve A	Curve B	Curve C	Curve D
200	55	33	12	−2
210	50	29	8	−7
220	46	25	4	−11
230	43	22	1	−14
240	40	19	−2	−16
250	38	17	−4	−19
260	36	15	−6	−21
270	34	13	08	−23
280	32	11	−10	−24
290	31	10	−11	−26
300	30	8	−13	−27
310	28	7	−14	−28
320	27	6	−15	−30
330	26	5	−16	−31
340	25	4	−17	−32
360	23	2	−19	−34
380	21	0	−21	−36
400	19	−2	−23	−37
420	18	−3	−24	−39
440	16	−5	−26	−40
460	15	−6	−27	−42
480	14	−7	−28	−43
500	13	−8	−29	−44
520	12	−9	−30	−45
540	11	−10	−31	−46
560	10	−11	−32	−47

Table 2.E.3.4—DF, Component Not Subject to PWHT—Brittle Fracture

$CET - T_{ref}$ (°F)	DF as a Function of Component Thickness (in.)								
	0.25	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
100	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.1	1.2
80	0.0	0.0	0.0	0.8	1.1	2	3	4	6
60	0.0	0.0	1.0	2	4	9	19	36	60
40	0.0	0.7	2	9	29	69	133	224	338
20	0.1	1.3	10	49	143	296	500	741	1008
0	0.9	3	39	175	424	759	1142	1545	1950
-20	1.2	7	109	405	850	1366	1897	2415	2903
-40	2	16	220	697	1317	1969	2596	3176	3703
-60	2	30	350	988	1740	2479	3160	3769	4310
-80	3	46	474	1239	2080	2873	3581	4203	4746
-100	4	61	579	1436	2336	3160	3883	4509	5000

Table 2.E.3.4M—DF, Component Not Subject to PWHT—Brittle Fracture

$CET - T_{ref}$ (°C)	DF as a Function of Component Thickness (mm)								
	6.4	12.7	25.4	38.1	50.8	63.5	76.2	88.9	101.6
56	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.1	1.2
44	0.0	0.0	0.0	0.8	1.1	2	3	4	6
33	0.0	0.0	1.0	2	4	9	19	36	60
22	0.0	0.7	2	9	29	69	133	224	338
11	0.1	1.3	10	49	143	296	500	741	1008
-0	0.9	3	39	175	424	759	1142	1545	1950
-11	1.2	7	109	405	850	1366	1897	2415	2903
-22	2	16	220	697	1317	1969	2596	3176	3703
-33	2	30	350	988	1740	2479	3160	3769	4310
-44	3	46	474	1239	2080	2873	3581	4203	4746
-56	4	61	579	1436	2336	3160	3883	4509	5000

Table 2.E.3.5—DF, Component Subject to PWHT—Brittle Fracture

$CET - T_{ref}$ (°F)	DF as a Function of Component Thickness (in.)								
	0.25	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0
100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
80	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
60	0.0	0.0	0.0	0.0	0.0	0.5	0.9	1.1	1.3
40	0.0	0.0	0.0	0.5	1.1	1.3	2	3	4
20	0.0	0.0	0.6	1.2	2	4	7	13	23
0	0.0	0.0	1.1	2	6	14	29	53	88
-20	0.0	0.4	2	5	17	41	83	144	224
-40	0.0	0.9	3	12	38	90	171	281	416
-60	0.0	1.1	5	22	68	153	277	436	623
-80	0.0	1.2	7	34	102	219	382	582	810
-100	0.0	1.3	9	46	133	277	472	704	962

Table 2.E.3.5M—DF, Component Subject to PWHT—Brittle Fracture

$CET - T_{ref}$ (°C)	DF as a Function of Component Thickness (mm)								
	6.4	12.7	25.4	38.1	50.8	63.5	76.2	88.9	101.6
56	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
33	0.0	0.0	0.0	0.0	0.0	0.5	0.9	1.1	1.3
22	0.0	0.0	0.0	0.5	1.1	1.3	2	3	4
11	0.0	0.0	0.6	1.2	2	4	7	13	23
-0	0.0	0.0	1.1	2	6	14	29	53	88
-11	0.0	0.4	2	5	17	41	83	144	224
-22	0.0	0.9	3	12	38	90	171	281	416
-33	0.0	1.1	5	22	68	153	277	436	623
-44	0.0	1.2	7	34	102	219	382	582	810
-56	0.0	1.3	9	46	133	277	472	704	962

2.E.3.10 Figures

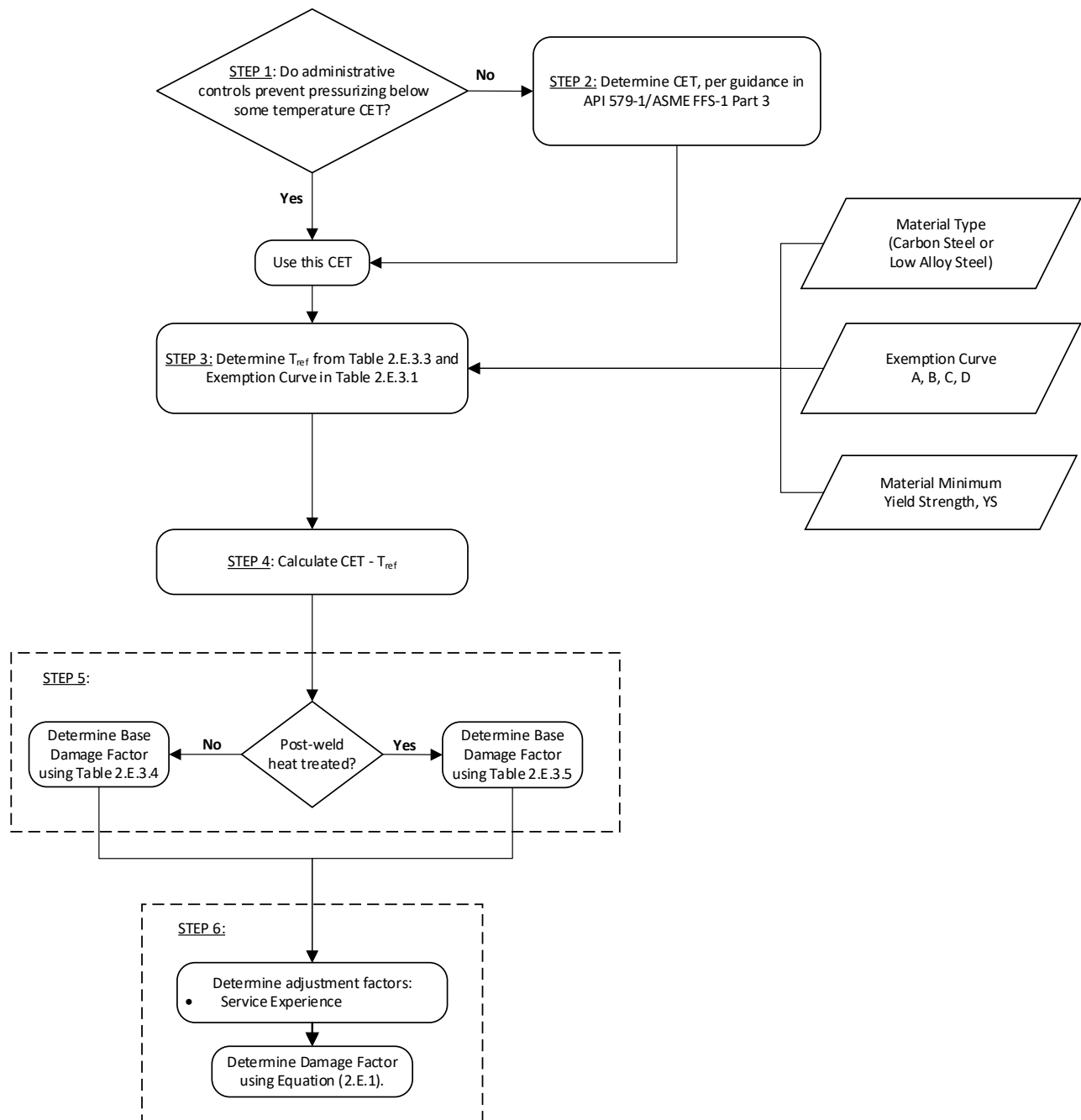


Figure 2.E.3.1—Determination of the Brittle Fracture DF

2.E.4 Low-alloy Steel Embrittlement DF

2.E.3.1 Scope

The DF calculation for low-alloy Cr-Mo steel components subject to embrittlement is covered in this section.

2.E.3.2 Description of Damage

The toughness of some low-alloy or Cr-Mo steels is reduced by a phenomenon called embrittlement after extended exposure to temperatures in the range of 650 °F to 1070 °F (343 °C to 577 °C). Of particular interest to the refining and petrochemical industries is the embrittlement of Cr-Mo steels used in operations within the temperature range for embrittlement. The reduction in fracture toughness only affects the material at the lower temperatures experienced during start-up and shutdown of equipment. Industry practice to avoid brittle fracture has been to reduce the operating pressure to one-fourth of the design pressure when the vessel temperature is less than some minimum process temperature. Typical industry practice for this minimum temperature is 300 °F to 350 °F (149 °C to 177 °C) for older vintage low-alloy steels or lower temperatures for more modern steels.

The embrittlement is caused by segregation of tramp elements and alloying elements along grain boundaries in the steel. The phosphorous and tin content of the steel are of particular importance in 2.25Cr-1Mo and 3Cr-1Mo alloys, and their effect is made worse by manganese and silicon, which are important alloying elements, while in 1.25Cr-0.5Mo and 1Cr-0.5Mo alloys, phosphorus, arsenic, and antimony are also of particular importance. A J-factor based on composition is typically specified to control the susceptibility to low-alloy steel embrittlement in 2.25Cr-1Mo alloys and 3Cr-1Mo alloys. The J-factor and X-bar factor are calculated using [Equation \(2.E.2\)](#) and [Equation \(2.E.3\)](#). Laboratory and long-term field studies have confirmed fair correlation between the J-factor and the amount of low-alloy steel embrittlement in 2.25Cr-1Mo and 3Cr-1Mo alloys and between X-bar factor and embrittlement of 1.25Cr-0.5Mo and 1Cr-0.5Mo alloys.

$$\text{J-factor} = (\% \text{Si} + \% \text{Mn}) \cdot (\% \text{P} + \% \text{Sn}) \cdot 10^4 \quad (2.E.2)$$

$$\text{X-bar} = (10\% \text{P} + 5\% \text{Sb} + 4\% \text{Sn} + \% \text{As}) \cdot 100 \quad (2.E.3)$$

One very important aspect of embrittlement is the tendency of weld metal and HAZs to show increased susceptibility to embrittlement vs the wrought base material. A few studies have shown that 2.25Cr-0.5Mo and 3Cr-1Mo are particularly susceptible. It is debatable whether or not 1.25Cr-0.5Mo and 1Cr-0.5Mo steels are also susceptible to temper embrittlement but are susceptible to in-service loss of toughness; therefore, these materials have been included in the DF calculations in this section.

2.E.3.3 Screening Criteria

If all of the following are true, then the component should be evaluated for susceptibility to low-alloy steel embrittlement.

- a) The material is 1Cr-0.5Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, or 3Cr-1 Mo low-alloy steel.
- b) The operating temperature is between 650 °F and 1070 °F (343 °C and 577 °C).

2.E.3.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for low-alloy steel embrittlement are provided in [Table 2.E.3.1](#).

2.E.3.5 Basic Assumption

Low-alloy steel embrittlement is evaluated in the same way as brittle fracture (see [Section 2.E.2](#)) except that a shift in the reference temperature is made to account for embrittlement.

2.E.3.6 Determination of the DF

2.E.3.6.1 Overview

A flow chart of the steps required to determine the DF for low-alloy steel embrittlement is shown in [Figure 2.E.3.1](#). The following sections provide additional information and the calculation procedure.

2.E.3.6.2 Inspection Effectiveness

For this damage mechanism, credit is not given for inspection. However, the results of metallurgical testing together with impact testing can be used to update the inputs to the DF calculation that may result in a change in this value.

2.E.3.6.3 Calculation of the DF

The following procedure may be used to determine the DF for low-alloy steel embrittlement; see [Figure 2.E.3.1](#).

- a) Step 1—Determine if administrative or process controls exist that will prevent the component from being fully pressurized below some temperature. If so, use this as the minimum pressurization temperature, T_{MPT} , and go to Step 3.
- b) Step 2—Determine the T_{MPT} that the component may be subjected to during operation, using the lowest of the following.
 - 1) The minimum design temperature, T_{MDT} .
 - 2) The T_{MDT} as estimated by the process engineer, including upsets.
- c) Step 3—Determine the reference temperature, T_{ref} , from [Table 2.E.2.3](#) using material yield strength, YS , and the material specification from [Table 2.E.2.1](#) ^[10].
- d) Step 4—Determine $\Delta FATT$. If $\Delta FATT$ is not known it may be estimated by one of the following methods, listed in decreasing order of accuracy.
 - 1) Determined by engineering analysis or actual impact testing of metal samples.
 - 2) Determined in a step cooling embrittlement test, SCE . The SCE can be related to the actual in-service $\Delta FATT$ using [Equation \(2.E.4\)](#), where age is the operating time in hours and SCE is the specified change in $FATT$.

$$\Delta FATT = 0.67 \cdot (\log(age) - 0.91) \cdot SCE \quad (2.E.4)$$

- 3) Determined by chemical composition correlations. Use the chemical composition to determine the J-factor or X-bar factor using Equation (2.E.2) and Equation (2.E.3). The J-factor and X-bar factor may be correlated to the expected $\Delta FATT$ after long-term service. Based on long-term exposures, this is conservatively correlated to the J-factor and X-bar factor in Equation (2.E.5) and Equation (2.E.6), respectively.

$$\Delta FATT = -77.321 + (0.57570 \cdot \text{J-factor}) - \left(5.5147 \cdot (10^{-4}) \times (\text{J-factor}^2) \right) \quad (2.E.5)$$

$$\Delta FATT = -87.335 + (11.437 \cdot \text{X-bar}) - \left(0.1472 \cdot (\text{X-bar}^2) \right) \quad (2.E.6)$$

- 4) Determined by using conservative assumptions based on year of fabrication. A conservative value of can be assumed for the long term $\Delta FATT$ depending on the year of fabrication as follows:

- fourth generation equipment (after to 1988): 150 °F (66 °C);
- third generation equipment (1981 to 1987): 250 °F (121 °C);
- second generation equipment (1973 to 1980): 300 °F (149 °C);
- first generation equipment (1965 to 1972): 350 °F (177 °C).

e) Step 5—Calculate $T_{\text{ref}} + \Delta FATT$ using T_{ref} from Step 3 and $\Delta FATT$ from Step 4.

f) Step 6—Calculate the DF, D_f^{tempe} , using Table 2.E.2.4 or Table 2.E.2.5 based on the component PWHT condition and where $T_{\text{ref}} + \Delta FATT$ is from Step 5.

NOTE Use $T_{\text{MPT}} - (T_{\text{ref}} + \Delta FATT)$ in place of $CET - T_{\text{ref}}$ with T_{MPT} from Step 1 or Step 2, as applicable.

2.E.3.7 Nomenclature

age	is the in-service operating time, hours
D_f^{tempe}	is the DF for low-alloy steel embrittlement
SCE	is the specified change in $FATT$
T_{MDT}	is the minimum design temperature, °F (°C)
T_{MPT}	is the minimum pressurization temperature, °F (°C)
T_{ref}	is the reference temperature, °F (°C)
YS	is the material yield strength
$\Delta FATT$	is the change in the fracture appearance transition temperature, °C for equations in this section

2.E.3.8 References

See References [76], [84], [85], [86], [87], [88], [89], and [90] in Annex 2.G.

2.E.3.9 Tables

Table 2.E.3.1—Data Required for Determination of the DF—Low-alloy Steel Embrittlement

Required Data	Comments
Impact test temperature, °F (°C)	If impact tested. If this is unknown, it should be assumed that impact tests were not done.
Administrative controls for upset management (Yes/No)	Are there controls and or awareness training to prevent the coincident occurrence of low temperatures (upset) at or near design pressures?
Minimum operating temperature under normal, start-up/shutdown, or upset conditions, °F (°C)	For low-alloy steel embrittlement, this may be the temperature below which the operating pressure is reduced for purposes of fracture control. If not known, the temperature should be set to the atmospheric boiling point of the fluid in the component if the fluid is a liquid.
Time in service, years	The number of years in service within the temperature range.
$\Delta FATT$, °F (°C)	The change in the fracture appearance transition temperature before and after embrittlement.
Chemical composition of steel (optional)	Specifically, the %Si, %Mn, %P, and %Sn for 2.25Cr-1Mo and 3Cr-1Mo steels and the %P, %Sb, %Sn, and %As for 1.25Cr-1Mo and 1Cr-1Mo steels, which contribute to the susceptibility to low-alloy steel embrittlement. If not known, a transition shift will be assumed.
Screening of materials (Y/N)	Was the material used for the component screened for susceptibility to low-alloy steel embrittlement by such methods as specifications for steel composition or specification of a transition temperature requirement in a step cooling embrittlement (<i>SCE</i>) test.
<i>SCE</i> specified delta temperature, °F (°C)	The delta temperature specified for <i>SCE</i> tests.

2.E.3.10 Figures

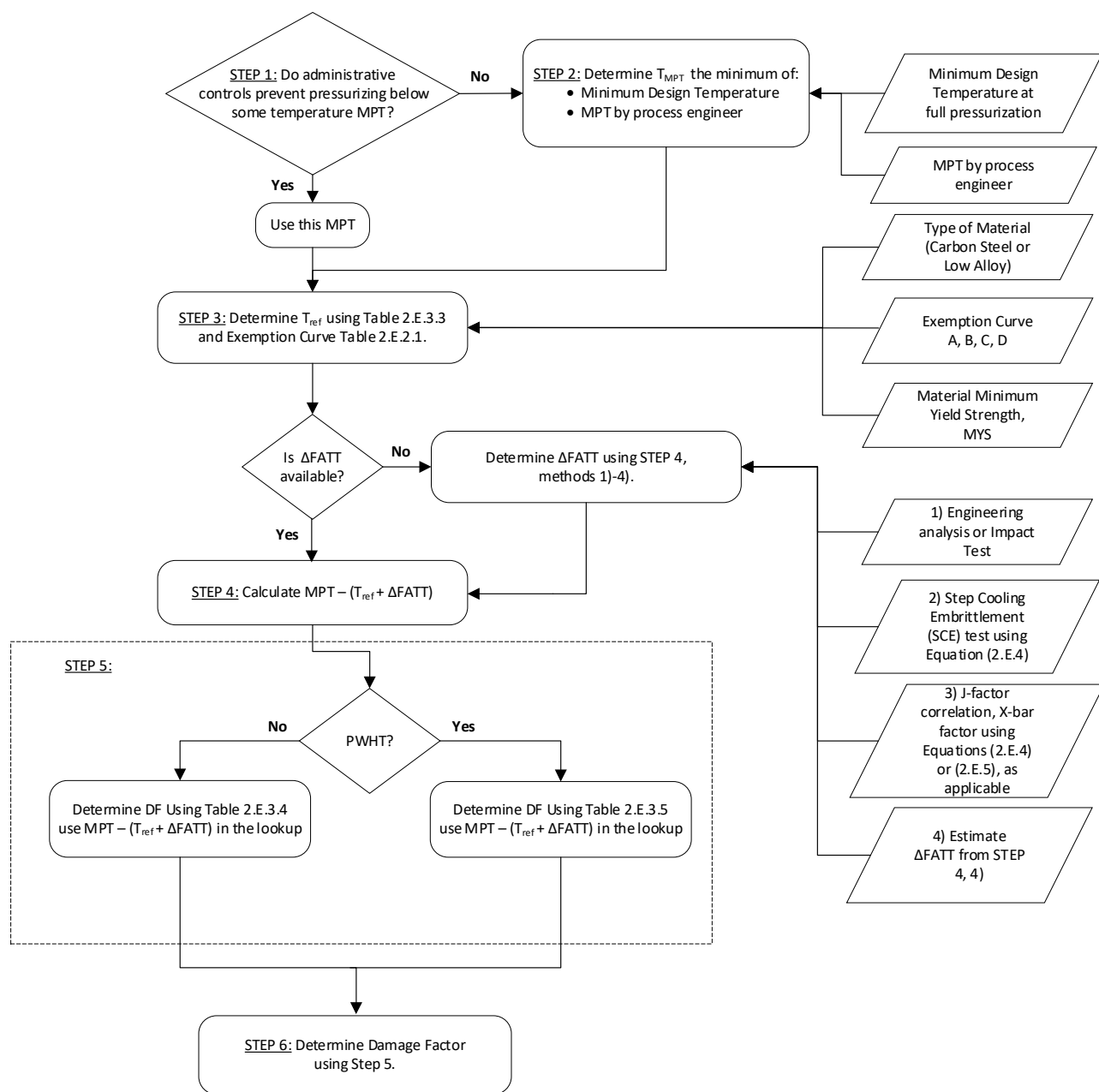


Figure 2.E.3.1—Determination of the Low-alloy Steel Embrittlement DF

2.E.5 885 °F Embrittlement DF

2.E.5.1 Scope

The DF calculation for components subject to 885 °F embrittlement is covered in this section.

2.E.5.2 Description of Damage

885 °F embrittlement is a reduction in toughness of ferritic stainless steels with a chromium content of greater than 13 %, after exposure to temperatures between 700 °F and 1000 °F (371 °C and 538 °C). The reduction in toughness is due to precipitation of a chromium-phosphorous intermetallic phase at elevated temperatures. As is the case with other mechanisms that result in a loss of toughness due to metallurgical changes, the effect on toughness is most pronounced not at the operating temperature, but at lower temperatures experienced during plant shutdowns or upsets.

The precipitation of the intermetallic phase is believed to occur most readily at a temperature around 885 °F (474 °C), hence the name for this mechanism. Steels with more than 27 % chromium are most severely affected, but these are not typically used in refinery or petrochemical processes. Martensitic stainless steels such as Type 410 are normally considered to be immune to this problem. Type 405 is a ferritic stainless steel that is subject to the problem if it contains chromium levels at the high end of its composition range.

The existence of 885 °F embrittlement can reveal itself by an increase in hardness in affected areas. Physical testing of samples removed from service is the most positive indicator of a problem.

885 °F embrittlement is reversible by appropriate heat treatment to dissolve precipitates, followed by rapid cooling. Heat treatment temperature is typically in the range of 1400 °F to 1500 °F (760 °C to 816 °C), so this may not be practical for many components.

2.E.5.3 Screening Criteria

If both of the following are true, then the component should be evaluated for susceptibility to 885 °F embrittlement.

- a) The material is a high chromium (> 12 % Cr) ferritic steel.
- b) The operating temperature is between 700 °F and 1050 °F (371 °C and 566 °C).

2.E.5.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for 885 °F embrittlement are provided in [Table 2.E.5.1](#).

2.E.5.5 Basic Assumption

Since 885 °F embrittlement may occur in a relatively short period of time, it is assumed in the development of the DF that any of the ferritic materials listed in [Table 2.E.5.2](#) that have been exposed to temperatures in the 700 °F to 1000 °F (371 °C to 538 °C) range are affected.

API 579-1/ASME FFS-1 [\[10\]](#) recommends that for embrittled materials, the toughness should be determined by the K_{Ic} (fracture arrest) curves, truncated at 100 °F (38 °C). It is further recommended that for severely embrittled materials, 50 % of this value should be used. The ductile-to-brittle transition temperatures for ferritic stainless steels (400 series) typically are in the 50 °F to 100 °F (10 °C to 38 °C) range.

2.E.5.6 Determination of the DF

2.E.5.6.1 Overview

A flow chart of the steps required to determine the DF for 885 °F embrittlement is shown in [Figure 2.E.5.1](#). The following sections provide additional information and the calculation procedure.

2.E.5.6.2 Inspection Effectiveness

For this damage mechanism, credit is not given for inspection. However, the results of metallurgical testing can be used to update the inputs to the DF calculation that may result in a change in this value.

2.E.5.6.3 Calculation of the DF

The following procedure may be used to determine the DF for 885 °F embrittlement; see [Figure 2.E.5.1](#).

- a) Step 1—Determine if administrative or process controls exist that will prevent the component from being fully pressurized below some temperature. If so, use this temperature for $T_{\min}$ and go to Step 3.
- b) Step 2—Determine the minimum temperature, $T_{\min}$, that the component may be subjected to during operation, using the lowest of the following:
 - 1) the minimum design temperature;
 - 2) the minimum temperature as estimated by the process engineer, including upsets.
- c) Step 3—Determine the reference temperature. Use $T_{\text{ref}} = 28\text{ °C}$ (80 °F) unless the actual ductile to brittle transition temperature is known.
- d) Step 4—Determine $T_{\min} - T_{\text{ref}}$, where $T_{\min}$ is from Step 1 or Step 2, as applicable, and T_{ref} is from Step 3.
- e) Step 5—Determine the DF, $D_f^{885\text{F}}$, using [Table 2.E.5.3](#) based on $T_{\min} - T_{\text{ref}}$ from Step 4.

2.E.5.7 Nomenclature

$D_f^{885\text{F}}$ is the DF for 885 °F embrittlement

$T_{\min}$ is the minimum temperature, °F (°C)

T_{ref} is the reference temperature, °F (°C)

2.E.5.8 References

See References [\[65\]](#), [\[66\]](#), [\[67\]](#), and [\[68\]](#) in [Annex 2.G](#).

2.E.5.9 Tables

Table 2.E.5.1—Data Required for Determination of the DF—885 °F Embrittlement

Required Data	Comments
Administrative controls for upset management (Yes/No)	Are there controls and or awareness training to prevent the coincident occurrence of low temperatures (upset) at or near design pressures?
Minimum operating temperature under normal, start-up/shutdown, or upset conditions, °F (°C)	This may be the temperature below which the operating pressure is reduced for purposes of fracture control. If not entered, the temperature will be set to the atmospheric boiling point of the fluid in the component if the fluid is a liquid.
T_{ref} , °F (°C)	The original transition temperature.

Table 2.E.5.2—Materials Affected by 885 °F Embrittlement

AISI Designation	% Chromium
Type 405	11.5 to 14.5
Type 430	16 to 18
Type 430F	16 to 18
Type 442	18 to 23
Type 446	23 to 27

Table 2.E.5.3—DF—885 °F Embrittlement

$T_{min} - T_{ref}$		DF
°C	°F	
> 56	> 100	0
56	100	2
44	80	8
33	60	30
22	40	87
11	20	200
0	0	371
-11	-20	581
-22	-40	806
-33	-60	1022
-44	-80	1216
-56	-100	1381

2.E.5.10 Figures

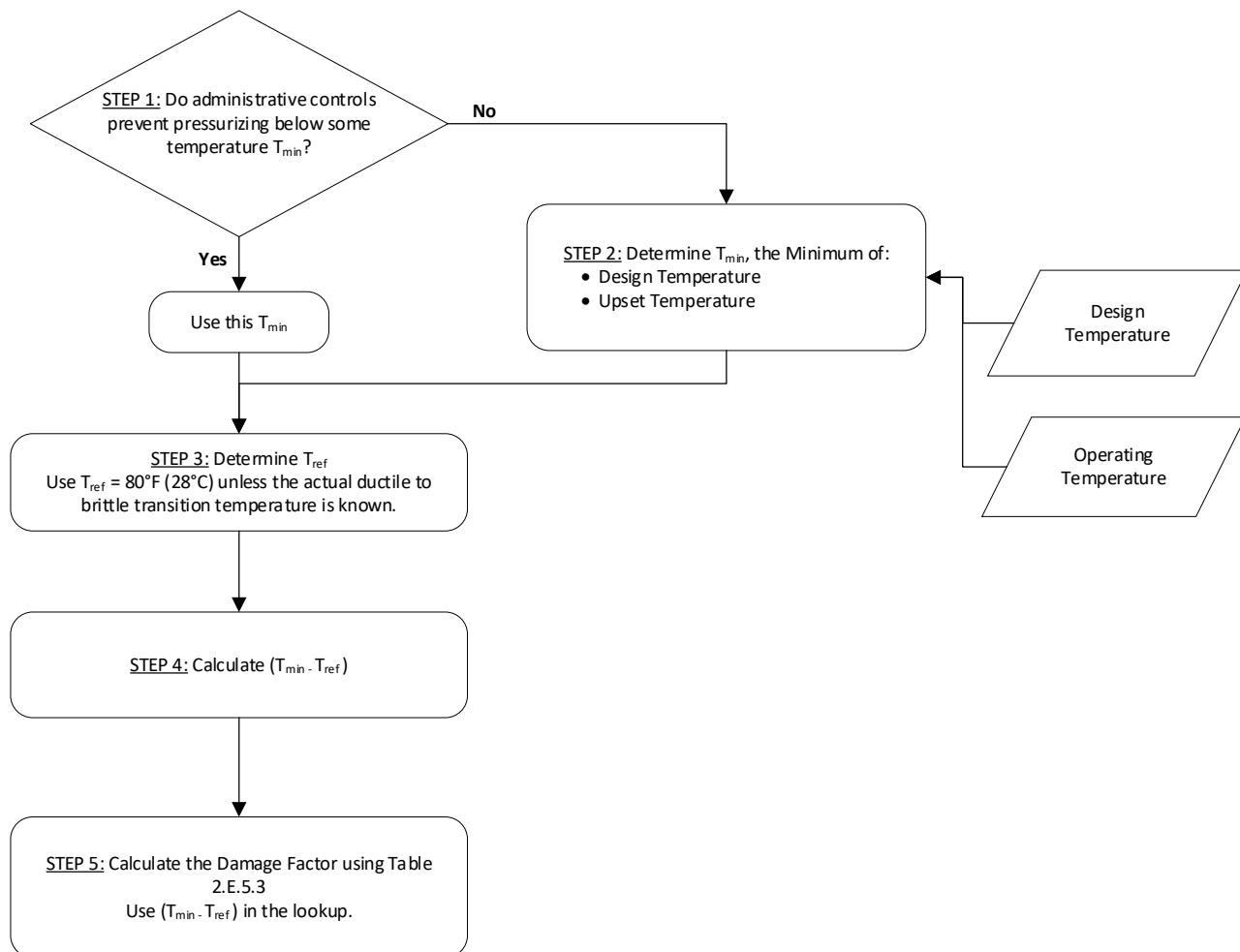


Figure 2.E.5.1—Determination of the 885 °F Embrittlement DF

2.E.6 Sigma Phase Embrittlement DF

2.E.6.1 Scope

The DF calculation for components subject to sigma phase embrittlement is covered in this section.

2.E.6.2 Description of Damage

Sigma phase is a hard, brittle intermetallic compound of iron and chromium with an approximate composition of $\text{Fe}_{0.6}\text{Cr}_{0.4}$. It occurs in ferritic (Fe-Cr), martensitic (Fe-Cr), and austenitic (Fe-Cr-Ni) stainless steels when exposed to temperatures in the range of 1100 °F to 1700 °F (593 °C to 927 °C). The rate of formation and the amount of sigma formed are dependent on chemical composition of the alloy and prior cold work history. Ferrite stabilizers (Cr, Si, Mo, Al, W, V, Ti, Nb) tend to promote sigma formation, while austenite stabilizers (C, Ni, N, Mn) tend to retard sigma formation. Austenitic stainless steel alloys typically exhibit a maximum of about 10 % sigma phase, or less with increasing nickel. However, other alloys with a nominal composition of 60 % Fe, 40 % Cr (about the composition of sigma) can be transformed to essentially 100 % sigma. A transformation vs time curve for such a Fe-Cr alloy showed 100 % conversion to sigma in 3 hours at 1377 °F (747 °C). Conversion to sigma in austenitic stainless steels can also occur in a few hours, as evidenced by the known tendency for sigma to form if an austenitic stainless steel is subjected to a PWHT at 1275 °F (691 °C). Sigma is unstable at temperatures above 1650 °F (899 °C), and austenitic stainless steel components can be de-sigmatized by solution annealing at 1950 °F (1066 °C) for 4 hours followed by a water quench.

Mechanical properties of sigmatized materials are affected depending upon both the amount of sigma present and the size and shape of the sigma particles. For this reason, prediction of mechanical properties of sigmatized material is difficult.

The tensile and yield strength of sigmatized stainless steels increases slightly compared with solution annealed material. This increase in strength is accompanied by a reduction in ductility (measured by % elongation and reduction in area) and a slight increase in hardness.

The property that is most affected by sigma formation is the toughness. Impact tests show decreased impact energy absorption and decreased percent shear fracture sigmatized stainless steels vs solution annealed material. The effect is most pronounced at temperatures below 1000 °F (538 °C) although there may be some reduction in impact properties at higher temperatures as well. However, because austenitic stainless steels exhibit such good impact properties in the solution annealed condition, then even with considerable degradation, the impact properties may be comparable to other steels used in the process industries. A draft FFS report from the Materials Properties Council recommends default fracture toughness values of $150 \text{ ksi}\sqrt{\text{in.}}$ and $90 \text{ ksi}\sqrt{\text{in.}}$ for base and weld material, respectively, for thermally embrittled austenitic stainless steels.

Tests performed on sigmatized stainless steel samples from FCC regenerator internals showed that even with 10 % sigma formation, the Charpy impact toughness was 39 ft-lb at 1200 °F (53 joules at 649 °C). This would be considered adequate for most steels but is much less than the 190 ft-lb (258 joules) obtained for solution annealed stainless steel. In this specimen, the impact toughness was reduced to 13 ft-lb at room temperature, a marginal figure but still acceptable for many applications. The percent of shear fracture is another indicator of material toughness, indicating what percent of the Charpy impact specimen broke in a ductile fashion. For the 10 % sigmatized specimen referenced above, the values ranged from 0 % at room temperature to 100 % at 1200 °F (649 °C). Thus, although the impact toughness is reduced at high temperature, the specimens broke in a 100 % ductile fashion, indicating that the material is still suitable. The lack of fracture ductility at room temperature indicates that care should be taken to avoid application of high stresses to sigmatized materials during shutdown, as a brittle fracture could result. [Table 2.E.6.2](#) summarizes impact property data found for Type 304 and 321 stainless steels.

2.E.6.3 Screening Criteria

If both of the following are true, then the component should be evaluated for susceptibility to sigma phase embrittlement.

- a) The material an austenitic stainless steel.
- b) The operating temperature is between 1100 °F and 1700 °F (593 °C and 927 °C).

2.E.6.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for sigma phase embrittlement are provided in [Table 2.E.6.1](#).

2.E.6.5 Basic Assumption

Since data is scarce and exhibits considerable scatter, it is assumed that sigmatized austenitic stainless steels will behave in a brittle fashion similar to ferritic steels. The data available showed a reduction in properties but not the original properties. It is assumed that in the calculation of the DF, the original impact toughness of austenitic stainless steels is about $300 \text{ ksi}\sqrt{\text{in.}}$ ($330 \text{ Mpa}\sqrt{\text{m}}$).

The references were searched for additional test data, which were scarce and exhibited considerable scatter. The test data found are shown in [Table 2.E.6.3](#). The data in this table were used to construct property trend lines of Low Sigma (1 % and 2 %), High Sigma (10 %), and Medium Sigma (Average of Low and High).

2.E.6.6 Determination of the DF

2.E.6.6.1 Overview

A flow chart of the steps required to determine the DF for sigma phase embrittlement is shown in [Figure 2.E.6.1](#). The following sections provide additional information and the calculation procedure.

2.E.6.6.2 Inspection Effectiveness

For this damage mechanism, credit is not given for inspection. However, the results of metallurgical testing can be used to update the inputs to the DF calculation that may result in a change in this value.

2.E.6.6.3 Calculation of the DF

The following procedure may be used to determine the DF for sigma phase embrittlement; see [Figure 2.E.6.1](#).

- a) Step 1—Determine the evaluation temperature $T_{\min}$. The material may be evaluated at normal operating conditions or at a lower temperature such as shutdown or upset temperature.
- b) Step 2—Determine the estimated % sigma in the material. This can be made through comparisons with materials in similar service or via metallographic examination of a sample.
- c) Step 3—Determine the DF, D_f^{sigma} , using [Table 2.E.6.3](#) based on $T_{\min}$ from Step 1 and the estimated % sigma from Step 2.

2.E.6.7 Nomenclature

D_f^{sigma} is the DF for sigma phase embrittlement

$T_{\min}$ is the minimum temperature, °F (°C)

2.E.6.8 References

See References [66], [67], [68], [69], [70], [72], [73], [74], [75], [76], and [77], in Annex 2.G.

2.E.6.9 Tables

Table 2.E.6.1—Data Required for Determination of the DF—Sigma Phase Embrittlement

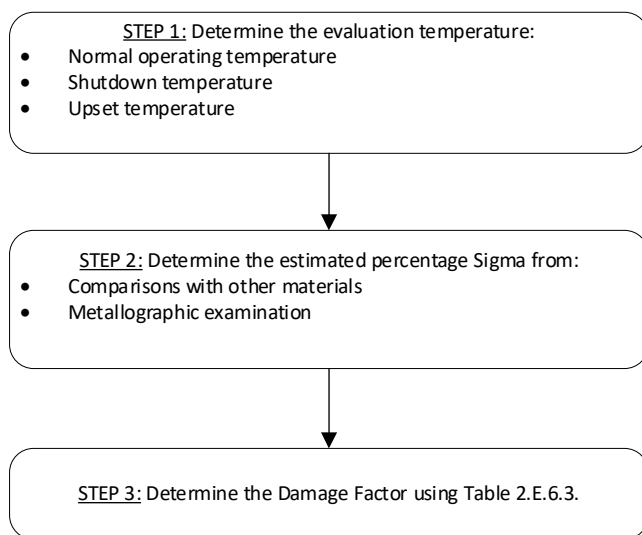
Required Data	Comments
Administrative controls for upset management (Yes/No)	Are there controls and or awareness training to prevent the coincident occurrence of low temperatures (upset) at or near design pressures?
Minimum operating temperature under normal, start-up/shutdown, or upset conditions, °F (°C)	This may be the temperature below which the operating pressure is reduced for purposes of fracture control. If not known, the temperature should be set to the atmospheric boiling point of the fluid in the component if the fluid is a liquid.
Amount of sigma	Estimate of the amount of sigma phase present. Low ($> 1\%$, $< 5\%$) Medium ($\geq 5\%$, $< 10\%$) High ($\geq 10\%$)

Table 2.E.6.2—Data for Property Trends of Toughness vs Temperature—Sigma Phase

Test Temperature		304 SS 2 % SIGMA		321 SS 10 % SIGMA		304 SS 1 % SIGMA		304 SS 2 % SIGMA		347 SS 1 % SIGMA	
°C	°F	% of Impact	% Shear	% of Impact	% Shear	% of Impact	% Shear	% of Impact	% Shear	% of Impact	% Shear
21	70	21	0	7	0	—	—	21	10	50	90
260	500	38	25	10	20	—	—	—	—	100	100
482	900	44	50	15	40	20	10	—	—	100	100
649	1200	63	100	21	60	71	90	77	90	100	100

Table 2.E.6.3—DF—Sigma Phase

$T_{\min}$ Evaluation Temperature		DF as a Function of Sigma Content		
(°C)	(°F)	Low Sigma	Medium Sigma	High Sigma
649	1200	0.0	0.0	18
538	1000	0.0	0.0	53
427	800	0.0	0.2	160
316	600	0.0	0.9	481
204	400	0.0	1.3	1333
93	200	0.1	3	3202
66	150	0.3	5	3871
38	100	0.6	7	4196
10	50	0.9	11	4196
−18	0	1.0	20	4196
−46	−50	1.1	34	4196

2.E.6.10 Figures**Figure 2.E.6.1—Determination of the Sigma Phase Embrittlement DF**

2.E.7 Piping Mechanical Fatigue DF

2.E.7.1 Scope

The DF calculation for piping components subject to mechanical fatigue is covered in this section.

2.E.7.2 Description of Damage

Fatigue failures of piping systems present a very real hazard under certain conditions. Properly designed and installed piping systems should not be subject to such failures, but prediction of vibration in piping systems at the design stage is very difficult, especially if there are mechanical sources of cyclic stresses such as reciprocating pumps and compressors. In addition, even if a piping systems are not subject to mechanical fatigue in the as-built condition, changing conditions such as failure of pipe supports, increased vibration from out of balance machinery, chattering of relief valves during process upsets, changes in flow and pressure cycles, or adding weight to unsupported branch connections (pendulum effect) can render a piping system susceptible to failure. Awareness of these influences incorporated into an MOC program can reduce the POF.

2.E.7.3 Screening Criteria

If both of the following are true, then the component should be evaluated for susceptibility to mechanical fatigue.

- a) The component is pipe.
- b) There have been past fatigue failures in this piping system or there is visible/audible shaking in this piping system or there is a source of cyclic vibration within approximately 50 ft (15.24 m) and connected to the piping (directly or indirectly via structure). Shaking and source of shaking can be continuous or intermittent. Transient conditions often cause intermittent vibration.

2.E.7.4 Required Data

The basic component data required for analysis are given in [Part 2, Table 4.1](#), and the specific data required for determination of the DF for mechanical fatigue are provided in [Table 2.E.7.1](#).

2.E.7.5 Basic Assumption

Properly designed piping has a low tendency for mechanical fatigue failure due to the low period of vibration or low stress amplitude. The period is determined by the piping diameter, thickness, mass, support spacing, and support type.

Based on input from plant engineers and inspectors from several disciplines, the following key indicators of a high POF were identified.

- a) Previous failures due to fatigue.
- b) Audible, visible, or otherwise noticeable piping vibration (including small branch connections) that is greater than typical plant piping systems.
- c) Connection to reciprocating machinery, extreme cavitation through let-down or mixing valves, or relief valve chatter.

The presence of any or all of the above indicators determines the base susceptibility, which is then modified by various adjustment factors.

2.E.7.6 Determination of the DF

2.E.7.6.1 Overview

A flow chart of the steps required to determine the DF for mechanical fatigue is shown in [Figure 2.E.7.1](#). The following sections provide additional information and the calculation procedure.

2.E.7.6.2 Inspection Effectiveness

For this damage mechanism, credit is not given for inspection. However, the results of metallurgical testing can be used to update the inputs to the DF calculation that may result in a change in this value.

Mechanical fatigue failures in piping are not that common. Unfortunately, when failures occur, they can be of high consequence. In addition, traditional nondestructive testing techniques are of little value in preventing such failures. The reason that crack detection techniques are not by themselves adequate are as follows.

- a) Most of the time to failure in piping fatigue is in the initiation phase, where a crack in the process of forming has formed but is so small that it is undetectable.
- b) By the time a crack has reached a detectable size, the crack growth rate is high, and failure will likely occur in less than a typical inspection frequency.
- c) Cyclic stresses in vibrating piping tend to have a fairly high frequency, which increases the crack growth rate.
- d) Cracks form and grow in locations that are typically difficult to inspect, such as at fillet weld toes, the first unengaged thread root, and defects in other welds.
- e) The initiation site for crack growth is not necessarily on the outside of the pipe; in fact, a crack can grow from an embedded defect undetectable from either side without special techniques.

Therefore, inspection for mechanical fatigue in piping systems depends heavily on detection and correction of the conditions that lead to susceptibility. Such techniques include the following.

- 1) Visual examination of pipe supports to assure that all supports are functioning properly (i.e. they are actually supporting the pipe).
- 2) Visual examination of any cyclic motion of the pipe. If the pipe can be seen to be vibrating or moving in a cyclic manner, the pipe should be suspected of mechanical fatigue failure.
- 3) Visual examination of all fillet welded supports and attachments to piping. Fillet welds are especially susceptible to failure by fatigue, and these may provide an early warning of problems if cracks or failures are found.
- 4) As a general rule, small branch connections with unsupported valves or controllers on them are highly susceptible to failure. Examine these for signs of motion, and provide proper support for all such installations.
- 5) Surface inspection methods [penetrant testing (PT), magnetic testing (MT)] can be effective in a focused and frequent inspection plan.
- 6) Manually feeling the pipe to detect vibration. This requires experience, but normally process plant piping will not vibrate any more severely than a car engine at idle speed.
- 7) Measurement of piping vibration using special monitoring equipment. There are no set values of vibration that will be acceptable or nonacceptable under all conditions, so experience with using and interpreting vibration data is required.

- 8) Visual inspection of a unit during transient conditions and different operating scenarios (e.g. start-ups, shutdowns, upsets, etc.) looking for intermittent vibrating conditions.
- 9) Checking for audible sounds of vibration emanating from piping components such as control valves and fittings.

2.E.7.6.3 Calculation of the DF

The following procedure may be used to determine the DF for mechanical fatigue; see [Figure 2.E.7.1](#).

- a) Step 1—Determine the number of previous failures that have occurred, and determine the base DF, D_{fB}^{PF} , based on the following criteria.
 - 1) None— $D_{fB}^{PF} = 1$.
 - 2) One— $D_{fB}^{PF} = 50$.
 - 3) Greater than one— $D_{fB}^{PF} = 500$.
- b) Step 2—Determine the amount of visible/audible shaking or audible noise occurring in the pipe, and determine the base DF, D_{fB}^{AS} , based on the following criteria.
 - 1) Minor— $D_{fB}^{AS} = 1$.
 - 2) Moderate— $D_{fB}^{AS} = 50$.
 - 3) Severe— $D_{fB}^{AS} = 500$.
- c) Step 3—Determine the adjustment factor for visible/audible shaking based on the following criteria. This adjustment is based on observation that some piping systems may endure visible shaking for years. A repeated stress with a cycle of only 1 hertz (1/s) results in over 30 million cycles in a year. Most systems, if they were subject to failure by mechanical fatigue, would be expected to fail before reaching tens or hundreds of million cycles. One should note that intermittent cycles are cumulative.
 - 1) Shaking less than 2 weeks— $F_{fB}^{AS} = 1$.
 - 2) Shaking between 2 and 13 weeks— $F_{fB}^{AS} = 0.2$.
 - 3) Shaking between 13 and 52 weeks— $F_{fB}^{AS} = 0.02$.
- d) Step 4—Determine the type of cyclic loading connected directly or indirectly within approximately 50 ft (15.24 m) of the pipe, and determine the base DF, D_{fB}^{CF} , based on the following criteria.
 - 1) Reciprocating machinery— $D_{fB}^{CF} = 50$.
 - 2) PRV chatter— $D_{fB}^{CF} = 25$.
 - 3) Valve with high pressure drop— $D_{fB}^{CF} = 10$.

4) None— $D_{fB}^{CF} = 1$.

e) Step 5—Determine the base DF using Equation (2.76).

$$D_{fB}^{mfat} = \max \left[D_{fB}^{PF}, \left(D_{fB}^{AS} \cdot F_{fB}^{AS} \right), D_{fB}^{CF} \right] \quad (2.76)$$

f) Step 6—Determine the final value of the DF using Equation (2.77).

$$D_f^{mfat} = D_{fB}^{mfat} \cdot F_{CA} \cdot F_{PC} \cdot F_{CP} \cdot F_{JB} \cdot F_{BD} \quad (2.77)$$

The adjustment factors are determined as follows.

- 1) Adjustment for Corrective Action, F_{CA} —Established based on the following criteria.
 - Modification based on complete engineering analysis— $F_{CA} = 0.002$.
 - Modification based on experience— $F_{CA} = 0.2$.
 - No modifications— $F_{CA} = 2$.
- 2) Adjustment for Pipe Complexity, F_{PC} —Established based on the following criteria.
 - 0 to 5 total pipe fittings— $F_{PC} = 0.5$.
 - 6 to 10 total pipe fittings— $F_{PC} = 1$.
 - Greater than 10 total pipe fittings— $F_{PC} = 2$.
- 3) Adjustment for Condition of Pipe, F_{CP} —Established based on the following criteria.
 - Missing or damaged supports, improper support— $F_{CP} = 2$.
 - Broken gussets, gussets welded directly to the pipe— $F_{CP} = 2$.
 - Good condition— $F_{CP} = 1$.
- 4) Adjustment for Joint Type or Branch Design, F_{JB} —Established based on the following criteria.
 - Threaded, socket weld, saddle on— $F_{JB} = 2$.
 - Saddle in fittings— $F_{JB} = 1$.
 - Piping tee, weldolets— $F_{JB} = 0.2$.
 - Sweepolets— $F_{JB} = 0.02$.
- 5) Adjustment for Branch Diameter, F_{BD} —Established based on the following criteria.
 - All branches less than or equal to 2 NPS— $F_{BD} = 1$.
 - Any branch greater than 2 NPS— $F_{BD} = 0.02$.

2.E.7.7 Nomenclature

D_f^{mfat}	is the DF for mechanical fatigue
D_{fB}^{AS}	is the base DF for shaking
D_{fB}^{mfat}	is the base DF for mechanical fatigue
D_{fB}^{PF}	is the base DF for previous failures
F_{BD}	is the DF adjustment for branch diameter
F_{CA}	is the DF adjustment for corrective action
F_{CP}	is the DF adjustment for condition of pipe
F_{fB}^{AS}	is the adjustment factor for audible shaking
F_{JB}	is the DF adjustment for joint type
F_{PC}	is the DF adjustment for pipe complexity

2.E.7.8 References

See Reference [\[75\]](#) in [Annex 2.G](#).

2.E.7.9 Tables

Table 2.E.7.1—Data Required for Determination of the DF—Mechanical Fatigue

Required Data	Comments
Number of previous fatigue failures: None, One, or > 1	If there has been no history of fatigue failures and there have been no significant changes, then the likelihood of a fatigue failure is believed to be low.
Severity of vibration (audible or visible shaking): Minor, Moderate, or Severe	The severity of shaking can be measured in these subjective terms or can be measured as indicated at the bottom of this table in optional basic data. Examples of shaking are: Minor—no visible shaking, barely perceptible feeling of vibration when the pipe is touched; Moderate—little or no visible shaking, definite feeling of vibration when the pipe is touched; Severe—visible signs of shaking in pipe, branches, attachments, or supports. Severe feeling of vibration when the pipe is touched.
Number of weeks pipe has been shaking: 0 to 2 weeks, 2 to 13 weeks, 13 to 52 weeks	If there have been no significant recent changes in the piping system and the amount of shaking has not changed for years, or the amount of accumulative cycles is greater than the endurance limit, then it can be assumed that the cyclic stresses are below the endurance limit. (Most piping shaking will be at a frequency greater than 1 hertz. One hertz for 1 year is approximately 3×10^7 cycles, well beyond the endurance limit for most construction materials.)
Sources of cyclic stress in the vicinity of the item (e.g. within 50 ft): reciprocating machinery, PRV chatter, high-pressure drop valves (e.g. let-down and mixing valves), none	Determine to what cyclic source the piping is connected. The connections could be direct or indirect, e.g. through structural supports.

Table 2.E.7.1—Data Required for Determination of the DF—Mechanical Fatigue

Required Data	Comments
Corrective actions taken: modifications based on complete engineering analysis, modifications based on experience, no modifications	Credit is given for analysis work that shows that the shaking piping is not a fatigue concern.
Piping complexity: based on 50 ft (15.24 m) of pipe, choose: 0 to 5 branches, fittings, etc. 5 to 10 branches, fittings, etc. > 10 branches, fittings, etc.	Determine the piping complexity in terms of the number of branched connections, number of fittings, etc.
Type of joint or branch design used in this piping: threaded, socket welded, saddle on, saddle in, piping tee, weldolet, sweepolet	Determine the type of joint or branch connection that is predominant throughout this section of piping that is being evaluated.
Condition of the pipe: missing/damaged supports, unsupported weights on branches, broken gussets, gussets/supports welded directly to pipe, good condition	What is the condition of the piping section being evaluated in terms of support?

2.E.7.10 Figures

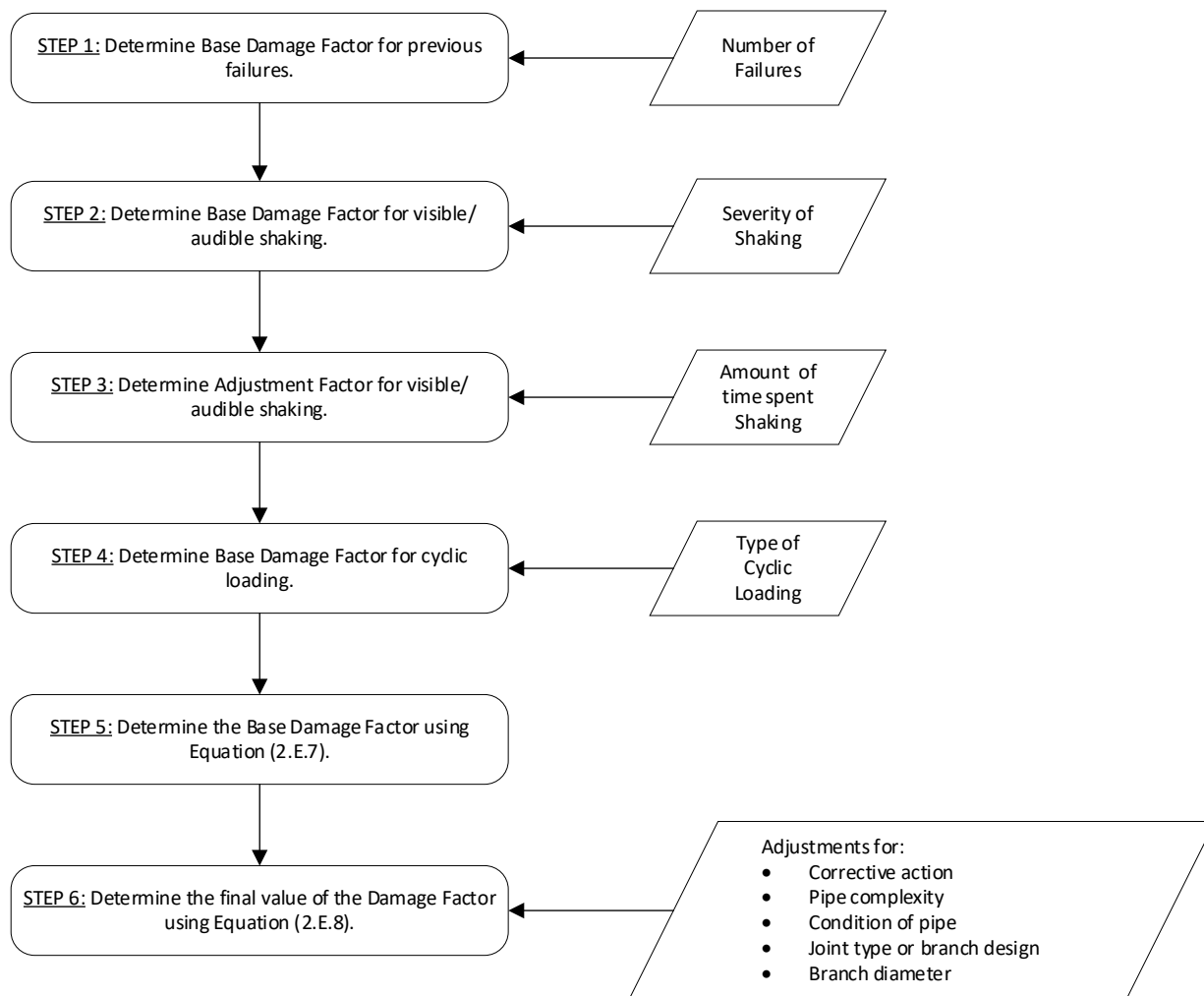


Figure 2.E.7.1—Determination of the Piping Mechanical Fatigue

Part 2, Annex 2.F—Levels of Inspection Effectiveness

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Risk-based Inspection Methodology

Part 2—Probability of Failure Methodology

Annex 2.F—Levels of Inspection Effectiveness

2.F.1 Overview

Inspection effectiveness directly impacts the calculation of the POF. Consequently, the POF provided in [Part 2](#) is intended to be used to provide a risk ranking and inspection plan for a component subject to process and environmental conditions typically found in the refining and petrochemical industry. Inspection effectiveness is thus an integral part of a robust inspection planning methodology.

2.F.2 Inspection Effectiveness

2.F.2.1 The Value of Inspection

An estimate of the POF for a component is dependent on how well the independent variables of the limit state are known [\[15\]](#). In the models used for calculating the POF, the flaw size (e.g. metal loss for thinning or crack size for environmental cracking) may have significant uncertainty, especially when these parameters need to be projected into the future. An inspection program may be implemented to obtain a better estimate of the damage rate and associated flaw size.

An inspection program is the combination of NDE methods [i.e. visual testing (VT), UT, RT, etc.], frequency of inspection, and the location and coverage of an inspection. These factors at a minimum define the “inspection effectiveness.” Inspection programs vary in their effectiveness for locating and sizing damage and thus for determining damage rates. Once the likely damage mechanisms have been identified, the inspection program should be evaluated to determine the effectiveness in finding the identified mechanisms. The effectiveness of an inspection program may be limited by:

- a) lack of coverage of an area subject to damage,
- b) inherent limitations of some inspection methods to detect and quantify certain types of damage,
- c) selection of inappropriate inspection methods and tools,
- d) application of methods and tools by inadequately trained inspection personnel,
- e) inadequate inspection procedures,
- f) the damage rate under some conditions (e.g. start-up, shutdown, or process upsets) may increase the likelihood or probability that failure may occur within a very short time; even if damage is not found during an inspection, failure may still occur as a result of a change or upset in conditions,
- g) inaccurate analysis of results leading to inaccurate trending of individual components (problem with a statistical approach to trending), and
- h) probability of detection of the applied NDE technique for a given component type, metallurgy, environment (including temperature), and geometry.

It is also important to evaluate the benefits of multiple inspections and to also recognize that the most recent inspection may best reflect the current state of the component under the current operating conditions. If the operating conditions have changed, damage rates based on inspection data from the previous operating conditions may not be valid.

Determination of inspection effectiveness should consider, but not be limited to, the following:

- 1) equipment or component type;
- 2) active and credible damage mechanism(s);
- 3) susceptibility to and rate of damage;
- 4) NDE methods, coverage, and frequency; and
- 5) accessibility to expected damaged areas.

Refer to API 580 for more information on using inspection effectiveness with RBI programs.

2.F.2.2 Inspection Effectiveness Categories

LoIE examples for specific equipment types (heat exchangers, PRVs, tanks, and buried components) are provided in [Sections 2.F.3](#) through [2.F.7](#). The associated inspection effectiveness examples (i.e. NDE technique and coverage) for each damage mechanism are provided in [Section 2.F.8](#) through [2.F.11](#).

Inspection effectiveness is graded A through E, with an A inspection providing the most effective inspection available (90 % effective) and an E inspection representing an ineffective or no inspection category. The inspection categories presented are intended as examples and to provide a guideline for assigning inspection effectiveness grades. The effectiveness grade of any inspection technique depends on many factors such as the skill, competency, and training of inspectors, as well as the level of expertise used in selecting inspection locations. Refer to [Table 2.F.2.1](#) for a description of the inspection effectiveness categories.

The tables describing the LoIE per damage mechanism included in this annex are examples only. It is the responsibility of the user to review these tables and do the following.

- a) Adapt and adopt similar tables for their specific use.
- b) Adapt user-specific knowledge and experience to add NDE techniques and areas of concern not currently in the tables.
- c) Implement these strategies as part of the user's RBI program as an aid for inspection planning.

It is not the intent of this document to specifically prescribe the exact NDE and/or areas of concern for the included damage factors. The user has the responsibility to utilize competent subject matter experts to review the tables and create similar items to be utilized in the user's inspection program. Inspections are ranked according to their expected effectiveness at detecting damage and correctly predicting the rate of damage. The actual effectiveness of a given inspection technique depends on the characteristics of the damage mechanism, and total inspection credit can be approximated to an equivalent higher effectiveness inspection in accordance with the relationships in [Part 2, Section 3.4.3](#). Furthermore, damage factors are determined as a function of inspection effectiveness.

2.F.2.3 Tables

Table 2.F.2.1—Inspection Effectiveness Categories

Inspection Effectiveness Category	Inspection Effectiveness Description	Description
A	Highly Effective	The inspection methods will correctly identify the true damage state in nearly every case (or 80 % to 100 % confidence)
B	Usually Effective	The inspection methods will correctly identify the true damage state most of the time (or 60 % to 80 % confidence)
C	Fairly Effective	The inspection methods will correctly identify the true damage state about half of the time (or 40 % to 60 % confidence)
D	Poorly Effective	The inspection methods will provide little information to correctly identify the true damage state (or 20 % to 40 % confidence)
E	Ineffective	The inspection method will provide no or almost no information that will correctly identify the true damage state and are considered ineffective for detecting the specific damage mechanism (less than 20 % confidence)
NOTE On an inspection effectiveness Category E, the terminology of Ineffective may refer to one or more of the following cases. 1. No inspection was completed. 2. The inspection was completed at less than the requirements stated above. 3. An ineffective inspection technique and/or plan was utilized. 4. An unproven inspection technique was utilized. 5. Insufficient information was available to adequately assess the effectiveness of the inspection.		

2.F.3 PRVs

2.F.3.1 General

Inspection programs vary in their effectiveness for determining failure rates. Examples of inspection effectiveness for PRDs are provided in [Table 2.F.3.1](#). The inspection effectiveness is based on the ability of the inspection to adequately predict the failure (or pass) state of the PRD being inspected. Limitations in the ability of a program to improve confidence in the failure rate result from the inability of some test methods to detect and quantify damage.

Refer to the [Part 5, Section 6.3.4](#) for further discussion on the inclusion of inspection effectiveness ranking into the determination of POF for PRDs.

2.F.3.2 Tables

Table 2.F.3.1—Inspection and Testing Effectiveness for PRDs

Inspection Effectiveness	Component Type	Description of Inspection
Highly Effective A	PRD	A bench test has been performed on the PRD in the as-received condition from the unit, and the initial leak pressure, opening pressure, and reseal pressure have been documented on the test form. The inlet and outlet piping has been examined (e.g. VT or RT techniques) for signs of excessive plugging or fouling ² .
	Rupture disk	No inspection methods are available to meet the requirements for an A level inspection.
Usually Effective B	PRD	A bench test has been performed; however, the PRD was cleaned or steamed out prior to the bench test. Additionally, a VT has been performed where detailed documentation of the condition of the PRD internal components was made. The inlet and outlet piping has been examined (e.g. VT or RT techniques) for signs of excessive plugging or fouling ² . An in situ test has been performed using the actual process fluid to pressurize the system. The inlet and outlet piping has been examined (e.g. VT or RT techniques) for signs of excessive plugging or fouling ² .
	Rupture disk	The rupture disk is removed and visually inspected for damage or deformations. The inlet and outlet piping has been examined (e.g. VT or RT techniques) for signs of excessive plugging or fouling ² .
Fairly Effective C	PRD	A VT has been performed without a pop test, where detailed documentation of the condition of the PRD internal components was made. The inlet and outlet piping has been examined (e.g. VT or RT techniques) for signs of excessive plugging or fouling ² . An assist-lift test or in situ test has been performed where the actual process fluid was not used to pressurize the system.
	Rupture disk	No inspection methods are available to meet the requirements for a C level inspection.
Ineffective D	PRD	Valve overhaul performed with no documentation of internal component conditions; no pop test conducted/documented. Any test (bench, assist-lift, in situ, or visual test) performed without examining the inlet and outlet piping for excessive plugging or fouling.
	Rupture disk	No details of the internal component were documented.

NOTE 1 This table does not prescribe specifically to the five effectiveness categories as discussed in this annex. However, given the methodology presented, it is in agreement with the division of those categories.

NOTE 2 This table assumes the PRD is in fouling service. If the PRD is in a documented, non-fouling service, the owner–operator may decide to waive the inlet and outlet piping inspection requirement.

2.F.4 Heat Exchanger Tube Bundles

2.F.4.1 Inspection Planning with Inspection History

2.F.4.1.1 Effect of Inspection on POF

The information gained from an inspection of the tube bundle can be used to assess the actual condition of the bundle and to make adjustments to the POF rate curves as necessary.

An inspection provides the following two things.

- 1) Reduction in condition uncertainty due to the effectiveness of the inspection resulting in the use of a more accurate failure rate curve [e.g. moving from a 50 % additional uncertainty (AU) curve for no inspection history to a curve 20 % AU curve for Usually Effective Inspection]. See [Section 2.F.4.1.2](#) for a discussion of inspection effectiveness.
- 2) Knowledge of the true condition of the bundle. This can result in a shift of the failure rate curve to the right or to the left. The current condition of the bundle could either be quantified by remaining wall thickness data or by an estimate of the remaining life that comes directly from an actual inspection.

2.F.4.1.2 Reduction in Uncertainty Due to Inspection Effectiveness

If the tube bundle has been inspected, the uncertainty is reduced and the POF at any time changes. [Table 2.F.4.1](#) provides the recommended default values for the uncertainty applied to the failure rate curve as a function of inspection effectiveness.

At this point, the concept of inspection effectiveness is introduced, similar to the methodology used in other modules. [Table 2.F.4.1](#) provides the recommended default values for the uncertainty applied to the failure rate curve as a function of inspection effectiveness.

As improved inspection techniques are used, the amount of uncertainty decreases and the Weibull plot shifts to the right. Using this concept will result in more rigorous inspection techniques being implemented as the bundle reaches end of life.

In the example bundle problem, the impact of more rigorous inspection techniques can be seen by evaluating the predicted duration as a function of inspection effectiveness in [Table 2.F.4.1](#). The definitions for inspection effectiveness are provided in [Table 2.F.2.1](#).

As explained in various sections of this recommended practice, it is the responsibility of the owner–operator to interpret and define inspection strategies that satisfy the level of desired effectiveness to achieve the level of confidence in the condition of the tubes (susceptible population) in question. This may involve a defined logic to establish sample size and the use of one or multiple inspection techniques to find a single or multiple potential damage mechanisms at the desired level of effectiveness. Owner–operators may elect to create inspection effectiveness tables specific to that company or site’s practices that satisfy the effectiveness criteria (A, B, C, D, and E) to help with consistency.

Typical examples of heat exchanger tube damage/degradation include and are not limited to, in relation to the tubes:

- a) internal and/or external, localized or generalized corrosion;
- b) preferential weld corrosion;
- c) pitting [may be localized or generalized, inside diameter (ID) and/or outside diameter (OD)];
- d) cracking (circumferential and/or longitudinal);

- e) fretting;
- f) tube end damage (cracking and/or corrosion);
- g) seal weld cracking/failure;
- h) erosion/erosion-corrosion.

Examples of various typical NDE methods for tube inspection include and are not limited to:

- a) VT;
- b) UT thickness readings where accessible;
- c) eddy current testing;
- d) remote field eddy current testing;
- e) near-field eddy current testing;
- f) rotating/spinning UT probe examination;
- g) laser scanning;
- h) halide leak, hydrostatic, soap bubble, and other leak testing;
- i) acoustic testing;
- j) splitting of tubes for VT and other types of inspection like PT, pit depth gauging, caliper measurements.

These lists of types of damage/degradation and typical NDE methods is provided as an example of items that the user should review when considering and/or creating inspection effectiveness tables. Understand that there are no specific LoIE tables developed as an example for tube bundle inspection. Rather, [Table 2.F.4.1](#) is provided as a basic guideline for the owner–operator created LoIE table(s), which is based on their experience and confidence in the results.

2.F.4.1.3 Tables

Table 2.F.4.1—Inspection Effectiveness and Uncertainty

Inspection Effectiveness	Uncertainty (%)
A—Highly Effective	5
B—Usually Effective	10
C—Moderately Effective	20
D—Usually Not Effective	30
E—Ineffective	50

2.F.5 Storage Tank Components

2.F.5.1 Inspection Effectiveness for Storage Tanks

API 653 states that RBI may be utilized as an alternative to establishing the initial internal inspection date as well as the reassessment date. However, when an RBI assessment is performed, the maximum initial internal interval shall not apply to tanks storing the following:

- a) highly viscous substances that solidify at temperatures below 110 °F—some examples of these substances are asphalt, roofing flux, residuum, vacuum bottoms, and reduced crude, or
- b) any substance or mixture that
 - 1) is not identified or regulated either as a hazardous chemical or material under the applicable laws of the jurisdiction, and
 - 2) the owner–operator has determined will not adversely impact surface or groundwater beyond the facility or affect human health or the environment.

In order for the owner–operator to establish the internal inspection interval using RBI, a methodology of assigning inspection effectiveness must be provided. API 581 provides for several areas of inspection that are accounted for within the risk assessment methodology. Overall, the results of the RBI assessment can be used to establish a storage tank inspection strategy that defines the most appropriate inspection methods, appropriate frequency for internal, external, and in-service inspections, and prevention and mitigation steps to reduce the likelihood and consequence of storage tank leakage or failure.

Furthermore, API 653 requires that when using RBI, the assessments shall:

- a) follow all requirements listed in API 653,
- b) consist of a systematic evaluation of both the likelihood of failure and the associated consequences of failure,
- c) be thoroughly documented, clearly defining all factors contributing to both likelihood and consequence of AST leakage or failure,
- d) be performed by a team including inspection and engineering expertise knowledgeable in the proper application of API 580 principles, AST design, construction, and types of damage.

LoIE [Tables 2.F.5.1](#) through [2.F.5.3](#) outline inspection areas combined with examples of inspection effectiveness categories for storage tank components.

2.F.5.2 Tables

Table 2.F.5.1—LoIE Example for Storage Tank Shell Course Internal Corrosion

Inspection Category	Inspection Effectiveness Category	Inspection (see Note)
A	Highly Effective	Both inspections shall be done: — intrusive inspection—good VT with pit depth gage measurements at suspect locations — UT scanning follow up on suspect location and as general confirmation of wall thickness
B	Usually Effective	Both inspections shall be done: — external spot UT scanning based on visual information from previous internal inspection of this storage tank or similar service tanks — Internal video survey with external UT follow-up
C	Fairly Effective	External spot UT scanning based at suspect locations without benefit of any internal inspection information on storage tank type or service
D	Poorly Effective	External spot UT based at suspect locations without benefit of any internal inspection information on storage tank type or service
E	Ineffective	Ineffective inspection technique/plan was utilized
NOTE Inspection quality is high.		

Table 2.F.5.2—LoIE Example for Storage Tank Shell Course External Corrosion

Inspection Category	Inspection Effectiveness Category	Insulated Tank Inspection Example (see Note)	Non-insulated Tank Inspection Example (see Note)
A	Highly Effective	— > 95 % external VT prior to removal of insulation — Remove > 90 % of insulation at suspect locations OR — > 90 % pulse eddy current inspection — VT of the exposed surface area with follow-up by UT or pit gauge as required	> 95 % VT of the exposed surface area AND Follow-up by UT or pit gauge as required
B	Usually Effective	— > 95 % external VT prior to removal of insulation — Remove > 50 % of insulation at suspect locations OR — > 50 % pulse eddy current inspection — VT of the exposed surface area with follow-up by UT or pit gauge as required	> 50 % VT of the exposed surface area AND Follow-up by UT or pit gauge as required
C	Fairly Effective	— > 95 % external VT prior to removal of insulation — Remove > 30 % of insulation at suspect locations OR — > 30 % pulse eddy current inspection — VT of the exposed surface area with follow-up by UT or pit gauge as required	> 25 % VT of the exposed surface area AND Follow-up by UT or pit gauge as required
D	Poorly Effective	— > 95 % external VT prior to removal of insulation — Remove > 10 % of insulation at suspect locations OR — > 10 % pulse eddy current inspection — VT of the exposed surface area with follow-up by UT or pit gauge as required	> 10 % VT of the exposed surface area AND Follow-up by UT or pit gauge as required
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE Inspection quality is high.			

Table 2.F.5.3—LoIE Example for Storage Tank Bottoms

Inspection Category	Inspection Effectiveness Category	Soil Side (see Note)	Product Side (see Note)
A	Highly Effective	Floor scan > 90 % AND UT follow-up NOTE — Include welds if warranted from the results on the plate scanning — Hand scan of the critical zone	Bare plate: — Commercial blast — Effective supplementary light — Visual 100 % (API 653) — Pit depth gauge — 100 % vacuum box testing of suspect welded joints Coating or liner: — Sponge test 100 % — Adhesion test — Scrape test
B	Usually Effective	Floor scan > 50 % AND UT follow-up OR Extreme value analysis (EVA) or other statistical method with floor scan follow-up (if warranted by the result)	Bare plate: — Brush blast — Effective supplementary light — Visual 100 % (API 653) — Pit depth gauge Coating or liner: — Sponge test > 75 % — Adhesion test — Scrape test
C	Fairly Effective	Floor scan 5 to 10+ % plates AND Supplement with scanning near shell AND UT follow-up OR Use a “Scan Circle-and-X” pattern (progressively increase if damage found during scanning) Other testing: — Helium/argon test — Hammer test — Cut coupons	Bare plate: — Broom swept — Effective supplementary light — Visual 100 % — Pit depth gauge Coating or liner: — Sponge test 50 % to 75 % — Adhesion test — Scrape test
D	Poorly Effective	Possible testing: — Spot UT — Flood test	Bare plate: — Broom swept — No effective supplementary lighting — Visual > 50 % Coating or liner: — Sponge test < 50 %
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE Inspection quality is high.			

2.F.6 Buried Components

2.F.6.1 Inspection Effectiveness for Buried Components

Similar to other equipment, components that are buried may use RBI to assign inspection intervals. LoIE Table 2.F.6.1 provides an example of inspection effectiveness categories for buried components.

2.F.6.2 Tables

Table 2.F.6.1—LoIE Example for Buried Components

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ¹	Nonintrusive Inspection Example ¹
A	Highly Effective	100 % internal inspection via state-of-the-art pigging and in-line inspection technologies [UT, magnetic flux leakage (MFL), internal rotary UT, etc.]	100 % external inspection of equipment that is only partially buried using an NDE crawler with circumferential inspection technology (MFL, lamb-wave UT) - Complete excavation, 100 % external VT, and 100 % inspection with NDE technologies ² - Sample soil and water resistivity and chemistry measurements along entire structure - CP system maintained and managed by NACE certified personnel and complying with NACE SP0169 ^[145] includes stray current surveys on a regular basis - Pipe-to-soil potentials should be measured at properly determined intervals
B	Usually Effective	Internal inspection via pigging and in-line inspection technologies (UT, MFL, internal rotary UT, etc.) of selected areas/sections, combined with statistical analysis or EVA	External inspection of equipment that is only partially buried using an NDE crawler with circumferential inspection technology (MFL, lamb-wave UT) on selected areas/sections, combined with statistical analysis or EVA - Close interval survey used to assess the performance of the CP system locally and utilized to select the excavation sites (based on the findings) - Excavation at “selected” locations, 100 % external visual, and 100 % inspection with NDE technologies ² - CP system maintained and managed by NACE certified personnel and complying with NACE SP0169 ^[145] includes stray current surveys on a regular basis - Sample soil and water resistivity and chemistry measurements along entire structure - Direct current voltage gradient (DCVG) to determine coating damage
C	Fairly Effective	Partial inspection by internal smart pig or specialized crawler device, including a representative portion of the buried pipe (< 25 %)	Partial excavation guided-wave UT global search inspection in each direction of pipe. Corrosion inspection and maintenance managed by NACE certified and CP specialist, or equivalent.
D	Poorly Effective	Hydrostatic testing	Spot check with conventional NDE technologies ² equipment of local areas exposed by excavation
E	Ineffective	Ineffective inspection technique/plan was utilized	

NOTE 1 Inspection quality is high.

NOTE 2 “NDE technologies” include, but are not limited to, UT thickness measurement such as handheld devices at close-interval grid locations, UT B-scan, automated ultrasonic scanning, guided-wave UT global search, crawler with circumferential inspection technology such as MFL or lamb-wave UT, and digital radiography in more than one direction.

2.F.7 Inspection Effectiveness for Thinning

2.F.7.1 Use of the Inspection Effectiveness Tables

LoIE [Table 2.F.7.1](#) and [Table 2.F.7.2](#) are examples for LoIEs for thinning damage mechanisms. The LoIE tables for Thinning damage include inspection examples for nonmetallic liners, if applicable.

Table 2.F.7.1—LoIE Example for General Thinning

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2, 3, 4}	Nonintrusive Inspection Example ^{1, 2, 3, 4}
A	Highly Effective	Components with and Without Cladding For the total surface area: > 50 % VT (partial internals removed) AND > 50 % of the spot ultrasonic thickness measurements Components with Internal Liners For the total surface area: 100 % VT AND 100 % holiday test AND 100 % UT or magnetic tester for disbonding for bonded liners	Components with and Without Cladding For the total surface area: 100 % UT/RT of CMLs OR For selected areas: 10 % UT scanning OR 10 % profile radiography Components with Internal Liners No inspection techniques are yet available to meet the requirements for an “A” level inspection
B	Usually Effective	Components with and Without Cladding For the total surface area: > 25 % VT AND > 25 % of the spot ultrasonic thickness measurements Components with Internal Liners For the total surface area: > 65 % VT AND > 65 % holiday test AND > 65 % UT or magnetic tester for disbonding for bonded liners	Components with and Without Cladding For the total surface area: > 75 % spot UT OR > 5 % UT scanning, automated or manual OR > 5 % profile radiography of the selected area(s) Components with Internal Liners For the total surface area: 100 % automated or manual ultrasonic scanning

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2, 3, 4}	Nonintrusive Inspection Example ^{1, 2, 3, 4}
C	Fairly Effective	Components with and Without Cladding For the total surface area: > 5 % VT AND > 5 % of the spot ultrasonic thickness measurements Components with Internal Liners For the total surface area: > 35 % VT OR > 35 % holiday test OR > 35 % UT or magnetic tester for disbonding for bonded liners	Components with and Without Cladding For the total surface area: > 50 % spot UT or random UT scans (automated or manual) OR random profile radiography of the selected area(s) Components with Internal Liners For the total surface area: > 65 % automated or manual ultrasonic scanning
D	Poorly Effective	Components with and Without Cladding For the total surface area: < 5 % VT without thickness measurements Components with Internal Liners For the total surface area: > 5 % VT OR > 5 % holiday test OR > 5 % UT or magnetic tester for disbonding for bonded liners	Components with and Without Cladding For the total surface area: > 25 % spot UT Components with Internal Liners For the total surface area: > 35 % automated or manual ultrasonic scanning
E	Ineffective	Components with and Without Cladding Ineffective inspection technique/plan was utilized Components with Internal Liners Ineffective inspection technique/plan was utilized	Components with and Without Cladding Ineffective inspection technique/plan was utilized Components with Internal Liners Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high. NOTE 2 Inspection points (CMLs, scans, etc.) are set up by knowledgeable individuals. NOTE 3 That the number of CMLs and area for scanning (UT or profile radiography) is one that will detect damage if occurring. NOTE 4 Percentage refers to percent of established CMLs examined (e.g. for spot UT) or the percent surface area examined.			

Table 2.F.7.2—LoIE Example for Local Thinning

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2, 3, 4}	Nonintrusive Inspection Example ^{1, 2, 3, 4}
A	Highly Effective	Components with and Without Cladding For the total surface area: 100 % VT (with removal of internal packing, trays, etc.) AND 100 % follow-up at locally thinned areas Components with Internal Liners For the total surface area: 100 % VT AND 100 % holiday test AND 100 % UT or magnetic tester for disbonding for bonded liners	Components with and Without Cladding For the total suspect area: 100 % coverage of the CMLs using ultrasonic scanning or profile radiography Components with Internal Liners No inspection techniques are yet available to meet the requirements for an “A” level inspection
B	Usually Effective	Components with and Without Cladding For the total surface area: > 75 % VT AND 100 % follow-up at locally thinned areas Components with Internal Liners For the total surface area: > 65 % VT AND > 65 % holiday test AND > 65 % UT or magnetic tester for disbonding for bonded liners	Components with and Without Cladding For the total suspect area: > 75 % coverage of the CMLs using ultrasonic scanning or profile radiography Components with Internal Liners For the total surface area: 100 % automated or manual ultrasonic scanning
C	Fairly Effective	Components with and Without Cladding For the total surface area: > 50 % VT AND 100 % follow-up at locally thinned areas Components with Internal Liners For the total surface area: > 35 % VT OR > 35 % holiday test OR > 35 % UT or magnetic tester for disbonding for bonded liners	Components with and Without Cladding For the total suspect area: > 50 % coverage of the CMLs using ultrasonic scanning or profile radiography Components with Internal Liners For the total surface area: > 65 % automated or manual ultrasonic scanning

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2, 3, 4}	Nonintrusive Inspection Example ^{1, 2, 3, 4}
D	Poorly Effective	Components with and Without Cladding For the total surface area: > 20 % VT AND 100 % follow-up at locally thinned areas Components with Internal Liners For the total surface area: > 5 % VT OR > 5 % holiday test OR > 5 % UT or magnetic tester for disbonding for bonded liners	Components with and Without Cladding For the total suspect area: > 20 % coverage of the CMLs using ultrasonic scanning or profile radiography Components with Internal Liners For the total surface area: > 35 % automated or manual ultrasonic scanning
E	Ineffective	Components with and Without Cladding Ineffective inspection technique/plan was utilized Components with Internal Liners Ineffective inspection technique/plan was utilized	Components with and Without Cladding Ineffective inspection technique/plan was utilized Components with Internal Liners Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high. NOTE 2 Percentage coverage in nonintrusive inspection includes welds. NOTE 3 Follow-up inspection can be UT, pit gauge, or suitable NDE techniques that can verify minimum wall thickness. NOTE 4 Profile radiography technique is sufficient to detect wall loss at all planes.			

2.F.8 Inspection Effectiveness Tables for SCC

2.F.8.1 Use of the Inspection Effectiveness Tables

LoIE Tables 2.F.8.1 through 2.F.8.9 are examples for LoIEs for SCC damage mechanisms.

2.F.8.2 Tables

Table 2.F.8.1—LoIE Example for Amine Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2}	Nonintrusive Inspection Example ^{1, 2}
A	Highly Effective	For the total weld area: 100 % wet fluorescent magnetic (particle) testing/alternating current field measurement (WFMT/ACFM) with UT follow-up of relevant indications	For the total weld area: 100 % automated or manual ultrasonic scanning
B	Usually Effective	For selected welds/weld area: > 75 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 75 % automated or manual ultrasonic scanning OR Acoustic emission (AE) testing with 100 % follow-up of relevant indications
C	Fairly Effective	For selected welds/weld area: > 35 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 35 % automated or manual ultrasonic scanning OR > 35 % RT
D	Poorly Effective	For selected welds/weld area: > 10 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 10 % automated or manual ultrasonic scanning OR > 10 % RT
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized

NOTE 1 Inspection quality is high.

NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).

Table 2.F.8.2—LoIE Example for ACSCC

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2}	Nonintrusive Inspection Example ^{1, 2}
A	Highly Effective	For the total weld area: 100 % WFMT/ACFM with UT follow-up of relevant indications	For the total weld area: 100 % automated or manual ultrasonic scanning
B	Usually Effective	For selected welds/weld area: > 75 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 75 % automated or manual ultrasonic scanning OR AE testing with 100 % follow-up of relevant indications
C	Fairly Effective	For selected welds/weld area: > 35 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 35 % automated or manual ultrasonic scanning OR > 35 % RT
D	Poorly Effective	For selected welds/weld area: > 10 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 10 % automated or manual ultrasonic scanning OR > 10 % RT
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high.			
NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).			

Table 2.F.8.3—LoIE Example for Caustic Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2, 3}	Nonintrusive Inspection Example ^{1, 2, 3}
A	Highly Effective	For the total weld area: 100 % WFMT/ACFM with UT follow-up of relevant indications	For the total weld area: 100 % automated or manual ultrasonic scanning
B	Usually Effective	For selected welds/weld area: > 75 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 75 % automated or manual ultrasonic scanning OR AE testing with 100 % follow-up of relevant indications
C	Fairly Effective	For selected welds/weld area: > 35 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 35 % automated or manual ultrasonic scanning OR > 35 % RT
D	Poorly Effective	For selected welds/weld area: > 10 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 10 % automated or manual ultrasonic scanning OR > 10 % RT
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high. NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert). NOTE 3 Cold bends may need inspection also for caustic cracking.			

Table 2.F.8.4—LoIE Example for CISCC

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2, 3}	Nonintrusive Inspection Example ^{1, 2, 3}
A	Highly Effective	For the total surface area: 100 % dye penetrant or eddy current test with UT follow-up of relevant indications	No inspection techniques are yet available to meet the requirements for an “A” level inspection
B	Usually Effective	For selected areas: > 65 % dye penetrant or eddy current testing with UT follow-up of all relevant indications	For selected areas: 100 % automated or manual ultrasonic scanning OR AE testing with 100 % follow-up of relevant indications
C	Fairly Effective	For selected areas: > 35 % dye penetrant or eddy current testing with UT follow-up of all relevant indications	For selected areas: > 65 % automated or manual ultrasonic scanning OR > 65 % RT
D	Poorly Effective	For selected areas: > 10 % dye penetrant or eddy current testing with UT follow-up of all relevant indications	For selected areas: > 35 % automated or manual ultrasonic scanning OR > 35 % RT
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high.			
NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).			
NOTE 3 Internal SCC.			

Table 2.F.8.5—LoIE Example for PTA Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2, 3}	Nonintrusive Inspection Example ^{1, 2, 3}
A	Highly Effective	For the total surface area: 100 % dye penetrant or eddy current test with UT follow-up of relevant indications	No inspection techniques are yet available to meet the requirements for an “A” level inspection
B	Usually Effective	For selected areas: > 65 % dye penetrant or eddy current testing with UT follow-up of all relevant indications	For selected areas: 100 % automated or manual ultrasonic scanning OR AE testing with 100 % follow-up of relevant indications
C	Fairly Effective	For selected areas: > 35 % dye penetrant or eddy current testing with UT follow-up of all relevant indications	For selected areas: > 65 % automated or manual ultrasonic scanning OR > 65 % RT
D	Poorly Effective	For selected areas: > 10 % dye penetrant or eddy current testing with UT follow-up of all relevant indications	For selected areas: > 35 % automated or manual ultrasonic scanning OR > 35 % RT
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high.			
NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).			
NOTE 3 There is no highly effective inspection without a minimum of partial insulation removal and external VT and PT.			

Table 2.F.8.6—LoIE Example for SSC

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2}	Nonintrusive Inspection Example ^{1, 2}
A	Highly Effective	For the total weld area: 100 % WFMT/ACFM with UT follow-up of relevant indications	For the total weld area: 100 % automated or manual ultrasonic scanning
B	Usually Effective	For selected welds/weld area: > 75 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 75 % automated or manual ultrasonic scanning OR AE testing with 100 % follow-up of relevant indications
C	Fairly Effective	For selected welds/weld area: > 35 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 35 % automated or manual ultrasonic scanning OR > 35 % RT
D	Poorly Effective	For selected welds/weld area: > 10 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 10 % automated or manual ultrasonic scanning OR > 10 % RT
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high.			
NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).			

Table 2.F.8.7—LoIE Example for HIC/SOHIC-H₂S Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2, 3}	Nonintrusive Inspection Example ^{1, 2, 3}
A	Highly Effective	For the total surface area: — > 95 % A or C scan with straight beam — Followed by time of flight diffraction (TOFD)/shear wave — 100 % visual	For the total surface area: — SOHIC: — > 90 % C scan of the base metal using advanced UT — For the weld and HAZ—100 % shear wave and TOFD AND — HIC: Two 1-ft² areas, C scan of the base metal using advanced UT on each plate and the heads
B	Usually Effective	For the total surface area: — > 75 % A or C scan with straight beam — Followed by TOFD/shear wave — 100 % visual	For the total surface area: — > 65 % C scan of the base metal using advanced UT AND — HIC: Two 0.5-ft² areas, C scan of the base metal using advanced UT on each plate and the heads
C	Fairly Effective	For the total surface area: — > 35 % A or C scan with straight beam — Followed by TOFD/shear wave — 100 % visual OR — > 50 % WFMT/ACFM — UT follow-up of indications — 100 % visual of total surface area	For the total surface area: — > 35 % C scan of the base metal using advanced UT AND — HIC: One 1-ft² area, C scan of the base metal using advanced UT on each plate and the heads
D	Poorly Effective	For the total surface area: — > 10 % A or C scan with shear wave — 100 % visual OR — > 25 % WFMT/ACFM — UT follow-up of indications — 100 % visual of total surface area	For the total surface area: — > 5 % C scan of the base metal using advanced UT AND — HIC: One 0.5-ft² area, C scan of the base metal using advanced UT on each plate and the heads
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high.			
NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).			
NOTE 3 Inspection area: welds and plates that are susceptible to the damage mechanism.			

Table 2.F.8.8—LoIE Example for HSC-HF Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2}	Nonintrusive Inspection Example ^{1, 2}
A	Highly Effective	For the total weld area: 100 % WFMT/ACFM with UT follow-up of relevant indications	For the total weld area: 100 % automated or manual ultrasonic scanning
B	Usually Effective	For selected welds/weld area: > 75 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 75 % automated or manual ultrasonic scanning OR AE testing with 100 % follow-up of relevant indications
C	Fairly Effective	For selected welds/weld area: > 35 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 35 % automated or manual ultrasonic scanning OR > 65 % RT
D	Poorly Effective	For selected welds/weld area: > 10 % WFMT/ACFM with UT follow-up of all relevant indications	For selected welds/weld area: > 10 % automated or manual ultrasonic scanning OR > 35 % RT
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high.			
NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).			

Table 2.F.8.9—LoIE Example for HIC/SOHIC-HF Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example ^{1, 2}	Nonintrusive Inspection Example ^{1, 2, 3}
A	Highly Effective	For the total surface area: — 100 % A or C scan with straight beam — Followed by TOFD/shear wave — 100 % visual	For the total surface area: — SOHIC: — > 90 % C scan of the base metal using advanced UT — For the weld and HAZ—100 % shear wave and TOFD AND — HIC: Two 1-ft² areas, C scan of the base metal using advanced UT on each plate and the heads
B	Usually Effective	For the total surface area: — > 65 % A or C scan with straight beam — Followed by TOFD/shear wave — 100 % visual	For the total surface area: — > 65 % C scan of the base metal using advanced UT AND — HIC: Two 0.5-ft² areas, C scan of the base metal using advanced UT on each plate and the heads
C	Fairly Effective	For the total surface area: — > 35 % A or C scan with straight beam — Followed by TOFD/shear wave — 100 % visual OR — > 50 % WFMT/ACFM — UT follow-up of indications — 100 % visual of total surface area	For the total surface area: — > 35 % C scan of the base metal using advanced UT AND — HIC: One 1-ft² area, C scan of the base metal using advanced UT on each plate and the heads
D	Poorly Effective	For the total surface area: — > 10 % A or C scan with shear wave — > 50 % visual OR — > 25 % WFMT/ACFM — UT follow-up of indications — 100 % visual of total surface area	For the total surface area: — > 5 % C scan of the base metal using advanced UT AND — HIC: One 0.5-ft² area, C scan of the base metal using advanced UT on each plate and the heads
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized

NOTE 1 Inspection quality is high.

NOTE 2 Inspection points (CMLs, scans, etc.) are set up by knowledgeable individuals.

NOTE 3 Inspection area: welds and plates that are susceptible to the damage mechanism.

2.F.9 Inspection Effectiveness for External Damage

2.F.9.1 Use of the Inspection Effectiveness Tables

LoIE Tables 2.F.9.1 through 2.F.9.4 are example for LoIEs for external damage mechanisms.

2.F.9.2 Tables

Table 2.F.9.1—LoIE Example for External Corrosion

Inspection Category	Inspection Effectiveness Category	Inspection (see Note)
A	Highly Effective	VT of > 95 % of the exposed surface area with follow-up by UT, RT, or pit gauge as required
B	Usually Effective	VT of > 60 % of the exposed surface area with follow-up by UT, RT, or pit gauge as required
C	Fairly Effective	VT of > 30 % of the exposed surface area with follow-up by UT, RT, or pit gauge as required
D	Poorly Effective	VT of > 5 % of the exposed surface area with follow-up by UT, RT, or pit gauge as required
E	Ineffective	Ineffective inspection technique/plan was utilized
NOTE Inspection quality is high.		

Table 2.F.9.2—LoIE Example for External CISC Cracking

Inspection Category	Inspection Effectiveness Category	Inspection ^{1, 2, 3}
A	Highly Effective	For the suspected surface area: 100 % dye penetrant or eddy current test with UT follow-up of relevant indications
B	Usually Effective	For the suspected surface area: > 60 % dye penetrant or eddy current testing with UT follow-up of all relevant indications
C	Fairly Effective	For the suspected surface area: > 30 % dye penetrant or eddy current testing with UT follow-up of all relevant indications
D	Poorly Effective	For the suspected surface area: > 5 % dye penetrant or eddy current testing with UT follow-up of all relevant indications
E	Ineffective	Ineffective inspection technique/plan was utilized
NOTE 1 Inspection quality is high.		
NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).		
NOTE 3 Inspection area: welds and plates that are susceptible to the damage mechanism.		

Table 2.F.9.3—LoIE Example for CUI

Inspection Category	Inspection Effectiveness Category	Insulation Removed ^{1, 2, 3, 4}	Insulation Not Removed ^{1, 2, 3, 4}
A	Highly Effective	For the total surface area: 100 % external VT prior to removal of insulation AND Remove 100 % of the insulation for damaged or suspected areas AND 100 % VT of the exposed surface area with UT, RT, or pit gauge follow-up of the selected corroded areas	For the total surface area: 100 % external VT AND 100 % profile or real-time radiography of damaged or suspect area AND Follow-up of corroded areas with 100 % VT of the exposed surface with UT, RT, or pit gauge
B	Usually Effective	For the total surface area: 100 % external VT prior to removal of insulation AND Remove > 50 % of suspect areas AND Follow-up of corroded areas with 100 % VT of the exposed surface area with UT, RT, or pit gauge	For the total surface area: 100 % external VT AND Follow-up with profile or real-time radiography of > 65 % of suspect areas AND Follow-up of corroded areas with 100 % VT of the exposed surface with UT, RT, or pit gauge
C	Fairly Effective	For the total surface area: 100 % external VT prior to removal of insulation AND Remove > 25 % of suspect areas AND Follow-up of corroded areas with 100 % VT of the exposed surface area with UT, RT, or pit gauge	For the total surface area: 100 % external VT AND Follow-up with profile or real-time radiography of > 35 % of suspect areas AND Follow-up of corroded areas with 100 % VT of the exposed surface with UT, RT, or pit gauge
D	Poorly Effective	For the total surface area: 100 % external VT prior to removal of insulation AND Remove > 5 % of total surface area of insulation including suspect areas AND Follow-up of corroded areas with 100 % VT of the exposed surface area with UT, RT, or pit gauge	For the total surface area: 100 % external VT AND Follow-up with profile or real-time radiography of > 5 % of total surface area of insulation including suspect areas AND Follow-up of corroded areas with 100 % VT of the exposed surface with UT, RT, or pit gauge
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized

NOTE 1 Inspection quality is high.

NOTE 2 Suspect area shall be considered the total surface area unless defined by knowledgeable individual (subject matter expert).

NOTE 3 Suspect areas include damaged insulation, penetrations, terminations, etc.

NOTE 4 Surface preparation is sufficient to detect minimum wall for the NDE technique used to measure thickness.

Table 2.F.9.4—LoIE Example for CUI CISCC

Inspection Category	Inspection Effectiveness Category	Insulation Removed (see Note)	Insulation Not Removed (see Note)
A	Highly Effective	For the suspected area: 100 % external VT prior to removal of insulation AND > 100 % dye penetrant or eddy current test with UT follow-up of relevant indications	No inspection techniques are yet available to meet the requirements for an “A” level inspection
B	Usually Effective	For the suspected area: 100 % external VT prior to removal of insulation AND > 60 % dye penetrant or eddy current testing with UT follow-up of all relevant indications	No inspection techniques are yet available to meet the requirements for a “B” level inspection
C	Fairly Effective	For the suspected area: 100 % external VT prior to removal of insulation AND > 30 % dye penetrant or eddy current testing with UT follow-up of all relevant indications	No inspection techniques are yet available to meet the requirements for a “C” level inspection
D	Poorly Effective	For the suspected area: 100 % external VT prior to removal of insulation AND > 5 % dye penetrant or eddy current testing with UT follow-up of all relevant indications	No inspection techniques are yet available to meet the requirements for a “D” level inspection
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized
NOTE Inspection quality is high.			

2.F.10 Inspection Effectiveness Tables for HTHA Damage

Currently there is no LoIE for HTHA damage. Please refer to [Part 2, Section 19](#), which has a discussion on HTHA as it pertains to this document. It is the owner–operator’s responsibility and accountability to develop an effective inspection program for assets potentially affected by HTHA and document their methodology, investigation, and results.

2.F.11 Inspection Effectiveness for Steam Traps, Mechanical Pumps, and Control Valves

2.F.11.1 Use of the Inspection Effectiveness Tables

LoIE [Table 2.F.11.1](#) is an example of LoIEs for steam traps, mechanical pumps, and control valves.

2.F.11.2 Tables

Table 2.F.11.1—Inspection and Testing Effectiveness for Steam Traps, Mechanical Pumps, and Control Valves

Inspection Effectiveness	Description of Inspection or Testing
Highly Effective	The steam trap inspection system/tool that is certified according to recognized standard and can be used for the energy management system. The inspectors are trained and certified to use the test equipment or the inspection tool. Comprehensive data collection as per Part 5, Table 7.3 (e.g. including related valves, piping, and location data).
Usually Effective	Online monitoring with diagnostic functions such as: failure detection and early warning signs of failure
Fairly Effective	Noncertified tools and/or noncertified inspector OR Certification unknown OR Online monitoring without diagnostic function
Poorly Effective	Visual assessment OR Incorrect inspection method
Ineffective	No inspection

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Risk-based Inspection Methodology

Part 2—Probability of Failure Methodology

Annex 2.G—Bibliography

2.G.1 General

The references for [Part 2](#) of this document are provided in [Section 2.G.2](#) of this annex.

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Risk-based Inspection Methodology

Part 3—Consequence of Failure Methodology

1 Scope

The calculation of the consequence of a leak or rupture of a component is covered in this document. This document is [Part 3](#) of a five-part volume set presenting the API 581 RBI methodology. The consequence calculated is not intended to be used in a rigorous consequence analysis of a component, such as might be employed during unit design, equipment siting, and for other safety purposes. However, the methods provided are consistent with these approaches.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Standard 520, *Sizing, Selection, and Installation of Pressure-relieving Devices, Part 1—Sizing and Selection*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 1—Introduction to Risk-Based Inspection Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 2—Probability of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 4—Inspection Planning Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 5—Special Equipment*

3 General

3.1 Overview

The COF methodology is performed to aid in establishing a ranking of equipment items on the basis of risk. The consequence measures presented in this part are intended to be used for establishing priorities for inspection programs. Methodologies for two levels of analysis are provided. A Level 1 COF methodology is detailed in [Section 4](#) for a defined list of hazardous fluids. The Level 2 COF methodology is provided in [Section 5](#) and is intended as a more rigorous approach that can be applied to a wider range of hazardous fluids. A storage tank COF methodology is provided in [Part 5, Section 4](#).

3.2 Consequence Categories

The major consequence categories are analyzed using different techniques, as follows.

- a) Flammable and explosive consequence is calculated using event trees to determine the probabilities of various outcomes (e.g. pool fires, flash fires, VCEs) to determine the magnitude of the consequence. Consequence areas can be determined based on serious personnel injuries and component damage from thermal radiation and explosions. Financial losses are determined based on the area affected by the release.
- b) Toxic consequence is calculated to determine the magnitude of the consequence area as a result of overexposure of personnel to toxic concentrations within a vapor cloud. Where fluids are flammable and

toxic, the toxic event probability assumes that if the release is ignited, the toxic consequence is negligible (i.e. toxics are consumed in the fire). Financial losses are determined based on the area affected by the release.

- c) Nonflammable/nontoxic release consequences from chemical splashes and high-temperature steam burns are determined based on serious injuries to personnel. Physical explosions and BLEVEs can also cause serious personnel injuries and component damage.
- d) Financial consequence includes losses due to business interruption and costs associated with environmental releases. Business interruption consequence is estimated as a function of the flammable and nonflammable consequence area results. Environmental consequence is determined directly from the mass available for release or from the release rate.

3.3 Collateral Damage

Collateral damage such as exposure of electrical, instrumentation, and control equipment to hazardous releases is not considered. As an example, serious delayed consequences can occur when control instrumentation is exposed to releases of chlorine.

3.4 Overview of COF Methodology

3.4.1 General

Two levels of COF methodology are defined as Level 1 and Level 2.

3.4.2 Level 1 Consequence Analysis

The Level 1 consequence analysis can be performed for a defined list of representative fluids. This methodology uses table lookups and graphs that are used to calculate the consequence of releases without the need of specialized modeling software or techniques. A series of consequence modeling analyses were performed for these reference fluids using dispersion modeling software with the results incorporated into lookup tables. The following assumptions are made in the Level 1 consequence analysis.

- a) The release fluid phase is a liquid or a gas, depending on the storage phase and the expected phase after release to the atmosphere. In general, cooling effects of flashing liquid, rainout, jet liquid entrainment, or two-phase releases are not considered.
- b) Fluid properties for representative fluids containing mixtures are based on average values (e.g. MW, NBP, density, specific heats, AIT).
- c) Probability of ignition as well as the probability of other release events (VCE, pool fire, jet fire, etc.) were predetermined for each of the representative fluids as a function of temperature, fluid AIT, and release type. These probabilities are constants and independent of the release rate.
- d) BLEVEs were not included in the Level 1 assessment.
- e) Pressurized nonflammable explosions during a vessel rupture, such as nonflammable pressurized air or nitrogen, were not included in the Level 1 assessment.
- f) Meteorological conditions were assumed in the dispersion calculations (see [Annex 3.A](#)).
- g) Toxic products produced during a combustion reaction (e.g. burning chlorinated hydrocarbons producing phosgene, HCl producing chlorine gas, amines producing hydrogen cyanide, sulfur producing sulfur dioxide) were not considered in the Level 1 assessment.

3.4.3 Level 2 Consequence Analysis

The Level 2 consequence analysis is used in cases where the assumptions of the Level 1 consequence analysis are not valid. Examples of where the more rigorous calculations may be desired or necessary are as follows.

- a) The specific fluid is not represented adequately within the list of reference fluid groups provided, including cases where the fluid is a wide-range boiling mixture or where the fluids toxic consequence is not represented adequately by any of the reference fluid groups.
- b) The stored fluid is close to its critical point, in which case the ideal gas assumptions for the vapor release equations are invalid.
- c) The effects of two-phase releases, including liquid jet entrainment as well as rainout, need to be included in the assessment.
- d) The effects of BLEVEs need to be included in the assessment.
- e) The effects of pressurized nonflammable explosions, such as possible when nonflammable pressurized gases (e.g. air or nitrogen) are released during a vessel rupture, need to be included in the assessment.
- f) The meteorological assumptions (see [Annex 3.A](#)) used in the dispersion calculations (that form the basis for the Level 1 consequence analysis) do not represent the site data.

Level 2 consequence areas do not consider the release of a toxic product during a combustion reaction (e.g. burning chlorinated hydrocarbons producing phosgene, HCl producing chlorine gas, amines producing hydrogen cyanide, sulfur producing sulfur dioxide).

3.5 COF Methodology

The COF of releasing a hazardous fluid is determined in 12 steps. A description of these steps and a cross-reference to the associated section of this document for the Level 1 and Level 2 consequence analysis are provided in [Table 3.1](#). A flow chart of the methodology is provided in [Figure 3.1](#).

Detailed procedures for each of the 12 steps are provided for both the Level 1 and Level 2 consequence analysis. Level 2 consequence analysis calculations for several of the 12 steps are identical to the Level 1 and references are made to those sections, where appropriate. The requirements and a step-by-step procedure for storage tanks are provided in [Part 5, Section 4](#).

3.6 Safety-, Financial-, and Injury-based COF

COF results are presented in terms of either safety, financial loss, or injuries. Financial-based COF is provided for all components. Area-based COF is provided for all components, with the exception of storage tank bottoms, PRDs, and heat exchanger bundles (see [Table 3.2](#)).

3.7 Use of Atmospheric Dispersion Modeling

Calculation of the Level 2 COF associated with several event outcomes (flash fires, VCEs) associated with releases of flammable and toxic fluids require the use of hazards analysis software capable of performing atmospheric dispersion analysis (cloud modeling). Assumptions and additional background for the Level 1 dispersion modeling calculations are provided in [Annex 3.A](#). Additional information on the use of cloud dispersion modeling is provided in [Section 5.7.5](#).

3.8 Tables

Table 3.1—Steps in Consequence Analysis

Step	Description	Section in This Part	
		Level 1 Consequence Analysis	Level 2 Consequence Analysis
1	Determine the released fluid and its properties, including the release phase.	4.1	5.1
2	Select a set of release hole sizes to determine the possible range of consequence in the risk calculation.	4.2	
3	Calculate the theoretical release rate.	4.3	5.3
4	Estimate the total amount of fluid available for release.	4.4	
5	Determine the type of release, continuous or instantaneous, to determine the method used for modeling the dispersion and consequence.	4.5	
6	Estimate the impact of detection and isolation systems on release magnitude.	4.6	
7	Determine the release rate and mass for the consequence analysis.	4.7	5.7
8	Calculate flammable/explosive consequence.	4.8	5.8
9	Calculate toxic consequences.	4.9	5.9
10	Calculate nonflammable, nontoxic consequence.	4.10	5.10
11	Determine the final probability weighted component damage and personnel injury consequence areas.	4.11	5.11
12	Calculate C_f^{fin} .	4.12	
13	Calculate C_f^{inj} .	4.13	

Table 3.2—COF Calculation Type Based on Equipment and Component Type

Equipment/Component Type	Consequence Calculation Type		
	Area Based	Financial Based	Safety Based
Air cooler	Yes	Yes	Yes
Compressor	Yes	Yes	Yes
Heat exchanger (shell, channel)	Yes	Yes	Yes
Heat exchanger bundle	No	Yes	No
Pipe	Yes	Yes	Yes
PRD	No	Yes	No
Pressure vessel (drum, column filter, reactor)	Yes	Yes	Yes
Pump	Yes	Yes	Yes
Tank course	Yes	Yes	Yes
Tank bottom	No	Yes	No

3.9 Figures

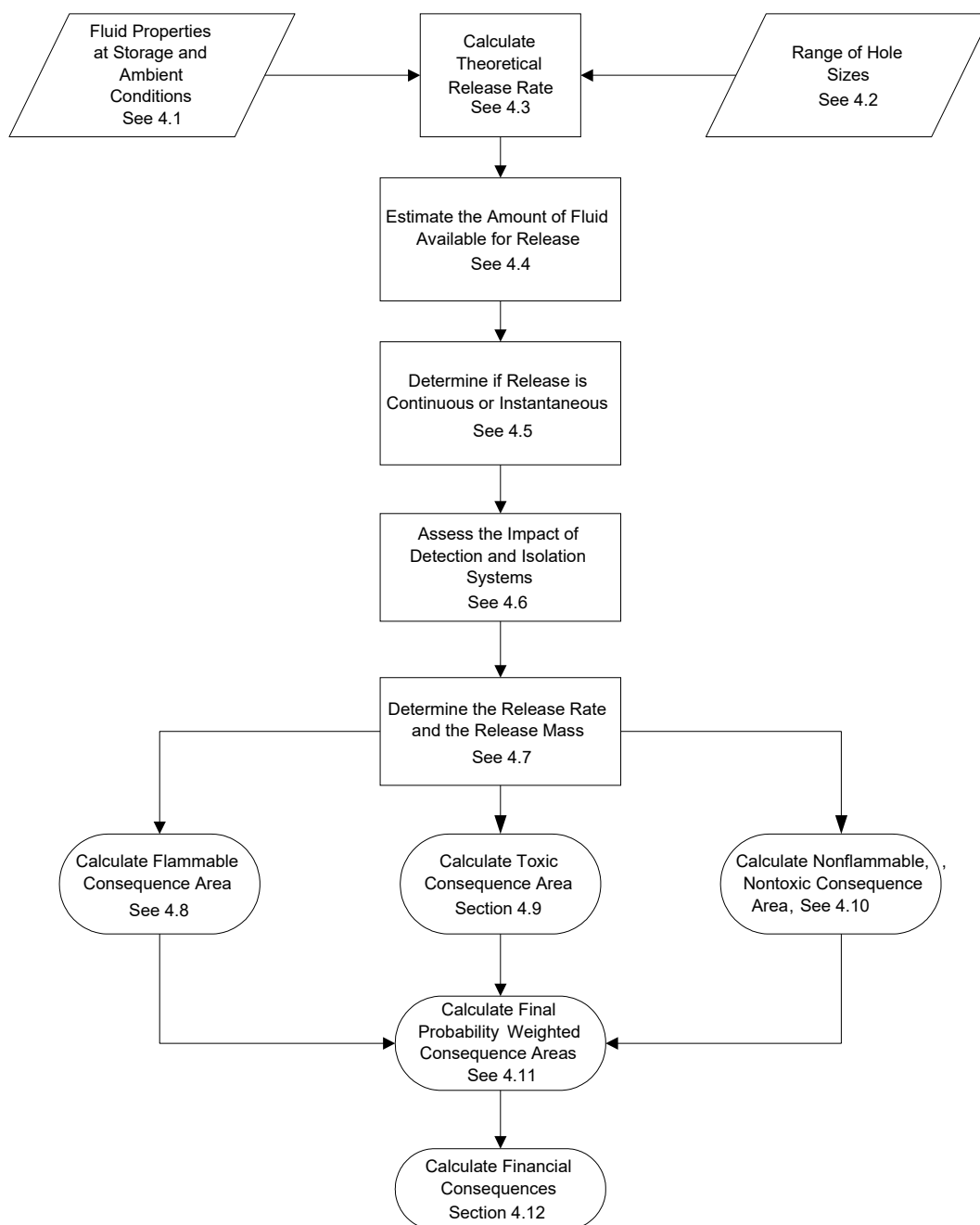


Figure 3.1—Level 1 COF Methodology

4 COF—Level 1

4.1 Determine the Representative Fluid and Associated Properties

4.1.1 Representative Fluids

In the Level 1 consequence analysis, a representative fluid that most closely matches the fluid contained in the pressurized system being evaluated is selected from the representative fluids shown in [Table 4.1](#). Because very few refinery and chemical plant streams are pure materials, the selection of a representative

fluid almost always involves making some assumptions. [Annex 3.A](#) provides guidance on selecting a representative fluid when an obvious match in [Table 4.1](#) cannot be found or when the fluid is a mixture with or without toxic components.

4.1.2 Fluid Properties

The required fluid properties estimated for each of the representative fluids as provided in [Table 4.2](#) are dependent on the stored phase of the fluid below.

a) Stored liquid:

- 1) NBP,
- 2) density, ρ_l ; and
- 3) AIT.

b) Stored vapor or gas:

- 1) NBP;
- 2) MW;
- 3) ideal gas specific heat capacity ratio, k ;
- 4) constant pressure specific heat, C_p ; and
- 5) AIT.

The properties of fluids (or individual components of mixtures) typically can be found in standard chemical reference books. The NBP is used in determining the phase of the fluid when released to the atmosphere. The MW or density is used to determine the release rate of a liquid or gas, respectively.

4.1.3 Choice of Representative Fluids for Acids and Caustic Fluids

The appropriate choice of reference fluid for acids and caustics is acid/caustic. Acid/caustic should be used when the release fluid is nonflammable and nontoxic but presents a personnel hazard when contacted during the release. Acid/caustic is modeled as a liquid spray; see [Section 4.10.3](#).

4.1.4 Estimation of Ideal Gas Specific Heat Capacity Ratio

If the value of the ideal gas specific heat capacity ratio is unknown, an estimate can be made provided a value of the constant pressure specific heat capacity, C_p , is available, using [Equation \(3.1\)](#).

$$k = \frac{C_p}{C_p - R} \quad (3.1)$$

The constant specific heat capacity, C_p , may be calculated using equations provided in [Table 4.2](#).

4.1.5 Flammable Fluid Types

The initial consequence analysis results were determined for instantaneous or continuous releases using the equations provided in lookup tables. The results were later modified to smooth transitions between instantaneous to continuous releases as well as smoothing the impact or releases as the operating temperature approaches the AIT (see [Section 4.8.5](#) and [Section 4.8.6](#)).

- a) Type 0 Fluids—Consequence area equations were not smoothed during development for the initial set of reference fluids. Blending using adjustment factors through the transitions are applied to the consequence area calculation in these Type 0 fluids shown in [Table 4.1](#).
- b) Type 1 Fluids—Instantaneous to continuous blending was performed during development of Type 1 reference fluids and the resulting consequence area equations accounted for the adjustments. As a result, instantaneous/continuous blending factors are not applied to Type 1 fluids.

4.1.6 Release Phase

The dispersion characteristics of a fluid and the probability of consequence outcomes (events) after release are dependent on the phase (i.e. gas, liquid, or two-phase) of the fluid after it is released to the atmosphere. Releases from pressurized units can be two-phase releases, especially if the fluid is viscous or has a tendency to foam. Released fluids operating under pressure above their boiling points will flash and produce a two-phase release. Guidelines for determining the phase of the released fluid when using the Level 1 consequence analysis are provided in [Table 4.3](#) if more sophisticated methods are not available. Consultation with process or operations personnel is appropriate in this determination. For steam, the release phase is gas. For the representative fluid, acid/caustic, the release phase is always liquid (see [Section 4.1.3](#)).

Where more rigorous calculations are desired in order to include the effect of two-phase flashing releases as described in [Section 5.3.4](#), a Level 2 consequence analysis can be performed.

4.1.7 Calculation of Release Phase

- a) Step 1.1—Select a representative fluid group from [Table 4.1](#).
- b) Step 1.2—Determine the stored fluid phase: liquid or gas. If stored fluid is two-phase, use the conservative assumption of liquid. Alternatively, a Level 2 consequence analysis can be performed.
- c) Step 1.3—Determine the stored fluid properties.
 - 1) For a stored liquid:
 - stored liquid density, ρ_l [lb/ft³ (kg/m³)], estimated from [Table 4.2](#);
 - AIT [°R (K)], estimated from [Table 4.2](#).
 - 2) For a stored gas:
 - MW [lb/lb-mol (kg/kg-mol)] can be estimated from [Table 4.2](#);
 - ideal gas specific heat ratio, k , can be estimated using [Equation \(3.1\)](#) and the C_p values as determined using [Table 4.2](#);
 - AIT [°R (K)] can be estimated from [Table 4.2](#).
- d) Step 1.4—Determine the steady state phase of the fluid after release to the atmosphere using [Table 4.3](#) and the phase of the fluid stored in the equipment as determined in Step 1.2.

4.2 Release Hole Size Selection

4.2.1 General

A discrete set of release events or release hole sizes are used since it would be impractical to perform the consequence analysis for a continuous spectrum of release hole sizes. The release hole sizes allow for a manageable analysis, reflects the range of possible outcomes, and is consistent with quantitative risk assessment practices.

The release hole sizes shown in [Table 4.4](#) are based on the component type and geometry as described in [Annex 3.A](#). The maximum release hole size is based on a 16 in. diameter as a practical limit for a catastrophic component failure since failure do not involve disintegration of the equipment.

4.2.2 Calculation of Release Hole Sizes

The following steps are repeated for each release hole size.

- a) Step 2.1—Based on the component type and [Table 4.4](#), determine the release hole size diameters, d_n . If $D < d_n$, $d_n = D$.
- b) Step 2.2—Determine the generic failure frequency, gff_n , for the n^{th} release hole size from [Part 2](#), [Table 3.1](#), and the total gff_n from the table or from [Equation \(3.2\)](#).

$$gff_{\text{total}} = \sum_{n=1}^4 gff_n \quad (3.2)$$

4.3 Release Rate Calculation

4.3.1 Overview

Release rates depend upon the physical properties of the material, the initial phase, the process operating conditions, and the assigned release hole sizes. The release rate equation is selected based on the phase of the material inside the component and the discharge regime (sonic or subsonic) as the material is released.

The initial phase of the hazardous material is the phase of the stored fluid in process conditions (i.e. flashing and aerosolization are not included). For two-phase systems (condensers, phase separators, evaporators, reboilers, etc.), choosing liquid as the initial state inside the equipment is conservative and may be preferred. An exception may be for two-phase piping systems where an upstream spill inventory should be considered. If a majority of the upstream material can be released as gas, then a gas phase should be modeled. The results should be checked accordingly for conservatism. Components containing two phases should have a closely approximated potential spill inventory to prevent overly conservative results. The release rate equations are provided in the following sections. The initial phase within the equipment can be determined using a fluid property solver that eliminates assumptions on the release rate calculations.

4.3.2 Liquid Release Rate Calculation

Discharges of liquids through a sharp-edged orifice is discussed in the work by Crowl and Louvar [\[1\]](#) and may be calculated using [Equation \(3.3\)](#).

$$W_n = C_d \cdot K_{v,n} \cdot \rho_l \cdot \frac{A_n}{C_1} \sqrt{\frac{2 \cdot g_c \cdot (P_s - P_{\text{atm}})}{\rho_l}} \quad (3.3)$$

In Equation (3.3), the discharge coefficient, C_d , for fully turbulent liquid flow from sharp-edged orifices is in the range of $0.60 \leq C_d \leq 0.65$. A value of $C_d = 0.61$ is recommended [17]. Equation (3.3) is used for both flashing and non-flashing liquids.

The viscosity correction factor, $K_{v,n}$, can be determined from Figure 4.1 or approximated using Equation (3.4), both of which have been reprinted from API 520, Part 1. As a conservative assumption, a value of 1.0 may be used.

$$K_{v,n} = \left(0.9935 + \frac{2.878}{Re_n^{0.5}} + \frac{342.75}{Re_n^{1.5}} \right)^{-1.0} \quad (3.4)$$

4.3.3 Vapor Release Rate Equations

There are two regimes for flow of gases or vapors through an orifice: sonic (or choked) for higher internal pressures and subsonic flow for lower pressures [15 psig (103.4 kPa) or less]. Because most process equipment operate above 15 psig (103.4 kPa), sonic (choked) flow releases are the most common in the process industry [1].

Vapor release rates are calculated in a two-step process. In the first step, the flow regime is determined, and in the second step the release rate is calculated using the equation for the specific flow regime. The transition pressure at which the flow regime changes from sonic to subsonic is defined by Equation (3.5).

$$P_{\text{trans}} = P_{\text{atm}} \left(\frac{k+1}{2} \right)^{\frac{k}{k-1}} \quad (3.5)$$

The two equations used to calculate vapor flow rate are shown below.

- a) If the storage pressure, P_s , within the equipment item is greater than the transition pressure, P_{trans} , calculated using Equation (3.5), then the release rate is calculated using Equation (3.6). This equation is based on discharges of gases and vapors at sonic velocity through an orifice; see Crowl and Louvar [1].

$$W_n = \frac{C_d}{C_2} \cdot A_n \cdot P_s \sqrt{\left(\frac{k \cdot MW \cdot g_c}{R \cdot T_s} \right) \left(\frac{2}{k+1} \right)^{\frac{k+1}{k-1}}} \quad (3.6)$$

- b) If the storage pressure is less than or equal to P_{trans} , calculated using Equation (3.5), then the release rate is calculated using Equation (3.7). This equation is based on the discharge of a gas or vapor at subsonic velocity through an orifice; see Crowl and Louvar [1].

$$W_n = \frac{C_d}{C_2} \cdot A_n \cdot P_s \sqrt{\left(\frac{MW \cdot g_c}{R \cdot T_s} \right) \left(\frac{2 \cdot k}{k-1} \right) \left(\frac{P_{\text{atm}}}{P_s} \right)^{\frac{2}{k}} \left[1 - \left(\frac{P_{\text{atm}}}{P_s} \right)^{\frac{k-1}{k}} \right]} \quad (3.7)$$

- c) In Equation (3.6) and Equation (3.7), the discharge coefficient, C_d , for fully turbulent gas or vapor flow from sharp-edged orifices is typically in the range of $0.61 \leq C_d \leq 1.0$. Crowl and Louvar [1] indicate that a discharge coefficient of $C_d = 0.61$ is suitable for subsonic gas/vapor releases having a Reynolds number of greater than 30,000. They recommend a conservative discharge coefficient of $C_d = 1.0$ for sonic gas/vapor releases or for situations where the discharge coefficient is uncertain. The conservative value of $C_d = 1.0$ is recommended for both sonic and subsonic gas/vapor releases.

4.3.4 Calculation of Release Rate

- a) Step 3.1—Select the appropriate release rate equation as described above using the stored fluid phase determined in Step 1.2.
- b) Step 3.2—For each release hole size, calculate the release hole size area, A_n , using Equation (3.8) based on d_n .

$$A_n = \frac{\pi d_n^2}{4} \quad (3.8)$$

NOTE If $D < d_n$, then set $d_n = D$.

- c) Step 3.3—For liquid releases, for each release hole size, calculate the viscosity correction factor, $K_{v,n}$, using Figure 4.1 or Equation (3.4), as defined in Section 4.3.2.
- d) Step 3.4—For each release hole size, calculate the release rate, W_n , for each release area, A_n , determined in Step 3.2 using Equations (3.3), (3.6), or (3.7).

4.4 Estimate the Fluid Inventory Available for Release

4.4.1 Overview

The leaking component inventory is combined with inventory from other associated components that contribute fluid mass. Additional background on the development of the inventory group concept is provided in Annex 3.A.

4.4.2 Maximum Mass Available for Release (Available Mass)

The available mass for release is estimated for each release hole size as the lesser of the following two quantities.

- a) Inventory Group Mass—The component being evaluated is part of a larger group of components that can be expected to provide fluid inventory to the release. These equipment items together form an inventory group. Additional guidance for creating logical inventory groups is provided in Annex 3.A. The inventory group calculation is used as an upper limit on the mass of fluid available for a release and does not indicate that this amount of fluid would be released in all leak scenarios. The inventory group mass is calculated using Equation (3.9).

$$mass_{inv} = \sum_{i=1}^N mass_{comp,i} \quad (3.9)$$

- b) Component Mass—It is assumed that for large leaks, operator intervention will occur within 3 minutes, thereby limiting the amount of released material (see Annex 3.A for additional background). Therefore, the amount of available mass for the release is limited to the mass of the component plus an additional mass, $mass_{add,n}$, that is calculated based on 3 minutes of leakage from the component's inventory group. This $mass_{add,n}$ is calculated assuming the same flow rate from the leaking component but is limited to an 8 in. (203 mm) release hole size. The $mass_{add,n}$ is calculated for each release hole size using Equation (3.10).

$$mass_{add,n} = 180 \cdot \min[W_n, W_{max8}] \quad (3.10)$$

In Equation (3.10), the maximum flow rate, $W_{\max 8}$, to be added to the release from the surrounding components, $W_{\max 8}$ [limited by an 8 in. (203 mm) diameter leak], is calculated using Equations (3.3), (3.6), or (3.7), as applicable, with the hole area, $W_n = 50.3 \text{ in.}^2$ (32,450 mm²).

The maximum mass available, $mass_{\text{avail},n}$, for release is calculated using Equation (3.11).

$$mass_{\text{avail},n} = \min \left[\left\{ mass_{\text{comp}} + mass_{\text{add},n} \right\}, mass_{\text{inv}} \right] \quad (3.11)$$

Plant detection, isolation, and mitigation techniques, as described in Section 4.6, will limit the duration of the release such that the actual mass released to atmosphere can be significantly less than the available mass as determined above.

Further guidance on the basis of the above methodology for calculating the available mass and the inventory grouping is provided in Annex 3.A.

4.4.3 Calculation of Inventory Mass

- a) Step 4.1—Group components and equipment items into inventory groups (see Annex 3.A).
- b) Step 4.2—Calculate the fluid mass, $mass_{\text{comp}}$, in the component being evaluated.
- c) Step 4.3—Calculate the fluid mass in each of the other components that is included in the inventory group, $mass_{\text{comp},i}$.
- d) Step 4.4—Calculate the fluid mass in the inventory group, $mass_{\text{inv}}$, using Equation (3.9).
- e) Step 4.5—Calculate the flow rate from an 8 in. (203 mm) diameter hole, $W_{\max 8}$, using Equations (3.3), (3.6), or (3.7), as applicable, with $A_n = A_8 = 50.3 \text{ in.}^2$ (32,450 mm²). This is the maximum flow rate that can be added to the equipment fluid mass from the surrounding equipment in the inventory group.
- f) Step 4.6—For each release hole size, calculate the added fluid mass, $mass_{\text{add},n}$, resulting from 3 minutes of flow from the inventory group using Equation (3.10), where W_n is the leakage rate for the release hole size being evaluated and $W_{\max 8}$ is from Step 4.5.
- g) Step 4.7—For each release hole size, calculate the available mass, $mass_{\text{avail},n}$, for release using Equation (3.11).

4.5 Determine the Release Type (Continuous or Instantaneous)

4.5.1 Release Type—Instantaneous or Continuous

The release is modeled as one of two following types.

- a) Instantaneous Release—An instantaneous or puff release is one that occurs so rapidly that the fluid disperses as a single large cloud or pool.
- b) Continuous Release—A continuous or plume release is one that occurs over a longer period of time, allowing the fluid to disperse in the shape of an elongated ellipse (depending on weather conditions).

The transition point between continuous and instantaneous release types is 55.6 lb/s (25.22 kg/s) or $\frac{10,000 \text{ lb}}{180 \text{ s}} = 55.6 \text{ lb/s}$. Further guidance on the background and importance of selecting the proper type of release is provided in Annex 3.A.

4.5.2 Calculation of Release Type

- a) Step 5.1—For each release hole size, determine if the release type is instantaneous or continuous. The following guidance should be followed to assign continuous and instantaneous releases (see [Figure 4.2](#)).
- 1) Small release hole size of < 0.25 in. (6.35 mm) are continuous.
 - 2) Medium, large, and rupture release hole size cases when $> 10,000$ lb (4,536 kg) mass is released in < 3 minutes is instantaneous.
 - 3) Release rates, W_n , of > 55.6 lb/s (25.22 kg/s) are instantaneous.
 - 4) All other releases are considered as continuous.

4.6 Estimate the Impact of Detection and Isolation Systems on Release Magnitude

4.6.1 Overview

Refining and petrochemical plants typically have a variety of detection, isolation, and mitigation systems that are designed to reduce the effects of a release of hazardous materials. These systems affect a release in different ways. Some systems reduce magnitude and duration of the release by detecting and isolating the leak. Other systems reduce the consequence area by minimizing the chances for ignition or limiting the spread of material. A methodology for quantifying the effectiveness of detection, isolation, and mitigation systems is included in the COF calculation.

Detection, isolation, and mitigation systems for RBI analysis affects the release in the following two ways.

- a) Detection and Isolation Systems—These systems are designed to detect and isolate a leak and tend to reduce the magnitude and duration of the release (see [Section 4.6.2](#)).
- b) Mitigation Systems—These systems are designed to mitigate or reduce the consequence of a release (see [Section 4.8.3](#)).

4.6.2 Assessing Detection and Isolation Systems

Detection and isolation systems that are present in the unit can have a significant impact on the magnitude and duration of the hazardous fluid release. Guidance for assigning a qualitative letter rating (A, B, or C) to the unit's detection and isolation systems is provided in [Table 4.5](#). Detection System A is usually found in specialty chemical applications and is not often used in refineries.

The information presented in [Table 4.5](#) is used when evaluating the consequence of continuous releases; see [Section 4.7.1](#).

4.6.3 Impact on Release Magnitude

Detection and isolation systems can reduce the magnitude of the release. For the release of both flammable and toxic materials, isolation valves serve to reduce the release rate or mass by a specified amount, depending on the quality of these systems. The recommended reduction values are presented in [Table 4.6](#).

4.6.4 Impact on Release Duration

Detection and isolation systems can reduce the duration of the release. This is important when calculating the consequence of toxic releases because toxic consequences are a function of concentration and exposure duration. The duration is used as direct input to the estimation of flammable and toxic consequences.

The quality ratings of the detection and isolation systems have been translated into an estimate of leak duration. Total leak duration, $ld_{\max,n}$, presented in Table 4.7, is the sum of the following:

- a) time to detect the leak,
- b) time to analyze the incident and decide upon corrective action, and
- c) time to complete appropriate corrective actions.

NOTE There is no total leak duration provided in Table 4.7 for the rupture case [largest release hole size, if greater than 4 in. (102 mm) diameter].

4.6.5 Releases to the Environment

Environmental consequence is mitigated in two ways: physical barriers act to contain leaks on site, and detection and isolation systems limit the duration of the leak. In API 581, the volume contained on site is accounted for directly in the spill calculation. Detection and isolation systems serve to reduce the duration of the leak and, thus, the final spill volume.

4.6.6 Calculation for Detection and Isolation

- a) Step 6.1—Determine the detection and isolation systems present in the unit.
- b) Step 6.2—Using Table 4.5, select the appropriate classification (A, B, C) for the detection system.
- c) Step 6.3—Using Table 4.5, select the appropriate classification (A, B, C) for the isolation system.
- d) Step 6.4—Using Table 4.6 and the classifications determined in Steps 6.2 and 6.3, determine the release reduction factor, $fact_{di}$.
- e) Step 6.5—Using Table 4.7 and the classifications determined in Steps 6.2 and 6.3, determine the maximum leak duration for each of the selected release hole sizes, $ld_{\max,n}$.

4.7 Determine the Release Rate and Mass for COF

4.7.1 Continuous Release Rate

For continuous releases, the release is modeled as a steady state plume; therefore, the release rate (units are lb/s) is used as the input to the consequence analysis. The release rate that is used in the analysis is the theoretical release as discussed in Section 4.3, adjusted for the presence of unit detection and isolations as discussed in Section 4.6 [see Equation (3.12)].

$$rate_n = W_n \cdot (1 - fact_{di}) \quad (3.12)$$

4.7.2 Instantaneous Release Mass

For transient instantaneous puff releases, the release mass is required to perform the analysis. The available release mass, $mass_{avail,n}$, as determined in Section 4.4.2 for each release hole size, $mass_{avail,n}$, is used to determine an upper bound release mass, $mass_n$, as shown in Equation (3.13).

$$mass_n = \min[\{rate_n \cdot ld_n\}, mass_{avail,n}] \quad (3.13)$$

In this equation, the leak duration, ld_n , cannot exceed the maximum duration $ld_{\max,n}$, established in [Section 4.6.4](#) based on the detection and isolation systems present. [Equation \(3.14\)](#) can be used to calculate the actual duration of the release, ld_n .

$$ld_n = \min \left[\left\{ \frac{mass_{\text{avail},n}}{rate_n} \right\}, \{60 \cdot ld_{\max,n}\} \right] \quad (3.14)$$

4.7.3 Calculation of Release Rate and Mass

- a) Step 7.1—For each release hole size, calculate the adjusted release rate, $rate_n$, using [Equation \(3.12\)](#), where the theoretical release rate, W_n , is from Step 3.2.

NOTE 1 The release reduction factor, $fact_{di}$, determined in Step 6.4 accounts for any detection and isolation systems that are present.

- b) Step 7.2—For each release hole size, calculate the leak duration, ld_n , of the release using [Equation \(3.14\)](#), based on the available mass, $mass_{\text{avail},n}$, from Step 4.6 and the adjusted release rate, $rate_n$, from Step 7.1.

NOTE 2 The leak duration cannot exceed the maximum duration, $ld_{\max,n}$, determined in Step 6.5.

- c) Step 7.3—For each release hole size, calculate the upper bound release mass, $mass_n$, using [Equation \(3.13\)](#) based on the release rate, $rate_n$, from Step 3.2, the leak duration, ld_n , from Step 7.2, and the available mass, $mass_{\text{avail},n}$, from Step 4.6.

4.8 Determine Flammable and Explosive Consequence

4.8.1 Overview

Equations to calculate flammable and explosive consequence have been developed for the representative fluids presented in [Table 4.1](#). Consequence areas are estimated from a set of equations using release rate (for continuous releases) or release mass (for instantaneous releases) as input. Technical background information pertaining to the development of the empirical equations for the flammable consequence areas is provided in [Annex 3.A](#). An assumption is made that the probability of ignition for a continuous release is constant and is a function of the material released and whether or not the fluid is at or above its AIT. The probability does not increase as a function of release rate. For an instantaneous release, the probability of ignition increases. The probability of ignition and other event tree probabilities for the Level 1 COF are documented in [Annex 3.A](#). An instantaneous release is defined as any release larger than 10,000 lb (4,536 kg) in 3 minutes, which is equivalent to a release rate of 55.6 lb/s (25.2 kg/s). A continuous release of 55.6 lb/s (25.2 kg/s) would have a lower consequence than an instantaneous release at 55.6 lb/s (25.2 kg/s) of the same material. Therefore, the Level 1 COF blends the continuous and instantaneous releases results (see [Section 4.8.7](#)).

4.8.2 Consequence Area Equations

4.8.2.1 Generic Equations

The following equations are used to determine the flammable consequence areas for component damage and personnel injury. The background for development of these generic equations is provided in [Annex 3.A](#).

- a) Continuous Release—For a continuous release, [Equation \(3.15\)](#) is used. Coefficients for this equation for component damage areas and personnel injury areas are provided in [Table 4.8](#) and [Table 4.9](#), respectively.

$$CA_{f,n}^{\text{CONT}} = a(rate_n)^b \quad (3.15)$$

- b) Instantaneous Release—For an instantaneous release, Equation (3.16) is used. Coefficients for this equation for component damage areas and personnel injury areas are provided in Table 4.8 and Table 4.9, respectively.

$$CA_{t,n}^{INST} = a(mass_n)^b \quad (3.16)$$

4.8.2.2 Development of Generic Equations

Equation (3.15) and Equation (3.16) were used to calculate overall consequence areas following a three-step process.

- a) An event tree analysis was performed by listing possible events or outcomes and providing estimates for the probabilities of each event. The two main factors that define the paths on the event tree for the release of flammable material are the probability of ignition and the timing of ignition. The event trees used are provided in Figure 4.3 where event probabilities were set as a function of release type (continuous or instantaneous) and temperature (proximity to the AIT). These probabilities are provided in Annex 3.A.
- b) The consequence areas as a result of each event were calculated using appropriate analysis techniques, including cloud dispersion modeling. Additional background on the methods used for these calculations are provided in Annex 3.A.
- c) The consequence areas of each individual event were combined into a single probability weighted empirical equation representing the overall consequence area of the event tree (see Annex 3.A).

4.8.2.3 Threshold Limits

Threshold limits for thermal radiation and overpressure, sometimes referred to as impact criteria, were used to calculate the consequence areas for a particular event outcome (pool fire, VCE, etc.).

- a) Component damage criteria:
 - 1) explosion overpressure—5 psig (34.5 kPa);
 - 2) thermal radiation—12,000 Btu/(hr-ft²) [37.8 kW/m²] (jet fire, pool fire, and fireball); and
 - 3) flash fire—25 % of the area within the lower flammability limits (LFLs) of the cloud when ignited.
- b) Personnel injury criteria:
 - 1) explosion overpressure—34.5 kPa (5 psig);
 - 2) thermal radiation—4000 Btu/(hr-ft²) [12.6 kW/m²] (jet fire, fireball, and pool fire); and
 - 3) flash fire—the LFL limits of the cloud when ignited.

The predicted results using the above threshold limits were intended to produce a relative risk ranking that, while being considered to be reasonably accurate, are not the highest levels of consequence that could be estimated for a given accident sequence. As are most effects data, the component damage and personnel injury criteria listed above are subject to intensive scientific debate, and values other than those used in this methodology could be suggested.

4.8.3 Adjustment of Consequence Areas to Account for Mitigation Systems

4.8.3.1 Evaluating Post-leak Mitigation of Consequence

Evaluating post-leak response is an important step in consequence analysis. In this step, the various mitigation systems in place are evaluated for their effectiveness in limiting the consequence areas. Toxic releases are typically characterized as a prolonged buildup, then reduction, in cloud concentration, with accumulated exposure throughout. Flammable events are more often releases that are either ignited quickly or the material is quickly dispersed below its LFL. For these reasons, different approaches are necessary for evaluating the post-leak response based on the type of consequence. Mitigation systems and their effect on flammable release events are presented in this section.

4.8.3.2 Effects of Mitigation Measures on Flammable Consequence Magnitudes

The adjustments to the magnitude of the consequence for flammable releases based on unit mitigation systems are provided in [Table 4.10](#). These values are based on engineering judgment, using experience in evaluating mitigation measures in quantitative risk analyses. The consequence area reduction factor, $fact_{mit}$, to account for the presence of mitigation systems is provided in [Table 4.10](#).

4.8.4 Adjustment of Consequence Areas for Energy Efficiencies

Comparison of calculated consequence with those of actual historical releases indicates that there is a need to correct large instantaneous releases for energy efficiency. This correction is made for instantaneous events exceeding a release mass of 10,000 lb (4,536 kg) by dividing the calculated consequence areas by the adjustment factor, $eneff_n$, given by [Equation \(3.17\)](#).

$$eneff_n = 4 \cdot \log_{10}[C_{4A} \cdot mass_n] - 15 \quad (3.17)$$

NOTE The adjustment defined by [Equation \(3.17\)](#) is not applied to continuous releases.

4.8.5 Blending of Results Based on Release Type

The Level 1 consequence area calculations yield significantly different results, depending on whether the continuous area equations are used or the instantaneous area equations are used. The blending factor is determined as follows based on the release type.

- a) For Continuous Releases—A blending factor is calculated to smooth the results for releases near the continuous to instantaneous transition [10,000 lb (4,536 kg) released in less than 3 minutes or a release rate of 55.6 lb/s (25.2 kg/s)] using [Equation \(3.18\)](#).

$$fact_n^{IC} = \min \left[\left\{ \frac{rate_n}{C_5} \right\}, 1.0 \right] \quad (3.18)$$

When instantaneous equation constants are not provided in [Table 4.8](#) and [Table 4.9](#) for the reference fluid, the blending factor is defined in [Equation \(3.19\)](#).

$$fact_n^{IC} = 0.0 \quad (3.19)$$

- b) For Instantaneous Releases—Blending is not required for instantaneous releases 10,000 lb (4,536 kg) released in less than 3 minutes or a release rate of 55.6 lb/s (25.2 kg/s)]. The blending factor, $fact_n^{IC}$, for an instantaneous release is defined in [Equation \(3.20\)](#).

$$fact_n^{IC} = 1.0 \quad (3.20)$$

The blended release area is calculated using [Equation \(3.21\)](#).

NOTE This area is proportionate to the proximity of the actual release rate, $rate_n$, is to the continuous/instantaneous transition rate of 55.6 lb/s (25.2 kg/s).

$$CA_n^{IC-blend} = CA_n^{INST} \cdot fact_n^{IC} + CA_n^{CONT} (1 - fact_n^{IC}) \quad (3.21)$$

4.8.6 Blending of Results Based on AIT

Consequence area calculations yield significantly different results depending on whether the autoignition not likely consequence equations are used or the autoignition likely consequence area equations are used. The consequence areas are blended using [Equation \(3.22\)](#).

$$CA^{AIT-blend} = CA^{AIL} fact^{AIT} + CA^{AINL} (1 - fact^{AIT}) \quad (3.22)$$

The AIT blending factor, $fact^{AIT}$, is determined using the following equations.

$$fact^{AIT} = 0 \quad \text{for } T_s + C_6 \leq AIT \quad (3.23)$$

$$fact^{AIT} = \frac{(T_s - AIT + C_6)}{2 \cdot C_6} \quad \text{for } T_s + C_6 > AIT > T_s - C_6 \quad (3.24)$$

$$fact^{AIT} = 1 \quad \text{for } T_s - C_6 \geq AIT \quad (3.25)$$

NOTE T_s is in °R (°K).

4.8.7 Determination of Final Flammable Consequence Areas

The final flammable consequence areas are determined as a probability weighted average of the individual (blended) flammable areas calculated for each release hole size. This is performed for both the component damage and the personnel injury consequence areas. The probability weighting utilizes the generic frequencies of the release hole sizes selected per [Section 4.2](#).

The equation for probability weighting of the component damage consequence areas is given by [Equation \(3.26\)](#).

$$CA_{f,cmd}^{flam} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{cmd,n}^{flam}}{gff_{total}} \right) \quad (3.26)$$

The equation for probability weighting of the personnel injury consequence areas is given by [Equation \(3.27\)](#).

$$CA_{f,inj}^{flam} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{inj,n}^{flam}}{gff_{total}} \right) \quad (3.27)$$

In Equation (3.28) and Equation (3.29), the gff_n for each release hole size and gff_{total} are provided in Part 2, Table 3.1.

4.8.8 Calculation of Consequence Area

- a) Step 8.1—Select the consequence area mitigation reduction factor, $fact_{mit}$, from Table 4.10.
- b) Step 8.2—For each release hole size, calculate the energy efficiency correction factor, $eneff_n$, using Equation (3.17).
- c) Step 8.3—Determine the fluid type, either Type 0 or Type 1, from Table 4.1.
- d) Step 8.4—For each release hole size, calculate the component damage consequence areas for autoignition not likely, continuous release (AINL-CONT), $CA_{cmd,n}^{AINL-CONT}$.

- 1) Determine the appropriate constants a and b from the Table 4.8. The release phase as determined in Step 1.4 will be needed to assure selection of the correct constants.

$$a = a_{cmd}^{AINL-CONT} \quad (3.28)$$

$$b = b_{cmd}^{AINL-CONT} \quad (3.29)$$

- 2) Use Equation (3.30) to calculate the consequence area.

$$CA_{cmd,n}^{AINL-CONT} = a(rate_n)^b \cdot (1 - fact_{mit}) \quad (3.30)$$

- e) Step 8.5—For each release hole size, calculate the component damage consequence areas for autoignition likely, continuous release (AIL-CONT), $CA_{cmd,n}^{AIL-CONT}$.

- 1) Determine the appropriate constants, a and b , from the Table 4.8. The release phase as determined in Step 1.4 will be needed to assure selection of the correct constants.

$$a = a_{cmd}^{AIL-CONT} \quad (3.31)$$

$$b = b_{cmd}^{AIL-CONT} \quad (3.32)$$

- 2) Use Equation (3.33) to calculate the consequence area.

$$CA_{cmd,n}^{AIL-CONT} = a(rate_n)^b \cdot (1 - fact_{mit}) \quad (3.33)$$

- f) Step 8.6—For each release hole size, calculate the component damage consequence areas for autoignition not likely, instantaneous release (AINL-INST), $CA_{cmd,n}^{AINL-INST}$.

- 1) Determine the appropriate constants, a and b , from the Table 4.8. The release phase as determined in Step 1.4 will be needed to assure selection of the correct constants.

$$a = a_{cmd}^{AINL-INST} \quad (3.34)$$

$$b = b_{cmd}^{AINL-INST} \quad (3.35)$$

- 2) Use Equation (3.36) for the consequence area.

$$CA_{\text{cmd},n}^{\text{AIL-INST}} = a \left(mass_n \right)^b \cdot \left(\frac{1 - fact_{\text{mit}}}{eneff_n} \right) \quad (3.36)$$

g) Step 8.7—For each release hole size, calculate the component damage consequence areas for autoignition likely, instantaneous release (AIL-INST), $CA_{\text{cmd},n}^{\text{AIL-INST}}$.

- 1) Determine the appropriate constants, a and b , from the Table 4.8. The release phase as determined in Step 1.4 will be needed to assure selection of the correct constants.

$$a = a_{\text{cmd}}^{\text{AIL-INST}} \quad (3.37)$$

$$b = b_{\text{cmd}}^{\text{AIL-INST}} \quad (3.38)$$

- 2) Use Equation (3.39) to calculate the consequence area.

$$CA_{\text{cmd},n}^{\text{AIL-INST}} = a \left(mass_n \right)^b \cdot \left(\frac{1 - fact_{\text{mit}}}{eneff_n} \right) \quad (3.39)$$

h) Step 8.8—For each release hole size, calculate the personnel injury consequence areas for autoignition not likely, continuous release (AINL-CONT), $CA_{\text{inj},n}^{\text{AINL-CONT}}$.

- 1) Determine the appropriate constants, a and b , from the Table 4.9. The release phase as determined in Step 1.4 will be needed to assure selection of the correct constants.

$$a = a_{\text{inj}}^{\text{AINL-CONT}} \quad (3.40)$$

$$b = b_{\text{inj}}^{\text{AINL-CONT}} \quad (3.41)$$

- 2) Calculate the consequence area using Equation (3.42).

$$CA_{\text{inj},n}^{\text{AINL-CONT}} = \left[a \cdot (rate_n)^b \right] \cdot (1 - fact_{\text{mit}}) \quad (3.42)$$

i) Step 8.9—For each release hole size, calculate the personnel injury consequence areas for autoignition likely, continuous release (AIL-CONT), $CA_{\text{inj},n}^{\text{AIL-CONT}}$.

- 1) Determine the appropriate constants, a and b , from the Table 4.9. The release phase as determined in Step 1.4 will be needed to assure selection of the correct constants.

$$a = a_{\text{inj}}^{\text{AIL-CONT}} \quad (3.43)$$

$$b = b_{\text{inj}}^{\text{AIL-CONT}} \quad (3.44)$$

- 2) Calculate the consequence area using Equation (3.45).

$$CA_{\text{inj},n}^{\text{AIL-CONT}} = \left[a \cdot (rate_n)^b \right] \cdot (1 - fact_{\text{mit}}) \quad (3.45)$$

j) Step 8.10—For each release hole size, calculate the personnel injury consequence areas for autoignition not likely, instantaneous release (AINL-INST), $CA_{\text{inj},n}^{\text{AINL-INST}}$.

- 1) Determine the appropriate constants, a and b , from the [Table 4.9](#). The release phase as determined in Step 1.4 will be needed to assure selection of the correct constants.

$$a = a_{inj}^{AINL-INST} \quad (3.46)$$

$$b = b_{inj}^{AINL-INST} \quad (3.47)$$

- 2) Calculate the consequence area using [Equation \(3.48\)](#).

$$CA_{inj,n}^{AINL-INST} = \left[a \cdot (mass_n)^b \right] \cdot \left(\frac{1 - fact_{mit}}{eneff_n} \right) \quad (3.48)$$

- k) Step 8.11—For each release hole size, calculate the personnel injury consequence areas for autoignition likely, instantaneous release (AIL-INST), $CA_{inj,n}^{AIL-INST}$.

- 1) Determine the appropriate constants, a and b , from the [Table 4.9](#). The release phase as determined in Step 1.4 will be needed to assure selection of the correct constants.

$$a = a_{inj}^{AIL-INST} \quad (3.49)$$

$$b = b_{inj}^{AIL-INST} \quad (3.50)$$

- 2) Calculate the consequence area using [Equation \(3.51\)](#).

$$CA_{inj,n}^{AIL-INST} = \left[a \cdot (mass_n)^b \right] \cdot \left(\frac{1 - fact_{mit}}{eneff_n} \right) \quad (3.51)$$

- l) Step 8.12—For each release hole size, calculate the instantaneous/continuous blending factor, $fact_n^{IC}$, using [Equations \(3.18\)](#), [\(3.19\)](#), or [\(3.20\)](#), as applicable. Instantaneous/continuous blending is not required for Type 1 fluids. For Type 1 fluids, use the component damage and personnel injury areas based on release type.
- m) Step 8.13—Calculate the AIT blending factor, $fact^{AIT}$, using [Equations \(3.23\)](#), [\(3.24\)](#), or [\(3.25\)](#), as applicable.
- n) Step 8.14—For Type 0 fluids, calculate the continuous/instantaneous blended consequence areas for Type 0 fluid components using [Equations \(3.52\)](#) through [\(3.55\)](#) based on the consequence areas calculated in Steps 8.4, 8.5, 8.6, 8.7, 8.8, 8.9, 8.10, and 8.11, and the continuous/instantaneous blending factor, $fact_n^{IC}$, from Step 8.12. Instantaneous/continuous blending is not required for Type 1 fluids. For Type 1 fluids, use the component damage and personnel injury areas based on release type from Steps 8.4 to 8.11.

$$CA_{cmd,n}^{AIL} = CA_{cmd,n}^{AIL-INST} \cdot fact_n^{IC} + CA_{cmd,n}^{AIL-CONT} \cdot (1 - fact_n^{IC}) \quad (3.52)$$

$$CA_{inj,n}^{AIL} = CA_{inj,n}^{AIL-INST} \cdot fact_n^{IC} + CA_{inj,n}^{AIL-CONT} \cdot (1 - fact_n^{IC}) \quad (3.53)$$

$$CA_{cmd,n}^{AINL} = CA_{cmd,n}^{AINL-INST} \cdot fact_n^{IC} + CA_{cmd,n}^{AINL-CONT} \cdot (1 - fact_n^{IC}) \quad (3.54)$$

$$CA_{inj,n}^{AINL} = CA_{inj,n}^{AINL-INST} \cdot fact_n^{IC} + CA_{inj,n}^{AINL-CONT} \cdot (1 - fact_n^{IC}) \quad (3.55)$$

- o) Step 8.15—Calculate the AIT blended consequence areas for all components using Equations (3.56) and (3.57) based on the consequence areas determined in Step 8.14 and the AIT blending factors, $fact^{AIT}$ calculated in Step 8.13. The resulting consequence areas are the component damage and personnel injury flammable consequence areas, $CA_{cmd,n}^{flam}$ and $CA_{inj,n}^{flam}$, for each release hole sizes selected in Step 2.2.

$$CA_{cmd,n}^{flam} = CA_{cmd,n}^{AIL} \cdot fact^{AIT} + CA_{cmd,n}^{AINL} \cdot (1 - fact^{AIT}) \quad (3.56)$$

$$CA_{inj,n}^{flam} = CA_{inj,n}^{AIL} \cdot fact^{AIT} + CA_{inj,n}^{AINL} \cdot (1 - fact^{AIT}) \quad (3.57)$$

- p) Step 8.16—Determine the final consequence areas (probability weighted on release hole size) for component damage and personnel injury using Equation (3.58) and Equation (3.59) based on the consequence areas from Step 8.15.

$$CA_{f,cmd}^{flam} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{cmd,n}^{flam}}{gff_{total}} \right) \quad (3.58)$$

$$CA_{f,inj}^{flam} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{inj,n}^{flam}}{gff_{total}} \right) \quad (3.59)$$

4.9 Determine Toxic Consequence

4.9.1 General

Toxic fluids are similar to flammables in that not all toxic releases result in a single type of effect. By themselves, HF, ammonia, and chlorine pose only a toxic hazard. On the other hand, some toxic materials such as hydrogen sulfide (H₂S) are both toxic and flammable. However, any toxic material, when mixed with hydrocarbons, can pose flammable and toxic hazards.

The toxic consequence is calculated using a hazards analysis in conjunction with atmospheric dispersion models similar to the flammable procedure described in Section 4.8.

4.9.2 Common Refining Toxic Materials

The procedure for determination of toxic consequence of four toxic materials that typically contribute to toxic risks for a refinery—hydrogen fluoride (HF), hydrogen sulfide (H₂S), ammonia (NH₃), and chlorine (Cl)—is provided in Section 4.9.6 and Section 4.9.7.

4.9.3 Common Chemical Industry Toxic Materials

The determination of toxic consequence includes 10 additional toxic chemicals commonly used in the chemical industry as described in Section 4.9.8. Level 1 toxic consequence analysis uses probit data for determining the consequence areas (see Table 4.14).

4.9.4 Representative Fluids for Toxic Mixtures

Modeling of releases where the toxic component is part of a mixture is a special case for the Level 1 consequence analysis. For these cases, the analysis requires the selection of a representative fluid from [Table 4.1](#) for the purpose of determining the release rate that is used in the consequence assessment. The representative fluid should be selected based upon the average boiling point, density, and MW of the mixture; see [Section 4.1.2](#). A Level 2 consequence analysis per [Section 5](#) rigorously calculates the fluid composition and release mixture.

4.9.5 Determination of the Toxic Release Rate and Mass

The toxic release rate or mass to be used in the toxic consequence analysis is determined based on the mass fraction of the toxic component, $mfrac^{tox}$, that is present in the release fluid.

$$rate_n^{tox} = mfrac^{tox} \cdot W_n \quad (3.60)$$

$$mass_n^{tox} = mfrac^{tox} \cdot mass_n \quad (3.61)$$

For pure toxic fluids ($mfrac^{tox} = 1.0$), the toxic release rate, $rate_n^{tox}$, is equal to the release rate, W_n , as calculated in [Section 4.3](#), and the toxic release mass, $mass_n^{tox}$, is equal to the release mass, $mass_n$, as calculated in [Section 4.7](#). For mixtures, the toxic release rate and release mass are modified based on the percentage of the toxic component in the mixture and the storage phase (liquid or vapor) of the mixture.

NOTE The magnitude reduction factor, $fact_{di}$, to account for detection and isolation systems is not applied to toxic releases (see [Section 4.6](#)).

4.9.6 Estimation of Toxic Consequence Area for HF and H₂S

- The background for the development of the toxic consequence equations for HF and H₂S is provided in [Annex 3.A](#). For determination of the toxic consequence areas, the assumption was made that the release phase would always be a gas or vapor.
- The toxic consequence areas for continuous releases of HF or H₂S as a function of the release rate may be calculated using [Equation \(3.62\)](#).

$$CA_{inj,n}^{tox-CONT} = C_8 \cdot 10^{\left(c \cdot \log_{10} \left[C_{4B} \cdot rate_n^{tox} \right] + d\right)}$$

$$CA_{inj,n}^{tox-CONT} = C_8 \cdot \left(\left[C_{4B} \cdot rate_n^{tox} \right]^c \cdot 10^d \right) \quad (3.62)$$

NOTE 1 For continuous releases, the toxic release rate, $rate_n^{tox}$, is used as the input to [Equation \(3.62\)](#). The constants, c and d , to be used in [Equation \(3.62\)](#) are provided in [Table 4.11](#) as a function of release duration. Interpolation between curves using the actual duration (defined in [Section 4.9.10](#)) is acceptable.

- The toxic consequence areas for instantaneous releases of HF or H₂S as a function of the release rate may be calculated using [Equation \(3.63\)](#).

$$CA_{inj,n}^{tox-INST} = C_8 \cdot 10^{\left(c \cdot \log_{10} \left[C_{4B} \cdot mass_n^{tox} \right] + d\right)}$$

$$CA_{inj,n}^{tox-INST} = C_8 \cdot \left(\left[C_{4B} \cdot mass_n^{tox} \right]^c \cdot 10^d \right) \quad (3.63)$$

NOTE 2 For instantaneous releases, the toxic release mass, $mass_n^{tox}$, is used as the input to Equation (3.63). The constants, c and d , to be used in Equation (3.63) are provided in Table 4.11.

4.9.7 Estimation of Toxic Consequence Area for Ammonia and Chlorine

- a) The background for the development of the toxic consequence equations for ammonia and chlorine are provided in Annex 3.A. For determination of the consequence areas, the assumption was made that the release phase would always be a gas or vapor.
- b) The toxic consequence areas for continuous releases of ammonia or chlorine as a function of the release rate may be calculated using Equation (3.64).

$$CA_{inj,n}^{tox-CONT} = e \left(rate_n^{tox} \right)^f \quad (3.64)$$

NOTE 1 For continuous releases, the toxic release rate, $rate_n^{tox}$, is used as the input to Equation (3.64). The constants e and f for Equation (3.64) are provided in Table 4.12 as a function of release duration. Interpolation between curves using the actual duration is acceptable.

- c) The toxic consequence areas for instantaneous releases of ammonia or chlorine as a function of the release rate may be calculated using Equation (3.65).

$$CA_{inj,n}^{tox-INST} = e \left(mass_n^{tox} \right)^f \quad (3.65)$$

NOTE 2 For instantaneous releases, the toxic release mass, $mass_n^{tox}$, is used as the input to Equation (3.65). The constants e and f for Equation (3.65) are provided in Table 4.12.

4.9.8 Estimation of Toxic Consequence Area for Additional Common Chemicals

- a) The background for the development of the toxic consequence equations for 10 additional common chemicals shown below is provided in Annex 3.A. For determination of the consequence areas, the assumption was made that the release phase could either be a vapor, liquid, or powder. Additionally, the consequence equations were developed for continuous release equations only.
 - 1) Aluminum Chloride ($AlCl_3$)—Powder.
 - 2) Carbon Monoxide (CO)—Gas only.
 - 3) Hydrogen Chloride (HCl)—Gas only.
 - 4) Nitric Acid—Gas or liquid.
 - 5) Nitrogen Dioxide (NO_2)—Gas or liquid.
 - 6) Phosgene—Gas or liquid.
 - 7) Toluene Diisocyanate (TDI)—Liquid only.
 - 8) Ethylene Glycol Monoethyl Ether (EE)—Gas or liquid.
 - 9) Ethylene Oxide (EO)—Gas only.
 - 10) Propylene Oxide (PO)—Gas or liquid.

- b) Procedures for these chemicals have been developed in much the same manner as that for ammonia and chlorine and are further described in [Annex 3.A](#).
- c) The toxic consequence area can be approximated as a function of duration (except for AlCl_3) using [Equation \(3.64\)](#) and the constants e and f provided in [Table 4.13](#).

4.9.9 Material Concentration Cut-off

As a general rule, it is not necessary to evaluate a toxic release if the concentration of the stored fluid within the component or equipment item is at or below the immediately dangerous to life or health (IDLH) value. For HF, this is 30 ppm, for H_2S this is 100 ppm, for NH_3 this is 300 ppm, and for Cl this is 10 ppm. Other IDLH values are provided in [Table 4.14](#).

4.9.10 Release Duration

The potential toxic consequence is estimated using both the release duration and release rate, whereas the flammable impact relies on just the magnitude of the release, i.e. rate or mass. The duration of a release depends on the following:

- a) the inventory in the equipment item and connected systems,
- b) time to detect and isolate the leak,
- c) any response measures that may be taken.

The maximum release duration is set at 1 hour, for the following two reasons.

- a) It is expected that the plant's emergency response personnel will employ a shutdown procedure and initiate a combination of mitigation measures to limit the duration of a release.
- b) It is expected that personnel will either be moved out of the area or be evacuated by emergency responders within 1 hour of the initial exposure.

The release duration can be estimated as the inventory in the system divided by the initial release rate. While the calculated duration may exceed 1 hour, there may be systems in place that will significantly shorten this time, such as isolation valves and rapid-acting leak detection systems. Times should be determined on a case-by-case basis. The leak duration, ld_n^{tox} , should be calculated for each release hole size as the minimum of:

- a) 1 hour,
- b) release mass (mass available) divided by release rate (see [Section 4.7](#)), and
- c) maximum leak duration, $ld_{\text{max},n}$ listed in [Table 4.7](#).

$$ld_n^{\text{tox}} = \min \left(3600, \left\{ \frac{\text{mass}_n}{W_n} \right\}, \{ 60 \cdot ld_{\text{max},n} \} \right) \quad (3.66)$$

4.9.11 Toxic Outcome Probabilities

In the event the release involves both toxic and flammable outcomes, it is assumed that either the flammable outcome consumes the toxic material or that the toxic materials disperse and flammable materials have insignificant consequences. In this case, the probability for the toxic event is the remaining non-ignition frequency for the event (i.e. the probability of safe dispersion).

4.9.12 Consequence of Releases Containing Multiple Toxic Chemicals

Consequence results for releases of multicomponent toxic chemicals are uncommon but determined by calculating the consequence area for each of the individual toxic components within the mixture. The overall toxic consequence area is the largest of the individual toxic areas.

4.9.13 Effects of Mitigation Measures on Toxic Releases

To this point, isolation and detection capabilities have been taken into account in calculating the quantity of material that may be released during a loss-of-containment event (see [Section 4.7.1](#)). However, there may be additional systems in place, such as water sprays, that can mitigate a release once the material has reached the atmosphere.

The effectiveness of mitigating systems are accounted for by reducing the release rate and duration for continuous releases or by reducing the release mass for instantaneous releases. The RBI analyst will need to provide their own reduction factors, based on the effectiveness of their particular spray-system design or passive mitigation technology.

Where mitigation is a major issue, specialists should be consulted to get an accurate input. As an example, it is possible to mitigate HF releases with a water spray. However, the fraction of HF that is removed by a water spray may vary from near 0 % to near 100 % depending on the size of the release, the droplet size, flow rate and orientation of the spray, and several other variables.

4.9.14 Determination of Final Toxic Consequence Areas

The final toxic consequence is determined as a probability weighted average of the individual toxic calculated for each release hole size. A consequence area calculation is performed for the personnel injury areas only since toxic releases do not result in component damage. The probability weighting utilizes the generic frequencies of the release hole sizes obtained in Step 2.3. [Equation \(3.67\)](#) is used to calculate the probability weighted toxic consequence area.

$$CA_{f, inj}^{tox} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{inj, n}^{tox}}{gff_{total}} \right) \quad (3.67)$$

4.9.15 Calculation of Toxic Consequence Areas

- Step 9.1—For each release hole size selected in Step 2.2, calculate the effective duration of the toxic release using [Equation \(3.66\)](#).
- Step 9.2—Determine the toxic percentage of the toxic component, $mfrac^{tox}$, in the release material. If the release fluid is a pure fluid, $mfrac^{tox} = 1.0$.

NOTE If there is more than one toxic component in the released fluid mixture, this procedure can be repeated for each toxic component.

- Step 9.3—For each release hole size, calculate the release rate, $rate_n^{tox}$, and release mass, $mass_n^{tox}$, to be used in the toxic analysis using [Equation \(3.60\)](#) and [Equation \(3.61\)](#).
- Step 9.4—For each release hole size, calculate the toxic consequence area for each of the release hole sizes.

- 1) HF and H₂S—Calculate $CA_{inj,n}^{tox}$ using Equation (3.62) for a continuous release or Equation (3.63) for an instantaneous release. The constants used in these equations are from Table 4.11.
 - 2) Ammonia and Chlorine—Calculate $CA_{inj,n}^{tox}$ using Equation (3.64) for a continuous release or Equation (3.65) for an instantaneous release. The constants used in these equations are from Table 4.12.
 - 3) For Toxic Fluids Listed in Section 4.9.8—Calculate $CA_{inj,n}^{tox}$ using Equation (3.64) for continuous and instantaneous releases (using 3 minute release for instantaneous releases). The constants used in these equations are from Table 4.13.
- e) Step 9.5—If there are additional toxic components in the released fluid mixture, Steps 9.2 through 9.4 should be repeated for each toxic component.
- f) Step 9.6—Determine the final toxic consequence areas for personnel injury in accordance with Equation (3.67).

4.10 Determine Nonflammable, Nontoxic Consequence

4.10.1 General

Consequences associated with the release of nonflammable, nontoxic materials are not as severe as with other materials; however, they can still result in serious injury to personnel and damage to equipment.

4.10.2 Consequence of Steam Leaks

Steam represents a hazard to personnel who are exposed to it at high temperatures. Steam leaks do not result in a component damage consequence. In general, steam is at 212 °F (100 °C) immediately after exiting a hole in an equipment item. Within a few feet, depending upon its pressure, steam will begin to mix with air, cool, and condense. At a concentration of about 20 %, the steam/air mixture cools to about 140 °F (60 °C). The approach used here is to assume that injury occurs above 140 °F (60 °C). This temperature was selected as the threshold for injury to personnel, as this is the temperature above which OSHA requires that hot surfaces be insulated to protect against personnel burns. This recommended practice assumes that injury occurs as a result of a 5 second exposure [2] to temperatures of 140 °F (60 °C).

To determine an equation for the consequence area of a continuous release of steam, four release cases (0.25 in., 1 in., 4 in., and 16 in.) were run through atmospheric dispersion software for varying steam pressures. A plot of the release rate vs the area covered by a 20 % concentration of steam shows a linear relationship in accordance with Equation (3.68).

$$CA_{inj,n}^{CONT} = C_9 \cdot rate_n \quad (3.68)$$

For instantaneous release cases, four masses of steam were modeled: 10 lb, 100 lb, 1,000 lb, and 10,000 lb (4.5 kg, 45.4 kg, 454.0 kg, and 4,540 kg), and the relationship between release mass and consequence area to 20 % concentration was found to be in accordance with Equation (3.69).

$$CA_{inj,n}^{INST} = C_{10} (mass_n)^{0.6384} \quad (3.69)$$

For nonflammable releases of steam, the continuous/instantaneous blending of results should be performed as described in Section 4.8.5. The blending factor, $fact_n^{IC}$, for steam leaks is calculated using Equation (3.70).

$$fact_n^{IC} = \min \left[\left\{ \frac{rate_n}{C_5} \right\}, 1.0 \right] \quad (3.70)$$

4.10.3 Consequences of Acid and Caustic Leaks

For caustics/acids that have splash type consequences, water was chosen as a representative fluid to determine the personnel consequence area. Acid or caustic leaks do not result in a component damage consequence. The consequence area was defined as the 180° semi-circular area covered by the liquid spray or rainout. Modeling was performed at three pressures; 15 psig, 30 psig, and 60 psig (103.4 kPa, 206.8 kPa, and 413.7 kPa) for four release hole sizes (see [Table 4.4](#)). Continuous liquid releases were modeled only since instantaneous gas releases are assumed not to produce rainout. The results were analyzed to obtain a correlation between release rate and consequence area and were divided by 5 since it is believed that serious injuries to personnel are only likely to occur within about 20 % of the total splash area as calculated by the above method.

The resulting consequence area for nonflammable releases of acids and caustics is calculated using [Equation \(3.71\)](#) and [Equation \(3.72\)](#).

$$CA_{inj,n}^{CONT} = 0.2 \cdot ax^b \quad (3.71)$$

$$CA_{inj,n}^{INST} = 0.0 \quad (3.72)$$

The constants a and b shown in [Equation \(3.71\)](#), are functions of pressure and are shown in [Table 4.9](#).

Since there are no consequences associated with an instantaneous release of acid or caustic, the instantaneous/continuous blending factor, $fact_n^{IC}$, is equal to 0.0.

4.10.4 Blending of Results Based on Release Type

The consequence area calculations yield significantly different results depending on whether the continuous area equations are used or the instantaneous area equations are used. The nonflammable, nontoxic personnel injury consequence area for steam or acid leaks can be calculated for each hole size using [Equation \(3.73\)](#).

$$CA_{inj,n}^{leak} = CA_{inj,n}^{INST} \cdot fact_n^{IC} + CA_{inj,n}^{CONT} (1 - fact_n^{IC}) \quad (3.73)$$

NOTE There is no need to calculate a component damage area for nonflammable releases of steam or acid/caustic.

$$CA_{cmd,n}^{leak} = 0.0 \quad (3.74)$$

4.10.5 Determination of Final Nonflammable, Nontoxic Consequence Areas

The final nonflammable, nontoxic consequence areas are determined as a probability weighted average of the individual consequence areas calculated for each release hole size. Nonflammable, nontoxic consequences do not impact equipment so damage areas are not calculated. Probability weighting uses the generic frequencies of the release hole sizes provided in [Part 2, Table 3.1](#). [Equation \(3.75\)](#) is used to calculate the probability weighted nonflammable, nontoxic consequence area for steam, caustic, or acid releases.

$$CA_{f,inj}^{nfnt} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{inj,n}^{leak}}{gff_{total}} \right) \quad (3.75)$$

The term $CA_{inj,n}^{leak}$ in Equation (3.75) represents the personnel injury areas for each of the holes sizes either due to steam or acid releases as described in Section 4.10.2 and Section 4.10.3.

4.10.6 Calculation of Nonflammable, Nontoxic Consequence Areas

a) Step 10.1—For each release hole size, calculate the nonflammable, nontoxic consequence area.

- 1) For Steam—Calculate $CA_{inj,n}^{CONT}$ using Equation (3.68) and $CA_{inj,n}^{INST}$ using Equation (3.69).
- 2) For Acids or Caustics—Calculate $CA_{inj,n}^{CONT}$ for liquid releases using Equations (3.71) and (3.72).

NOTE 1 Data are not provided for an instantaneous release; therefore, $CA_{inj,n}^{INST} = 0.0$.

b) Step 10.2—For each release hole size, calculate the instantaneous/continuous blending factor, $fact_n^{IC}$. For steam, use Equation (3.70). For acids or caustics, $fact_n^{IC} = 0.0$.

c) Step 10.3—For each release hole size, calculate the blended nonflammable, nontoxic personnel injury consequence area for steam or acid leaks, $CA_{inj,n}^{leak}$, using Equation (3.73) based on the consequence areas from Step 10.1 and the blending factor, $fact_n^{IC}$, from Step 10.2.

NOTE 2 There is no need to calculate a component damage area for the Level 1 nonflammable releases (steam or acid/caustic):

$$CA_{cmd,n}^{leak} = 0.0 \quad (3.76)$$

d) Step 10.4—Determine the final nonflammable, nontoxic consequence areas for personnel injury, CA_{inj}^{nfnt} , using Equation (3.75) based on consequence areas calculated for each release hole size in Step 10.3.

NOTE 3 There is no need to calculate a final nonflammable, nontoxic consequence area for component damage area for the Level 1 nonflammable releases (steam or acid/caustic), or:

$$CA_{f,cmd}^{nfnt} = 0.0 \quad (3.77)$$

4.11 Determine the Component Damage and Personnel Injury Consequence Areas

4.11.1 Overview

The final consequence areas for component damage and personnel injury are the maximum areas of those calculated for:

- a) flammable consequence; see Section 4.8,
- b) toxic consequence; see Section 4.9, and
- c) nonflammable, nontoxic consequence (see Section 4.10).

4.11.2 Final Component Damage Consequence Area

The final component damage consequence area is:

$$CA_{f,cmd} = \max \left[CA_{f,cmd}^{flam}, CA_{f,cmd}^{tox}, CA_{f,cmd}^{nfnt} \right] \quad (3.78)$$

NOTE Since the component damage consequence areas for toxic releases, CA_{cmd}^{tox} , and nonflammable, nontoxic releases, CA_{cmd}^{nfnt} , are both equal to zero, the final component damage consequence area is equal to the consequence area calculated for flammable releases, CA_{cmd}^{flam} .

$$CA_{f,cmd} = CA_{f,cmd}^{flam} \quad (3.79)$$

4.11.3 Final Personnel Injury Consequence Area

The final personnel injury consequence area is:

$$CA_{inj} = \max \left[CA_{f,inj}^{flam}, CA_{f,inj}^{tox}, CA_{f,inj}^{nfnt} \right] \quad (3.80)$$

4.11.4 Final Consequence Area

The final consequence area is:

$$CA_f = \max \left[CA_{f,cmd}, CA_{f,inj} \right] \quad (3.81)$$

4.11.5 Calculation of Final Consequence Area

- Step 11.1—Calculate the final component damage consequence area, $CA_{f,cmd}$, using [Equation \(3.79\)](#).
- Step 11.2—Calculate the final personnel injury consequence area, $CA_{f,inj}$, using [Equation \(3.80\)](#).
- Step 11.3—Calculate the final consequence area, CA_f , using [Equation \(3.81\)](#).

4.12 Determine the Financial Consequence

4.12.1 Overview

There are many costs associated with any failure of equipment in a process plant. These include but are not limited to:

- cost of equipment repair and replacement;
- cost of damage to surrounding equipment in affected areas;
- costs associated with production losses and business interruption as a result of downtime to repair or replace damaged equipment;
- costs due to potential injuries associated with a failure;
- environmental cleanup costs.

The approach used is to consider the above costs on both an equipment specific basis and an affected area basis. Thus, any failure (loss of containment) has costs associated with it, even when the release of the hazardous material does not result in damage to other equipment in the unit or serious injury to personnel. Recognizing and using this fact presents a more realistic value of the consequences associated with a failure.

The C_f^{fin} of a loss of containment and subsequent release of hazardous materials can be determined by adding up the individual costs discussed above:

$$C_f^{\text{fin}} = FC_{f,\text{cmd}} + FC_{f,\text{affa}} + FC_{f,\text{prod}} + FC_{f,\text{inj}} + FC_{f,\text{environ}} \quad (3.82)$$

The risk is calculated as the COF (now expressed as cost in dollars) times the POF. For a rigorous and flexible analysis, the consequence (cost) is evaluated at the hole size level. Risk is also evaluated at the release hole size level by using the POF associated with each release hole size. The total risk is calculated as the sum of the risks of each release hole size.

4.12.2 Component Damage Cost

The method chosen for these calculations operates under the presumption that there is a specific cost associated with each possible leak scenario (release hole size) and that these are unique to each component type. This approach was chosen based on the inherent differences in the costs associated with repairing components having small hole damage to that of components having extreme damage as a result of equipment rupture.

A small hole in a piping system can sometimes be repaired with little or no impact on production by use of a temporary clamp until a permanent repair can be scheduled during normal maintenance shutdowns. Larger holes usually do not allow this option, and shutdown plus repair costs are greatly increased.

Example component damage costs, $holecost_n$, for different release hole sizes for each component are shown in Table 4.15. Actual failure cost data for component should be used if available. The sources cited were used to estimate the relative installed costs of the equipment. Since repair or replacement of a component usually does not involve replacement of all supports, foundations, etc., the example repair and replacement costs presented do not reflect actual installed cost.

The example cost estimates shown in Table 4.15 are based on carbon steel prices obtained in 2001. The $holecost_n$ may be multiplied by $costfactor$ (user defined) to reflect changed in carbon steel and replacement costs from the 2001 basis and experience. It is suggested that these costs be multiplied by a material cost factor, $matcost$, for other materials. Table 4.16 shows the suggested values for these material cost factors. These factors are based on a variety of sources from manufacturer's data and cost quotations.

The consequence cost to repair or replace the component that has been damaged is a probability weighted average of the individual repair costs determined for each release hole size and is calculated using Equation (3.83). The probability weighting utilizes the generic frequencies of the release hole sizes provided in Part 2, Table 3.1.

$$FC_{f,\text{cmd}} = \left(\frac{\sum_{n=1}^4 gff_n \cdot holecost_n}{gff_{\text{total}}} \right) \cdot matcost \cdot costfactor \quad (3.83)$$

4.12.3 Damage Costs to Surrounding Equipment in Affected Area

It is necessary to calculate the component damage costs to other equipment components in the vicinity of the failure, if the failure results in a flammable (or explosive) event. Toxic releases do not result in damage to surrounding equipment. Typically, a constant value of the process unit replacement cost, $equipcost$, is used. In other words, as a starting point, the average cost of other equipment components surrounding any given component is about the same regardless of location within the process unit. This could be refined for individual components by allowing the default value to be overridden with a higher or lower value where appropriate.

The consequence cost to repair or replace surrounding components that have become damaged in the affected area is calculated using the component damage area, CA_{cmd} , calculated in Step 8.15 using Equation (3.56) and Equation (3.84).

$$FC_{f,affa} = CA_{f,cmd} \cdot equipcost \quad (3.84)$$

4.12.4 Business Interruption Costs

The costs associated with business interruption are determined based on the amount of downtime (and lost production) associated with repairing the damage to the specific piece of equipment that has had loss of containment (due to holes or rupture) as well as the downtime associated with repairing the surrounding equipment in the area of the plant affected by the release (consequence area).

- a) For each release hole size, an estimated downtime for each equipment type, $Outage_n$ is presented in Table 4.17. Centrifugal pumps are assumed to have online spares, so the assumption is made that there is no downtime associated with the failure of these equipment types. The probability weighting of the downtime required to repair damage for a specific equipment item is given by Equation (3.85). The probability weighting uses the generic frequencies of the release hole sizes provided in Table 3.1 of Part 2.

$$Outage_{cmd} = \left(\frac{\sum_{n=1}^4 gff_n \cdot Outage_n}{gff_{total}} \right) \cdot Outage_{mult} \quad (3.85)$$

NOTE Downtimes presented in Table 4.17 are the minimum time required to repair equipment damage in the event of a loss of containment. When a loss of containment occurs, such as a nonflammable/nontoxic event, a financial impact results based on the cost to perform a leak repair. If actual downtimes are significantly higher than the time in Table 4.17, the outage multiplier, $Outage_{mult}$, may be used to reflect the increase.

- b) If a component has a failure (loss of containment through hole or rupture) resulting in an affected area (consequence area), the cost of downtime for replacement and repair of surrounding equipment in the affected area must be considered. For more details regarding the calculation of surrounding equipment downtime, refer to *Dow's Fire and Explosion Index* [33]. The downtime associated with repairing the surrounding equipment in the affected area is calculated using Equation (3.86).

$$Outage_{affa} = 10^{1.242 + 0.585 \cdot \log_{10} [FC_{affa} \cdot (10)^{-6}]} \quad (3.86)$$

- c) The cost of the business interruption associated with repairing damaged equipment is equal to the cost associated with lost production due to the shutdown of the facility.

$$FC_{f,prod} = (Outage_{cmd} + Outage_{affa}) (prodcost) \quad (3.87)$$

4.12.5 Potential Injury Costs

Another cost to consider when a failure occurs is the potential injury costs. When a business takes injury costs into account in a risk management scheme, then appropriate resources can be spent to prevent these injuries from happening. Just as failure to consider the business cost of a zero affected area event can lead to under-ranking this event with respect to risk, a risk could be present that is not considered in allocating inspection resources if injury costs are not considered.

In the Level 1 consequence analysis, a constant population density, $popdens$, is used as a default for all equipment in the unit (see Section 4.13.3). This default value can be overridden by higher or lower values

depending on specific equipment location with respect to controls rooms, walkways, roads, etc. In addition to the population density, the cost per individual, $injcost$, affected must be determined. This value must be sufficiently high to adequately represent typical costs to businesses of an injury up to and including fatal injuries. When assigning this value, consideration should be given to the following:

- a) any existing company standards for such calculations,
- b) local medical/compensation costs associated with long-term disability,
- c) legal/settlement costs, and
- d) indirect costs such as increased regulatory scrutiny, loss of reputation.

The costs associated with personnel injury are calculated using [Equation \(3.88\)](#):

$$FC_{inj} = CA_{inj} \cdot popdens \cdot injcost \quad (3.88)$$

Alternatively, the consequence related to injury, C_f^{inj} , may be calculated using safety consequence in [Section 4.13](#).

4.12.6 Environmental Cleanup Costs

Environmental consequence as a result of loss of containment can be significant and should be added to the other costs including fines and other financial penalties. The methods presented here are based on the amount of material spilled to the ground, the number of days to clean up the spill, and the environmental hazards associated with the properties of the fluid released.

The cost of cleanup depends on where the release is likely to be spilled. For example, spills into waterways will be much more costly than spills above ground. In addition, spills that work their way below ground will be more costly than spills above ground. The environmental cost, $envcost$, in \$/bbl, must be provided as an estimate by the analyst.

Fluids that are released as a liquid per [Section 4.1.6](#) are considered to have the potential for environmental costs. Additionally, it is assumed that any liquid with a NBP less than 93 °C (200 °F) will readily evaporate and thus the environmental costs will be negligible. If the release is likely to autoignite, the environmental costs should not be included since the release will probably ignite and burn.

The fraction of the release fluid for remediation is a function of the evaporation rate. Estimates of release fluid evaporation fraction, $frac_{evap}$, as a function of the NBP is provided in [Table 4.18](#). As an alternative, the following equation can be used to estimate $frac_{evap}$:

$$frac_{evap} = \left[\begin{aligned} & -7.1408 + 8.5827(10)^{-3} \cdot ((C_{12} \cdot NBP) + C_{41}) \\ & -3.5594(10)^{-6} \cdot ((C_{12} \cdot NBP) + C_{41})^2 \\ & + \frac{2331.1}{(C_{12} \cdot NBP) + C_{41}} - \frac{203,545}{((C_{12} \cdot NBP) + C_{41})^2} \end{aligned} \right] \quad (3.89)$$

where C_{41} is a conversion factor that is equal to 0 when using the NBP in Fahrenheit (U.S. customary units) and equal to 32 when using Celsius (SI units).

The spill volume of fluid that requires cleanup is calculated using [Equation \(3.90\)](#) for each release hole size using the fluid liquid density, ρ_l (see [Table 4.2](#)), and the fraction of release that does not evaporate.

$$vol_n^{env} = \frac{C_{13} \cdot mass_n (1 - frac_{evap})}{\rho_l} \quad (3.90)$$

The final spill volume to be cleaned up is a probability weighted average of the spill volumes for each of the release hole sizes. The probability weighting utilizes the generic frequencies of the release hole sizes provided in [Part 2, Table 3.1](#). The environmental cost to clean up the weighted spill volume is calculated using [Equation \(3.91\)](#).

$$FC_{f,enviro} = \left(\frac{\sum_{n=1}^4 gff_n \cdot vol_n^{env}}{gff_{total}} \right) \cdot envcost \quad (3.91)$$

4.12.7 Calculation of Financial Consequence

- a) Step 12.1—Calculate the cost (consequence in \$) to repair the specific piece of equipment, $FC_{f,cmd}$, using [Equation \(3.83\)](#) with the release hole size damage costs from [Table 4.15](#) and GFFs for the release hole sizes from Step 2.2. The material cost factor, $matcost$, is obtained from [Table 4.16](#).
- b) Step 12.2—Calculate the cost of damage to surrounding equipment in the affected area, $FC_{f,affa}$, using [Equation \(3.84\)](#) and component damage consequence area, $CA_{f,cmd}$, calculated in Step 11.1. The equipment cost factor, $equipcost$, is the unit equipment replacement cost in \$/ft² (\$/m²).
- c) Step 12.3—For each release hole size, calculate the cost of business interruption due to the outage days required to repair the damage to equipment.
 - 1) Calculate the probability weighted repair of the specific piece of equipment using [Equation \(3.85\)](#) and the downtime for each release hole size, $Outage_n$, from [Table 4.17](#).
 - 2) Calculate the downtime required to repair the surrounding equipment in the affected area, $Outage_{affa}$, using [Equation \(3.86\)](#) and the cost of damage to the surrounding equipment in the affected area, $FC_{f,affa}$, calculated in Step 12.2.
 - 3) Calculate the cost of business interruption, $FC_{f,prod}$, using [Equation \(3.87\)](#). The production costs, $prodcost$, is the cost of lost production on the unit, \$/day.
- d) Step 12.4—Calculate the costs associated with personnel injury using [Equation \(3.91\)](#) and the personnel injury consequence area, $CA_{f,inj}$, calculated in Step 11.2. The unit population density, $popdens$, is the average number of personnel on the unit per ft² (personnel/m²). The personnel injury cost, $injcost$, is the cost incurred by the company as a result serious injury or fatality of personnel.
- e) Step 12.5—Calculate the costs associated with environmental cleanup.
 - 1) Estimate the spill volume from each release hole size, using [Equation \(3.93\)](#), the release mass from Step 7.3, and the fluid liquid density and evaporation fraction obtained from [Table 4.18](#).
 - 2) Calculate the probability weighted environmental cleanup costs, $FC_{f,enviro}$, using [Equation \(3.94\)](#) and the spill volume calculated for each release hole size, vol_n^{env} . The environmental costs, $envcost$, are the environmental cleanup costs, \$/bbl.

- f) Step 12.6—Calculate the total C_f^{fin} using Equation (3.85), which is the sum of the costs determined in Steps 12.1 through 12.5.

4.13 Determine Safety Consequence

4.13.1 General

The final safety consequence, C_f^{inj} , is defined as the product of final personnel injury consequence area, CA_f^{inj} , and population density, popdens , of the area representing the number of injuries that may occur, as shown in Equation (3.92). The consequence of an event occurring results in a higher risk in a unit with a larger number of personnel than the same event in a unit with a smaller number of personnel present.

$$C_f^{\text{inj}} = CA_f^{\text{inj}} \cdot \text{popdens} \quad (3.92)$$

The popdens of a unit is typically based on the average population density of the process unit, but may be defined as a part of a unit, as preferred by the owner-operator. The popdens should consider the area of the unit and the typical number of personnel present during each shift and day of the week, including consideration for routine operation and high maintenance or project activity. The popdens is calculated using Equation (3.99).

Determination of the CA_f^{inj} is described in Section 4.11.3 and calculated using Equation (3.80). Flammable injury COF is calculated using Section 4.8.8, Step 8.15, toxic injury area from Section 4.9.15, Step 9.6, and nonflammable, nontoxic injury area from Section 4.10.

4.13.2 Determination of Population Density

The average personnel, $\text{Pers \#}_{\text{avg}}$, is the average number of personnel present in a unit at any given time. The $\text{Pers \#}_{\text{avg}}$ present should consider full time personnel or operators over the 24 hour day for 365 days of a year, plus the additional people are present for a fraction of time, calculated using Equation (3.93).

$$\text{Pers \#}_{\text{avg}} = \frac{(\text{Pers \#}_1 \cdot \text{Present\%}_{n1}) + (\text{Pers \#}_2 \cdot \text{Present\%}_{n2}) + (\text{Pers \#}_3 \cdot \text{Present\%}_{n3}) + \dots}{100} \quad (3.93)$$

where $\text{Pers \#}_n$ and $\text{Present\%}_n$ are the personnel population and percent of time personnel are present, respectively, for each unit staffing activity.

The popdens is calculated using Equation (3.94).

$$\text{popdens} = \frac{\text{Pers \#}_{\text{avg}}}{A_{\text{red}}^{\text{safety}}} \quad (3.94)$$

Alternatively, the consequence related to injury, C_f^{inj} , may be calculated potential injury costs as part of the financial consequence in Section 4.12.6.

4.13.3 Calculation of Safety Consequence

- a) Step 13.1—Calculate the CA_f^{inj} using Equation (3.80).
- b) Step 13.2—Calculate the average personnel, $\text{Pers \#}_{\text{avg}}$, present in the unit using Equation (3.93).

- c) Step 13.3—Calculate the area the unit covers, $Area_n^{\text{safety}}$. The $Area_n^{\text{safety}}$ should be defined within the unit boundaries and may include additional areas beyond the unit boundaries that may be impacted. Considering the area within the unit boundaries is acceptable when impacted areas beyond the unit boundaries are sparsely populated.
- d) Step 13.4—Calculate the unit population density, $popdens$, using average population present, $Pers\#_{\text{avg}}$, and the $Area_n^{\text{safety}}$ using Equation (3.94).
- e) Step 13.5—Calculate the SC_f^{inj} using the CA_f^{inj} and $popdens$ using Equation (3.92).

4.14 Nomenclature

The following lists the nomenclature used in Section 4. The coefficients C_1 through C_{41} , which provide the metric and U.S. conversion factors for the equations, are provided in Annex 3.B.

A_n	is the hole area associated with the n^{th} release hole size, in. ² (mm ²)
AIT	is the autoignition temperature of the released fluid, K (°R)
$Area_n^{\text{safety}}$	is the area being evaluated for a safety consequence, typically a process unit, ft ² (m ²)
a	is a constant provided for reference fluids for Level 1 consequence analysis
$a_{\text{cmd}}^{\text{AIL-CONT}}$	is a constant AIL continuous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$a_{\text{cmd}}^{\text{AIL-INST}}$	is a constant AIL instantaneous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$a_{\text{cmd}}^{\text{AINL-CONT}}$	is a constant for AINL continuous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$a_{\text{cmd}}^{\text{AINL-INST}}$	is a constant for AINL instantaneous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$a_{\text{inj}}^{\text{AIL-CONT}}$	is a constant AIL continuous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$a_{\text{inj}}^{\text{AIL-INST}}$	is a constant AIL instantaneous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$a_{\text{inj}}^{\text{AINL-CONT}}$	is a constant for AINL continuous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$a_{\text{inj}}^{\text{AINL-INST}}$	is a constant for AINL instantaneous release provided for reference fluids for Level 1 consequence analysis for personnel injury area

b	is a variable provided for reference fluids for Level 1 consequence analysis for analysis
$b_{cmd}^{AIL-CONT}$	is a constant AIL continuous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$b_{cmd}^{AIL-INST}$	is a constant AIL instantaneous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$b_{cmd}^{AINL-CONT}$	is a constant AINL continuous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$b_{cmd}^{AINL-INST}$	is a constant AINL instantaneous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$b_{inj}^{AIL-CONT}$	is a constant AIL continuous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$b_{inj}^{AIL-INST}$	is a constant AIL instantaneous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$b_{inj}^{AINL-CONT}$	is a constant AINL continuous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$b_{inj}^{AINL-INST}$	is a constant AINL instantaneous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
C_d	is the release hole coefficient of discharge, unitless
C_f^{area}	is the safety consequence impact area, ft ² (m ²)
C_f^{fin}	is the financial consequence, \$
C_f^{inj}	is the injury consequence, injuries
C_p	is the specific heat of the released fluid, Btu/lb-°R (J/kg-K)
CA^{AIL}	is the flammable consequence area where autoignition is likely to occur, ft ² (m ²)
CA^{AINL}	is the flammable consequence area where autoignition is not likely to occur, ft ² (m ²)
$CA^{AIT-blend}$	is the AIT blended flammable consequence area, ft ² (m ²)
$CA_{cmd,n}^{AIL}$	is the continuous/instantaneous blended component damage flammable consequence area that is likely to autoignite, associated with the n^{th} release hole size, ft ² (m ²)

$CA_{cmd,n}^{AIL-CONT}$	is the component damage flammable consequence area for continuous releases that is likely to autoignite, associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{cmd,n}^{AIL-INST}$	is the component damage flammable consequence area for instantaneous releases that is likely to autoignite, associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{cmd,n}^{AINL}$	is the continuous/instantaneous blended component damage flammable consequence area that is not likely to autoignite, associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{cmd,n}^{AINL-CONT}$	is the component damage flammable consequence area for continuous releases that is not likely to autoignite, associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{cmd,n}^{AINL-INST}$	is the component damage flammable consequence area for instantaneous releases that is not likely to autoignite, associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{cmd,n}^{\text{flam}}$	is the blended component damage flammable consequence area, associated with the n^{th} release hole size, ft^2 (m^2)
CA_f	is the final consequence area, ft^2 (m^2)
$CA_{f,cmd}$	is the final component damage consequence area, ft^2 (m^2)
$CA_{f,cmd}^{\text{flam}}$	is the final probability weighted component damage flammable consequence area, ft^2 (m^2)
$CA_{f,cmd}^{\text{nfnt}}$	is the component damage nonflammable, nontoxic consequence area, ft^2 (m^2)
$CA_{f,cmd}^{\text{tox}}$	is the final probability weighted component damage toxic consequence area, ft^2 (m^2)
$CA_{f,inj}$	is the final personnel injury consequence area, ft^2 (m^2)
$CA_{f,inj}^{\text{flam}}$	is the final probability weighted personnel injury flammable consequence area, ft^2 (m^2)
$CA_{f,inj,n}^{\text{flam}}$	is the blended personnel injury flammable consequence area, associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,inj}^{\text{nfnt}}$	is the final probability weighted personnel injury consequence area for nonflammable, nontoxic releases such as steam or acids, ft^2 (m^2)
$CA_{f,inj}^{\text{tox}}$	is the final probability weighted personnel injury toxic consequence area, ft^2 (m^2)
$CA_{f,max}$	is the final maximum consequence area, ft^2 (m^2)
$CA_{f,n}^{\text{CONT}}$	is the consequence area for a continuous release, ft^2 (m^2)

$CA_{f,n}^{INST}$	is the consequence area for an instantaneous release, ft ² (m ²)
$CA_{inj,n}^{AIL-CONT}$	is the personnel injury flammable consequence area for continuous releases that is likely to autoignite, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{AIL-INST}$	is the personnel injury flammable consequence area for instantaneous releases that is likely to autoignite, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{AINL-CONT}$	is the personnel injury flammable consequence area for continuous releases that is not likely to autoignite, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{AINL-INST}$	is the personnel injury flammable consequence area for instantaneous releases that is not likely to autoignite, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{CONT}$	is the personnel injury consequence area for continuous releases, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{INST}$	is the personnel injury consequence area for instantaneous releases, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{acid}$	is the personnel injury consequence area for caustic and acid leaks, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{leak}$	is the personnel injury nonflammable, nontoxic consequence area for steam or acid leaks, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{stm}$	is the personnel injury consequence area for steam leaks, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{tox-CONT}$	is the personnel injury toxic consequence area for a continuous release, associated with the n^{th} release hole size, ft ² (m ²)
$CA_{inj,n}^{tox-INST}$	is the personnel injury toxic consequence area for an instantaneous release, associated with the n^{th} release hole size, ft ² (m ²)
$CA_n^{IC-blend}$	is the continuous/instantaneous blended flammable consequence area, ft ² (m ²)
c	is a gas release constant used in HF and H ₂ S releases for the COF 1 toxic area analysis
$costfactor$	is the cost factor reflecting the change in carbon steel and replacement costs from the 2001
d	is a gas release constant used in HF and H ₂ S releases for the Level 1 toxic consequence area analysis
d_n	is the diameter of the n^{th} release hole size, in. (mm)

e	Is a gas release constant used in NH ₃ and Cl releases for the Level 1 toxic consequence area analysis
$eneff_n$	is the energy efficiency correction factor for instantaneous events exceeding a release mass of 10,000 lb (4,536 kg)
$envcost$	is the environmental cleanup costs, \$/bbl
$equipcost$	is the process unit replacement costs for component, \$/ft ² (\$/m ²)
FC_{affa}	is the financial consequence of damage to surrounding equipment on the unit, \$
FC_{cmd}	is the financial consequence of component damage, \$
$FC_{environ}$	is the financial consequence of environmental cleanup, \$
FC_{inj}	is the financial consequence as a result of serious injury to personnel, \$
FC_{prod}	is the financial consequence of lost production on the unit, \$
f	is a gas release constant used in NH ₃ and Cl releases for the Level 1 toxic consequence area analysis
$fact^{AIT}$	is the AIT consequence area blending factor
$fact_{di}$	is the release magnitude adjustment factor, based on the detection and isolations systems present in the unit.
$fact_{mit}$	is the consequence area adjustment factor, based on the mitigation systems present in the unit
$fact_n^{IC}$	is the continuous/instantaneous consequence area blending factor determined for each release hole size, associated with the n^{th} release hole size
$frac_{evap}$	is the fraction of the released liquid pool that evaporates, needed to estimate the volume of material for environmental cleanup
g	is a gas release constant used in acid and caustic releases for the Level 1 area consequence analysis
g_c	is the gravitational constant = $32.2(\text{lbm} - \text{ft})/(\text{lbf} - \text{s}^2) \left[1.0(\text{kg} - \text{m})/(\text{N} - \text{s}^2) \right]$
gff_n	are the generic failure frequencies for each of the n release hole sizes selected for the type of equipment being evaluated
gff_{total}	is the sum of the individual release hole size generic frequencies
h	is a gas release constant for acid and caustic for the Level 1 area consequence analysis
$holecost_n$	is the equipment repair cost, provided for each of the release hole sizes selected, \$

$injcost$	is the cost associated with serious injury or fatality of personnel, \$
$K_{v,n}$	is the liquid flow viscosity correction factor, associated with the n^{th} release hole size, unitless
k	is the release fluid ideal gas specific heat capacity ratio, unitless
$ld_{\max,n}$	is the maximum leak duration based on isolation and detection systems associated with the n^{th} release hole size, minutes
ld_n	is the actual leak duration of the flammable release based on the available mass and the calculated release rate, associated with the n^{th} release hole size, seconds
ld_n^{tox}	is the leak duration of the toxic release based on the available mass and the calculated release rate, associated with the n^{th} release hole size, seconds
MW	is the release fluid molecular weight, lb/lb-mol (kg/kg-mol)
$mass_{\text{add},n}$	is the mass contributed by the surrounding equipment in the inventory group (limited by $W_{\max 8}$), associated 3 minutes release of the n^{th} release hole size, lb (kg)
$mass_{\text{avail},n}$	is the available mass for release of each of the release hole sizes, $mass_{\text{add},n}$, and is the sum of the component release mass, $mass_{\text{comp}}$, and 3 minutes release, through the associated with the n^{th} release hole size, lb (kg)
$mass_{\text{comp}}$	is the component mass for the component or piece of equipment being evaluated, lb (kg)
$mass_{\text{comp},i}$	is the component mass for each of the i components or pieces or equipment that is included in the inventory group, lb (kg)
$mass_{\text{inv}}$	is the inventory group mass, lb (kg)
$mass_n$	is the adjusted or mitigated discharge mass used associated with the n^{th} release hole size, lb (kg)
$mass_n^{\text{tox}}$	is the release mass of toxic component used in the toxic consequence calculation associated with the n^{th} release hole size, lb (kg)
$matcost$	is the material cost factor
$mfrac^{\text{tox}}$	is the mass fraction of toxic material in the released fluid mixture
NBP	is the normal boiling point, °F (°C)
$Outage_{\text{affa}}$	is the numbers of days of downtime required to repair damage to the surrounding equipment, days
$Outage_{\text{cmd}}$	is the probability weighted (on release hole size) numbers of days of downtime required to repair the specific piece of equipment that is being evaluated, days

$Outage_{mult}$	is the equipment outage multiplier that can be used to increase the default outage days for an equipment item, unitless
$Outage_n$	is the number of downtime days to repair damage associated with the n^{th} release hole size, days
P_{atm}	is the atmospheric pressure, psia (kPa)
P_s	is the storage or normal operating pressure, psia (kPa)
P_{trans}	is the transition back pressure, psia (kPa). Higher back pressures will result in subsonic vapor flow through the release hole, lower back pressures will cause choked or sonic flow across the release hole
$Pers\#_{avg}$	is the average number of people in a defined area at any given time
$Pers\#_n$	is the number of personnel present in a defined area for each unit staffing activity
$Present\%_n$	is the percent of time personnel are present in the defined area for each unit staffing activity, typically developed by reviewing population for a year
$popdens$	is the population density of personnel or employees in the unit, personnel/m ² (personnel/ft ²)
$prodcost$	is the cost of lost production due to downtime to repair equipment, \$/day
R	is the universal gas constant = 1545 ft-lbf/(lb-mol-°R) [8.314 J/(kg-mol-K)]
Re_n	is the Reynolds Number for flow through the release, associated with the n^{th} release hole size, unitless
$rate_n$	is the adjusted release rate for detection and isolation systems associated with the n^{th} release hole size, lb/s (kg/s)
$rate_n^{tox}$	is the release mass rate of toxic component used in the consequence calculation, associated with the n^{th} release hole size, lb/s (kg/s)
T_s	is the storage or normal operating temperature, °R (K)
t_n	is the time to release 10,000 lb of fluid mass, calculated for each of the n release hole sizes selected, seconds
vol_n^{env}	is the spill volume to be cleaned up, used to determine environmental cleanup costs, calculated for each of the n release hole sizes selected, barrels
W_{max8}	is the maximum flow rate of additional mass that can be added to the release as contributed from the surrounding equipment in the inventory group, lb/s (kg/s)
W_n	is the gas or liquid release rate associated with the n^{th} release hole size, lb/s (kg/s)
x_i	is the mole fraction of the component and $Property_i$ may be the NBP, MW, or density of the individual components in the fluid mixture

ρ	is the density, lb/ft ³ (kg/m ³)
ρ_{atm}	is the atmospheric air density, lb/ft ³ (kg/m ³)
ρ_l	is the liquid density at storage or normal operating conditions, lb/ft ³ (kg/m ³)
ρ_v	is the vapor density, lb/ft ³ (kg/m ³)

4.15 Tables

Table 4.1—List of Representative Fluids Available for Level 1 Consequence Analysis

Representative Fluid	Fluid Type (see Section 4.1.5)	Examples of Applicable Materials
C ₁ –C ₂	Type 0	Methane, ethane, ethylene, liquefied natural gas (LNG), fuel gas
C ₃ –C ₄	Type 0	Propane, butane, isobutane, liquefied petroleum gas (LPG)
C ₅	Type 0	Pentane
C ₆ –C ₈	Type 0	Gasoline, naphtha, light straight run, heptane
C ₉ –C ₁₂	Type 0	Diesel, kerosene
C ₁₃ –C ₁₆	Type 0	Jet fuel, kerosene, atmospheric gas oil
C ₁₇ –C ₂₅	Type 0	Gas oil, typical crude
C ₂₅ +	Type 0	Residuum, heavy crude, lube oil, seal oil
H ₂	Type 0	Hydrogen
H ₂ S	Type 0	Hydrogen sulfide
HF	Type 0	Hydrogen fluoride
HCl	Type 0	Hydrochloric acid
Water	Type 0	Water
Steam	Type 0	Steam
Acid	Type 0	Acid, caustic
Aromatics	Type 1	Benzene, toluene, xylene, cumene
AlCl ₃	Type 0	Aluminum chloride
Pyrophoric	Type 0	Pyrophoric materials
Ammonia	Type 0	Ammonia
Chlorine	Type 0	Chlorine
CO	Type 1	Carbon monoxide
DEE	Type 1 (see Note 2)	Diethyl ether
HCl	Type 0 (see Note 1)	Hydrogen chloride
Nitric acid	Type 0 (see Note 1)	Nitric acid
NO ₂	Type 0 (see Note 1)	Nitrogen dioxide
Phosgene	Type 0	Phosgene
TDI	Type 0 (see Note 1)	Toluene diisocyanate
Methanol	Type 1	Methanol
PO	Type 1	Propylene oxide
Styrene	Type 1	Styrene
EEA	Type 1	Ethylene glycol monoethyl ether acetate
EE	Type 1	Ethylene glycol monoethyl ether
EG	Type 1	Ethylene glycol
EO	Type 1	Ethylene oxide
NOTE 1 HCl, nitric acid, NO ₂ , and TDI are Type 1 toxic fluids.		
NOTE 2 DEE is a Type 0 toxic fluid.		

Table 4.2—Properties of the Representative Fluids Used in Level 1 Consequence Analysis

Fluid	MW	Liquid Density (lb/ft ³)	NBP (°F)	Ambient State	Ideal Gas Specific Heat Eq.	C_p					AIT (°F)
						Ideal Gas Constant <i>A</i>	Ideal Gas Constant <i>B</i>	Ideal Gas Constant <i>C</i>	Ideal Gas Constant <i>D</i>	Ideal Gas Constant <i>E</i>	
C_1 – C_2	23	15.639	–193	Gas	Note 1	12.3	1.150E-01	–2.87E-05	–1.30E-09	N/A	1036
C_3 – C_4	51	33.61	–6.3	Gas	Note 1	2.632	0.3188	–1.347E-04	1.466E-08	N/A	696
C_5	72	39.03	97	Liquid	Note 1	–3.626	0.4873	–2.6E-04	5.3E-08	N/A	544
C_6 – C_8	100	42.702	210	Liquid	Note 1	–5.146	6.762E-01	–3.65E-04	7.658E-08	N/A	433
C_9 – C_{12}	149	45.823	364	Liquid	Note 1	–8.5	1.01E+00	–5.56E-04	1.180E-07	N/A	406
C_{13} – C_{16}	205	47.728	502	Liquid	Note 1	–11.7	1.39E+00	–7.72E-04	1.670E-07	N/A	396
C_{17} – C_{25}	280	48.383	651	Liquid	Note 1	–22.4	1.94E+00	–1.12E-03	–2.53E-07	N/A	396
C_{25+}	422	56.187	981	Liquid	Note 1	–22.4	1.94E+00	–1.12E-03	–2.53E-07	N/A	396
Pyrophoric	149	45.823	364	Liquid	Note 1	–8.5	1.01E+00	–5.56E-04	1.180E-07	N/A	Note 4
Aromatic	104	42.7	293	Liquid	Note 2	8.93E+04	2.15E+05	7.72E+02	9.99E+04	2.44E+03	914
Styrene	104	42.7	293	Liquid	Note 2	8.93E+04	2.15E+05	7.72E+02	9.99E+04	2.44E+03	914
Water	18	62.3	212	Liquid	Note 3	2.76E+05	–2.09E+03	8.125	–1.41E-02	9.37E-06	N/A
Steam	18	62.3	212	Gas	Note 2	3.34E+04	2.68E+04	2.61E+03	8.90E+03	1.17E+03	N/A
Acid/caustic-LP	18	62.3	212	Liquid	Note 2	2.76E+05	–2.09E+03	8.125	–1.41E-02	9.37E-06	N/A
Acid/caustic-MP	18	62.3	212	Liquid	Note 2	2.76E+05	–2.09E+03	8.125	–1.41E-02	9.37E-06	N/A
Acid/caustic-HP	18	62.3	212	Liquid	Note 2	2.76E+05	–2.09E+03	8.125	–1.41E-02	9.37E-06	N/A
Methanol	32	50	149	Liquid	Note 2	3.93E+04	8.79E+04	1.92E+03	5.37E+04	8.97E+02	867
Anhydrous ammonia	17.03	38.55	–28.2	Gas	Note 1	27.26	2.31E-04	2.24E-07	2.17E-10	5.41E-14	N/A
H_2	2	4.433	–423	Gas	Note 1	27.1	9.270E-03	–1.38E-05	7.650E-09	N/A	752
H_2S	34	61.993	–75	Gas	Note 1	31.9	1.440E-03	2.430E-05	–1.18E-08	N/A	500
HF	20	60.37	68	Gas	Note 1	29.1	6.610E-04	–2.03E-06	2.500E-09	N/A	32000
HCl	36	74	–121	Gas	—	—	—	—	—	—	N/A
CO	28	50	–312	Gas	Note 2	2.91E+04	8.77E+03	3.09E+03	8.46E+03	1.54E+03	1128
DEE	74	45	95	Liquid	Note 2	8.62E+04	2.55E+05	1.54E+03	1.44E+05	–6.89E+02	320
Nitric acid	63	95	250	Liquid	—	—	—	—	—	—	N/A
$AlCl_3$	133.5	152	382	Powder	Note 1	6.49E+01	8.74E+01	1.82E-02	–4.65E-04	N/A	1036
NO_2	46	58	275	Liquid	—	—	—	—	—	—	N/A
Phosgene	99	86	181	Liquid	—	—	—	—	—	—	N/A
TDI	174	76	484	Liquid	—	—	—	—	—	—	1148

Fluid	MW	Liquid Density (lb/ft ³)	NBP (°F)	Ambient State	Ideal Gas Specific Heat Eq.	C_p					AIT (°F)
						Ideal Gas Constant <i>A</i>	Ideal Gas Constant <i>B</i>	Ideal Gas Constant <i>C</i>	Ideal Gas Constant <i>D</i>	Ideal Gas Constant <i>E</i>	
PO	58	52	93	Liquid	Note 2	4.95E+04	1.74E+05	1.56E+03	1.15E+05	7.02E+02	840
EEA	132	61	313	Liquid	Note 2	1.06E+05	2.40E+05	6.59E+02	1.50E+05	1.97E+03	715
EE	90	58	275	Liquid	Note 2	3.25E+04	3.00E+05	1.17E+03	2.08E+05	4.73E+02	455
EG	62	69	387	Liquid	Note 2	6.30E+04	1.46E+05	1.67E+03	9.73E+04	7.74E+02	745
EO	44	55	51	Gas	Note 2	3.35E+04	1.21E+05	1.61E+03	8.24E+04	7.37E+02	804

NOTE 1 $C_p = A + BT + CT^2 + DT^3$ with T in K, units for C_p are J/(kg-mol-K).

NOTE 2 $C_p = A + B \left(\frac{\frac{C}{T}}{\sinh\left[\frac{C}{T}\right]} \right)^2 + D \left(\frac{\frac{E}{T}}{\cosh\left[\frac{E}{T}\right]} \right)^2$ with T in K, units for C_p are J/(kg-mol-K).

NOTE 3 $C_p = A + BT + CT^2 + DT^3 + ET^4$ with T in K, units for C_p are J/(kg-mol-K).

NOTE 4 Pyrophoric materials, by definition, autoignite and therefore a very low value for the AIT is assumed.

NOTE 5 Conversion factor for units of C_p is 1 J/(kg-mol-K) = 5.27×10^{-4} Btu/(kg-mol-°R).

NOTE 6 For Note 1, $R = 8.314$ J/mol-K; for Notes 2 and 3, $R = 8314$ Jkmol-K.

Table 4.2M—Properties of the Representative Fluids Used in Level 1 Consequence Analysis

Fluid	MW	Liquid Density (kg/m ³)	NBP (°C)	Ambient State	Ideal Gas Specific Heat Eq.	C_p					AIT (°C)
						Ideal Gas Constant <i>A</i>	Ideal Gas Constant <i>B</i>	Ideal Gas Constant <i>C</i>	Ideal Gas Constant <i>D</i>	Ideal Gas Constant <i>E</i>	
C ₁ –C ₂	23	250.512	–125	Gas	Note 1	12.3	1.15E-01	–2.87E-05	–1.30E-09	N/A	558
C ₃ –C ₄	51	538.379	–21	Gas	Note 1	2.632	0.3188	–1.35E-04	1.47E-08	N/A	369
C ₅	72	625.199	36	Liquid	Note 1	–3.626	0.4873	–2.60E-04	5.30E-08	N/A	284
C ₆ –C ₈	100	684.018	99	Liquid	Note 1	–5.146	6.76E-01	–3.65E-04	7.66E-08	N/A	223
C ₉ –C ₁₂	149	734.012	184	Liquid	Note 1	–8.5	1.01E+00	–5.56E-04	1.18E-07	N/A	208
C ₁₃ –C ₁₆	205	764.527	261	Liquid	Note 1	–11.7	1.39E+00	–7.72E-04	1.67E-07	N/A	202
C ₁₇ –C ₂₅	280	775.019	344	Liquid	Note 1	–22.4	1.94E+00	–1.12E-03	–2.53E-07	N/A	202
C ₂₅₊	422	900.026	527	Liquid	Note 1	–22.4	1.94E+00	–1.12E-03	–2.53E-07	N/A	202
Pyrophoric	149	734.012	184	Liquid	Note 1	–8.5	1.01E+00	–5.56E-04	1.18E-07	N/A	Note 4
Aromatic	104	683.986	145	Liquid	Note 2	8.93E+04	2.15E+05	7.72E+02	9.99E+04	2.44E+03	490
Styrene	104	683.986	145	Liquid	Note 2	8.93E+04	2.15E+05	7.72E+02	9.99E+04	2.44E+03	490
Water	18	997.947	100	Liquid	Note 3	2.76E+05	–2.09E+03	8.125	–1.41E-02	9.37E-06	N/A
Steam	18	997.947	100	Gas	Note 2	3.34E+04	2.68E+04	2.61E+03	8.90E+03	1.17E+03	N/A
Acid/caustic- LP	18	997.947	100	Liquid	Note 3	2.76E+05	–2.09E+03	8.125	–1.41E-02	9.37E-06	N/A
Acid/caustic- MP	18	997.947	100	Liquid	Note 3	2.76E+05	–2.09E+03	8.125	–1.41E-02	9.37E-06	N/A
Acid/caustic- HP	18	997.947	100	Liquid	Note 3	2.76E+05	–2.09E+03	8.125	–1.41E-02	9.37E-06	N/A
Methanol	32	800.920	65	Liquid	Note 2	3.93E+04	8.79E+04	1.92E+03	5.37E+04	8.97E+02	464
Anhydrous ammonia	17.03	0.769	–33.34	Gas	Note 1	27.26	2.31E-04	2.24E-07	2.17E-10	5.41E-14	N/A
H ₂	2	71.010	–253	Gas	Note 1	27.1	9.27E-03	–1.38E-05	7.65E-09	N/A	400
H ₂ S	34	993.029	–59	Gas	Note 1	31.9	1.44E-03	2.43E-05	–1.18E-08	N/A	260
HF	20	967.031	20	Gas	Note 1	29.1	6.61E-04	–2.03E-06	2.50E-09	N/A	17760
HCl	36	1185.362	–85	Gas	—	—	—	—	—	—	N/A
CO	28	800.920	–191	Gas	Note 2	2.91E+04	8.77E+03	3.09E+03	8.46E+03	1.54E+03	609
DEE	74	720.828	35	Liquid	Note 2	8.62E+04	2.55E+05	1.54E+03	1.44E+05	–6.89E+02	160
Nitric acid	63	1521.749	121	Liquid	—	—	—	—	—	—	N/A
AlCl ₃	133.5	2434.798	194	Powder	Note 1	6.49E+01	8.74E+01	1.82E-02	–4.65E-04	N/A	558
NO ₂	90	929.068	135	Liquid	—	—	—	—	—	—	N/A
Phosgene	99	1377.583	83	Liquid	—	—	—	—	—	—	N/A
TDI	174	1217.399	251	Liquid	—	—	—	—	—	—	620

Fluid	MW	Liquid Density (kg/m ³)	NBP (°C)	Ambient State	Ideal Gas Specific Heat Eq.	C _p					AIT (°C)
						Ideal Gas Constant <i>A</i>	Ideal Gas Constant <i>B</i>	Ideal Gas Constant <i>C</i>	Ideal Gas Constant <i>D</i>	Ideal Gas Constant <i>E</i>	
PO	58	832.957	34	Liquid	Note 2	4.95E+04	1.74E+05	1.56E+03	1.15E+05	7.02E+02	449
EEA	132	977.123	156	Liquid	Note 2	1.06E+05	2.40E+05	6.59E+02	1.50E+05	1.97E+03	379
EE	90	929.068	135	Liquid	Note 2	3.25E+04	3.00E+05	1.17E+03	2.08E+05	4.73E+02	235
EG	62	1105.270	197	Liquid	Note 2	6.30E+04	1.46E+05	1.67E+03	9.73E+04	7.74E+02	396
EO	44	881.013	11	Gas	Note 2	3.35E+04	1.21E+05	1.61E+03	8.24E+04	7.37E+02	429

NOTE 1 $C_p = A + BT + CT^2 + DT^3$ with T in K, units for C_p are J/(kg-mol-K).

NOTE 2 $C_p = A + B \left(\frac{\frac{C}{T}}{\sinh \left[\frac{C}{T} \right]} \right)^2 + D \left(\frac{\frac{E}{T}}{\cosh \left[\frac{E}{T} \right]} \right)^2$ with T in K, units for C_p are J/(kg-mol-K).

NOTE 3 $C_p = A + BT + CT^2 + DT^3 + ET^4$ with T in K, units for C_p are J/(kg-mol-K).

NOTE 4 Pyrophoric materials, by definition, autoignite and therefore a very low value for the AIT is assumed.

NOTE 5 For Note 1, $R = 8.314$ J/mol-K; for notes 2 and 3, $R = 8314$ J/mol-K.

Table 4.3—Level 1 Guidelines for Determining the Phase of a Fluid

Phase of Fluid at Normal Operating (Storage) Conditions	Phase of Fluid at Ambient (After Release) Conditions	Determination of Final Phase for Consequence Calculation
Gas	Gas	Model as gas
Gas	Liquid	Model as gas
Liquid	Gas	Model as gas <i>unless</i> the fluid boiling point at ambient conditions is greater than 80 °F, then model as a liquid
Liquid	Liquid	Model as liquid

Table 4.4—Release Hole Sizes and Areas Used in Level 1 and 2 Consequence Analyses

Release Hole Number	Release Hole Size	Range of Hole Diameters (in.)	Release Hole Diameter, d_n (in.)
1	Small	0 to $\frac{1}{4}$	$d_1 = 0.25$
2	Medium	$> \frac{1}{4}$ to 2	$d_2 = 1$ $d_2 = \min[D, 1]$
3	Large	> 2 to 6	$d_3 = 4$ $d_3 = \min[D, 4]$
4	Rupture	> 6	$d_4 = \min[D, 16]$

Table 4.4M—Release Hole Sizes and Areas Used in Level 1 and 2 Consequence Analyses

Release Hole Number	Release Hole Size	Range of Hole Diameters (mm)	Release Hole Diameter, d_n (mm)
1	Small	0 to 6.4	$d_1 = 6.4$
2	Medium	> 6.4 to 51	$d_2 = 25$ $d_2 = \min[D, 25]$
3	Large	> 51 to 152	$d_3 = 102$ $d_3 = \min[D, 102]$
4	Rupture	> 152	$d_4 = \min[D, 406]$

Table 4.5—Detection and Isolation System Rating Guide

Type of Detection System	Detection Classification
Instrumentation designed specifically to detect material losses by changes in operating conditions (i.e. loss of pressure or flow) in the system.	A
Suitably located detectors to determine when the material is present outside the pressure-containing envelope.	B
Visual detection, cameras, or detectors with marginal coverage.	C
Type of Isolation System	Isolation Classification
Isolation or shutdown systems activated directly from process instrumentation or detectors, with no operator intervention.	A
Isolation or shutdown systems activated by operators in the control room or other suitable locations remote from the leak.	B
Isolation dependent on manually operated valves.	C

Table 4.6—Adjustments to Release Based on Detection and Isolation Systems

System Classifications		Release Magnitude Adjustment	Reduction Factor, $fact_{di}$
Detection	Isolation		
A	A	Reduce release rate or mass by 25 %	0.25
A	B	Reduce release rate or mass by 20 %	0.20
A or B	C	Reduce release rate or mass by 10 %	0.10
B	B	Reduce release rate or mass by 15 %	0.15
C	C	No adjustment to release rate or mass	0.00

Table 4.7—Leak Durations Based on Detection and Isolation Systems

Detection System Rating	Isolation System Rating	Maximum Leak Duration, ld_{max}
A	A	20 minutes for $< 1/4$ in. leaks 10 minutes for $d_2 = \frac{1}{4} > D \leq 1$ in. leaks 5 minutes for $d_3 = 1 > D \leq 4$ in. leaks 60 minutes for $d_4 = D \geq 4$ in. leaks
A	B	30 minutes for $< 1/4$ in. leaks 20 minutes for $d_2 = \frac{1}{4} > D \leq 1$ in. leaks 10 minutes for $d_3 = 1 > D \leq 4$ in. leaks 60 minutes for $d_4 = D \geq 4$ in. leaks
A	C	40 minutes for $< 1/4$ in. leaks 30 minutes for $d_2 = \frac{1}{4} > D \leq 1$ in. leaks 20 minutes for $d_3 = 1 > D \leq 4$ in. leaks 60 minutes for $d_4 = D \geq 4$ in. leaks
B	A or B	40 minutes for $< 1/4$ in. leaks 30 minutes for $d_2 = \frac{1}{4} > D \leq 1$ in. leaks 20 minutes for $d_3 = 1 > D \leq 4$ in. leaks 60 minutes for $d_4 = D \geq 4$ in. leaks
B	C	1 hour for $< 1/4$ in. leaks 30 minutes for $d_2 = \frac{1}{4} > D \leq 1$ in. leaks 20 minutes for $d_3 = 1 > D \leq 4$ in. leaks 60 minutes for $d_4 = D \geq 4$ in. leaks
C	A, B, or C	1 hour for $< 1/4$ in. leaks 40 minutes for $d_2 = \frac{1}{4} > D \leq 1$ in. leaks 20 minutes for $d_3 = 1 > D \leq 4$ in. leaks 60 minutes for $d_4 = D \geq 4$ in. leaks

Table 4.7M—Leak Durations Based on Detection and Isolation Systems

Detection System Rating	Isolation System Rating	Maximum Leak Duration, $ld_{\max}$
A	A	20 minutes for < 6.4 mm leaks 10 minutes for $d_2 = 6.4 > D \leq 25$ mm leaks 5 minutes for $d_3 = 25 > D \leq 102$ mm leaks 60 minutes for $d_4 = D \geq 102$ mm leaks
A	B	30 minutes for < 6.4 mm leaks 20 minutes for $d_2 = 6.4 > D \leq 25$ mm leaks 10 minutes for $d_3 = 25 > D \leq 102$ mm leaks 60 minutes for $d_4 = D \geq 102$ mm leaks
A	C	40 minutes for < 6.4 mm leaks 30 minutes for $d_2 = 6.4 > D \leq 25$ mm leaks 20 minutes for $d_3 = 25 > D \leq 102$ mm leaks 60 minutes for $d_4 = D \geq 102$ mm leaks
B	A or B	40 minutes for < 6.4 mm leaks 30 minutes for $d_2 = 6.4 > D \leq 25$ leaks 20 minutes for $d_3 = 25 > D \leq 102$ mm leaks 60 minutes for $d_4 = D \geq 102$ mm leaks
B	C	1 hour for < 6.4 mm leaks 30 minutes for $d_2 = 6.4 > D \leq 25$ mm leaks 20 minutes for $d_3 = 25 > D \leq 102$ mm leaks 60 minutes for $d_4 = D \geq 102$ mm leaks
C	A, B, or C	1 hour for < 6.4 mm leaks 40 minutes for $d_2 = 6.4 > D \leq 25$ mm leaks 20 minutes for $d_3 = 25 > D \leq 102$ mm leaks 60 minutes for $d_4 = D \geq 102$ mm leaks

Table 4.8—Component Damage Flammable Consequence Equation Constants

Fluid	Fluid Type	Continuous Releases Constants								Instantaneous Releases Constants							
		Autoignition Not Likely (AINL-CONT)				Autoignition Likely (AIL-CONT)				Autoignition Not Likely (AINL-INST)				Autoignition Likely (AIL-INST)			
		Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
		<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>
C_1 – C_2	Type 0	43.0	0.98			280.0	0.95			41.0	0.67			1079	0.62		
C_3 – C_4	Type 0	49.48	1.00			313.6	1.00			27.96	0.72			522.9	0.63		
C_5	Type 0	25.17	0.99	536.0	0.89	304.7	1.00			13.38	0.73	1.49	0.85	275.0	0.61		
C_6 – C_8	Type 0	29.0	0.98	182.0	0.89	312.4	1.00	525.0	0.95	13.98	0.66	4.35	0.78	275.7	0.61	57.0	0.55
C_9 – C_{12}	Type 0	12.0	0.98	130.0	0.90	391.0	0.95	560.0	0.95	7.1	0.66	3.3	0.76	281.0	0.61	6.0	0.53
C_{13} – C_{16}	Type 0			64.0	0.90			1023	0.92			0.46	0.88			9.2	0.88
C_{17} – C_{25}	Type 0			20.0	0.90			861.0	0.92			0.11	0.91			5.6	0.91
C_{25+}	Type 0			11.0	0.91			544.0	0.90			0.03	0.99			1.4	0.99
Pyrophoric	Type 1	12.0	0.98	130.0	0.90	391.0	0.95	560.0	0.95	7.1	0.66	3.3	0.76	281.0	0.61	6.0	0.53
Aromatics	Type 1	17.87	1.097	103.0	0	374.5	1.055			11.46	0.667	70.12	0	512.6	0.713	701.2	0
Styrene	Type 1	17.87	1.097	103.0	0	374.5	1.055			11.46	0.667	70.12	0	512.6	0.713	701.2	0
Water	Type 0																
Steam	Type 0																
Acid/caustic-LP	Type 0																
Acid/caustic-MP	Type 0																
Acid/caustic-HP	Type 0																
Methanol	Type 1	0.02256	0.9092	1750.6	0.9342					28.1170	0.6670	1.9188	0.9004				
H_2	Type 0	64.5	0.992			420.0	1.00			61.5	0.657			1430	0.618		
H_2S	Type 0	32.0	1.00			203.0	0.89			148.0	0.63			357.0	0.61		
HF	Type 0																
CO	Type 1	0.107	1.752							69.68	0.667						
DEE	Type 1	39.84	1.134	737.4	1.106	320.7	1.033	6289	0.649	155.7	0.667	5.105	0.919			5.672	0.919
PO	Type 1	14.61	1.114	1295	0.9560					65.58	0.667	3.404	0.869				
EEA	Type 1	0.002	1.035	117.0	0					8.014	0.667	69.0	0				
EE	Type 1	12.62	1.005	173.1	0					38.87	0.667	72.21	0				
EG	Type 1	7.721	0.973	108.0	0					6.525	0.667	69.0	0				
EO	Type 1	31.03	1.069							136.3	0.667						

Table 4.8M—Component Damage Flammable Consequence Equation Constants

Fluid	Fluid Type	Continuous Releases Constants								Instantaneous Releases Constants							
		Autoignition Not Likely (AINL-CONT)				Autoignition Likely (AIL-CONT)				Autoignition Not Likely (AINL-INST)				Autoignition Likely (AIL-INST)			
		Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
		<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>
C ₁ –C ₂	Type 0	8.669	0.98			55.13	0.95			6.469	0.67			163.7	0.62		
C ₃ –C ₄	Type 0	10.13	1.00			64.23	1.00			4.590	0.72			79.94	0.63		
C ₅	Type 0	5.115	0.99	100.6	0.89	62.41	1.00			2.214	0.73	0.271	0.85	41.38	0.61		
C ₆ –C ₈	Type 0	5.846	0.98	34.17	0.89	63.98	1.00	103.4	0.95	2.188	0.66	0.749	0.78	41.49	0.61	8.180	0.55
C ₉ –C ₁₂	Type 0	2.419	0.98	24.60	0.90	76.98	0.95	110.3	0.95	1.111	0.66	0.559	0.76	42.28	0.61	0.848	0.53
C ₁₃ –C ₁₆	Type 0			12.11	0.90			196.7	0.92			0.086	0.88			1.714	0.88
C ₁₇ –C ₂₅	Type 0			3.785	0.90			165.5	0.92			0.021	0.91			1.068	0.91
C ₂₅₊	Type 0			2.098	0.91			103.0	0.90			0.006	0.99			0.284	0.99
Pyrophoric	Type 1	2.419	0.98	24.60	0.90	76.98	0.95	110.3	0.95	1.111	0.66	0.559	0.76	42.28	0.61	0.848	0.53
Aromatics	Type 1	3.952	1.097	21.10	0	80.11	1.055			1.804	0.667	14.36	0	83.68	0.713	143.6	0
Styrene	Type 1	3.952	1.097	21.10	0	80.11	1.055			1.804	0.667	14.36	0	83.68	0.713	143.6	01.00
Water	Type 0																
Steam	Type 0																
Acid/caustic-LP	Type 0																
Acid/caustic-MP	Type 0																
Acid/caustic-HP	Type 0																
Methanol	Type 1	0.005	0.909	340.4	0.934					4.425	0.667	0.363	0.900				
H ₂	Type 0	13.13	0.992			86.02	1.00			9.605	0.657			216.5	0.618		
H ₂ S	Type 0	6.554	1.00			38.11	0.89			22.63	0.63			53.72	0.61		
HF	Type 0																
CO	Type 1	0.040	1.752							10.97	0.667						
DEE	Type 1	9.072	1.134	164.2	1.106	67.42	1.033	976.0	0.649	24.51	0.667	0.981	0.919			1.090	0.919
PO	Type 1	3.277	1.114	257.0	0.960					10.32	0.667	0.629	0.869				
EEA	Type 1	0	1.035	23.96	0					1.261	0.667	14.13	0				
EE	Type 1	2.595	1.005	35.45	0					6.119	0.667	14.79	0				
EG	Type 1	1.548	0.973	22.12	0					1.027	0.667	14.13	0				
EO	Type 1	6.712	1.069							21.46	0.667						

Table 4.9—Personnel Injury Flammable Consequence Equation Constants

Fluid	Fluid Type	Continuous Releases Constants								Instantaneous Releases Constants							
		Autoignition Not Likely (AINL-CONT)				Autoignition Likely (AIL-CONT)				Autoignition Not Likely (AINL-INST)				Autoignition Likely (AIL-INST)			
		Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
		<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>	<i>a</i>	<i>b</i>
C ₁ –C ₂	Type 0	110.0	0.96			745.0	0.92			79.0	0.67			3100	0.63		
C ₃ –C ₄	Type 0	125.2	1.00			836.7	1.00			57.72	0.75			1769	0.63		
C ₅	Type 0	62.05	1.00	1545	0.89	811.0	1.00			28.45	0.76	4.34	0.85	959.6	0.63		
C ₆ –C ₈	Type 0	68.0	0.96	516.0	0.89	828.7	1.00	1315	0.92	26.72	0.67	12.7	0.78	962.8	0.63	224.0	0.54
C ₉ –C ₁₂	Type 0	29.0	0.96	373.0	0.89	981.0	0.92	1401	0.92	13.0	0.66	9.5	0.76	988.0	0.63	20.0	0.54
C ₁₃ –C ₁₆	Type 0			183.0	0.89			2850	0.90			1.3	0.88			26.0	0.88
C ₁₇ –C ₂₅	Type 0			57.0	0.89			2420	0.90			0.32	0.91			16.0	0.91
C ₂₅₊	Type 0			33.0	0.89			1604	0.90			0.081	0.99			4.1	0.99
Pyrophoric	Type 1	29.0	0.96	373.0	0.89	981.0	0.92	1401	0.92	13.0	0.66	9.5	0.76	988.0	0.63	20.0	0.54
Aromatics	Type 1	64.14	0.963	353.5	0.883	1344	0.937	487.7	0.268	18.08	0.686	0.14	0.935	512.6	0.713	1.404	0.935
Styrene	Type 1	64.14	0.963	353.5	0.883	1344	0.937	487.7	0.268	18.08	0.686	0.14	0.935	512.6	0.713	1.404	0.935
Water	Type 0																
Steam	Type 0																
Acid/caustic-LP	Type 0			2699.5	0.2024			2699.5	0.2024								
Acid/caustic-MP	Type 0			3366.2	0.2878			3366.2	0.2878								
Acid/caustic-HP	Type 0			6690	0.2469			6690	0.2469								
Methanol	Type 1	0.0164	1.0083	4483.7	0.9015					37.71	0.6878	6.2552	0.8705				
H ₂	Type 0	165.0	0.933			1117	1.00			118.5	0.652			4193	0.621		
H ₂ S	Type 0	52.0	1.00			375.0	0.94			271.0	0.63			1253	0.63		
HF	Type 0																
CO	Type 1	27.0	0.991							105.3	0.692						
DEE	Type 1	128.1	1.025	971.9	1.219	1182	0.997	2658	0.864	199.1	0.682	47.13	0.814	821.7	0.657	52.36	0.814
PO	Type 1	38.76	1.047	1955	0.840					83.68	0.682	15.21	0.834				
EEA	Type 1	0.017	0.946	443.1	0.835					11.41	0.687	0.153	0.924				
EE	Type 1	35.56	0.969	46.56	0.800					162.0	0.660	0.152	0.927				
EG	Type 1	25.67	0.947	324.7	0.869					8.971	0.687	0.138	0.922				
EO	Type 1	49.43	1.105							220.8	0.665						

Table 4.9M—Personnel Injury Flammable Consequence Equation Constants

Fluid	Fluid Type	Continuous Releases Constants								Instantaneous Releases Constants							
		Autoignition Not Likely (AINL-CONT)				Autoignition Likely (AIL-CONT)				Autoignition Not Likely (AINL-INST)				Autoignition Likely (AIL-INST)			
		Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
		a	b	a	b	a	b	a	b	a	b	a	b	a	b	a	b
C ₁ –C ₂	Type 0	21.83	0.96			143.2	0.92			12.46	0.67			473.9	0.63		
C ₃ –C ₄	Type 0	25.64	1.00			171.4	1.00			9.702	0.75			270.4	0.63		
C ₅	Type 0	12.71	1.00	290.1	0.89	166.1	1.00			4.820	0.76	0.790	0.85	146.7	0.63		
C ₆ –C ₈	Type 0	13.49	0.96	96.88	0.89	169.7	1.00	252.8	0.92	4.216	0.67	2.186	0.78	147.2	0.63	31.89	0.54
C ₉ –C ₁₂	Type 0	5.755	0.96	70.03	0.89	188.6	0.92	269.4	0.92	2.035	0.66	1.609	0.76	151.0	0.63	2.847	0.54
C ₁₃ –C ₁₆	Type 0			34.36	0.89			539.4	0.90			0.242	0.88			4.843	0.88
C ₁₇ –C ₂₅	Type 0			10.70	0.89			458.0	0.90			0.061	0.91			3.052	0.91
C ₂₅₊	Type 0			6.196	0.89			303.6	0.90			0.016	0.99			0.833	0.99
Pyrophoric	Type 1	5.755	0.96	70.03	0.89	188.6	0.92	269.4	0.92	2.035	0.66	1.609	0.76	151.0	0.63	2.847	0.54
Aromatics	Type 1	12.76	0.963	66.01	0.883	261.9	0.937	56.00	0.268	2.889	0.686	0.027	0.935	83.68	0.713	0.273	0.935
Styrene	Type 1	12.76	0.963	66.01	0.883	261.9	0.937	56.00	0.268	2.889	0.686	0.027	0.935	83.68	0.713	0.273	0.935
HF	Type 0																
Water	Type 0																
Acid/caustic	Type 0			194.280	0.2024			194.280	0.2024								
Acid/caustic	Type 0			392.588	0.2878			392.588	0.2878								
Acid/caustic	Type 0			755.408	0.2469			755.408	0.2469								
Steam	Type 0																
Methanol	Type 1	0	1.008	849.9	0.902					6.035	0.688	1.157	0.871				
H ₂	Type 0	32.05	0.933			228.8	1.00			18.43	0.652			636.5	0.621		
H ₂ S	Type 0	10.65	1.00			73.25	0.94			41.43	0.63			191.5	0.63		
CO	Type 1	5.491	0.991							16.91	0.692						
DEE	Type 1	26.76	1.025	236.7	1.219	241.5	0.997	488.9	0.864	31.71	0.682	8.333	0.814	128.3	0.657	9.258	0.814
PO	Type 1	8.239	1.047	352.8	0.840					13.33	0.682	2.732	0.834				
EEA	Type 1	0	0.946	79.66	0.835					1.825	0.687	0.030	0.924				
EE	Type 1	7.107	0.969	8.142	0.800					25.36	0.660	0.029	0.927				
EG	Type 1	5.042	0.947	59.96	0.869					1.435	0.687	0.027	0.922				
EO	Type 1	11.00	1.105							34.70	0.665						

Table 4.10—Adjustments to Flammable Consequence for Mitigation Systems

Mitigation System	Consequence Area Adjustment	Consequence Area Reduction Factor, $fact_{mit}$
Inventory blowdown, coupled with isolation system classification B or higher	Reduce consequence area by 25 %	0.25
Fire water deluge system and monitors	Reduce consequence area by 20 %	0.20
Fire water monitors only	Reduce consequence area by 5 %	0.05
Foam spray system	Reduce consequence area by 15 %	0.15

Table 4.11—Gas Release Toxic Consequence Equation Constants for HF and H₂S

Continuous Releases Duration (minutes)	HF		H ₂ S	
	c	d	c	d
5	1.1401	3.5683	1.2411	3.9686
10	1.1031	3.8431	1.2410	4.0948
20	1.0816	4.1040	1.2370	4.238
40	1.0942	4.3295	1.2297	4.3626
60	1.1031	4.4576	1.2266	4.4365
Instantaneous Releases	1.4056	0.33606	0.9674	2.7840

Table 4.12—Gas Release Toxic Consequence Equation Constants for Ammonia and Chlorine

Continuous Releases Duration (minutes)	Anhydrous Ammonia		Chlorine	
	<i>e</i>	<i>f</i>	<i>e</i>	<i>f</i>
5	2,690	1.183	15,150	1.097
10	3,581	1.181	15,934	1.095
15	4,459	1.180	17,242	1.092
20	5,326	1.178	19,074	1.089
25	6,180	1.176	21,430	1.085
30	7,022	1.174	24,309	1.082
35	7,852	1.172	27,712	1.077
40	8,669	1.169	31,640	1.072
45	9,475	1.166	36,090	1.066
50	10,268	1.161	41,065	1.057
55	11,049	1.155	46,564	1.046
60	11,817	1.145	52,586	1.026
Instantaneous Releases	14.171	0.9011	14.976	1.177

Table 4.12M—Gas Release Toxic Consequence Equation Constants for Ammonia and Chlorine

Continuous Releases Duration (minutes)	Anhydrous Ammonia		Chlorine	
	<i>e</i>	<i>f</i>	<i>e</i>	<i>f</i>
5	636.7	1.183	3,350	1.097
10	846.3	1.181	3,518	1.095
15	1,053	1.180	3,798	1.092
20	1,256	1.178	4,191	1.089
25	1,455	1.176	4,694	1.085
30	1,650	1.174	5,312	1.082
35	1,842	1.172	6,032	1.077
40	2,029	1.169	6,860	1.072
45	2,213	1.166	7,788	1.066
50	2,389	1.161	8,798	1.057
55	2,558	1.155	9,890	1.046
60	2,714	1.145	10,994	1.026
Instantaneous Releases	2.684	0.9011	3.528	1.177

**Table 4.13—Continuous Gas and Liquid Release Toxic Consequence
Equation Constants for Miscellaneous Chemicals**

Chemical	Release Duration (minutes)	Gas Release Constants		Liquid Release Constants	
		<i>e</i>	<i>f</i>	<i>e</i>	<i>f</i>
Aluminum chloride (AlCl ₃)	All	17.663	0.9411	N/A	N/A
Carbon monoxide (CO)	3	41.412	1.15	N/A	N/A
	5	279.79	1.06	N/A	N/A
	10	834.48	1.13	N/A	N/A
	20	2,915.9	1.11	N/A	N/A
	40	5,346.8	1.17	N/A	N/A
	60	6,293.7	1.21	N/A	N/A
Hydrogen chloride (HCl)	3	215.48	1.09	N/A	N/A
	5	536.28	1.15	N/A	N/A
	10	2,397.5	1.10	N/A	N/A
	20	4,027.0	1.18	N/A	N/A
	40	7,534.5	1.20	N/A	N/A
	60	8,625.1	1.23	N/A	N/A
Nitric acid	3	53,013	1.25	5,110.0	1.08
	5	68,700	1.25	9,640.8	1.02
	10	96,325	1.24	12,453	1.06
	20	126,942	1.23	19,149	1.06
	40	146,941	1.22	31,145	1.06
	60	156,345	1.22	41,999	1.12
Nitrogen dioxide (NO ₂)	3	6,633.1	0.70	21,32.9	0.98
	5	9,221.4	0.68	2,887.0	1.04
	10	11,965	0.68	6,194.4	1.07
	20	14,248	0.72	13,843	1.08
	40	22,411	0.70	27,134	1.12
	60	24,994	0.71	41,657	1.13
Phosgene	3	12,902	1.20	3,414.8	1.06
	5	22,976	1.29	6,857.1	1.10
	10	48,985	1.24	21,215	1.12
	20	108,298	1.27	63,361	1.16
	40	244,670	1.30	178,841	1.20
	60	367,877	1.31	314,608	1.23

Chemical	Release Duration (minutes)	Gas Release Constants		Liquid Release Constants	
		<i>e</i>	<i>f</i>	<i>e</i>	<i>f</i>
Toluene diisocyanate (TDI)	3	N/A	N/A	3,692.5	1.06
	5	N/A	N/A	3,849.2	1.09
	10	N/A	N/A	4,564.9	1.10
	20	N/A	N/A	4,777.5	1.06
	40	N/A	N/A	4,953.2	1.06
	60	N/A	N/A	5,972.1	1.03
Ethylene glycol monoethyl ether (EE)	1.5	3.819	1.171	N/A	N/A
	3	7.438	1.181	N/A	N/A
	5	17.735	1.122	N/A	N/A
	10	33.721	1.111	3.081	1.105
	20	122.68	0.971	16.877	1.065
	40	153.03	0.995	43.292	1.132
	60	315.57	0.899	105.74	1.104
Ethylene oxide (EO)	1.5	2.083	1.222	N/A	N/A
	3	12.32	1.207	N/A	N/A
	5	31.5	1.271	N/A	N/A
	10	185	1.2909	N/A	N/A
	20	926	1.2849	N/A	N/A
	40	4,563	1.1927	N/A	N/A
	60	7,350	1.203	N/A	N/A
Propylene oxide	3	0.0019	1.913	N/A	N/A
	5	0.3553	1.217	10.055	1.198
	10	0.7254	1.2203	40.428	1.111
	20	1.7166	1.2164	77.743	1.114
	40	3.9449	1.2097	152.35	1.118
	60	4.9155	1.2522	1812.8	0.9855

**Table 4.13M—Continuous Gas and Liquid Release Toxic Consequence
Equation Constants for Miscellaneous Chemicals**

Chemical	Release Duration (minutes)	Gas Release Constants		Liquid Release Constants	
		e	f	e	f
Aluminum chloride (AlCl_3)	All	3.4531	0.9411	N/A	N/A
Carbon monoxide (CO)	3	9.55	1.15	N/A	N/A
	5	60.09	1.06	N/A	N/A
	10	189.42	1.13	N/A	N/A
	20	651.49	1.11	N/A	N/A
	40	1,252.67	1.17	N/A	N/A
	60	1,521.89	1.21	N/A	N/A
Hydrogen chloride (HCL)	3	47.39	1.09	N/A	N/A
	5	123.67	1.15	N/A	N/A
	10	531.45	1.10	N/A	N/A
	20	950.02	1.18	N/A	N/A
	40	1,851.8	1.20	N/A	N/A
	60	2,118.87	1.23	N/A	N/A
Nitric acid	3	13,230.9	1.25	1,114.96	1.08
	5	17,146	1.25	2,006.1	1.02
	10	23,851.3	1.24	2,674.47	1.06
	20	31,185	1.23	4,112.65	1.06
	40	35,813.7	1.22	6,688.99	1.06
	60	38,105.8	1.22	9,458.29	1.12
Nitrogen dioxide (NO_2)	3	1,071.74	0.70	430	0.98
	5	1,466.57	0.68	610.31	1.04
	10	1,902.9	0.68	1,340.93	1.07
	20	2,338.76	0.72	3,020.54	1.08
	40	3621.1	0.70	6,110.67	1.12
	60	4,070.48	0.71	9,455.68	1.13
Phosgene	3	3,095.33	1.20	733.39	1.06
	5	5,918.49	1.29	1,520.02	1.10
	10	12,129.3	1.24	4,777.72	1.12
	20	27,459.6	1.27	14,727.5	1.16
	40	63,526.4	1.30	42,905	1.20
	60	96,274.2	1.31	77,287.7	1.23

Chemical	Release Duration (minutes)	Gas Release Constants		Liquid Release Constants	
		e	f	e	f
Toluene diisocyanate (TDI)	3	N/A	N/A	793.04	1.06
	5	N/A	N/A	846.54	1.09
	10	N/A	N/A	1,011.9	1.10
	20	N/A	N/A	1,026.06	1.06
	40	N/A	N/A	1,063.8	1.06
	60	N/A	N/A	1,252.57	1.03
Ethylene glycol monoethyl ether (EE)	1.5	0.8954	1.171	N/A	N/A
	3	1.7578	1.181	N/A	N/A
	5	4.0002	1.122	N/A	N/A
	10	7.5400	1.111	0.6857	1.105
	20	24.56	0.971	3.6389	1.065
	40	31.22	0.995	9.8422	1.132
	60	59.67	0.899	23.513	1.104
Ethylene oxide (EO)	1.5	0.5085	1.222	N/A	N/A
	3	2.9720	1.207	N/A	N/A
	5	7.9931	1.271	N/A	N/A
	10	47.69	1.2909	N/A	N/A
	20	237.57	1.2849	N/A	N/A
	40	1,088.4	1.1927	N/A	N/A
	60	1,767.5	1.203	N/A	N/A
Propylene oxide	3	0.0008	1.913	N/A	N/A
	5	0.0864	1.217	2.4084	1.198
	10	0.1768	1.2203	9.0397	1.111
	20	0.4172	1.2164	17.425	1.114
	40	0.9537	1.2097	34.255	1.118
	60	1.2289	1.2522	367.06	0.9855

Table 4.14—Toxic Impact Criteria for Toxic Chemicals

Toxic Component	Probit Parameters			IDLH (ppm)	AEGL3-10 (ppm)	AEGL3-30 (ppm)	AEGL3-60 (ppm)	EPA Toxic Endpoint (mg/L)	ERPG-3
	A	B	N						
Acrolein	-9.93	2.05	1.00	2	—	—	—	0.50	—
Acrylonitrile	-29.42	3.01	1.43	85	—	—	—	0.08	75
Aluminum trichloride	-14.65	2.00	1.00	—	—	—	—	—	—
Ammonia	-35.90	1.85	2.00	300	—	—	—	0.14	750
Benzene	-109.8	5.30	2.00	500	—	—	—	—	1,000
Bromine	-9.04	0.92	2.00	3	—	—	—	0.01	5
Carbon monoxide	-37.98	3.70	1.00	1,200	1,700	600	330	—	500
Carbon tetrachloride	-6.29	0.41	2.50	200	—	—	—	—	750
Chlorine	-8.29	0.92	2.00	10	—	28	20	0.01	20
Ethylene glycol monoethyl ether	-15.54	1.00	2.00	—	—	—	—	—	—
Ethylene oxide	-6.21	1.00	1.00	800	—	—	—	—	—
Formaldehyde	-12.24	1.30	2.00	20	—	—	—	0.01	25
Hydrogen chloride	-16.85	2.00	1.00	50	620	210	100	0.03	150
Hydrogen cyanide	-29.42	3.01	1.43	50	27	21	15	—	25
Hydrogen fluoride	-48.33	4.853	1.00	30	170	62	44	—	—
Hydrogen sulfide	-31.42	3.01	1.43	100	76	60	50	—	100
Methanol	—	—	—	—	15,000	15,000	7,900	—	—
Methyl bromide	-56.81	5.27	1.00	—	—	—	—	—	200
Methyl isocyanate	-5.64	1.64	0.65	—	—	—	—	—	—
Nitric acid	-5.48	1.00	2.00	—	—	—	—	—	—
Nitrogen dioxide	-13.79	1.40	2.00	20	—	—	—	—	—
Phosgene	-19.27	3.69	1.00	2	3.6	1.5	0.75	—	—
Propylene oxide	-7.415	0.509	2.00	400	—	—	—	0.59	750
Styrene	—	—	—	700	—	—	—	—	1,000
Sulphur dioxide	-15.67	2.10	1.00	100	—	—	—	—	—
Toluene	-6.79	0.41	2.50	500	1,600	900	630	—	—
Toluene diisocyanate	-4.49	1.00	2.00	—	—	—	—	—	—

NOTE Shaded areas in the above table designate toxic fluids and toxic impact criteria modeled in the Level 1 consequence analysis described in [Section 4.9](#). In the Level 2 consequence analysis, all data can be considered for all other fluids and toxic impact criteria.

Table 4.15—Example Component Damage Costs

Equipment Type	Component Type	Damage Cost (2001 U.S. Dollars), <i>holecost</i>			
		Small	Medium	Large	Rupture
Compressor	COMPC	10,000	20,000	100,000	300,000
	COMPR	5,000	10,000	50,000	100,000
Heat exchanger	HEXSS, HEXTS, HEXTUBE	1,000	2,000	20,000	60,000
Pipe	PIPE-1	5	0	0	20
	PIPE-2	5	0	0	40
	PIPE-4	5	10	0	60
	PIPE-6	5	20	0	120
	PIPE-8	5	30	60	180
	PIPE-10	5	40	80	240
	PIPE-12	5	60	120	360
	PIPE-16	5	80	160	500
	PIPEGT16	10	120	240	700
Pump	PUMP2S, PUMP1S	1,000	2,500	5,000	5,000
	PUMPR	1,000	2,500	5,000	10,000
Tank	TANKBOTTOM	5,000	0	0	120,000
	TANKBOTEDGE	5,000	0	0	120,000
	COURSES-10	5,000	12,000	20,000	40,000
FINFAN	FINFAN_TUBE	1,000	2,000	20,000	60,000
	FINFAN HEADER	1,000	2,000	20,000	60,000
Vessel	KODRUM, DRUM	5,000	12,000	20,000	40,000
	FILTER	1,000	2,000	4,000	10,000
	REACTOR	10,000	24,000	40,000	80,000
	COLTOP, COLMID, COLBTM	10,000	25,000	50,000	100,000

Table 4.16—Material Cost Factors

Material	Cost Factor, <i>matcost</i>	Material	Cost Factor, <i>matcost</i>
Carbon steel	1.0	Clad Alloy 400	6.4
Organic coatings (< 80 mil)	1.2	90/10 Cu/Ni	6.8
1.25Cr-0.5Mo	1.3	Clad Alloy 600	7.0
2.25Cr-1Mo	1.7	CS PTFE lined	7.8
5Cr-0.5Mo	1.7	Clad nickel	8.0
7Cr-0.5Mo	2.0	Alloy 800	8.4
Clad 304 SS	2.1	70/30 Cu/Ni	8.5
Fiberglass	2.5	904L	8.8
PP lined	2.5	Alloy 20	11
9Cr-1Mo	2.6	Alloy 400	15
405 SS	2.8	Alloy 600	15
410 SS	2.8	Nickel	18
304 SS	3.2	Acid brick	20
Clad 316 SS	3.3	Refractory	20
Strip lined alloy	3.3	Alloy 625	26
Organic coating (> 80 mil)	3.4	Titanium	28
CS "saran" lined	3.4	Alloy "C"	29
CS rubber lined	4.4	Zirconium	34
316 SS	4.8	Alloy "B"	36
CS glass lined	5.8	Tantalum	535

Table 4.17—Estimated Equipment Outage

Equipment Type	Component Type	Estimated Outage in Days, $Outage_n$			
		Small	Medium	Large	Rupture
Compressor	COMPC, COMPR	N/A	3	7	N/A
Heat exchanger	HEXSS, HEXTS	2	3	3	10
	HEXTUBE	N/A	N/A	N/A	N/A
Pipe	PIPE-1, PIPE-2	0	N/A	N/A	1
	PIPE-4	0	1	N/A	2
	PIPE-6	0	1	2	3
	PIPE-8	0	2	2	3
	PIPE-10	0	2	2	4
	PIPE-12	1	3	4	4
	PIPE-16	1	3	4	5
	PIPEGT16	1	4	5	7
Pump	PUMP2S, PUMPR, PUMP1S	0	0	0	N/A
Tank	TANKBOTTOM	5	N/A	N/A	50
	TANKBOTEDGE	5	N/A	N/A	50
	COURSE-1 through 10	2	3	3	14
FINFAN	FINFAN_TUBE	0	N/A	N/A	1
	FINFAN HEADER	0	0	2	3
Vessel/FinFan	KODRUM	2	3	3	10
	FILTER	0	1	2	3
	DRUM	2	3	3	10
	REACTOR	4	6	6	21
	COLTOP, COLMID, COLBTM	3	4	5	21
NOTE 1 The outage day values listed above are estimates. The end user should review these to reflect their specific requirements. NOTE 2 N/A—Not applicable means that these hole sizes are not used for these component types. Refer to Annex 3.A, Section 3.A.3.2.					

Table 4.18—Fluid Leak Properties

Fluid	MW	Density (lb/ft ³)	NBP (°F)	Fraction Evaporated in 24 Hours (see Note) <i>fract_{evap}</i>
C ₁ –C ₂	23	15.639	–193	1.00
C ₃ –C ₅	58	36.209	31	1.00
C ₆ –C ₈	100	42.702	210	0.90
C ₉ –C ₁₂	149	45.823	364	0.50
C ₁₃ –C ₁₆	205	47.728	502	0.10
C ₁₇ –C ₂₅	280	48.383	651	0.05
C ₂₅₊	422	56.187	981	0.02
Acid	18	62.3	212	0.90
H ₂	2	4.433	–423	1.00
H ₂ S	34	61.993	–75	1.00
HF	20	60.37	68	1.00
CO	28	50	–312	1.00
DEE	74	45	95	1.00
HCL	36	74	–121	1.00
Nitric acid	63	95	250	0.80
NO ₂	90	58	275	0.75
Phosgene	99	86	181	1.00
TDI	174	76	484	0.15
Methanol	32	50	149	1.00
PO	58	52	93	1.00
Styrene	104	42.7	293	0.60
EEA	132	61	313	0.65
EE	90	58	275	0.75
EG	62	69	387	0.45
EO	44	55	51	1.00

NOTE Estimated values.

Table 4.18M—Fluid Leak Properties

Fluid	MW	Density (kg/m ³)	NBP (°C)	Fraction Evaporated in 24 Hours (see Note) <i>fract_{evap}</i>
C ₁ –C ₂	23	250.513	–125	1.00
C ₃ –C ₅	58	580.012	–1	1.00
C ₆ –C ₈	100	684.020	99	0.90
C ₉ –C ₁₂	149	734.014	184	0.50
C ₁₃ –C ₁₆	205	764.529	261	0.10
C ₁₇ –C ₂₅	280	775.021	344	0.05
C ₂₅₊	422	900.029	527	0.02
Acid	18	997.950	100	0.90
H ₂	2	71.010	–253	1.00
H ₂ S	34	993.032	–59	1.00
HF	20	967.034	20	1.00
CO	28	800.923	–191	1.00
DEE	74	720.831	35	1.00
HCL	36	1185.366	–85	1.00
Nitric acid	63	1521.754	121	0.80
NO ₂	90	929.071	135	0.75
Phosgene	99	1377.588	83	1.00
TDI	174	1217.403	251	0.15
Methanol	32	800.923	65	1.00
PO	58	832.960	34	1.00
Styrene	104	683.988	145	0.60
EEA	132	977.126	156	0.65
EE	90	929.071	135	0.75
EG	62	1105.274	197	0.45
EO	44	881.015	0	1.00
NOTE Estimated values.				

4.16 Figures

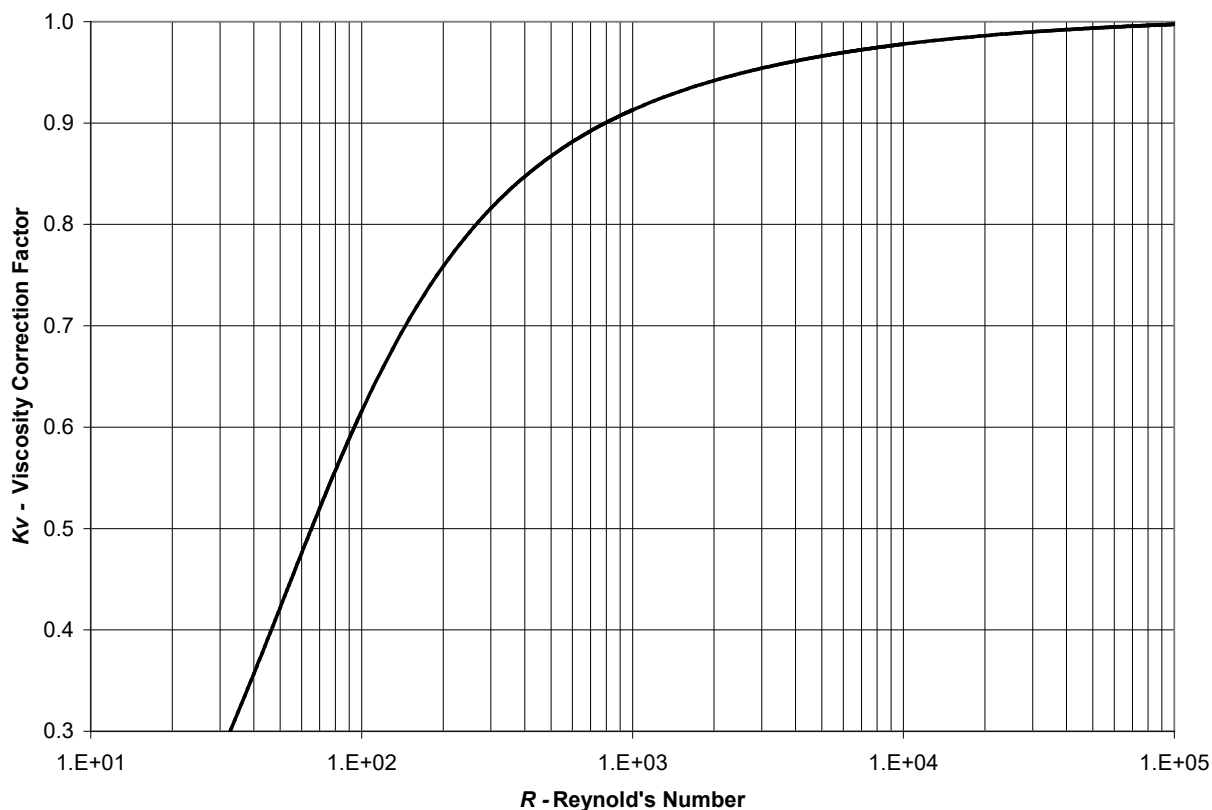


Figure 4.1—Liquid Flow Viscosity Correction Factor, K_v

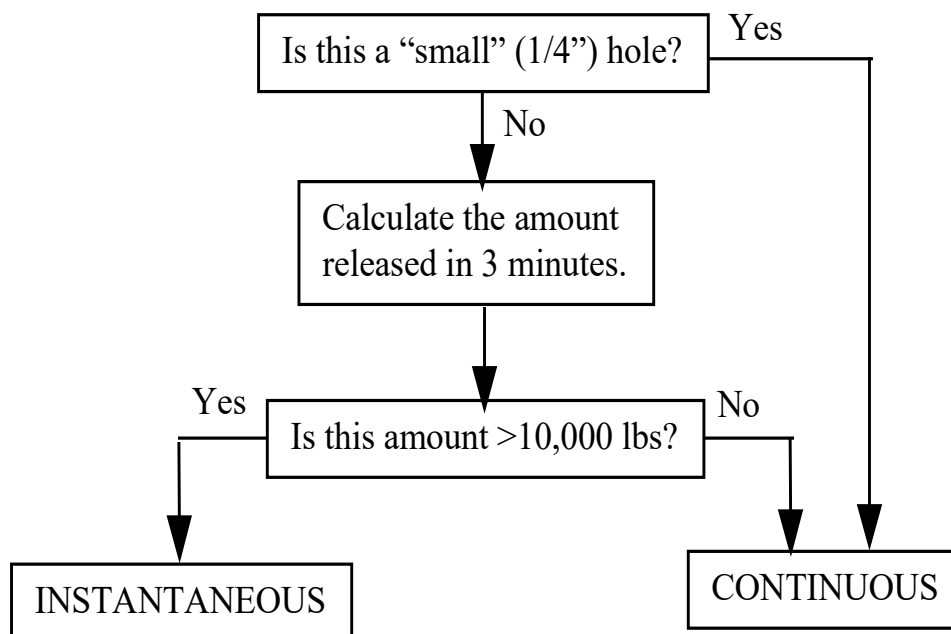
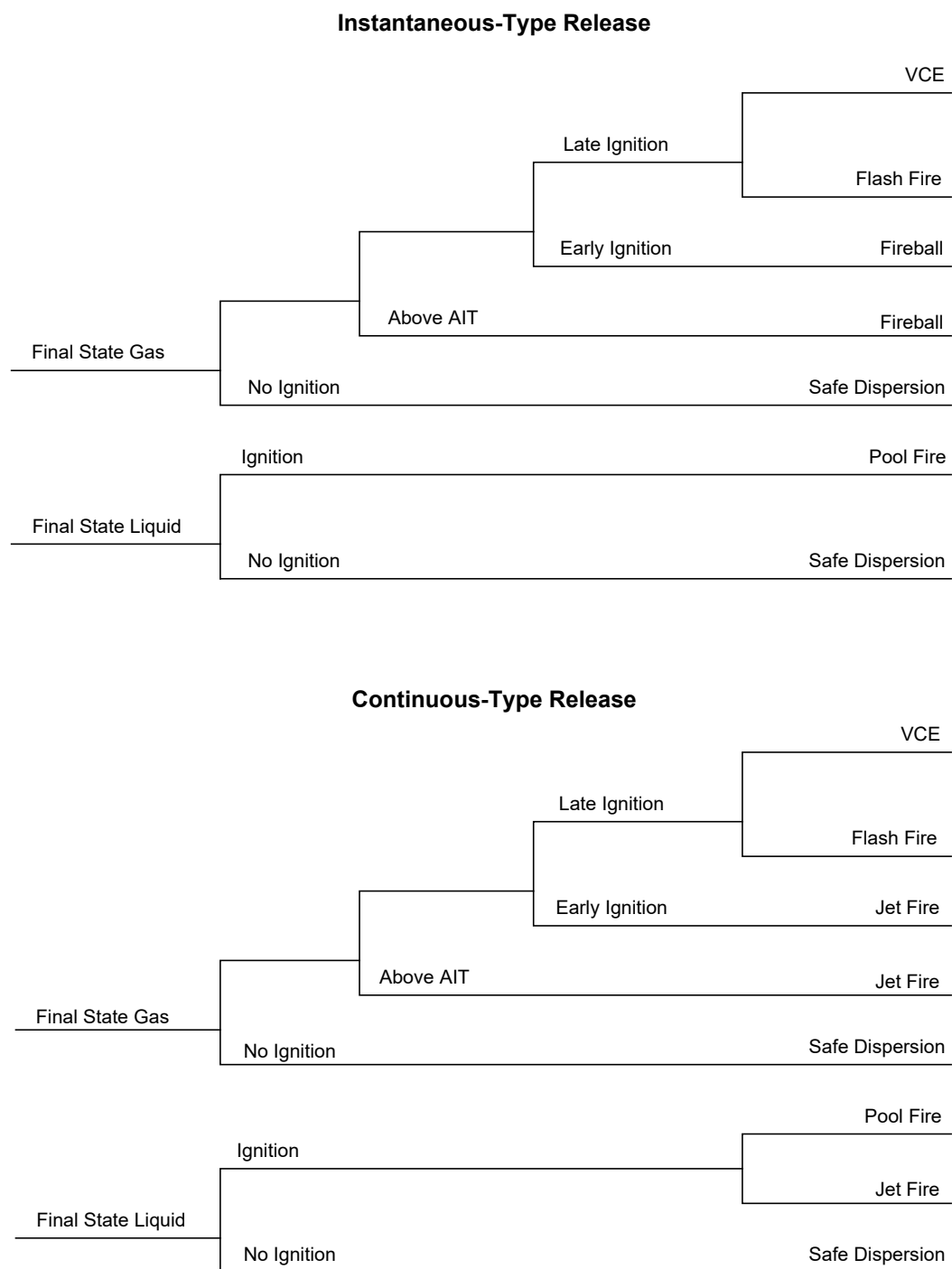


Figure 4.2—Instantaneous and Continuous Determination

**Figure 4.3—Level 1 COF Release Event Tree**

5 COF—Level 2

5.1 Determine the Fluid Composition and Associated Properties

5.1.1 General

The Level 2 consequence analysis provides the equations and background information necessary to rigorously calculate consequence areas for several flammable and toxic event outcomes. A summary of these events is provided in [Table 5.1](#).

The actual composition of the fluid, including mixtures, should be used in the analysis. Fluid property solvers are available that allow the analyst to calculate fluid physical properties more accurately. The fluid solver provides the ability to perform flash calculations to better determine the release phase of the fluid and to account for two-phase releases. In many of the consequence calculations, physical properties of the released fluid are required both at storage conditions and conditions after release to the atmosphere.

5.1.2 Required Properties at Storage Conditions

As shown in the flowchart of [Figure 5.1](#), at the start of the consequence analysis, an isothermal flash is used to determine the phase distribution and properties of the multicomponent feed mixture at the storage temperature, T_s , and pressure, P_s . The mass and mole fractions are determined along with the composition of each phase. Thermodynamic properties such as entropy and enthalpy are calculated along with transport properties such as thermal conductivity and viscosity. The required fluid properties at the storage conditions are listed below:

- a) storage phase (vapor, liquid, critical, or two-phase),
- b) mass fraction liquid, $frac_l$,
- c) mass fraction vapor, $frac_v$,
- d) MW,
- e) liquid density, ρ_l ,
- f) liquid viscosity, μ_l ,
- g) ideal gas specific heat ratio, $k = C_p/C_v$,
- h) enthalpy of mixture,
- i) entropy of mixture (to perform flash calculations),
- j) critical pressure and temperature, T_c and P_c ,
- k) AIT,
- l) saturation pressure, P_{sat_s} , at storage temperature,
- m) flammability limits, LFL and upper flammability limit (UFL),
- n) heat of combustion, HC_s , and
- o) toxic limits [e.g. IDLH, Emergency Response Planning Guideline (ERPG), acute exposure guideline level (AEGL), probits, etc.].

5.1.3 Required Properties at Flash Conditions

Analysis requires a fluid property package to isentropically flash (isenthalpic is acceptable) the stored fluid from its normal operating conditions to atmospheric conditions. The effects of flashing on the fluid temperature as well as the phase of the fluid at atmospheric conditions should also be evaluated. Liquid entrainment in the jet release as well as rainout effects could be evaluated to get a more representative evaluation of the release consequences. The isentropic flash calculation from storage conditions to atmospheric pressure, P_{atm} , simulates the release of the fluid from a leaking or ruptured storage container. The resulting flash temperature, T_f , is determined along with the phase distribution and properties of each phase at these conditions. The released mixture can either be a single-phase liquid, a single-phase vapor, or a two-phase mixture of both as shown in [Figure 5.1](#). The required fluid properties at the flashed conditions are listed below:

- a) flashed phase (vapor, liquid, or two-phase),
- b) flash temperature, T_f ,
- c) flash fraction, frac_{fsh} ,
- d) density of the liquid, ρ_l ,
- e) density of the vapor, ρ_v ,
- f) specific heat of the liquid, C_{p_l} ,
- g) heat of combustion of liquid, HC_l ,
- h) heat of combustion of vapor, HC_v ,
- i) latent heat of vaporization of liquid, ΔH_v ,
- j) bubble point temperature of liquid, T_b , and
- k) dew point temperature of vapors, T_d .

As shown in [Figure 5.1](#), where a fluid is flashed to a single-phase liquid, a bubble point temperature calculation is performed at atmospheric pressure to find the temperature, T_b , at which vapor bubbles first appear. Similarly, in the single-phase vapor case, a dew point calculation is performed at atmospheric pressure to find the temperature, T_d , at which liquid drops first start condensing.

For fluids that flash to two-phase, flash calculations at both the bubble point and the dew point of the flashed mixture may be required depending on the composition of the fluid.

- a) For pure fluids or binary mixtures (two components in mixture), additional calculations are not necessary because in these cases the bubble point and dew point temperatures are the same and equal to the isentropic flash temperature, i.e. $T_b = T_d = T_f$.
- b) For multicomponent mixtures, both the bubble point and the dew point calculations are required.

5.1.4 Calculation of Fluid Properties

- a) Step 1.1—Obtain the stored fluid composition. For mixtures, concentrate on the major components within the fluid mixture and attempt to get at least 90 % of the mixture identified and quantified. A more detailed breakdown of the composition is not warranted, unless there are small quantities of toxic materials that are in the mixture.

- b) Step 1.2—Using a fluid property solver, determine the fluid properties as specified in [Section 5.1.2 a\)](#) for the fluid at storage conditions. Research may be required to determine some of the fluid properties required for the analysis, such as LFL, UFL, heat of combustion, and toxic limits. The analyst may need to use MSDSs or other fluid databases, such as DIPPR [\[3\]](#), to determine these properties. Mixing rules (e.g. LaChatalier's mixing principle for LFL and UFL) are available to determine properties of mixtures, but in general a mole weighted method may be used as an estimate.
- c) Step 1.3—Using a fluid property solver, perform an isentropic flash (isenthalpic is acceptable) and determine the flash temperature, T_f , the phase of the flashed fluid, and the fraction of fluid flashed, $frac_{fsh}$.
- d) Step 1.4—Determine the bubble point or dew point temperature of the flashed fluid, as necessary.
- 1) For flashed liquid, determine the bubble point temperature, T_b , at atmospheric pressure.
 - 2) For flashed vapors, determine the dew point temperature, T_d , at atmospheric pressure.
 - 3) For fluids that flash to two-phase, the bubble point temperature, T_b , at atmospheric pressure and the dew point temperature, T_d , at atmospheric pressure should be determined.

NOTE For pure fluids and binary mixtures, no calculation is required since the bubble point temperature and the dew point temperature are equal to the flash temperature, T_f , as determined in Step 1.3.

5.2 Release Hole Size Selection

5.2.1 General

As with the Level 1 approach, a discrete set of release events or release hole sizes are used, as shown in [Table 4.4](#).

5.2.2 Calculation of Release Hole Sizes

The step-by-step methodology for selecting the release hole sizes are in accordance with the Level 1 consequence analysis (see [Section 4.2.2](#)).

5.3 Release Rate Calculation

5.3.1 Source Term Modeling

Quantification of the consequence of a release event requires calculations of the release amount (or rate of release), the duration of the release, and the state (e.g. gas, liquid or two-phase) of the material released. The terminology used for determining these parameters is source term modeling. The source term is used as an input to the various consequence models as well as the cloud dispersion analysis.

5.3.2 Determining the Release Phase

Estimation of the release amount or rate is covered for liquids and vapors (gases) in [Section 4.3](#). For calculating the release rate, the release phase must be determined.

NOTE The release phase is different than the phase of the fluid at storage conditions or the phase of the fluid after flashing to atmosphere as described in [Section 5.1.2](#) and [Section 5.1.3](#). This is the phase immediately downstream of the release point and is used for selecting the proper equation for calculating the release rate through the hole or crack opening.

To determine the release phase, the saturation pressure of the stored fluid at the storage temperature, P_{sat_s} , must be determined.

$$\text{if } P_{sat_s} \geq P_s \geq P_{atm} \Rightarrow \text{release phase is vapor} \quad (3.95)$$

$$\text{if } P_s \geq P_{sat_s} > P_{atm} \Rightarrow \text{release phase is two-phase} \quad (3.96)$$

$$\text{if } P_s \geq P_{atm} > P_{sat_s} \Rightarrow \text{release phase is liquid} \quad (3.97)$$

5.3.3 Vapor Release Source

As shown in Equation (3.95), if the saturation pressure of the fluid at storage temperature, P_{sat_s} , is greater than or equal to the storage pressure, P_s , the fluid will be stored as a gas or vapor and released as a gas or vapor. In this case, calculation of the theoretical release rate, W_n , can be in accordance with Equation (3.6) or Equation (3.7). Most gases will cool as they are depressured through an orifice, so in some cases, condensation will occur and liquid rainout needs to be considered as presented in Section 5.7.2.

For supercritical fluids (stored above critical pressure or temperature), the release rate can be estimated using Equation (3.6); however, in this case the specific heat ratio, k , should be evaluated at the NBP of the fluid mixture or at standard conditions. This will result in a conservative release rate. More rigorous methods, such as the HEM Omega [4] method, can be used to calculate the release rate of a supercritical fluid. In some cases, supercritical fluids will condense upon release, and liquid rainout needs to be considered as presented in Section 5.7.2.

5.3.4 Two-phase Release Source

As shown in Equation (3.96), if the saturation pressure of the fluid at the storage temperature, P_{sat_s} , is less than or equal to the storage pressure, P_s , but greater than atmospheric pressure, P_{atm} , the fluid will be stored as a liquid and will be released as a two-phase mixture. In this case, the release rate can be conservatively estimated using the liquid Equation (3.3). Alternatively, a more accurate two-phase flow calculation may be used. For this case, the effect of liquid entrainment in the released jet needs to be considered as well as rainout. Methods for evaluating these effects are presented in Section 5.7.2.

5.3.5 Liquid Release Source

Finally, as shown in Equation (3.97), if the saturation pressure of the fluid at the storage temperature, P_{sat_s} , is less than atmospheric pressure, P_{atm} , the fluid will be stored as a liquid and will be released as a liquid. In this case, the release rate can be determined using Equation (3.3).

5.3.6 Calculation of Release Rates

- a) Step 3.1—Determine the stored fluid's saturation pressure, P_{sat_s} , at the storage temperature.
- b) Step 3.2—Determine the release phase using Equations (3.95), (3.96), or (3.97).
- c) Step 3.3—For each release hole size selected in Step 2.1, calculate the release hole size area, A_n , using Equation (3.8) based on d_n .
- d) Step 3.4—For each release hole size, calculate the release rate, W_n , for each release area, A_n , determined in Step 3.3.

For liquid releases, use Equation (3.3).

- 1) For vapor releases, use Equations (3.6) or (3.7), as applicable.

- 2) For two-phase releases, use [Equation \(3.3\)](#), for a conservative approximation. As an alternative, a two-phase method, such as the HEM Omega method [\[4\]](#), may be utilized.

5.4 Estimate the Fluid Inventory Available for Release

5.4.1 General

The total amount of fluid inventory available for release is estimated in accordance with the Level 1 consequence analysis (see [Section 4.4](#)).

5.4.2 Calculation of Inventory Mass

The step-by-step procedure for estimated the available fluid inventory mass is in accordance with [Section 4.4.3](#).

5.5 Determine Release Type

5.5.1 General

The type of release is established in accordance with the Level 1 consequence analysis, see [Section 4.5](#).

5.5.2 Calculation of Release Type

The step-by-step procedure for determining if the release is classified and continuous or instantaneous is in accordance with [Section 4.5.2](#).

5.6 Estimate the Impact of Detection and Isolation Systems on Release Magnitude

5.6.1 General

The effects of detection and isolation systems are established in accordance with the Level 1 consequence analysis. See [Section 4.6](#).

5.6.2 Calculation for Detection and Isolation Systems

The step-by-step procedure for estimating the impact of detection and isolation systems is in accordance with [Section 4.6.6](#).

5.7 Determine the Release Rate and Mass for COF

5.7.1 General

The Level 2 consequence analysis models two-phase releases and distinguishes between the amount of the theoretical release rate that releases to the atmosphere as vapor or as an aerosol (vapor with entrained liquid) in the form of a jet and the amount of the release that drops to the ground as liquid to form a pool. Analysis requires a fluid property package to isentropically flash (isenthalpic is acceptable) the stored fluid from its normal operating conditions to atmospheric conditions. In addition, the effects of flashing on the fluid temperature as well as the phase of the fluid at atmospheric conditions should be evaluated. Liquid entrainment in the jet release as well as rainout effects could be evaluated to get a more representative evaluation of the release consequences.

5.7.2 Aerosol and Rainout Modeling

When a release is two-phase, there is an amount of liquid entrained in the jet (vapor) portion of the release (aerosol). The remaining liquid portion of the release, or rainout, can be estimated by the following correlation recommended by Kletz [5].

$$frac_{ro} = 1 - 2 \cdot frac_{fsh} \quad \text{for} \quad frac_{fsh} < 0.5 \quad (3.98)$$

$$frac_{ro} = 0.0 \quad \text{for} \quad frac_{fsh} \geq 0.5 \quad (3.99)$$

Other liquid rainout correlations are available from CCPS [6], Davenport [7], Prugh [8], and Mudan [9].

The fraction that flashes, $frac_{fsh}$, as it is released to the atmosphere can be determined using fluid property software by isentropically (isenthalpically is acceptable) expanding the release fluid from the storage conditions to the atmospheric conditions.

5.7.3 Calculation of Jet Release Rate and Pool Release Rate

Once the release rate is determined and the rainout fraction is estimated, the release rate for modeling pool type consequences, W_n^{pool} , and for modeling jet type consequences, W_n^{jet} , can be determined as follows:

$$W_n^{pool} = rate_n \cdot frac_{ro} \quad (3.100)$$

$$W_n^{jet} = rate_n (1 - frac_{ro}) \quad (3.101)$$

NOTE The jet release rate may include entrained liquid. To calculate the mass fraction of liquid entrained in the jet, use Equation (3.102).

$$frac_{entl} = \frac{(frac_l \cdot frac_{fsh})}{(1 - frac_{ro})} \quad (3.102)$$

5.7.4 Vapor Sources from Boiling or Non-boiling Pools

5.7.4.1 General

Vapors evaporating off of the surface of liquid pools, if not ignited immediately, can be the source of vapor clouds that could result in flash fires or VCEs. Quantifying these vapor rates is necessary when determining the impact of these event outcomes. The vapor source rate is dependent on whether the pool is a boiling or a non-boiling pool. The bubble point temperature, T_b , of the liquid is required to determine the type of analysis to be used for liquid pools on the ground.

5.7.4.2 Boiling Liquid Pools

If $T_b < T_g$, where T_g is the ground temperature, then we have the boiling liquid pool case. The temperature of the liquid will remain at its boiling-point temperature T_b (at least near the liquid-vapor interface) while vapor will be rapidly evaporating at a rate that is limited by how fast heat energy can be supplied to the liquid-vapor interface. The partial pressure of the vapor right above the liquid pool will be equal to the atmospheric pressure.

The vapor rate generated off of the surface of a boiling pool, $erate_b$, can be estimated using Equation (3.103) as provided by Shaw and Briscoe [10].

$$erate_n = \pi^{1.5} \left[\frac{X_{surf} \cdot k_{surf} \cdot (T_g - T_b)}{C_{14} \cdot \Delta H_v \sqrt{\pi \cdot \alpha_{surf}}} \right] (2 \cdot g \cdot \dot{V}_{p,n})^{0.5} t_{p,n} \quad (3.103)$$

The surface interaction parameters X_{surf} , k_{surf} , and α_{surf} in the above equation account for the liquid interaction with the surface on which the pool forms. These can be obtained from Table 5.2 repeated from Rijnmond Public Authority [11].

The size of the boiling pool reaches a steady state, when the evaporation rate, $erate_b$, is equal to the pool release rate, W_n^{pool} , as discussed in Section 5.7.3. At this point, the radius of the evaporating pool can be determined using Equation (3.104) as provided by Shaw and Briscoe [10].

$$r_{p,n} = \sqrt{\frac{2}{3}} \left(\frac{8g \cdot \dot{V}_{p,n}}{\pi} \right)^{0.25} t_{p,n}^{0.75} \quad (3.104)$$

5.7.4.3 Non-boiling Liquid Pools

If $T_b > T_g$, then we have the case of a non-boiling (evaporating) liquid pool, where the liquid temperature will be nearly equal to the ground temperature (after some initial transient period), and the vapor pressure right above the pool will be less than atmospheric pressure and equal to the bubble point pressure, $P_{b,g}$, corresponding to the ground temperature. Thus, an additional thermodynamic calculation is required to determine $P_{b,g}$. The evaporation rate in this case is primarily limited by how fast the newly generated vapor can be carried away from the interface by diffusion or convection.

The vapor rate generated off of the surface of a non-boiling pool, $erate_{nb}$, can be estimated using Equation (3.105) as provided by Shaw and Briscoe [10].

$$erate_n = C_{15} \cdot \left(\frac{P_{b,g} \cdot MW}{RT_s} \right) u_w^{0.78} \cdot r_{p,n}^{1.89} \quad (3.105)$$

The size of the non-boiling pool reaches a steady state when the evaporation rate, $erate_{b,n}$, is equal to the pool release rate, W_n^{pool} , as discussed in Section 5.7.3.

5.7.5 Cloud Dispersion Modeling

The ability to perform cloud dispersion analysis is a key component to performing the Level 2 consequence analyses. Modeling a release depends on the source term conditions, the atmospheric conditions, the release surroundings, and the hazard being evaluated. Employment of many commercially available models, including SLAB, account for these important factors and will produce the desired data for the Level 2 assessments [12]. Annex 3.A provides background on performing these studies and provides some guidance on available software. Additional guidance is provided by Hanna and Drivas [13].

The dispersion analysis is needed to determine several things. For flammable releases, such as flash fires, this will typically entail determination of the portion of the cloud area (area footprint, ft², at grade) where the air to fuel mixture is between the LFL and the UFL. For VCEs, the amount of flammable mass in the cloud is required. In this case, the amount of flammable material (lb) is required and therefore the cloud dispersion model must be able to predict the volumetric portion within the cloud that is above the LFL of the mixture.

For toxic releases, the cloud dispersion model must be able to calculate the concentration (ppm or vol %) of the toxic component of the release throughout the cloud. The portion of the cloud in terms of plant area that has a higher concentration than the relevant toxic impact criteria is determined. The toxic criteria may be based on a probit value, IDLH, ERPG, AEGL, LC₅₀, or other acceptable value.

5.7.6 Cloud Dispersion Calculation

- a) Step 7.1—For each release hole size, calculate the adjusted release rate, $rate_n$, using Equation (3.13) where the theoretical release rate, W_n , is from Step 3.2.

NOTE 1 The release reduction factor, $fact_{di}$, determined in Step 6.4 accounts for any detection and isolation systems that are present.

- b) Step 7.2—For each release hole size, calculate the leak duration, ld_n , of the release using Equation (3.15), based on the available mass, $mass_{avail,n}$, from Step 4.6 and the adjusted release rate, $rate_n$, from Step 7.1.

NOTE 2 The leak duration cannot exceed the maximum duration, $ld_{max,n}$, determined in Step 6.5.

- c) Step 7.3—Determine the rainout mass fraction from the released fluid using Equation (3.98) or (3.99), based on the flash fraction calculated in Step 1.3.
- d) Step 7.4—For each hole size selected in Step 2.1, calculate the release rate of liquid that settles to the ground for the pool calculations, W_n^{pool} , using Equation (3.100).
- e) Step 7.5—For each hole size selected, calculate the release rate of vapor (including entrained liquid remaining in the jet, W_n^{jet}), using Equation (3.101).
- f) Step 7.6—Calculate the mass fraction of entrained liquid, $frac_{entl}$, within the jet portion of the release using Equation (3.102).
- g) Step 7.7—Determine the vapor source rate and source area for the vapor cloud and flash fire dispersion analysis.
- 1) For vapor releases, use the jet release rate, W_n^{jet} , established in Step 7.5.
 - 2) For liquid releases, determine whether the pool is boiling or non-boiling in accordance with Section 5.7.4. For boiling pools, calculate the evaporation rate, $erate_n$, and the pool radius, $r_{p,n}$, using Equations (3.103) and (3.104). For non-boiling pools, calculate the evaporation rate, $erate_n$, and the pool radius, $r_{p,n}$, using Equation (3.105).

5.8 Determine Flammable and Explosive Consequences

5.8.1 Event Tree Calculations

5.8.1.1 Overview

Event tree analysis determines the probabilities of various outcomes as a result of release of hazardous fluids to the atmosphere. These probabilities are then used to weight the overall consequences of release.

The CCPS [14] defines an event tree as “a graphical logic model that identifies and quantifies possible outcomes following an initiating event. The event tree provides systematic coverage of the time sequence of event propagation, either through a series of protective system actions, normal plant functions and operator interventions (a preincident application), or where loss of containment has occurred, through the range of consequences possible (a postincident application).”

An overall event tree is presented in [Figure 5.2](#). The COF portion fits within the overall methodology as shown in [Figure 5.2](#). POF (*POL* for leakage or *POR* for rupture) is a function of the GFFs for particular pieces of equipment and the calculated damage state (DFs) of the piece of equipment or component being evaluated. The determination of the POF is covered in [Part 2](#) of this document.

The POF is then multiplied by the event probabilities as determined from the consequence analysis. Similar to trees employed by the CCPS ^[14] to evaluate consequences of releases in process units, the event trees presented in [Figure 5.2](#) through [Figure 5.5](#) display the potential outcomes that could occur from the initiating event (a release). The event tree for the leakage cases, which corresponds to the small, medium, and large release hole sizes as discussed in [Section 4.2](#), is shown in [Figure 5.3](#). The event tree for the rupture case is shown in [Figure 5.4](#).

5.8.1.2 Probability of Ignition Given a Release

For a release of a hazardous fluid, the two main factors that define the event outcome are the probability of ignition and the timing of ignition, in other words, immediate vs delayed ignition.

A study by Cox, Lees, and Ang in 1990 ^[15] indicates that the probability that a flammable release will ignite is proportional to the release rate of flammable material. Additional research on probabilities of ignition is provided in Reference ^[16]. The curve fit for the Cox, Lees, and Ang work can be seen as the lowest curves in [Figure 5.5](#), which applies to liquids, and [Figure 5.6](#), which applies to vapors. The additional curves provided in these figures are extrapolated to match the constant values assumed in the Level 1 consequence analysis provided in [Annex 3.A, Tables 3.A.3.3](#) through [3.A.3.6](#). These curves take into consideration the release rate and flash point. In general, the lower the flash point of the released fluid, the higher the probability of ignition. Using these curves eliminates the need to blend results between the continuous and instantaneous results as required in the Level 1 consequence analysis.

The mass fraction of flammable fluid in the release fluid mixture, $mfrac^{flam}$, must be known to calculate the release rate of flammable material:

$$rate_n^{flam} = rate_n \cdot mfrac^{flam} \quad (3.106)$$

The liquid and vapor portions of the flammable release rate are determined using [Equation \(3.107\)](#) and [Equation \(3.108\)](#).

$$rate_{l,n}^{flam} = rate_n^{flam} \cdot (1 - frac_{tsh}) \quad (3.107)$$

$$rate_{v,n}^{flam} = rate_n^{flam} \cdot frac_{tsh} \quad (3.108)$$

As an alternative to using [Figure 5.5](#) and [Figure 5.6](#), the probability of ignition at ambient conditions of a flammable liquid or vapor release may be calculated from [Equation \(3.109\)](#) or [Equation \(3.110\)](#), respectively. Since these are a function of release rate, the probabilities of ignition are calculated for each of the release hole sizes selected.

NOTE When the flammable liquid or vapor release rate exceeds a rate that would indicate an instantaneous release 10,000 lb (4,535.9 kg) release in 3 minutes or less], a maximum value of 25.22 kg/s (55.6 lb/s) should be used for

$rate_{l,n}^{flam}$ or $rate_{v,n}^{flam}$ in [Equation \(3.109\)](#) and [Equation \(3.110\)](#).

$$poi_{l,n}^{amb} = \exp \left(\left[a + b \cdot (C_{12} \cdot T_{fp}) + c \cdot (C_{12} \cdot T_{fp})^2 + d \cdot (C_{12} \cdot T_{fp})^3 \right] + \left[e + f \cdot (C_{12} \cdot T_{fp}) + g \cdot (C_{12} \cdot T_{fp})^2 + h \cdot (C_{12} \cdot T_{fp})^3 \right] \cdot \ln(C_{4B} \cdot rate_{l,n}^{flam}) \right) \quad (3.109)$$

where

$$a = -01.368924E-01$$

$$b = -07.598764E-03$$

$$c = 8.282163E-06$$

$$d = -06.124231E-09$$

$$e = 6.876128E-02$$

$$f = 1.193736E-04$$

$$g = 2.081034E-07$$

$$h = -04.057289E-11$$

$$poi_{v,n}^{amb} = \exp \left(\left[a + b \cdot (C_{12} \cdot T_{fp}) + c \cdot (C_{12} \cdot T_{fp})^2 + d \cdot (C_{12} \cdot T_{fp})^3 \right] + \left[e + f \cdot (C_{12} \cdot T_{fp}) + g \cdot (C_{12} \cdot T_{fp})^2 + h \cdot (C_{12} \cdot T_{fp})^3 \right] \cdot \ln(C_{4B} \cdot rate_{v,n}^{flam}) \right) \quad (3.110)$$

where

$$a = -06.053124E-02$$

$$b = -09.958413E-03$$

$$c = 1.518603E-05$$

$$d = -01.386705E-08$$

$$e = 4.564953E-02$$

$$f = 7.912392E-04$$

$$g = -06.489157E-07$$

$$h = 7.159409E-10$$

The probabilities of ignition calculated above are at ambient temperature. As the temperature approaches the AIT of the released fluid, the probability of ignition approaches a limiting or maximum value. For liquids released at or above the AIT, the maximum probability of ignition, poi_l^{ait} , is equal to 1.0 as shown in Equation (3.111).

$$poi_l^{ait} = 1.0 \quad (3.111)$$

For vapors released at or above the AIT, the maximum probability of ignition, poi_v^{ait} , is function of the MW of the fluid. See Equation (3.112). This equation provides a relationship for the maximum value at the AIT and

is in general agreement with the probabilities established for the Level 1 COF (see [Annex 3.A, Tables 3.A.3.3 and 3.A.3.4](#)). For fluids with a MW of 170 or greater, the limiting value will be 0.7. For hydrogen, the value will be 0.9. Linear interpolation is assumed in between these two extremes.

$$poi_v^{ait} = \max \left[0.7, 0.7 + 0.2 \left(\frac{170.0 - MW}{170.0 - 2.0} \right) \right] \quad (3.112)$$

Once the maximum value of the probability of ignition has been established using [Equation \(3.111\)](#) or [Equation \(3.112\)](#), [Equation \(3.113\)](#) for liquids and [Equation \(3.114\)](#) for vapors can be used to determine the probability of ignition for the released fluid at the actual process or storage temperature. These equations assumes linear interpolation between the value calculated at ambient conditions and the maximum value at the AIT.

$$poi_{l,n} = poi_{l,n}^{amb} + \left(poi_l^{ait} - poi_{l,n}^{amb} \right) \left(\frac{T_s - C_{16}}{AIT - C_{16}} \right) \quad (3.113)$$

$$poi_{v,n} = poi_{v,n}^{amb} + \left(poi_v^{ait} - poi_{v,n}^{amb} \right) \left(\frac{T_s - C_{16}}{AIT - C_{16}} \right) \quad (3.114)$$

For two-phase releases, the probability of ignition can be estimated as a mass weighted average of the vapor and liquid probabilities of ignition; see [Equation \(3.115\)](#).

$$poi_{2,n} = poi_{v,n} \cdot frac_{fsh} + poi_{l,n} \cdot (1 - frac_{fsh}) \quad (3.115)$$

5.8.1.3 Probability of Immediate vs Delayed Ignition Given Ignition

Given that ignition occurs, the probability of immediate vs delayed ignition depends on the type of release (continuous or instantaneous), the phase of the release, and how close the released fluid's temperature is to its AIT. The probability of immediate ignition given ignition is designated in [Figure 5.3](#) and [Figure 5.4](#) as poi_i . The probability of delayed ignition given ignition is $(1 - poi_i)$.

As the event tree figures show, the determination that a specific event occurs is greatly dependent on whether or not an ignition is either immediate or delayed. For example, an immediate ignition of a vapor release results in a jet fire or a fireball. If this same release were to have a delayed ignition, the resulting event could be a VCE or a flash fire. Likewise, a liquid release could either result in a flash fire, a VCE, or a pool fire depending on whether or not it is an immediate or a delayed ignition.

The probability of immediate ignition given ignition of a flammable liquid release, $poi_{l,n}$, and a flammable vapor release, $poi_{v,n}$, can be estimated using [Equation \(3.116\)](#) and [Equation \(3.117\)](#). As an alternative, Cox, Lees, and Ang ^[15] provides a curve for the probability that an ignition will be an immediate vs a delayed ignition.

$$poi_{l,n} = poi_{l,n}^{amb} + \left(\frac{T_s - C_{16}}{AIT - C_{16}} \right) \cdot \left(poi_l^{ait} - poi_{l,n}^{amb} \right) \quad (3.116)$$

$$poi_{v,n} = poi_{v,n}^{amb} + \left(\frac{T_s - C_{16}}{AIT - C_{16}} \right) \cdot \left(poi_v^{ait} - poi_{v,n}^{amb} \right) \quad (3.117)$$

The probabilities of immediate ignition, given ignition at ambient conditions, $poi_{l,n}^{amb}$ and $poi_{v,n}^{amb}$, are based on expert opinion and are provided in [Table 5.3](#) for instantaneous and continuous releases of liquids

and vapors. At the AIT or higher, it is assumed that the probability of immediate ignition given ignition for all release phases, poi^{ait} , is equal to 1.0. Equation (3.118) provides a linear interpolation for operating temperatures between ambient and the AIT.

For two-phase releases, the probability of immediate ignition given ignition can be assumed to be the mass weighted average of the probability calculated for liquid and the vapor as follows:

$$poi_{2,n} = frac_{fsh} \cdot poi_{v,n} + (1 - frac_{fsh}) \cdot poi_{l,n} \quad (3.118)$$

5.8.1.4 Probability of VCE vs Flash Fire Given Delayed Ignition

A delayed ignition will result in the event outcome of either a VCE or a flash fire. The probability of VCE given a delayed ignition, $pvcedi$, is dependent on what type of release occurs, instantaneous or continuous, and whether the release is a liquid or a vapor. Currently, the assumptions for these probabilities are provided in Table 5.3 and are in general agreement with the assumptions provided in Annex 3.A, Tables 3.A.3.3 through 3.A.3.6 for the Level 1 consequence analysis.

An improvement to these assumptions would be to prorate the probability of a VCE given a delayed ignition, $pvcedi$, based on the NFPA reactivity number. A fluid with a higher NFPA reactivity will have a higher probability of a VCE vs a flash fire. An even better method would be to use the flame speed for the particular fluid of interest. Higher flame speeds will have a higher probability of a VCE vs a flash fire. The problem with this method is that data for the flame speed of a particular fluid in a vapor cloud are not always available.

For liquids and vapors, the probability of VCE given a delayed ignition, $pvcedi_{l,n}$ or $pvcedi_{v,n}$, can be obtained from Table 5.3. For two-phase releases, the probability of VCE given a delayed ignition can be assumed to be the mass weighted average of the probability for liquid and the vapor as shown in Equation (3.119).

$$pvcedi_{2,n} = frac_{fsh} \cdot pvcedi_{v,n} + (1 - frac_{fsh}) \cdot pvcedi_{l,n} \quad (3.119)$$

Since either a VCE or a flash fire occurs as a result of a delayed ignition, the probability of a flash fire given a delayed ignition of a liquid or a vapor release are in accordance with Equation (3.120) and Equation (3.121).

$$pffdi_{l,n} = 1 - pvcedi_{l,n} \quad (3.120)$$

$$pffdi_{v,n} = 1 - pvcedi_{v,n} \quad (3.121)$$

For two-phase releases, the probability of flash fire given a delayed ignition can be assumed to be the mass weighted average of the probability calculated for liquid and the vapor as shown in Equation (3.122).

$$pffdi_{2,n} = frac_{fsh} \cdot pffdi_{v,n} + (1 - frac_{fsh}) \cdot pffdi_{l,n} \quad (3.122)$$

5.8.1.5 Probability of Fireball Given Immediate Ignition

Fireballs occur as a result of an immediate ignition of an instantaneous vapor or two-phase release upon rupture of a component. The probability can be determined using Equation (3.123) and Equation (3.124).

$$pfbii = 1.0 \quad \text{for instantaneous vapor or two-phase releases} \quad (3.123)$$

$$pfbii = 0.0 \quad \text{for all other cases} \quad (3.124)$$

5.8.1.6 Event Outcome Probabilities

Event trees are used to calculate the probability of every possible event or outcome (even safe outcomes) as a result of a hazardous release. The probability of a particular event outcome after a release can be determined by multiplying of all of the individual probabilities along the path of the event tree being taken. For example, the probability of a flash fire given leakage of a vapor can be determined from [Figure 5.3](#) using [Equation \(3.125\)](#).

$$pvce_{v,n} = poi_{v,n} \cdot (1 - poi_{v,n}) \cdot (1 - pvcedi_{v,n}) \quad (3.125)$$

The probability of safe release of a leaking two-phase release is given by [Equation \(3.126\)](#).

$$psafe_{2,n} = (1 - poi_{2,n}) \quad (3.126)$$

The probability of a pool fire given a rupture of a vessel containing liquid per [Figure 5.4](#) is given by [Equation \(3.127\)](#).

$$ppool_{l,n} = poi_{l,n} \cdot poi_{l,n} \quad (3.127)$$

5.8.2 Pool Fires

5.8.2.1 Overview

When a flammable liquid is released from a piece of equipment or pipeline, a liquid pool may form. As the pool forms, some of the liquid will evaporate and, if the vaporizing flammable materials find an ignition source while it is above its LFL, a pool fire can occur. Pool fires are considered to occur as a result of immediate ignition of a flammable liquid from a pressurized process vessel or pipe that develops a hole or ruptures.

Important characteristics of pool fires include its burning velocity, rate of heat release, flame height, flame plume deflection, and radiative heat flux. To model a pool fire correctly, necessary data for the calculations include the extent of the pool surface, the physical properties of the burning fluid, the physical and thermal properties of the substrate, and the ambient conditions.

A method for calculating the consequences associated with a pool fire is provided by CCPS [17]. This method entails calculating the burning rate off the surface of the pool that is a function of the pool area and the heat of combustion, the latent heat of vaporization, and the specific heat of the flammable liquid. The maximum size of the pool is determined at that point where the burning rate off the surface of the pool is equal to the release rate calculated through the hole or rupture from the protected piece of equipment (see [Section 5.8.2.3](#)).

The consequence area is estimated by considering the potential for personnel injury and component damage due to the effects of exposure to thermal radiation in the vicinity of the fire.

5.8.2.2 Pool Fire Burning Rate

The burning rate off of the surface of a pool fire is the rate at which the flammable material is evaporated during the fire is given in TNO [18] and can be determined using the following equations.

For non-boiling pools:

$$\dot{m}_b = \frac{C_{17} \cdot HC_l}{C_{p_l}(T_b - T_{atm}) + \Delta H_v} \quad (3.128)$$

For boiling pools, such as cryogenic liquids or LPGs:

$$\dot{m}_b = \frac{C_{17} \cdot HC_l}{\Delta H_v} \quad (3.129)$$

NOTE For liquid mixtures (such as gasoline), the burning rate can be approximated by calculating the burning rate for each component in the mixture, $\dot{m}_{b,i}$, and summing as follows:

$$\dot{m}_b = \sum_{i=1}^N \text{frac}_{\text{mole},i} \cdot \dot{m}_{b,i} \quad (3.130)$$

5.8.2.3 Pool Fire Size

The ultimate size of the pool fire is then determined to be the size where the liquid portion (rainout) of the release rate from the pressurized system, W_n^{pool} , is equal to the burning rate off the surface of the pool, $\dot{m}_b$, or:

$$A_{\text{burn pf},n} = \frac{W_n^{\text{pool}}}{\dot{m}_b} \quad (3.131)$$

For instantaneous releases of the flammable liquid inventory to the ground, a practical limit to the amount of pool spread should be used in the consequence calculations. The maximum size of the pool can be determined based on assuming a circle with depth of 0.0164 ft (5 mm), in accordance with The Netherlands Organization for Applied Scientific Research (TNO *Yellow Book*), 1997 [18], recommendations.

$$A_{\text{max pf},n} = \frac{\text{mass}_{\text{avail},n}}{C_{18} \cdot \text{frac}_{\text{ro}} \cdot \rho_l} \quad (3.132)$$

The pool fire area to be used in the consequence area calculation is then:

$$A_{\text{pf},n} = \min[A_{\text{burn pf},n}, A_{\text{max pf},n}] \quad (3.133)$$

The consequence of a pool release is directly dependent on the pool area, which is driven by assumptions made of the pool depth. In practice, areas have slopes for drainage, curbing, trenches, drains, and other ground contours that collect or remove fluids. Applying conservative pool depth values (e.g. 5 mm depth [18], 1 cm [19]) provides unrealistically large pool areas. Site condition should be considered when estimating pool size. A default limit of 10,000 ft² may be appropriate for all but the largest releases. From this area, the radius of the pool fire can be determined:

$$R_{\text{pf},n} = \sqrt{\frac{A_{\text{pf},n}}{\pi}} \quad (3.134)$$

5.8.2.4 Flame Length and Flame Tilt

The *SPFE Handbook for Fire Protection* [20] provides a correlation from Thomas that can be used for calculating the flame length of a pool fire, L_{pf} .

$$L_{\text{pf},n} = 110 \cdot R_{\text{pf},n} \left[\frac{\dot{m}_b}{\rho_{\text{atm}} \sqrt{2 \cdot g \cdot R_{\text{pf},n}}}} \right]^{0.67} u_s^{-0.21} \quad (3.135)$$

The nondimensional wind velocity, u_s , cannot be less than 1.0 and is dependent on the wind speed as follows:

$$u_{s,n} = \max \left[1.0, u_w \cdot \left(\frac{\rho_v}{2 \cdot g \cdot \dot{m}_b \cdot R_{pf,n}} \right)^{0.333} \right] \quad (3.136)$$

The American Gas Association provides the following correlation for estimating the flame tilt:

$$\cos \theta_{pf,n} = \frac{1}{\sqrt{u_{s,n}}} \quad (3.137)$$

5.8.2.5 Pool Fire Radiated Energy

The amount of energy radiated by the pool fire (often referred to as surface emitted heat flux) is a fraction of the total combustion power of the flame [18]. The fraction of the total combustion power that is radiated, β , is often quoted in the range of 0.15 to 0.35. A conservative value of 0.35 can be chosen. Therefore:

$$Q_{rad,n}^{pool} = \frac{C_{14} \cdot \beta \cdot \dot{m}_b \cdot HC_1 \cdot \pi \cdot R_{pf,n}^2}{2 \cdot \pi \cdot R_{pf,n} \cdot L_{pf,n} + \pi \cdot R_{pf,n}^2} \quad (3.138)$$

The amount of the radiated energy that actually reaches a target at some location away from the pool fire is a function of the atmospheric conditions as well as the radiation view factor between the pool and the target. The received thermal flux can be calculated as follows:

$$Ith_n^{pool} = \tau_{atm,n} \cdot Q_{rad,n}^{pool} \cdot F_{cyl,n} \quad (3.139)$$

The atmospheric transmissivity is an important factor since it determines how much of the thermal radiation is absorbed and scattered by the atmosphere. The atmospheric transmissivity can be approximated using the following formula recommended by Pietersen and Huerta [21]:

$$\tau_{atm,n} = C_{19} \cdot (P_w \cdot xs_n)^{-0.09} \quad (3.140)$$

The water partial pressure expressed as a function of ambient temperature and RH is given by Mudan and Croce [22] as follows:

$$P_w = C_{20} (RH) e^{\left[14.4114 - \left(\frac{C_{21}}{T_{atm}} \right) \right]} \quad (3.141)$$

The radiation view factor can be calculated modeling the flame as a vertical cylinder and accounting for flame tilt using the method provided by Mudan [23] as follows:

$$F_{cyl,n} = \sqrt{Fv_n^2 + Fh_n^2} \quad (3.142)$$

The vertical view factor can be calculated as follows:

$$F_{v_n} = \left(\left(\frac{X \cos \theta_{pf,n}}{Y - X \sin \theta_{pf,n}} \right) \cdot \left(\frac{X^2 + (Y+1)^2 - 2Y(1 + \sin \theta_{pf,n})}{\pi \sqrt{A'B'}} \right) \cdot \tan^{-1} \left[\frac{A'(Y-1)}{B'(Y+1)} \right] + \right. \\ \left. \left(\frac{\cos \theta_{pf,n}}{\pi \sqrt{C'}} \right) \cdot \left(\tan^{-1} \left[\frac{XY - (Y^2 - 1) \sin \theta_{pf,n}}{\sqrt{Y^2 - 1} \sqrt{C'}} \right] + \tan^{-1} \left[\frac{\sin \theta_{pf,n} \sqrt{Y^2 - 1}}{\sqrt{C'}} \right] \right) - \right. \\ \left. \left(\frac{X \cos \theta_{pf,n}}{\pi (Y - X \sin \theta_{pf,n})} \right) \cdot \tan^{-1} \left[\sqrt{\frac{Y-1}{Y+1}} \right] \right) \quad (3.143)$$

The horizontal view factor can be calculated as follows:

$$F_{h_n} = \left(\frac{1}{\pi} \tan^{-1} \left[\sqrt{\frac{Y+1}{Y-1}} \right] - \right. \\ \left(\frac{X^2 + (Y+1)^2 - 2(Y+1 + XY \sin \theta_{pf,n})}{\pi \sqrt{A'B'}} \right) \cdot \tan^{-1} \left[\sqrt{\frac{A'(Y-1)}{B'(Y+1)}} \right] + \\ \left. \left(\frac{\sin \theta_{pf,n}}{\pi \sqrt{C'}} \right) \cdot \left(\tan^{-1} \left[\frac{XY - (Y^2 - 1) \sin \theta_{pf,n}}{\sqrt{Y^2 - 1} \sqrt{C'}} \right] + \tan^{-1} \left[\frac{\sin \theta_{pf,n} \sqrt{Y^2 - 1}}{\sqrt{C'}} \right] \right) \right) \quad (3.144)$$

In Equation (3.143) and Equation (3.144), the following parameters are used.

$$X = \frac{L_{pf,n}}{R_{pf,n}} \quad (3.145)$$

$$Y = \frac{xs_n}{R_{pf,n}} \quad (3.146)$$

$$A' = X^2 + (Y+1)^2 - 2X(Y+1) \sin \theta_{pf,n} \quad (3.147)$$

$$B' = X^2 + (Y-1)^2 - 2X(Y-1) \sin \theta_{pf,n} \quad (3.148)$$

$$C' = 1 + (Y^2 - 1) \cos^2 \theta_{pf,n} \quad (3.149)$$

5.8.2.6 Pool Fire Safe Distance and Consequence Area

The procedure for determining the consequence area associated with a pool fire consists of calculating the distance away from the pool fire where the radiated energy from the pool fire is equal to the exposure limits (impact criteria) for thermal radiation as provided in [Section 4.8.2](#). A maximum permissible radiation of 4,000 Btu/hr-ft² (12.6 kW/m²) is used for serious personnel injury. The maximum permissible radiation for component damage is 12,000 Btu/hr-ft² (37.8 kW/m²).

NOTE The atmospheric transmissivity and the source view factor are functions of the distance from the flame source to the target. These are the two parameters that account for the fact that the received thermal radiation at any point away from the fire goes down as the distance increases. An iterative approach is required to determine the acceptable or safe distance away from the pool fire.

This procedure is carried out for personnel injury as well as component damage for each of the release hole sizes selected as described in [Section 4.2](#). Once the safe distances, $xs_{cmd,n}^{pool}$ and $xs_{inj,n}^{pool}$, are determined, [Equation \(3.150\)](#) and [Equation \(3.151\)](#) are used to calculate the pool fire consequence areas.

$$CA_{f,cmd,n}^{pool} = \pi \cdot \left(xs_{cmd,n}^{pool} + R_{pf,n} \right)^2 \quad (3.150)$$

$$CA_{f,inj,n}^{pool} = \pi \cdot \left(xs_{inj,n}^{pool} + R_{pf,n} \right)^2 \quad (3.151)$$

5.8.3 Jet Fires

5.8.3.1 General

Jet fires occur as a result of immediate ignition of a flammable fluid from a pressurized process vessel or pipe that develops a hole. Jet fires do not occur as a result of an immediate ignition from a loss of containment due to a rupture. See [Figure 5.4](#). Similar to pool fires, the main deleterious effect is the heat flux produced by the jet fire.

One method for calculating the consequences from a jet fire is provided in CCPS [17]. The method involves calculating the flame length of the jet fire and the radiative heat flux at distances away from the jet source. The distance at which the calculated thermal radiation from the jet fire equals the thermal radiation limit specified by the risk analyst [limit is 4,000 Btu/hr-ft² (12.6 kW/m²) for personnel and 12,000 Btu/hr-ft² (37.8 kW/m²) for equipment] provides the radius for the consequence area.

A conservative assumption is made that the jet fire arises vertically at a point located at grade since this will provide the largest effected area that exceeds the thermal radiation limit.

5.8.3.2 Jet Fire Radiated Energy

The amount of energy radiated by the jet (often referred to as surface emitted heat flux) is a fraction of the total combustion power of the flame. The fraction of the total combustion power that is radiated, β , is often quoted in the range of 0.15 to 0.35. A conservative value of 0.35 can be chosen. Therefore:

$$Q_{rad,n}^{jet} = C_{14} \cdot \beta \cdot W_n^{jet} \cdot HC_v \quad (3.152)$$

For mixtures, the heat of combustion can be evaluated using a mole weighted average of the individual component heats of combustion.

5.8.3.3 Jet Fire Safe Distance and Consequence Area

The amount of the radiated energy that actually reaches a target at some location away from the jet fire is a function of the atmospheric conditions as well as the radiation view factor between the source and the target. The received thermal flux can be calculated as follows:

$$Ith_n^{\text{jet}} = \tau_{\text{atm},n} \cdot Q_{\text{rad}}^{\text{jet}} \cdot Fp_n \quad (3.153)$$

If a point source model is used, then the radiation view factor between the source flame and the target can be approximated as follows:

$$Fp_n = \frac{1}{4\pi \cdot xs_n^2} \quad (3.154)$$

The point source view factor provides a reasonable estimate of received flux at distances far from the flame. More rigorous formulas that are based on specific flame shapes (e.g. cylinders; see [Equation \(3.142\)](#)) or that assume a solid plume radiation model may be used as alternatives to the simplified calculation shown above.

NOTE The atmospheric transmissivity and the point source view factor are functions of the distance from the flame source to the target. An iterative approach is required to determine the acceptable distance away from the jet fire and the resultant consequence area.

This procedure is carried out for personnel injury as well as component damage for each of the release hole sizes selected as described in [Section 4.2](#). Once the safe distances, $xs_{\text{cmd},n}^{\text{jet}}$ and $xs_{\text{inj},n}^{\text{jet}}$, are determined, [Equation \(3.155\)](#) and [Equation \(3.156\)](#) are used to calculate the jet fire consequence areas.

$$CA_{\text{f,cmd},n}^{\text{jet}} = \pi \cdot xs_{\text{cmd},n}^{\text{jet}^2} \quad (3.155)$$

$$CA_{\text{f,inj},n}^{\text{jet}} = \pi \cdot xs_{\text{inj},n}^{\text{jet}^2} \quad (3.156)$$

5.8.4 Fireballs

5.8.4.1 General

Fireballs result from the immediate ignition of a flammable, superheated liquid/vapor. Fireballs always occur in combination with a physical explosion or a BLEVE. The effects of fireballs need to be evaluated for instantaneous releases (or ruptures). Continuous releases do not result in fireballs.

CCPS [\[17\]](#) provides a suitable methodology for determining the effects of fireballs. Four factors have to be considered to determine the heat flux of a fireball: the mass of the flammable fluid, the fireball's diameter, duration, and thermal emissive power. The main parameter needed is the mass of flammable fluid in the stored equipment prior to rupture. The flammable mass for the fireball, $mass_{\text{fb}}$, is the fraction of the released mass that contains flammable material and can be determined using [Equation \(3.157\)](#).

$$mass_{\text{fb}} = m_{\text{frac}}^{\text{flam}} \cdot mass_{\text{avail},n} \quad (3.157)$$

The maximum mass available for release, $mass_{\text{avail},n}$, is defined in [Section 4.4.2](#) [see [Equation \(3.11\)](#)].

Once the flammable mass of the fireball is known, the diameter, duration, and height of the fireball can be readily calculated. The effects of thermal radiation on personnel and equipment can be determined in much the same way as has been previously done for jet fires and pool fires.

5.8.4.2 Fireball Size and Duration

The diameter of the fireball is a function of the flammable mass as follows:

$$D_{max_{fb}} = C_{22} \cdot mass_{fb}^{0.333} \quad (3.158)$$

The center height of the fireball is assumed to be:

$$H_{fb} = 0.75 \cdot D_{max_{fb}} \quad (3.159)$$

The duration of the fireball is also a function of the flammable mass as follows:

$$t_{fb} = C_{23} \cdot mass_{fb}^{0.333} \quad \text{for } mass_{fb} \leq 66,000 \text{ lb } [29,937 \text{ kg}] \quad (3.160)$$

$$t_{fb} = C_{24} \cdot mass_{fb}^{0.167} \quad \text{for } mass_{fb} > 66,000 \text{ lb } [29,937 \text{ kg}] \quad (3.161)$$

5.8.4.3 Fireball Radiated Energy

The amount of energy radiated by the fireball (often referred to as surface emitted heat flux) is a fraction of its total combustion power. The fraction of the total combustion power that is radiated, β_{fb} , is often quoted in the range of 0.25 to 0.4; see [Equation \(3.162\)](#).

$$Q_{rad}^{fball} = \frac{C_{14} \cdot \beta_{fb} \cdot mass_{fb} \cdot HC_l}{\pi \cdot D_{max_{fb}}^2 \cdot t_{fb}} \quad (3.162)$$

The fraction of combustion power that is radiated from a fireball can be calculated from a correlation by ^[24]:

$$\beta_{fb} = C_{25} \cdot P_B^{0.32} \quad (3.163)$$

The burst pressure used above for determining the radiation fraction depends on the consequence being calculated. If the calculation is for pressurized fixed equipment where the concern is for rupture during normal operation, the normal operating pressure is used. When the calculation is to be performed at elevated pressures such as the case when the COFs of PRDs are being evaluated, the likely overpressure that results from the failure to open upon demand should be used.

5.8.4.4 Fireball Safe Distance and Consequence Area

The amount of the radiated energy that actually reaches a target at some location away from the fireball is a function of the atmospheric conditions as well as the radiation view factor between the source and the target. The received thermal flux can be determined as before:

$$I_{th}^{fball} = \tau_{atm} \cdot Q_{rad}^{fball} \cdot F_{sph} \quad (3.164)$$

For a fireball, the spherical model for the geometric view factor is used:

$$F_{sph} = \frac{(D_{max_{fb}})^2}{4C_{fb}^2} \quad (3.165)$$

where

$$C_{fb} = \sqrt{\left(\frac{D_{max_{fb}}}{2.0}\right)^2 + \left(\frac{x_{s_{fball}}}{2.0}\right)^2} \quad (3.166)$$

NOTE The atmospheric transmissivity and the geometric view factor are functions of the distance from the flame source to the target, $x_{s_{fball}}$. An iterative approach is required to determine the acceptable distance away from the fireball.

This procedure is carried out for personnel injury as well as component damage for the rupture case. Once the safe distances, $x_{s_{cmd}}^{fball}$ and $x_{s_{inj}}^{fball}$, are determined, Equation (3.167) and Equation (3.168) are used to calculate the fireball consequence areas.

$$CA_{f,cmd}^{fball} = \pi \cdot (x_{s_{cmd}}^{fball})^2 \quad (3.167)$$

$$CA_{f,inj}^{fball} = \pi \cdot (x_{s_{inj}}^{fball})^2 \quad (3.168)$$

5.8.5 VCEs

5.8.5.1 General

When a sizable amount of flammable fluid is suddenly released into the air and is not immediately ignited, three things can happen: the cloud can encounter an ignition source and explode, producing a VCE; the cloud can encounter an ignition source and flash back, producing a flash fire (Section 5.8.6); or the cloud can safely disperse. For a VCE or flash fire to occur, the released material must form a partially mixed vapor cloud that contains vapor concentrations above the LFL. The cloud then encounters an ignition source and either explodes or flashes back. Since VCEs produce devastating effects on plants if they occur, significant research on their causes has been performed. From research on VCEs that have occurred, Lees [25] has identified several parameters that affect VCE behavior:

- a) quantity of material released,
- b) fraction of material vaporized,
- c) probability of ignition of the cloud,
- d) distance traveled by the cloud,
- e) time delay before ignition of the cloud,
- f) probability of explosion rather than fire,
- g) existence of a threshold quantity of material,
- h) efficiency of the explosion,

- i) location of ignition source with respect to the release.

VCEs can occur as a result of a delayed ignition of a vapor cloud. The source of the vapor cloud could either be from a vapor or two-phase jet release or evaporation off the surface of an un-ignited liquid flammable pool. Dispersion modeling of the cloud is required to evaluate the extent of a vapor cloud, since the amount of flammable material in the cloud is needed. (See the general discussion on cloud modeling presented in [Section 5.7.4](#).) A VCE is a deflagration (not detonation) that produces significant overpressure (blast wave) and occurs when the flame propagation through the cloud travels at extremely high velocities. If the flame propagates at a relatively slow velocity, a VCE, with the resulting overpressure, does not occur. In this case, a relatively low consequence, low energy, flash fire is the outcome (see [Section 5.8.6](#)).

5.8.5.2 Source of Vapor

The source of flammable vapor for the VCE could either be from a jet release or from an evaporating liquid pool release. For the jet release case, the source rate is simply the jet release rate as discussed in [Section 5.7.3](#).

For an evaporating pool, the vapor rate used as the source for the VCE is dependent on whether the pool is a boiling or non-boiling, as discussed in [Section 5.7.4](#) and shown in [Figure 5.1](#).

5.8.5.3 Amount of Flammable Material

The first step in evaluating the effects of a VCE is to determine the amount of flammable material that is in the source cloud. The mass is a function of the release rate, the atmospheric dispersion of the cloud, and the time of ignition. A suitable cloud dispersion model that can handle plumes (continuous release with steady state analysis) as well as puffs (instantaneous releases that required a transient model) should be used to evaluate the amount of flammable material that exists in the cloud at the time of ignition.

5.8.5.4 Explosion Yield Factor

An important parameter in the evaluation of the vapor cloud is the explosion yield factor, η . This is an empirical value that determines how much of the combustion power in the cloud is released into the pressure wave. Where the flammable mass in the cloud is calculated as the portion of the cloud between the LFL and the UFL of the flammable material, a conservative value for the explosion yield factor of 1.0 should be used.

Where the flammable mass is based on the total amount of flammable fluid released, then a yield factor, η , with a range of between $0.03 \leq \eta \leq 0.19$ is typically used, and this is a function of the material released. For example, typical hydrocarbons have a yield factor of 0.03, while highly reactive fluids, such as ethylene oxide, have yield factors up around 0.19. Additional yield factors are provided by Zebetakis [\[26\]](#).

5.8.5.5 Determination of Blast Overpressure

- a) General—There are several approaches to estimating the overpressure that results from a VCE. The first method is the TNT equivalency method, explained in Reference [\[27\]](#) and detailed in [Section 5.8.5.5 b\)](#). In this method, the source of the explosion is assumed to be at a point (point source model) and the characteristics of the explosion are similar to that of a TNT explosion. This approach will likely result in conservative estimates of the damage at locations closest to the source of the explosion. The TNT model has been adopted for its ease of use, ability to be consistently applied, and effectiveness in conservatively modeling the damage potential of VCEs.

Another model that will not be presented here is more complicated and highly dependent on user experience and knowledge but can provide more accurate (less conservative) results in the near field of the explosion. This method is known as the TNO multi-energy method (MEM), and it focuses on the characteristics of the site, rather than on the size of the release. This method recognizes that portions of the vapor cloud that are obstructed or partially confined could undergo blast-generating combustion. The key site characteristics that must be identified and classified by the user are equipment congestion and

flame confinement. Due to lack of reliable guidance in the current research on congestion and confinement, it is very challenging for the user to consistently apply this approach and, therefore, is not recommended for RBI purposes where consistency is key.

Yet another model is the Baker-Strehlow-Tang Energy Model [27], which essentially uses the same TNO multi-energy methodology, but along with congestion and flame confinement, it includes fuel mixture reactivity as a key parameter. As with the TNO MEM, the Baker-Strehlow-Tang approach requires user judgment to classify the site's congestion and flame confinement, which inherently leads to inconsistent applications. It is, therefore, not a recommended approach.

- b) TNT Equivalency Method—The TNT equivalency method, presented in CCPS [17], determines the amount of available energy in the cloud and relates this to an equivalent amount of TNT using Equation (3.169).

$$W_{\text{TNT}} = \frac{\eta \cdot \text{mass}_{\text{vce}} \cdot HC_{\text{s}}}{HC_{\text{TNT}}} \quad (3.169)$$

For mixtures, a mole weighting of the individual component heats of combustions can be used to estimate the heat of combustion for the mixture in the cloud. The heat of combustion of TNT, HC_{TNT} , is approximately 2000 Btu/lb (4648 J/kg).

- c) Use of Blast Curves—To determine the blast effect, the side-on blast wave overpressure can be calculated using blast curves. An acceptable curve for estimating the overpressure is the Hopkinson-scaled curve that is reproduced by CCPS [17]. Equation (3.170) is a curve fit of the Hopkinson-scaled data that provide a closed form solution for determining the side-on overpressure (units are bar):

$$P_{\text{SO},n} = C_{26} \cdot \left(\begin{aligned} & -0.059965896 + \frac{1.1288697}{\ln[\bar{R}_{\text{HS},n}]} - \frac{7.9625216}{(\ln[\bar{R}_{\text{HS},n}])^2} + \\ & \frac{25.106738}{(\ln[\bar{R}_{\text{HS},n}])^3} - \frac{30.396707}{(\ln[\bar{R}_{\text{HS},n}])^4} + \frac{19.399862}{(\ln[\bar{R}_{\text{HS},n}])^5} - \\ & \frac{6.8853477}{(\ln[\bar{R}_{\text{HS},n}])^6} + \frac{1.2825511}{(\ln[\bar{R}_{\text{HS},n}])^7} - \frac{0.097705789}{(\ln[\bar{R}_{\text{HS},n}])^8} \end{aligned} \right) \quad (3.170)$$

For use in Equation (3.171), the Hopkinson-scaled distance, $\bar{R}_{\text{HS},n}$, presented above requires units of $\text{m/kg}^{1/3}$ and is calculated from the actual distance from the blast center as follows:

$$\bar{R}_{\text{HS},n} = C_{27} \cdot \frac{x_{\text{s}}^{\text{vce}}}{W_{\text{TNT}}^{1/3}} \quad (3.171)$$

5.8.5.6 VCE Safe Distance and Consequence Area

The consequence areas for serious injury to personnel and component damage can be determined once the overpressure as a function of distance from the blast is known. For serious injuries to personnel, the consequence area can be based on the following probit equation provided by Eisenberg [28].

$$Pr = -23.8 + 2.92 \cdot \ln[C_{28} \cdot P_{\text{SO},n}] \quad (3.172)$$

This probit equation provides the probability of process building collapse due to structural damage as a result of overpressure. Data show that personnel can withstand much higher overpressures (15 to 30 psi

overpressure for lung hemorrhage) when out in the open and that typical serious injury occurs as a result of the collapse of buildings.

For component damage, an overpressure of 34.5 kPa (5.0 psi) has proven to be a good value to use when evaluating the consequence area to equipment as a result of overpressures from explosions.

NOTE The side-on overpressure is a function of the distance from the blast source to the target. An iterative approach is required to determine the acceptable distance away from the explosion.

This procedure is carried out for personnel injury as well as component damage for each of the release hole sizes selected as described in [Section 4.2](#). Once the safe distances, $xs_{cmd,n}^{vce}$ and $xs_{inj,n}^{vce}$, are determined, [Equation \(3.173\)](#) and [Equation \(3.174\)](#) are used to calculate the VCE consequence areas.

$$CA_{f,cmd,n}^{vce} = \pi \cdot \left(xs_{cmd,n}^{vce} \right)^2 \quad (3.173)$$

$$CA_{f,inj,n}^{vce} = \pi \cdot \left(xs_{inj,n}^{vce} \right)^2 \quad (3.174)$$

5.8.6 Flash Fires

5.8.6.1 General

Flash fires, like VCEs, can occur as a result of a delayed ignition of a vapor cloud. The source of the vapor cloud could either be from a vapor or two-phase jet release or evaporation off the surface of an un-ignited liquid flammable pool. Dispersion modeling of the cloud is required to evaluate the extent of a vapor cloud since the amount of flammable material and the area covered by the flammable portion in the cloud is needed. See the general discussion on cloud modeling presented in [Annex 3.A](#).

5.8.6.2 Flash Fire Consequence Area

A flash fire is a deflagration (not detonation); however, unlike VCEs, the flame speed is relatively slow and overpressures (blast waves) do not occur. Flash fires are much more common than VCEs and last for no more than a few tenths of a second. Unlike pool or jet fires (immediate ignition), flash fires need not consider radiation effects away from the fire boundary, since the combustion process is of short duration and relatively low intensity. The consequence area for personnel from a flash fire, $CA_{inj,n}^{flash}$, is merely the flammable cloud boundary and no further.

As with VCEs, a suitable cloud dispersion model that can handle plumes (continuous release with steady state analysis) as well as puffs (instantaneous releases that required a transient model) should be used. The cloud dispersion model is used to determine the boundary area of the vapor cloud that contains flammable material that is at or above the LFL of the mixture in the cloud. The resultant boundary area will equal the consequence area for serious injury to personnel. As a general rule of the thumb, the consequence area associated with damage to an equipment component from flash fires, $CA_{cmd,n}^{flash}$, is limited to 25 % of the area for serious injury to personnel.

$$CA_{f,cmd,n}^{flash} = 0.25 \cdot CA_{inj,n}^{flash} \quad (3.175)$$

5.8.7 Determination of Flammable Consequence for Each Release Case (Hole Size)

For each hole size or release case selected, the flammable consequence area is calculated as a probability weighted consequence area of all of the potential event outcomes on the event tree as shown in Equation (3.176) and Equation (3.177). For component damage, use Equation (3.176); for personnel injury, use Equation (3.177).

$$CA_{f,cmd,n}^{flam} = \left(ppool_n \cdot CA_{f,cmd,n}^{pool} + pjet_n \cdot CA_{f,cmd,n}^{jet} + pfball_n \cdot CA_{f,cmd,n}^{fball} + pvce_n \cdot CA_{f,cmd,n}^{vce} + pflash_n \cdot CA_{f,cmd,n}^{flash} \right) \quad (3.176)$$

$$CA_{f,inj,n}^{flam} = \left(ppool_n \cdot CA_{f,inj,n}^{pool} + pjet_n \cdot CA_{f,inj,n}^{jet} + pfball_n \cdot CA_{f,inj,n}^{fball} + pvce_n \cdot CA_{f,inj,n}^{vce} + pflash_n \cdot CA_{f,inj,n}^{flash} \right) \quad (3.177)$$

5.8.8 Determination of Final Flammable Consequence Areas

The final flammable consequence areas are determined as a probability weighted average of the individual flammable consequence areas calculated for each release hole size. This is performed for both the component damage and the personnel injury consequence areas. The probability weighting utilizes the generic frequencies of the release hole sizes selected per Section 4.2.

The equation for probability weighting of the component damage consequence areas is given by Equation (3.178).

$$CA_{f,cmd}^{flam} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{f,cmd,n}^{flam}}{gff_{total}} \right) \quad (3.178)$$

The equation for probability weighting of the personnel injury consequence areas is given by Equation (3.179).

$$CA_{f,inj}^{flam} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{f,inj,n}^{flam}}{gff_{total}} \right) \quad (3.179)$$

In Equation (3.178) and Equation (3.179), the total GFF is as calculated in Step 2.2.

5.8.9 Calculation of Flammable Consequence Areas

- a) Step 8.1—Determine the mass fraction of the release rate that contains a flammable component, $mfrac^{flam}$. This can be determined by adding the mass fractions of all flammable components in the mixture.
- b) Step 8.2—For each hole size, calculate the flammable release rate, $rate_n^{flam}$, using Equation (3.106). Also calculate the liquid portion, $rate_{l,n}^{flam}$, and the vapor portion, $rate_{v,n}^{flam}$, of the flammable release rate using Equation (3.107) and/or Equation (3.108), as applicable.

NOTE 1 For two-phase releases both values should be calculated.

c) Step 8.3—For each hole size, select the appropriate event tree using [Figure 5.2](#) and [Figure 5.3](#) and the phase of the fluid after flashing to atmosphere in Step 1.3. For the leak cases (small, medium, and large hole sizes), use [Figure 5.2](#). For the rupture case, use [Figure 5.3](#).

d) Step 8.4—For each hole size, including the rupture case, calculate the probability of ignition of the release.

- 1) Determine the probability of ignition at ambient temperature for the liquid portion of the release, $poi_{l,n}^{amb}$, using [Equation \(3.109\)](#) and the value of $rate_{l,n}^{flam}$ obtained in Step 8.2.

NOTE 2 For the rupture case or some of the larger hole sizes, a maximum value of 55.6 lb/s (25.2 kg/s) should be used.

- 2) Determine the probability of ignition at ambient temperature for the vapor portion of the release, $poi_{v,n}^{amb}$ using [Equation \(3.110\)](#) and the value of $rate_{v,n}^{flam}$ obtained in Step 8.2.

NOTE 3 For the rupture case and some of the larger hole sizes, a maximum value of 55.6 lb/s (25.2 kg/s) should be used.

- 3) Determine the maximum probability of ignition for the liquid, poi_l^{ait} , and the vapor, poi_v^{ait} , at the AIT using [Equation \(3.111\)](#) and [Equation \(3.112\)](#).

- 4) Calculate the probability of ignition for the liquid, $poi_{l,n}$, and the vapor, $poi_{v,n}$, at normal storage temperatures using [Equation \(3.113\)](#) and [Equation \(3.114\)](#), respectively.

- 5) For two-phase releases, calculate the probability of ignition, $poi_{2,n}$, at normal storage temperatures using [Equation \(3.115\)](#).

e) Step 8.5—For each hole size, determine the probability of immediate ignition given ignition.

- 1) Obtain the probabilities of immediate ignition at ambient conditions for the liquid portion and the vapor portions of the release, $poi_{l,n}^{amb}$ and $poi_{v,n}^{amb}$, from [Table 5.3](#), based on whether the release is an instantaneous or continuous liquid or vapor release.

- 2) Calculate the probability of immediate ignition given ignition at storage conditions for the liquid portion of the release, $poi_{l,n}$, and the vapor portion of the release, $poi_{v,n}$, using [Equation \(3.128\)](#) and [Equation \(3.129\)](#). Use a value for the probability of immediate ignition at the AIT, $poi^{ait}=1.0$.

- 3) For two-phase releases, calculate the probability of immediate ignition given ignition, $poi_{2,n}$, at normal storage temperatures using [Equation \(3.118\)](#) and the flash fraction, $frac_{fsh}$, calculated in Step 1.3.

f) Step 8.6—Determine the probability of VCE given a delayed ignition.

- 1) Determine the probability of VCE given delayed ignition, $pvcedi$, from [Table 5.3](#) as a function of the release type and phase of release. The probability of a VCE given delayed ignition for a liquid release is $pvcedi_{l,n}$; for a vapor it is $pvcedi_{v,n}$.

- 2) For two-phase releases, calculate the probability of VCE, given delayed ignition, $pvcedi_{2,n}$, using [Equation \(3.119\)](#) and the flash fraction, $frac_{fsh}$, calculated in Step 1.3.

- g) Step 8.7—Determine the probability of flash fire given delayed ignition.
- 1) Determine the probability of flash fire given delayed ignition, $pffdi$, from [Table 5.3](#) as a function of the release type and phase of release. Alternatively, [Equation \(3.120\)](#) and [Equation \(3.121\)](#) can be used to obtain these values.
 - 2) For two-phase releases, calculate the probability of flash fire given delayed ignition, $pffdi_{2,n}$, using [Equation \(3.122\)](#) and the flash fraction, $frac_{fsh}$, calculated in Step 1.3.
- h) Step 8.8—Determine the probability of a fireball given an immediate release, $pfbi$, using [Equation \(3.123\)](#) or [Equation \(3.124\)](#).
- i) Step 8.9—Select the appropriate event tree. For small, medium, and large hole sizes, select the event tree from [Figure 5.3](#) based on whether the release is a liquid, vapor, or two-phase release. For the rupture case, select the event tree from [Figure 5.4](#) based on whether the release is a liquid, vapor, or two-phase release.
- j) Step 8.10—For each hole size, determine the probability of each of the possible event outcomes on the event tree selected in Step 8.9. As an example, the probability of each of the event outcomes for leakage of a vapor from a small, medium, or large hole size is shown below. All other event tree outcomes can be calculated in a similar manner.

- 1) Probability of a pool fire given a release:

$$ppool_{v,n} = 0.0 \quad (3.180)$$

- 2) Probability of a jet fire given a release (continuous releases only):

$$pjet_{v,n} = poi_{v,n} \cdot poii_{v,n} \quad (3.181)$$

- 3) Probability of a VCE given a release:

$$pvce_{v,n} = poi_{v,n} \cdot (1 - poii_{v,n}) \cdot (1 - pvcedi_{v,n}) \quad (3.182)$$

- 4) Probability of a flash fire given a release (instantaneous releases only):

$$pflash_{v,n} = poi_{v,n} \cdot poii_{v,n} \quad (3.183)$$

- 5) Probability of a fireball:

$$pfbal_{v,n} = 0.0 \quad (3.184)$$

- 6) Probability of safe dispersion given a release:

$$psafe_{v,n} = 1 - poi_{v,n} \quad (3.185)$$

- k) Step 8.11—For each hole size, calculate the component damage consequence area of a pool fire, $CA_{f,cmd,n}^{pool}$, and the personnel injury consequence area, $CA_{f,inj,n}^{pool}$, of a pool fire.

- 1) Determine the pool type, i.e. non-boiling or boiling per the procedure described in [Section 5.8.2.2](#).
- 2) Calculate the burning rate off the pool surface, $\dot{m}_b$, using [Equation \(3.128\)](#), [\(3.129\)](#), or [\(3.130\)](#), based on whether the pool is a non-boiling or a boiling pool.

- 3) Calculate the burning pool fire size, $Aburn_{pf,n}$, using Equation (3.131). Use the pool release rate, W_n^{pool} , established in Step 7.4.
- 4) Determine the pool fire size to be used in the consequence analysis, $A_{pf,n}$, using Equation (3.133).

NOTE 4 The pool size will in general be equal to the burning pool fire size, $Aburn_{pf,n}$, calculated using Equation (3.143) but cannot exceed the maximum value calculated using Equation (3.132).

- 5) Calculate the radius of the pool fire, $R_{pf,n}$, using Equation (3.134) and the length of the pool fire, $L_{pf,n}$, using Equation (3.135). Also, calculate the pool flame tilt, $\theta_{pf,n}$, using Equation (3.137).
- 6) Calculate the amount of heat radiated from the pool fire, $Q_{rad,n}^{pool}$, using Equation (3.138).
- 7) A radiation limit of 12,000 Btu/hr-ft² (37.8 kW/m²) is used for component damage consequence area. For personnel injury, 4,000 Btu/hr-ft² (12.6 kW/m²) is used. These radiation limits are used to determine the safe distances, $xs_{cmd,n}^{pool}$ and $xs_{inj,n}^{pool}$, from the pool fire using the following four-step iterative procedure.
 - i) Guess at an acceptable distance from the pool fire, xs_n^{pool} .
 - ii) Calculate the atmospheric transmissivity, $\tau_{atm,n}$, and the view factor, $F_{cyl,n}$, using Equation (3.140) and Equation (3.142). Both of these parameters are functions of the distance from the pool fire chosen above, xs_n^{pool} .
 - iii) Calculate the received thermal heat flux, $I_{th,n}^{pool}$, at the distance chosen using Equation (3.139) and compare it to the acceptable radiation limit 12,000 Btu/hr-ft² (37.8 kW/m²) for component damage and 4,000 Btu/hr-ft² (12.6 kW/m²) for personnel injury.
 - iv) Adjust the distance, xs_n^{pool} , accordingly, and repeat the above steps until the calculated received thermal heat flux equals the allowable limit.
- 8) Calculate the component damage consequence area, $CA_{f,cmd,n}^{pool}$, and the personnel injury consequence area, $CA_{f,inj,n}^{pool}$, using Equation (3.150) and Equation (3.151).

- I) Step 8.12—For each hole size, calculate the component damage consequence area of a jet fire, $CA_{l,cmd,n}^{jet}$, and the personnel injury consequence area, $CA_{l,inj,n}^{jet}$, of a jet fire.

- 1) Calculate the amount of heat radiated from the jet fire, $Q_{rad,n}^{jet}$, using Equation (3.164). Use the jet release rate, W_n^{jet} , established in Step 7.5.
- 2) A radiation limit of 12,000 Btu/hr-ft² (37.8 kW/m²) is used for component damage consequence area. For personnel injury, 4,000 Btu/hr-ft² (12.6 kW/m²) is used. These radiation limits are used to determine the safe distances, $xs_{cmd,n}^{jet}$ and $xs_{inj,n}^{jet}$, from the jet fire using the following four-step iterative procedure.
 - i) Guess at an acceptable distance from the jet fire, xs_n^{jet} .

- ii) Calculate the atmospheric transmissivity $\tau_{atm,n}$, and the view factor, $F_{p,n}$, using Equation (3.140) and Equation (3.154). Both of these parameters are functions of the distance from the jet fire chosen above, xs_n^{jet} .
 - iii) Calculate the received thermal heat flux, Ith_n^{jet} , at the distance chosen using Equation (3.153) and compare it to the acceptable radiation limit 12,000 Btu/hr-ft² (37.8 kW/m²) for component damage and 4,000 Btu/hr-ft² (12.6 kW/m²) for personnel injury].
 - iv) Adjust the distance, xs_n^{jet} , accordingly, and repeat the above steps until the calculated received thermal heat flux equals the allowable limit.
- 3) Calculate the component damage consequence area, $CA_{f,cmd,n}^{jet}$, and the personnel injury consequence area, $CA_{f,inj,n}^{jet}$, using Equation (3.155) and Equation (3.156).
- m) Step 8.13—For the rupture case, calculate the component damage consequence area, $CA_{f,cmd,n}^{fball}$, and the personnel injury consequence area, $CA_{f,inj,n}^{fball}$, of a fireball.
- 1) Determine the flammable mass of the fluid contained in the equipment using Equation (3.157), the mass fraction of flammable material, $mfrac^{flam}$, obtained in Step 8.1, and the inventory mass available for release, $mass_{avail,n}$, determined in Step 4.7.
 - 2) Calculate the maximum diameter, D_{maxfb} , and the center height, H_{fb} , of the fireball using Equation (3.158) and Equation (3.159), respectively.
 - 3) Calculate the duration of the fireball, t_{fb} , using Equation (3.160) or (3.161) based on the mass of the fireball.
 - 4) Calculate the amount of energy radiated by the fireball, Q_{rad}^{fball} , using Equation (3.162).
 - 5) For the component damage consequence area, API 581 uses a radiation limit of 12,000 Btu/hr-ft² (37.8 kW/m²). For personnel injury, 4,000 Btu/hr-ft² (12.6 kW/m²) is used. These radiation limits are used to determine the safe distances, xs_{cmd}^{fball} and xs_{inj}^{fball} , from the fireball using the following four-step iterative procedure.
 - i) Guess at an acceptable distance from the fireball, xs_{inj}^{fball} .
 - ii) Calculate the atmospheric transmissivity, τ_{atm} , and the spherical view factor, F_{sph} , using Equation (3.140) and Equation (3.165). Both of these parameters are functions of the distance from the fireball chosen above, xs_{inj}^{fball} .
 - iii) Calculate the received thermal heat flux, Ith^{fball} , at the distance chosen using Equation (3.164) and compare it to the acceptable radiation limit 12,000 Btu/hr-ft² (37.8 kW/m²) for component damage and 4,000 Btu/hr-ft² (12.6 kW/m²) for personnel injury].
 - iv) Adjust the distance, xs^{fball} , accordingly, and repeat the above steps until the calculated received thermal heat flux equals the allowable limit.

- 6) Calculate the component damage consequence area, $CA_{f,cmd}^{fball}$, and the personnel injury consequence area, $CA_{f,inj}^{fball}$, using Equation (3.167) and Equation (3.168).
- n) Step 8.14—For each of the hole sizes, calculate the component damage consequence area, $CA_{f,cmd,n}^{vce}$, and the personnel injury consequence area, $CA_{f,inj,n}^{vce}$, of a VCE.

Using the vapor source rate and source area determined in Step 7.7, perform a cloud dispersion analysis in accordance with Section 5.7.4 and determine the mass of flammable material, $mass_{vce}$, in the vapor cloud. This is the portion of the cloud that has concentrations between the LFL and the UFL of the fluid being released. The LFL and UFL were obtained in Step 1.2.

- 1) Determine the amount of potential energy in the vapor cloud expressed as an equivalent amount of TNT, W_{TNT} , using Equation (3.181).

NOTE 5 The energy yield factor, η , is equal to 1.0 when the mass used in this step is based on the flammable mass of the cloud between the LFL and the UFL.

- 2) For the component damage consequence area, an overpressure limit of 5.0 psi (34.5 kPa). This overpressure limit is used to determine the safe distance, $xs_{cmd,n}^{vce}$, from the VCE using the following four-step iterative procedure.
- Guess at an acceptable component damage distance from the VCE, $xs_{cmd,n}^{vce}$.
 - Calculate the Hopkinson-scaled distance, $\bar{R}_{HS,n}$, using Equation (3.171). This parameter is a function of the distance from the VCE chosen above, $xs_{cmd,n}^{vce}$.
 - Calculate the side-on overpressure, $P_{SO,n}$, at the Hopkinson-scaled distance, $\bar{R}_{HS,n}$, using Equation (3.170).
 - Adjust the distance, $xs_{cmd,n}^{vce}$, accordingly, and repeat the above steps until the side-on overpressure, $P_{SO,n}$, is equal to 34.5 kPa (5.0 psi).
- 3) Calculate the component damage consequence area, $CA_{f,cmd,n}^{vce}$, using Equation (3.173).
- 4) A probit equation based on building collapse is used for personnel injury consequence area and is detailed in Section 5.8.5.5. This probit equation is used to determine the safe distance, $xs_{inj,n}^{vce}$, from the VCE using the following five-step iterative procedure.
- Guess at an acceptable personnel injury distance from the VCE, $xs_{inj,n}^{vce}$.
 - Calculate the Hopkinson-scaled distance, $\bar{R}_{HS,n}$, using Equation (3.171). This parameter is a function of the distance from the VCE chosen above, $xs_{inj,n}^{vce}$.
 - Calculate the side-on overpressure, $P_{SO,n}$, at the Hopkinson-scaled distance, $\bar{R}_{HS,n}$, using Equation (3.170).
 - Calculate the probit value, Pr , using Equation (3.172).

- v) Adjust the distance, $xs_{cmd,n}^{vce}$, accordingly, and repeat the above steps until the probit value is equal to 5.0.
- 5) Calculate the personal injury consequence area, $CA_{f,inj,n}^{vce}$, using Equation (3.174).
- o) Step 8.15—For each of the hole sizes, calculate the component damage consequence area, $CA_{f,cmd,n}^{flash}$, and the personnel injury consequence area, $CA_{f,inj,n}^{flash}$, of a flash fire.
 - 1) Using the vapor source rate and source area determined in Step 7.7, perform a cloud dispersion analysis in accordance with Section 5.7.4 and determine the grade level area or boundary of the cloud that is at or above the LFL of the mixture in the cloud. This grade level area is equal to the personnel injury consequence area, $CA_{f,inj,n}^{flash}$.
 - 2) The component damage consequence area for the flash fire, $CA_{f,cmd,n}^{flash}$, is 25 % of personnel injury consequence area $CA_{f,inj,n}^{flash}$, in accordance with Equation (3.175).
- p) Step 8.16—For each hole size, determine the component damage and personnel injury flammable consequence areas, $CA_{f,cmd,n}^{flam}$ and $CA_{f,inj,n}^{flam}$, using Equation (3.176) and Equation (3.177), respectively. Use the probability of each event outcome, as determined in Step 8.10, and the consequence area of each of the event outcomes, as determined in Steps 8.11 through 8.15.
- q) Step 8.17—Determine the final consequence areas (probability weighted on release hole size) for component damage, $CA_{f,cmd}^{flam}$, and personnel injury, $CA_{f,inj}^{flam}$, using Equation (3.178) and Equation (3.179), respectively.

5.9 Determine Toxic Consequences

5.9.1 General

To evaluate fluids in addition to the 14 provided in Level 1, as well as use of other published toxic criteria (IDLH, ERPG, AEGL), a Level 2 consequence analysis is required.

Toxic consequence procedure consists of performing a cloud dispersion analysis (see Section 5.7.4) to determine the extent and duration of the portions of the cloud that remain above the toxic impact criteria acceptable for the particular toxin being evaluated. The vapor source rate to be used as input to a cloud dispersion analysis either from a jet release or from evaporation off of a liquid pool is discussed in Section 5.7.4.

5.9.2 Toxic Impact Criteria

5.9.2.1 General

Table 4.14 provides toxic impact criteria for specific toxic fluids modeled in this methodology. Consequence areas are determined for toxic releases by comparing the cloud concentration to various published toxic impact criteria. In addition to probit equations, published criteria available for a fluid under consideration can be used. When multiple published criteria are available, the consequence area should be based on the following prioritization:

- a) probit analysis or LC_{50} ;

- b) ERPG-3, AEGL-3, or TEEL-3;
- c) IDLH or EPA Toxic Endpoint.

This order was established to best represent the 50 % fatality rule used for determining the consequence area. Group a) represents the consequence of 50 % fatality, Group b) represents the lower fatality limit, or 0 % fatality, and Group c) represents the limit in which nonfatal long-term health issues will arise.

5.9.2.2 Probit Analysis

Probit equations [\[29\]](#) provide a simple way of expressing probability of fatality due to exposure of personnel to concentrations and dosages of toxic releases. Coefficients for probit equations are provided for common toxic in [Table 4.14](#). The probit equation and some background into its use are provided in [Annex 3.A](#).

5.9.2.3 IDLH

The IDLH air concentration values used by the National Institute for Occupational Safety and Health (NIOSH) as respirator selection criteria were first developed in the mid-1970s. The documentation for IDLH concentrations is a compilation of the rationale and sources of information used by NIOSH during the original determination of 387 IDLHs and their subsequent review and revision in 1994.

The IDLH is a 30-minute exposure limit. The cloud dispersion model should determine areas in the cloud that have time-weighted average concentrations exceeding the IDLH for a period of 30 minutes or longer.

5.9.2.4 Emergency Response Planning Guidelines—ERPG-3

ERPGs have been developed for toxic chemicals by the American Industrial Hygiene Association (AIHA), for three levels of increasing danger to exposed personnel. The ERPG-3 criteria is used and represents the maximum concentration (ppm) below which it is believed nearly all individuals could be exposed for up to 1 hour without experiencing or developing life-threatening effects.

The cloud dispersion model should determine areas in the cloud that have time-weighted average concentrations exceeding the ERPG-3 limit for a period of 1 hour or longer.

5.9.2.5 Acute Exposure Guideline Limit 3—AEGL-3

AEGLs represent ceiling exposure values for the general public and are published for emergency periods of 10 minutes, 30 minutes, 1 hour, 4 hours, and 8 hours. The concentration in the toxic cloud is checked against exposure durations of 10 minutes, 30 minutes, and 1 hour, since it is assumed that the release will be detected and mitigated within that time frame.

AEGLs are published for three levels of exposure—AEGL-1, AEGL-2, and AEGL-3—each one representing increasing levels of danger to the exposed personnel. The most life-threatening level, AEGL-3, is used when comparing it against the concentrations as calculated by the cloud dispersion model. The AEGL-3 limit is the airborne concentration (ppm) of a substance at or above which it is predicted that the general population, including susceptible but excluding hypersusceptible individuals, could experience life-threatening effects or even death. Airborne concentrations below AEGL-3, but at or above AEGL-2, represent exposure levels that may cause irreversible or other serious, long-lasting effects or impaired ability to escape.

5.9.2.6 Lethal Concentration—LC₅₀

The median lethal concentration of a toxic substance is the atmospheric concentration (typically in ppm) causing one half of a tested population to die. These tests are often done on rats or mice. Although these values cannot be directly extrapolated from one species to another, they are generally used as an indicator of a substance's acute toxicity. The exposure time is indicated with the test and can vary between 10 minutes and 8 hours. The formula to determine an LC₅₀ is found in 49 *CFR* 173.133(b)(1)(i).

5.9.2.7 Temporary Emergency Exposure Limit 3—TEEL-3

Temporary emergency exposure limits (TEELs) were developed for the purpose of conducting consequence assessments for chemicals for which no AEGL or ERPG values existed. They have been developed by the U.S. Department of Energy Subcommittee on Consequence Assessment and Protective Actions, with four levels of increasing danger to exposed personnel. Consequence analysis uses the TEEL-3, which is the maximum concentration in air below which nearly all individuals could be exposed for a 15 minutes without experiencing or developing life-threatening health effects. The TEEL value is meant to be a temporary value that will be replaced by an ERPG or AEGL.

The cloud dispersion model should determine areas in the cloud that have time-weighted average concentrations exceeding the TEEL-3 limit for a period of 15 minutes or longer.

5.9.3 Release Duration

The potential toxic consequence is estimated using both the release duration and release rate (see [Section 4.9.10](#) for a discussion of determination of the duration). In general, the toxic leak duration, ld_n^{tox} , should be calculated per [Equation \(3.186\)](#) for each release hole size as the minimum of:

- a) 1 hour,
- b) inventory mass (mass available) divided by release rate (see [Section 4.7](#)),
- c) maximum leak duration, $ld_{\text{max},n}$, listed in [Table 4.7](#).

$$ld_n^{\text{tox}} = \min \left[3600, \left\{ \frac{\text{mass}_n}{W_n} \right\}, \{ 60 \cdot ld_{\text{max},n} \} \right] \quad (3.186)$$

5.9.4 Toxic Event Probabilities

In the event the release can involve both toxic and flammable outcomes, it is assumed that either the flammable outcome consumes the toxic material or the toxic materials are dispersed and flammable materials have insignificant consequences. In this case, the probability for the toxic event is the remaining non-ignition frequency for the event (i.e. the probability of safe dispersion).

$$ptox_n = psafe_n \quad (3.187)$$

5.9.5 Consequences of Releases Containing Multiple Toxic Chemicals

Consequence results for releases of multicomponent toxic chemicals are uncommon but can be handled. In this instance, the consequence areas are determined for each of the individual toxic components within the mixture. The overall toxic consequence area is the largest of the individual toxic areas.

5.9.6 Toxic Consequence Area

The results of a cloud dispersion analysis will provide a ground level area or boundary where the concentration of the toxic material exceeds the toxic criteria for the duration of interest, CA_n^{cloud} . The cloud dispersion analysis will be performed for each of the release hole sizes with the resulting area when multiplied by the toxic probability, $ptox_n$, is equal to the personnel injury toxic consequence area, $CA_{\text{inj},n}^{\text{tox}}$.

$$CA_{\text{f},\text{inj},n}^{\text{tox}} = ptox_n \cdot CA_{\text{f},n}^{\text{cloud}} \quad (3.188)$$

This area will be calculated for each toxic component that is part of the release stream (see [Section 5.9.5](#)) and for each toxic limit that is available for the toxic component being modeled.

The component damage toxic consequence area, $CA_{cmd,n}^{tox}$, is equal to 0.0.

Most cloud simulators treat the released fluid mixture as a homogeneous mixture, and the release rate used in the analysis is equal to the full rate of the release, not just the fraction of the toxic material. Most process streams are not pure fluids and typically the toxic portion is a small fraction of the total. Therefore, a modified toxic criteria is used to check against the concentrations predicted for the cloud as shown in [Equation \(3.189\)](#).

$$tox_{lim}^{mod} = \frac{tox_{lim}}{molfrac^{tox}} \quad (3.189)$$

For example, a hydrocarbon stream contains 5 mole% H₂S. H₂S has an AEGL-3 10-minute duration toxic limit of 100 ppm. Since the stream is not a pure stream, a modified toxic limit can be established as follows:

$$tox_{lim}^{mod} = \frac{100 \text{ ppm}}{0.05} = 2000 \text{ ppm} \quad (3.190)$$

When the cloud dispersion analysis is performed, the consequence area would be based on that portion of the cloud at grade level that exceeded 2000 ppm for a duration of 10 minutes or more.

5.9.7 Determination of Final Toxic Consequence Areas

The final toxic consequence areas are determined as a probability weighted average of the individual toxic consequence areas calculated for each release hole size. The probability weighting utilizes the generic frequencies of the release hole sizes selected per [Section 4.2](#).

The equation for probability weighting of the personnel injury consequence areas is given by [Equation \(3.191\)](#).

$$CA_{f,inj}^{tox} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{f,inj,n}^{tox}}{gff_{total}} \right) \quad (3.191)$$

In [Equation \(3.191\)](#), the total GFF is as calculated in Step 2.2.

5.9.8 Calculation of Toxic Consequence Areas

- Step 9.1—Determine the mole fraction of the release rate that contains a toxic component, $molefrac^{tox}$.
- Step 9.2—Calculate the release duration, ld_n^{tox} , using [Equation \(3.186\)](#).
- Step 9.3—Determine the toxic impact criteria, tox_{lim} , and the time durations associated with each. For example, an AEGL-3 toxic criteria can be based on a 10-minute, 30-minute, or 1-hour duration.
- Step 9.4—Determine the modified toxic limit, tox_{lim}^{mod} , using [Equation \(3.189\)](#).
- Step 9.5—For each hole size and for each toxic criteria available for the fluid, use the vapor source rate and source area determined in Step 7.7 and perform a cloud dispersion analysis in accordance with [Section 5.7.4](#). The leak duration, ld_n^{tox} , from Step 9.2 is used as an input into this analysis.

NOTE The concentration averaging time used in the dispersion analysis should be equal to the time duration applicable to the toxic criteria being evaluated.

- f) Step 9.6—From the cloud dispersion analysis, determine the grade level area or boundary of the cloud that is at or above the modified toxic exposure criteria established in Step 9.4. This area is the toxic cloud area, $CA_{f,n}^{\text{cloud}}$.
- g) Step 9.7—For each hole size, determine the probability of toxic release, $ptox_n$, using Equation (3.187) and the results from Step 8.10.
- h) Step 9.8—For each hole size, calculate the personnel injury toxic consequence area, $CA_{f,n}^{\text{cloud}}$, using Equation (3.188).
- i) Step 9.9—Calculate the probability weighted or final toxic personnel injury consequence area, $CA_{f,\text{inj}}^{\text{tox}}$, using Equation (3.191).

5.10 Determine Nonflammable Nontoxic Consequences

5.10.1 General

Many nonflammable nontoxic fluids will still result in a consequence area caused by loss of containment. These include steam, acids, and other fluids where the concern is for personnel being sprayed or splashed. Other nonflammable gases such as air and nitrogen, although not flammable, can have significant consequences if the equipment ruptures under excessive pressure.

5.10.2 Physical Explosions

5.10.2.1 General

A physical explosion occurs when a pressurized piece of equipment containing a vapor or two-phase fluid ruptures. Since a physical explosion can only occur after rupture, the consequence area for physical explosions is equal to zero for all hole sizes except the rupture case. An explosion or blast wave occurs as the contained energy is released into the atmosphere. A physical explosion can result with ruptures of equipment containing flammable or nonflammable materials. If the contained fluid is flammable, the pressure wave can be followed by other events, such as fireballs, pool fires, flash fires, or VCEs, depending on whether or not the release ignites and whether or not there is an immediate or delayed ignition.

5.10.2.2 TNT Equivalency Method

As with a VCE, a conservative method for calculating the effects of physical explosions is to use the TNT equivalency method. The energy associated with the rupture of a gas-filled vessel can be estimated using Equation (3.192), which is provided by Brode [31] and modified here to convert to an equivalent TNT.

$$W_{\text{TNT}} = C_{29} \cdot V_s \cdot \left(\frac{P_s - P_{\text{atm}}}{k - 1} \right) \quad (3.192)$$

5.10.2.3 Physical Explosion Safe Distance and Consequence Area

At this point, the calculation of the consequence area as a result of the release of energy from a gas-filled vessel rupture is identical to that described earlier for VCEs. The calculation of the blast overpressure uses blast curves as described in Section 5.8.5.5 c). The calculation of the consequence area is identical to Section 5.8.5.5.

In general, the procedure results in a safe distance for both component damage, xs_{cmd}^{pexp} , and personnel injury, xs_{inj}^{pexp} , from which a consequence area can be calculated per Equation (3.193) and Equation (3.194).

$$CA_{f,cmd}^{pexp} = \pi \cdot \left(xs_{cmd}^{pexp} \right)^2 \quad \text{for rupture case only} \quad (3.193)$$

$$CA_{f,inj}^{pexp} = \pi \cdot \left(xs_{inj}^{pexp} \right)^2 \quad \text{for rupture case only} \quad (3.194)$$

5.10.3 BLEVEs

5.10.3.1 General

A BLEVE can occur upon rupture of a vessel containing a superheated but pressurized liquid that flashes to vapor upon release to atmosphere. The classic example of a BLEVE is when an LPG storage vessel is exposed to fire. As a vapor space is created in the vessel, the vessel metal in the vapor space, if it is exposed to flame impingement, can fail at a pressure well below the MAWP of the vessel. If the vessel ruptures, the remaining superheated liquid will expand significantly, causing an overpressure blast wave. Quite often, a BLEVE will be followed by a fireball (see Section 5.8.4). Since a BLEVE can only occur from a rupture, the consequence area for BLEVEs is equal to zero for all hole sizes except the rupture case.

BLEVEs can also occur for nonflammable fluids, such as high-temperature pressurized water.

5.10.3.2 TNT Equivalency Method

Similar to VCEs (Section 5.8.5) and physical ruptures (Section 5.10.2) of gas-filled vessels, the TNT equivalency method can conservatively be used to estimate the blast pressure wave and the resultant consequence area. The energy associated with the BLEVE of a vessel containing superheated liquid can be estimated using Equation (3.195).

$$W_{TNT} = C_{30} \cdot n_v R T_s \cdot \ln \left[\frac{P_s}{P_{atm}} \right] \quad (3.195)$$

For cases where the vessel contains liquid and vapor just prior to the rupture, the released energy can be calculated by using Equation (3.192) to calculate the energy released from the vapor portion stored in the vessel and adding to that the energy released as calculated using Equation (3.195) for the expanding liquid portion.

5.10.3.3 BLEVE Safe Distance and Consequence Area

At this point, the calculation of the consequence area as a result of a BLEVE from a vessel rupture is identical to that described earlier for VCEs. The calculation of the blast overpressure uses blast curves as described in Section 5.8.5.5 c). The calculation of the consequence area is identical to Section 5.8.5.5.

In general, the procedure results in a safe distance for both component damage, xs_{cmd}^{bleve} , and personnel injury, xs_{inj}^{bleve} , from which a consequence area can be calculated per Equation (3.196) and Equation (3.197).

$$CA_{f,cmd}^{bleve} = \pi \cdot \left(xs_{cmd}^{bleve} \right)^2 \quad \text{for rupture case only} \quad (3.196)$$

$$CA_{f,inj}^{bleve} = \pi \cdot \left(xs_{inj}^{bleve} \right)^2 \quad \text{for rupture case only} \quad (3.197)$$

5.10.4 Steam Leaks and Chemical Spills

The consequence calculations for steam leaks or chemical burns, such as mild acids or caustic, are calculated in the same way as performed in the Level 1 consequence analysis (see [Section 4.10](#)).

5.10.5 Nonflammable, Nontoxic Event Tree Probabilities

Based on the consequence analysis event trees ([Figure 5.3](#) and [Figure 5.4](#)), nonflammable, nontoxic events are taken into account when released fluids fail to ignite. Therefore, the probability for a nonflammable, nontoxic event is the non-ignition frequency for the event (i.e. $1 - poi_n$).

$$pnfnt_n = psafe_n$$

5.10.6 Determination of Final Nonflammable, Nontoxic Consequence Areas

For each hole size, the component damage and personnel injury consequence area for each of the nonflammable, nontoxic events can be added up and probability weighted using [Equation \(3.198\)](#) and [Equation \(3.199\)](#).

$$CA_{f,cmd,n}^{nfnt} = pnfnt \cdot \max(CA_{f,cmd,n}^{pexp}, CA_{f,cmd,n}^{bleve}) \quad (3.198)$$

$$CA_{f,inj,n}^{nfnt} = pnfnt \cdot \max(CA_{f,inj,n}^{pexp}, CA_{f,inj,n}^{bleve}, CA_{f,inj,n}^{leak}) \quad (3.199)$$

The final nonflammable, nontoxic consequence areas are determined as a probability weighted average of the individual consequence areas calculated for each release hole size. The probability weighting uses the generic frequencies of the release hole sizes as provided in [Part 2, Table 3.1](#). [Equation \(3.200\)](#) and [Equation \(3.201\)](#) are used to calculate the final probability weighted nonflammable, nontoxic consequence areas.

$$CA_{f,cmd}^{nfnt} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{f,cmd,n}^{nfnt}}{gff_{total}} \right) \quad (3.200)$$

$$CA_{f,inj}^{nfnt} = \left(\frac{\sum_{n=1}^4 gff_n \cdot CA_{f,inj,n}^{nfnt}}{gff_{total}} \right) \quad (3.201)$$

5.10.7 Calculation of Nonflammable, Nontoxic Consequence Areas

- a) Step 10.1—For each hole size, calculate the personnel injury areas for steam and acid leaks, $CA_{f,inj,n}^{leak}$, as is detailed in Steps 10.1 through 10.3 of [Section 4.10.6](#).
- b) Step 10.2—For the rupture case, calculate the component damage consequence area, $CA_{f,cmd}^{pexp}$, and the personnel injury consequence area, $CA_{f,inj}^{pexp}$, of a physical explosion.
 - 1) Calculate the stored vapor volume, V_s , of the equipment component being evaluated.

- 2) Determine the amount of potential energy in the stored vapor expressed as an equivalent amount of TNT, W_{TNT} , using Equation (3.204).
 - 3) An overpressure limit of 34.5 kPa (5.0 psi) is used for component damage consequence area. This overpressure limit is used to determine the safe distance, $x_{\text{cmd}}^{\text{pexp}}$, from the explosion using the following four-step iterative procedure.
 - i) Guess at an acceptable component damage distance from the physical explosion, $x_{\text{cmd}}^{\text{pexp}}$.
 - ii) Calculate the Hopkinson-scaled distance, $\bar{R}_{\text{HS}}$, using Equation (3.171). This parameter is a function of the distance from the physical explosion chosen above, $x_{\text{cmd}}^{\text{pexp}}$.
 - iii) Calculate the side-on overpressure, P_{SO} , at the Hopkinson-scaled distance, $\bar{R}_{\text{HS}}$, using Equation (3.170).
 - iv) Adjust the distance, $x_{\text{cmd}}^{\text{pexp}}$, accordingly, and repeat the above steps until the side-on overpressure, P_{SO} , is equal to 5.0 psi (34.5 kPa).
 - 4) Calculate the component damage consequence area, $CA_{\text{f,cmd}}^{\text{pexp}}$, using Equation (3.193).
 - 5) A probit equation based on building collapse is used for personnel injury consequence area and detailed in Section 5.8.5.5. This probit equation is used to determine the safe distance, $x_{\text{inj}}^{\text{pexp}}$, from the VCE using the following five-step iterative procedure.
 - i) Guess at an acceptable personnel injury distance from the VCE, $x_{\text{inj}}^{\text{pexp}}$.
 - ii) Calculate the Hopkinson-scaled distance, $\bar{R}_{\text{HS}}$, using Equation (3.171). This parameter is a function of the distance from the VCE chosen above, $x_{\text{inj}}^{\text{pexp}}$.
 - iii) Calculate the side-on overpressure, P_{SO} , at the Hopkinson-scaled distance, $\bar{R}_{\text{HS}}$, Equation (3.170).
 - iv) Calculate the probit value, Pr , using Equation (3.172).
 - v) Adjust the distance, $x_{\text{inj}}^{\text{pexp}}$, accordingly, and repeat the above steps until the probit value is equal to 5.0.
 - 6) Calculate the personal injury consequence area, $CA_{\text{f,inj}}^{\text{pexp}}$, using Equation (3.174).
- c) Step 10.3—For the rupture case, calculate the component damage consequence area, $CA_{\text{f,cmd}}^{\text{bleve}}$, and the personnel injury consequence area, $CA_{\text{f,inj}}^{\text{bleve}}$, of a BLEVE.
- 1) Calculate the number of moles of stored liquid that flash to vapor upon release to atmosphere, n_v .
 - 2) Determine the amount of potential energy in the flashed liquid expressed as an equivalent amount of TNT, W_{TNT} , using Equation (3.195).

- 3) For two-phase cases, add to this value the equivalent amount of TNT for the stored vapor energy using [Equation \(3.192\)](#).
- 4) For the component damage consequence area, an overpressure limit of 5.0 psig. This overpressure limit is used to determine the safe distance, xs_{cmd}^{bleve} , from the BLEVE using the following four-step iterative procedure.
 - i) Guess at an acceptable component damage distance from the BLEVE, xs_{cmd}^{bleve} .
 - ii) Calculate the Hopkinson-scaled distance, $\bar{R}_{HS}$, using [Equation \(3.171\)](#). This parameter is a function of the distance from the BLEVE chosen above, xs_{cmd}^{bleve} .
 - iii) Calculate the side-on overpressure, P_{SO} , at the Hopkinson-scaled distance, $\bar{R}_{HS}$, using [Equation \(3.170\)](#).
 - iv) Adjust the distance, xs_{cmd}^{bleve} , accordingly, and repeat the above steps until the side-on overpressure, P_{SO} , is equal to 5.0 psi (34.5 kPa).
- 5) Calculate the component damage consequence area, $CA_{f,cmd}^{bleve}$, using [Equation \(3.196\)](#).
- 6) For the personnel injury consequence area, a probit equation based on building collapse (see [Section 5.8.5.5](#)). This probit equation is used to determine the safe distance, xs_{inj}^{bleve} , from the BLEVE using the following five-step iterative procedure.
 - i) Guess at an acceptable personnel injury distance from the BLEVE, xs_{inj}^{bleve} .
 - ii) Calculate the Hopkinson-scaled distance, $\bar{R}_{HS}$, using [Equation \(3.171\)](#). This parameter is a function of the distance from the BLEVE chosen above, xs_{inj}^{bleve} .
 - iii) Calculate the side-on overpressure, P_{SO} , at the Hopkinson-scaled distance, $\bar{R}_{HS}$, using [Equation \(3.170\)](#).
 - iv) Calculate the probit value, Pr , using [Equation \(3.172\)](#).
 - v) Adjust the distance, xs_{inj}^{bleve} , accordingly, and repeat the above steps until the probit value is equal to 5.0.
- 7) Calculate the personal injury consequence area, $CA_{f,inj}^{bleve}$, using [Equation \(3.174\)](#).
- d) Step 10.4—For each hole size, sum up the consequence areas for each of the nonflammable, nontoxic events using [Equation \(3.198\)](#) and [Equation \(3.199\)](#). The resultant component damage consequence area is $CA_{f,cmd,n}^{nfnt}$, and personnel injury area is $CA_{f,inj,n}^{nfnt}$.
- e) Step 10.5—Calculate the final, probability weighted nonflammable, nontoxic consequence areas, $CA_{f,cmd}^{nfnt}$ and $CA_{f,inj}^{nfnt}$, using [Equation \(3.200\)](#) and [Equation \(3.201\)](#).

5.11 Determine the Component Damage and Personnel Injury Consequence Areas

5.11.1 Overview

The final consequence areas for component damage and personnel injury are the maximum areas of those calculated for:

- a) flammable consequences (see [Section 5.8](#));
- b) toxic consequences (see [Section 5.9](#));
- c) nonflammable, nontoxic consequences (see [Section 5.10](#)).

5.11.2 Final Component Damage Consequence Area

The final component damage consequence area is calculated using [Equation \(3.202\)](#). Since the consequence areas associated with nonflammable, nontoxic releases and safe events are all associated with the same probability (the probability of non-ignition, given a release), the maximum area is taken to maintain a total probability of events equal to 1.0. Although the consequence area of a safe release is zero, it is included in the calculation for completeness.

$$CA_{f,cmd} = CA_{f,cmd}^{flam} + \max \left[psafe \cdot CA_{f,cmd}^{safe}, CA_{f,cmd}^{nfnt} \right] \quad (3.202)$$

5.11.3 Final Personnel Injury Consequence Area

The final personnel injury consequence area is calculated using [Equation \(3.203\)](#). Since the consequence areas associated with nonflammable, nontoxic releases, toxic releases, and safe events are all associated with the same probability (the probability of non-ignition, given a release), the maximum area is taken to maintain a total probability of events equal to 1.0. Although the consequence area of a safe release is zero, it is included in the calculation for completeness.

$$CA_{f,inj} = CA_{f,inj}^{flam} + \max \left[psafe \cdot CA_{f,inj}^{safe}, CA_{f,inj}^{tox}, CA_{f,inj}^{nfnt} \right] \quad (3.203)$$

5.11.4 Final Consequence Area

The final consequence area is:

$$CA_f = \max \left[CA_{f,cmd}, CA_{f,inj} \right] \quad (3.204)$$

5.11.5 Calculation for Final Consequence Area

- a) Step 11.1—Calculate the final component damage consequence area, $CA_{f,cmd}$, using [Equation \(3.202\)](#).
- b) Step 11.2—Calculate the final personnel injury consequence area, $CA_{f,inj}$, using [Equation \(3.203\)](#).

5.12 Determine the Financial Consequence

5.12.1 General

The financial consequence is determined accordance with the Level 1 consequence analysis; see [Section 4.12.7](#).

5.12.2 Calculation of Financial Consequence

The step-by-step procedure for estimating the impact of detection and isolation systems is in accordance with [Section 4.12.2](#).

5.13 Determination of SC

The method to determine the safety consequence based on the personnel injury consequence area is provided in [Section 4.13](#). For a Level 2 assessment of SC_f , use the Level 2 personnel injury consequence area, CA_{inj} , calculated in [Section 5.11.3](#).

5.14 Nomenclature

Coefficients C_1 through C_{41} that provide the metric and U.S conversion factors for the equations are provided in [Annex 3.B](#). The following lists the nomenclature used in [Section 5](#).

$A_{pf,n}$	is the pool fire surface area, associated with the n^{th} release hole size, ft^2 (m^2)
$A_{burn_{pf,n}}$	is the pool fire area based on burning rate, associated with the n^{th} release hole size, ft^2 (m^2)
AIT	is the autoignition temperature of the released fluid, °R (K)
$A_{max_{pf,n}}$	is the maximum pool fire area based on a pool depth of 0.0164 ft (5 mm), associated with the n^{th} release hole size, ft^2 (m^2)
BP_s	is the boiling point temperature of the stored fluid at normal operating conditions, °R (K)
C_{fb}	is the distance from the center of the fireball to the target, ft (m)
CA_f	is the final consequence area, ft^2 (m^2)
$CA_{f,cmd}^{\text{bleve}}$	is the component damage consequence area for a BLEVE associated with the rupture case, ft^2 (m^2)
$CA_{f,cmd}^{\text{fball}}$	is the component damage consequence area for a fireball associated with the rupture case, ft^2 (m^2)
$CA_{f,cmd}^{\text{flam}}$	is the final overall component damage flammable consequence area, ft^2 (m^2)
$CA_{f,cmd}^{\text{nfnt}}$	is the final probability weighted component damage consequence area for nonflammable, nontoxic releases, ft^2 (m^2)
$CA_{f,cmd}^{\text{pexp}}$	is the component damage consequence area for a physical explosion associated with the rupture case only, ft^2 (m^2)
$CA_{f,cmd,n}^{\text{flam}}$	is the component damage flammable consequence area associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,cmd,n}^{\text{flash}}$	is the component damage consequence area for a flash fire associated with the n^{th} release hole size, ft^2 (m^2)

$CA_{f,cmd,n}^{jet}$	is the component damage consequence area for a jet fire associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,cmd,n}^{pool}$	is the component damage consequence area for a pool fire associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,cmd,n}^{safe}$	is the component damage consequence area for a safe release associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,cmd,n}^{vce}$	is the component damage consequence area for a VCE associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,inj}^{bleve}$	is the personnel injury consequence area for a BLEVE associated with the rupture case, ft^2 (m^2)
$CA_{f,inj}^{fball}$	is the personnel injury consequence area for a fireball associated with the rupture case, ft^2 (m^2)
$CA_{f,inj}^{flam}$	is the final overall personnel injury flammable consequence area, ft^2 (m^2)
$CA_{f,inj}^{nfnt}$	is the final probability weighted personnel injury consequence area for nonflammable, nontoxic releases, ft^2 (m^2)
$CA_{f,inj}^{pexp}$	is the personnel injury consequence area for a physical explosion associated with the rupture case only, ft^2 (m^2)
$CA_{f,inj}^{tox}$	is the final overall personnel injury toxic consequence area, ft^2 (m^2)
$CA_{f,inj,n}^{flam}$	is the personnel injury flammable consequence area associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,inj,n}^{flash}$	is the personnel injury consequence area for a flash fire associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,inj,n}^{jet}$	is the personnel injury consequence area for a jet fire associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,inj,n}^{leak}$	is the personnel injury nonflammable, nontoxic consequence area for steam or acid leaks, associated with the n^{th} release hole size, ft^2 (m^2)
$CA_{f,inj,n}^{nfnt}$	is the personnel injury nonflammable, nontoxic consequence area, associated with the n^{th} release hole size, ft^2 (m^2)

$CA_{f, inj, n}^{pool}$	is the personnel injury consequence area for a pool fire associated with the n^{th} release hole size, ft ² (m ²)
$CA_{f, inj, n}^{safe}$	is the personnel injury consequence area for a safe release associated with the n^{th} release hole size, ft ² (m ²)
$CA_{f, inj, n}^{tox}$	is the personnel injury toxic consequence area associated with the n^{th} release hole size, ft ² (m ²)
$CA_{f, inj, n}^{vce}$	is the personnel injury consequence area for a VCE associated with the n^{th} release hole size, ft ² (m ²)
$CA_{f, n}^{cloud}$	is the footprint at grade level of the portion of the vapor cloud that exceeds the toxic exposure limit of the toxic component being evaluated, associated with the n^{th} release hole size, ft ² (m ²)
Cp_l	is the specific heat of the pool liquid, Btu/lb-°R (J/kg-K)
$Dmax_{fb}$	is the maximum diameter of the fireball, ft (m)
$erate_n$	is the liquid pool mass evaporation rate associated with the n^{th} release hole size, lb/s (kg/s)
F_{cyl_n}	is the radiation view factor for a cylindrical shape, unitless
Fh_n	is the horizontal radiation view factor for a cylindrical shape associated with the n^{th} release hole size, unitless
Fp_n	is the radiation view factor for a point source associated with the n^{th} release hole size, ft ⁻² (m ⁻²)
$Fsph$	is the view factor for a spherical shape, unitless
Fv_n	is the vertical radiation view factor for a cylindrical shape associated with the n^{th} release hole size, unitless
$fact_{di}$	is the release magnitude reduction factor, based on the detection and isolations systems present in the unit
$frac_{fsh}$	is the mass fraction of the stored fluid that flashes to vapor upon release to the atmosphere
$frac_l$	is the mass fraction liquid of the stored fluid under storage conditions
$frac_{mole, i}$	is the mole fractions for the i^{th} component in the fluid mixture
$frac_{ro}$	is the rainout mass fraction
$frac_v$	is the mass fraction vapor of the stored fluid under storage conditions
g	is the acceleration due to gravity on earth at sea level = 32.2 ft/s ² (9.81 m/s ²)

g_c	is the gravitational constant = $32.2(\text{lbm} - \text{ft})/(\text{lbf} - \text{s}^2) \left[1.0(\text{kg} - \text{m})/(\text{N} - \text{s}^2) \right]$
gff_n	are the generic failure frequencies for each of the n release hole sizes selected for the type of equipment being evaluated
gff_{total}	is the sum of the individual release hole size generic frequencies
H_{fb}	is the center height of the fireball, ft (m)
HC_l	is the heat of combustion of the liquid fuel for the pool fire calculations, Btu/lb (J/kg)
HC_s	is the heat of combustion of the stored fluid or mixture, Btu/lb (J/kg)
HC_{TNT}	is the heat of combustion of TNT ≈ 2000 , Btu/lb (J/kg)
HC_v	is the heat of combustion of the vapor fuel for the jet fire calculations, Btu/lb (J/kg)
I_{th}^{fball}	is the radiant heat flux received at a distant receiver location from a fireball associated with the rupture case, Btu/hr-ft ² (W/m ²)
$I_{th}_n^{\text{jet}}$	is the radiant heat flux received at a distant receiver location from a jet fire associated with the n^{th} release hole size, Btu/hr-ft ² (W/m ²)
$I_{th}_n^{\text{pool}}$	is the radiant heat flux received at a distant receiver location from a pool fire associated with the n^{th} release hole size, Btu/hr-ft ² (W/m ²)
k	is the release fluid ideal gas specific heat capacity ratio, unitless
k_{surf}	is the thermal conductivity of the surface for liquid pools, Btu/hr-ft ² (W/m ²)
$ld_{\text{max},n}$	is the maximum leak duration associated with the n^{th} release hole size, minutes
ld_n	is the actual leak duration of the flammable release based on the available mass and the calculated release rate, associated with the n^{th} release hole size, seconds
ld_n^{tox}	is the actual leak duration of the toxic release based on the available mass and the calculated release rate, associated with the n^{th} release hole size, seconds
$L_{\text{pf},n}$	is the pool fire flame length, associated with the n^{th} release hole size, ft (m)
LFL	is the lower flammability limit for the fluid
$\dot{m}_b$	is the burning flux rate of a pool fire, lb/ft ² -s (kg/m ² -s)
$\dot{m}_{b,i}$	is the burning flux rate of a pool fire for the i^{th} component in the fluid mixture in the pool fire, lb/ft ² -s (kg/m ² -s)
$mass_{\text{avail},n}$	is the available mass for release for each of the release hole sizes selected, associated with the n^{th} release hole size, lb (kg)
$mass_{\text{fb}}$	is the flammable mass of the stored liquid used in the fireball calculation, lb (kg)

$mass_{VCE}$	is the mass of flammable material in the vapor cloud used in the VCE calculation, lb (kg)
$mfrac^{flam}$	is the flammable mass fraction of the released fluid mixture
$mfrac^{tox}$	is the toxic mass fraction of the released fluid mixture
$molefrac^{tox}$	is the toxic mole fraction of the released fluid mixture
MW	is the release fluid molecular weight, lb/lb-mol (kg/kg-mol)
n_v	is the moles that flash from liquid to vapor upon release to atmosphere, lb/lb-mol (kg/kg-mol)
P_{atm}	is the atmospheric pressure, psia (kPa)
P_B	is the component or equipment burst pressure, psia (kPa)
$P_{b,g}$	is the bubble point pressure of the released fluid at the ground temperature, psia (kPa)
Pr	is the probit value, typically set at 5 (50 % probability)
P_s	is the storage or normal operating pressure, psia (kPa)
$P_{SO,n}$	is the side-on overpressure associated with the n^{th} release hole size, psia (kPa)
P_w	is the atmospheric water partial pressure, psia (kPa)
P_{sat_s}	is the saturation pressure of the stored fluid at operating (storage) temperature, psia (kPa)
$pfbll_n$	is the probability of a fireball given a release associated with the n^{th} release hole size
$pfbll_{v,n}$	is the probability of a fireball given a vapor release associated with the n^{th} release hole size
$pfbii$	is the probability of fireball given an immediate ignition of a vapor or two-phase instantaneous release
$pffdi$	is the probability of flash fire given a delayed ignition
$pffdi_{l,n}$	is the probability of flash fire given a delayed ignition of a release of a flammable liquid associated with the n^{th} release hole size
$pffdi_{v,n}$	is the probability of flash fire given a delayed ignition of a release of a flammable vapor associated with the n^{th} release hole size
$pflash_n$	is the probability of a flash fire given a release associated with the n^{th} release hole size
$pflash_{v,n}$	is the probability of a flash fire given a vapor release associated with the n^{th} release hole size

$pjet_n$	is the probability of a jet fire given a release associated with the n^{th} release hole size
$pjet_{v,n}$	is the probability of a jet fire given a vapor release associated with the n^{th} release hole size
$pnfnt_n$	is the probability of nonflammable, nontoxic event given a release associated with the n^{th} hole size
poi	is the probability of ignition given a release
$poi_{l,n}$	is the probability of ignition given a liquid release associated with the n^{th} release hole size
poi_l^{ait}	is the maximum probability of ignition for a liquid release at or above the AIT
$poi_{l,n}^{\text{amb}}$	is the probability of ignition given a liquid release at ambient temperature associated with the n^{th} release hole size
$poi_{v,n}$	is the probability of ignition given a vapor release associated with the n^{th} release hole size
poi_v^{ait}	is the maximum probability of ignition for a vapor release at or above the AIT
$poi_{v,n}^{\text{amb}}$	is the probability of ignition given a vapor release at ambient temperature associated with the n^{th} release hole size
$poi_{2,n}$	is the probability of ignition given a two-phase release associated with the n^{th} release hole size
poi_i	is the probability of immediate ignition given ignition
poi_i^{ait}	is the probability of immediate ignition given ignition if the fluid were to be released at or above its AIT , assumed = 1.0
$poi_{l,n}$	is the probability of immediate ignition given ignition of a liquid release associated with the n^{th} release hole size
$poi_{l,n}^{\text{amb}}$	is the probability of immediate ignition given ignition if a liquid were to be released at ambient temperature associated with the n^{th} release hole size
$poi_{v,n}$	is the probability of immediate ignition given ignition of a vapor release associated with the n^{th} release hole size
$poi_{v,n}^{\text{amb}}$	is the probability of immediate ignition given ignition if a vapor were to be released at ambient temperature associated with the n^{th} release hole size
$poi_{2,n}$	is the probability of immediate ignition given ignition of a two-phase release associated with the n^{th} release hole size
$ppool_{l,n}$	is the probability of a pool fire given a release of a flammable liquid associated with the n^{th} release hole size

$ppool_l_n$	is the probability of a pool fire given a release associated with the n^{th} release hole size
$ppool_{v,n}$	is the probability of a pool fire given a release of a flammable vapor associated with the n^{th} release hole size
$psafe_n$	is the probability of a safe release given a release associated with the n^{th} release hole size
$psafe_{v,n}$	is the probability of a safe release given a vapor release associated with the n^{th} release hole size
$psafe_{2,n}$	is the probability of a safe release given a release of a flammable two-phase fluid associated with the n^{th} release hole size
$ptox_n$	is the probability of a toxic release given a release associated with the n^{th} release hole size
$pvce_{l,n}$	is the probability of a VCE given a release of a flammable vapor associated with the n^{th} release hole size
$pvce_n$	is the probability of a VCE given a release associated with the n^{th} release hole size
$pvce_{v,n}$	is the probability of a VCE given a vapor release associated with the n^{th} release hole size
$pvcedi$	is the probability of VCE given a delayed ignition
$pvcedi_{l,n}$	is the probability of VCE given a delayed ignition of a release of a flammable liquid associated with the n^{th} release hole size
$pvcedi_{v,n}$	is the probability of VCE given a delayed ignition of a release of a flammable vapor associated with the n^{th} release hole size
Q_{rad}^{fball}	is the total energy flux radiated from a fireball, Btu/hr-ft ² (W/m ²)
$Q_{rad}_n^{\text{jet}}$	is the total energy radiated from a jet fire associated with the n^{th} release hole size, Btu/hr (W)
$Q_{rad}_n^{\text{pool}}$	is the total energy flux radiated from a pool fire associated with the n^{th} release hole size, Btu/hr-ft ² (W/m ²)
R	is the universal gas constant = 1545 ft-lbf/(lb-mol-°R) [8314 J/(kg-mol-K)]
$R_{pf,n}$	is the pool fire radius, calculated for each of the n release hole sizes selected, ft (m)
RH	is the atmospheric relative humidity, %
$\bar{R}_{HS,n}$	is the Hopkinson's scaled distance used in the blast calculations associated with the n^{th} release hole size, lb/ft ^{1/3} (m/kg ^{1/3})
$r_{p,n}$	is the pool radius, calculated for each of the n^{th} release hole sizes selected, ft (m)

$rate_{l,n}^{flam}$	is the flammable liquid portion of the adjusted or mitigated discharge rate used in the consequence calculation associated with the n^{th} release hole size, lb/s (kg/s)
$rate_n$	is the adjusted or mitigated discharge rate used in the consequence calculation associated with the n^{th} release hole size, lb/s (kg/s)
$rate_n^{flam}$	is the flammable portion of the adjusted or mitigated discharge rate used in the consequence calculation associated with the n^{th} release hole size, lb/s (kg/s)
$rate_n^{tox}$	is the toxic portion of the adjusted or mitigated discharge rate used in the consequence calculation associated with the n^{th} release hole size, lb/s (kg/s)
$rate_{v,n}^{flam}$	is the flammable vapor portion of the adjusted or mitigated discharge rate used in the consequence calculation associated with the n^{th} release hole size, lb/s (kg/s)
SC_f	is the safety consequence which is the number of personnel injuries resulting from a release with the potential to cause injuries within a calculated area based on the average number of people in the area at any given time, injuries
T_{atm}	is the atmospheric temperature, °R (K)
T_b	is the bubble point temperature of released liquid, °R (K)
T_d	is the dew point temperature of released vapor, °R (K)
T_f	is the flash temperature of the released fluid, °R (K)
T_{fp}	is the flash point of the released fluid, °R (K)
T_g	is the ground temperature, °R (K)
T_s	is the storage or normal operating temperature, °R (K)
t_{fb}	is the fireball duration, seconds
$t_{p,n}$	is the time it takes for the liquid pool to reach steady state, seconds
tox_{lim}	is the toxic exposure limit for a toxic component in the released stream (e.g. IDLH, AEGL-3, ERPG), usually expressed in ppm.
tox_{lim}^{mod}	is the modified toxic exposure limit to account for cloud modeling of mixtures, ppm
UFL	is the upper flammability limit for the fluid
$u_{s,n}$	is the nondimensional wind speed associated with the n^{th} release hole size, unitless
u_w	is the wind speed measured at 6 ft off of grade, ft/s (m/s)
$\dot{V}_{p,n}$	is the volumetric vapor rate leaving the pool surface associated with the n^{th} release hole size, m ³ /s (ft ³ /s)

V_s	is the equipment stored vapor volume, ft ³ (m ³)
W_n	is the theoretical release rate associated with the n^{th} release hole size, lb/s (kg/s)
W_n^{jet}	is the portion of the release rate that forms a jet associated with the n^{th} release hole size, lb/s (kg/s)
W_n^{pool}	is the portion of the release rate that forms a pool on the ground associated with the n^{th} release hole size, lb/s (kg/s)
W_{TNT}	is the energy released in an explosion expressed as an equivalent mass of TNT, lb (kg)
X_{surf}	is the surface roughness factor, unitless
x_s^{fball}	is the safe distance from the flame surface of a fireball, ft (m)
$x_s^{\text{bleve}}_{\text{cmd}}$	is the safe distance from a BLEVE for component damage associated with the rupture case, ft (m)
$x_s^{\text{fball}}_{\text{cmd}}$	is the safe distance from a fireball for component damage associated with the rupture case, ft (m)
$x_s^{\text{pexp}}_{\text{cmd}}$	is the safe distance from a physical explosion for component damage associated with the rupture case, ft (m)
$x_s^{\text{jet}}_{\text{cmd},n}$	is the safe distance from the jet fire flame surface for component damage associated with the n^{th} release hole size, ft (m)
$x_s^{\text{pool}}_{\text{cmd},n}$	is the safe distance from the pool fire flame surface for component damage associated with the n^{th} release hole size, ft (m)
$x_s^{\text{vce}}_{\text{cmd},n}$	is the safe distance from the VCE for component damage associated with the n^{th} release hole size, ft (m)
$x_s^{\text{bleve}}_{\text{inj}}$	is the safe distance from a BLEVE for personnel injury associated with the rupture case, ft (m)
$x_s^{\text{fball}}_{\text{inj}}$	is the safe distance from a fireball for personnel injury associated with the rupture case, ft (m)
$x_s^{\text{pexp}}_{\text{inj}}$	is the safe distance from a physical explosion for personnel injury associated with the rupture case, ft (m)
$x_s^{\text{jet}}_{\text{inj},n}$	is the safe distance from the jet fire flame surface for personnel injury associated with the n^{th} release hole size, ft (m)

$x_{inj,n}^{pool}$	is the safe distance from the pool fire flame surface for personnel injury associated with the n^{th} release hole size, ft (m)
$x_{inj,n}^{vce}$	is the safe distance from the VCE for personnel injury associated with the n^{th} release hole size, ft (m)
x_{s_n}	is the safe distance from the flame surface to the target location associated with the n^{th} release hole size, ft (m)
$x_{s_n}^{jet}$	is the safe distance from the jet fire flame surface associated with the n^{th} release hole size, ft (m)
$x_{s_n}^{pool}$	is the safe distance from the pool fire flame surface associated with the n^{th} release hole size, ft (m)
$x_{s_n}^{vce}$	is the safe distance from the VCE associated with the n^{th} release hole size, ft (m)
α_{surf}	is the thermal diffusivity of the surface under the liquid pool, ft ² /s (m ² /s)
β	is the fraction of combustion power radiated from a flame
β_{fb}	is the fraction of combustion power radiated from a fireball
ΔH_V	is the latent heat of vaporization of the liquid in the pool, Btu/lb (J/kg)
η	is the explosion yield factor, unitless
ρ_{atm}	is the atmospheric air density, lb/ft ³ (kg/m ³)
ρ_l	is the liquid density at storage or normal operating conditions, lb/ft ³ (kg/m ³)
ρ_v	is the vapor density at storage or normal operating conditions, lb/ft ³ (kg/m ³)
$\theta_{pf,n}$	is the pool fire flame tilt associated with the n^{th} release hole size, radians
τ_{atm}	is the atmospheric transmissivity, unitless
$\tau_{atm,n}$	is the atmospheric transmissivity associated with the n^{th} release hole size, unitless

5.15 Tables

Table 5.1—Event Outcomes for Level 2 Consequence Analysis

Event Outcome	Description	General Procedure
Pool fires [10], [17], [18], [19], [21], [22], [24]	Occur as a result of immediate ignition of a flammable liquid from a pressurized process vessel or pipe that leaks or ruptures.	1. Determine pool fire size 2. Calculate burning rate 3. Calculate flame length and tilt 4. Determine radiant energy emitted 5. Determine energy received at distant points (need view factor and atmospheric transmissivity) 6. Calculate safe distance
Jet fires [17], [18], [20]	Occur as a result of immediate ignition of a flammable vapor or two-phase jet release from a pressurized process vessel or pipe that develops a hole.	1. Calculate flame length 2. Determine radiant energy emitted 3. Determine energy received at distant points (need view factor and atmospheric transmissivity) 4. Calculate safe distance
Fireballs [17], [18], [20]	Occur as result of the immediate ignition of a flammable, superheated liquid/vapor released due to a vessel or pipe rupture. Fireballs always occur in combination with a physical explosion or a BLEVE.	1. Determine available flammable mass 2. Determine fireball diameter, height and duration 3. Determine radiant energy emitted 4. Determine energy received at distant points (need view factor and atmospheric transmissivity) 5. Calculate safe distance
Flash fires [6], [17], [18]	Occur as a result of a delayed ignition of a vapor cloud. The source of the vapor cloud could either be from a vapor or two-phase jet release or evaporation off the surface of an un-ignited liquid flammable pool.	1. Determine if cloud source is continuous (plume) or instantaneous (puff) 2. Utilize cloud dispersion model to determine the grade level area of flammable material (greater than LFL) that is in the source cloud
Vapor cloud explosions [5], [6], [7], [17], [18], [21], [22], [4]		1. Determine if cloud source is continuous (plume) or instantaneous (puff) 2. Utilize cloud dispersion model to determine the amount of flammable material (between LFL and UFL) that is in the source cloud 3. Determine equivalent amount of TNT 4. Calculate overpressure as a function of distance 5. Calculate safe distance
BLEVEs [17], [18], [26]	Occur upon rupture of a vessel containing a superheated but pressurized liquid that flashes to vapor upon release to atmosphere	1. Determine equivalent amount of TNT that is a function of the storage pressure and the amount of liquid that flashes to vapor upon release 2. Calculate overpressure as a function of distance 3. Calculate safe distance
Physical explosions [17], [18], [33], [30]	Occur upon rupture of a vessel containing a pressurized flammable or nonflammable vapor	1. Determine equivalent amount of TNT that is a function of the storage pressure and volume of vapor 2. Calculate overpressure as a function of distance 3. Calculate safe distance
Toxic releases	Occurs upon release of toxic fluid to the atmosphere through a hole or due to a rupture	1. Determine if cloud source is continuous (plume) or instantaneous (puff) 2. Utilize cloud dispersion model to determine the portion of the cloud at grade level that exceeds the toxic limit (concentration and duration) of the fluid

Table 5.2—Surface Interaction Parameters with Liquid Pools

Surface	Thermal Conductivity, k_{surf} (Btu/hr-ft-°R)	Thermal Diffusivity, α_{surf} (ft ² /s)	Surface Roughness, X_{surf} (unitless)
Concrete ¹	0.53	4.48×10^{-6}	1.0
Soil (average)	0.56	4.94×10^{-6}	3.0
Soil (sandy, dry)	0.15	2.13×10^{-6}	3.0
Soil (moist, 8 % water, sandy)	0.34	3.62×10^{-6}	3.0
NOTE 1 Use as default.			
NOTE 2 Rijnmond Public Authority [11].			

Table 5.2M—Surface Interaction Parameters with Liquid Pools

Surface	Thermal Conductivity, k_{surf} (W/m-K)	Thermal Diffusivity, α_{surf} (m ² /s)	Surface Roughness, X_{surf} (unitless)
Concrete ¹	0.92	4.16×10^{-7}	1.0
Soil (average)	0.96	4.59×10^{-7}	3.0
Soil (sandy, dry)	0.26	1.98×10^{-7}	3.0
Soil (moist, 8 % water, sandy)	0.59	3.36×10^{-7}	3.0
NOTE 1 Use as default.			
NOTE 2 Rijnmond Public Authority [11].			

Table 5.3—Event Probabilities

Release Type	Fluid Phase	Probability of Immediate Ignition, Given Ignition		Probability of VCE or Flash Fire, Given Delayed Ignition	
		At Ambient Temperature poi_n^{amb}	At AIT poi^{ait}	VCE, $pvcedi_{i,n}$ or $pvcedi_{v,n}$	Flash Fire, $pffdi_{i,n}$ or $pffdi_{v,n}$
Continuous	Liquid	0.20	1.00	0.25	0.75
Continuous	Vapor	0.50	1.00	0.50	0.50
Instantaneous	Liquid	0.20	1.00	0.125	0.875
Instantaneous	Vapor	0.10	1.00	0.25	0.75

5.16 Figures

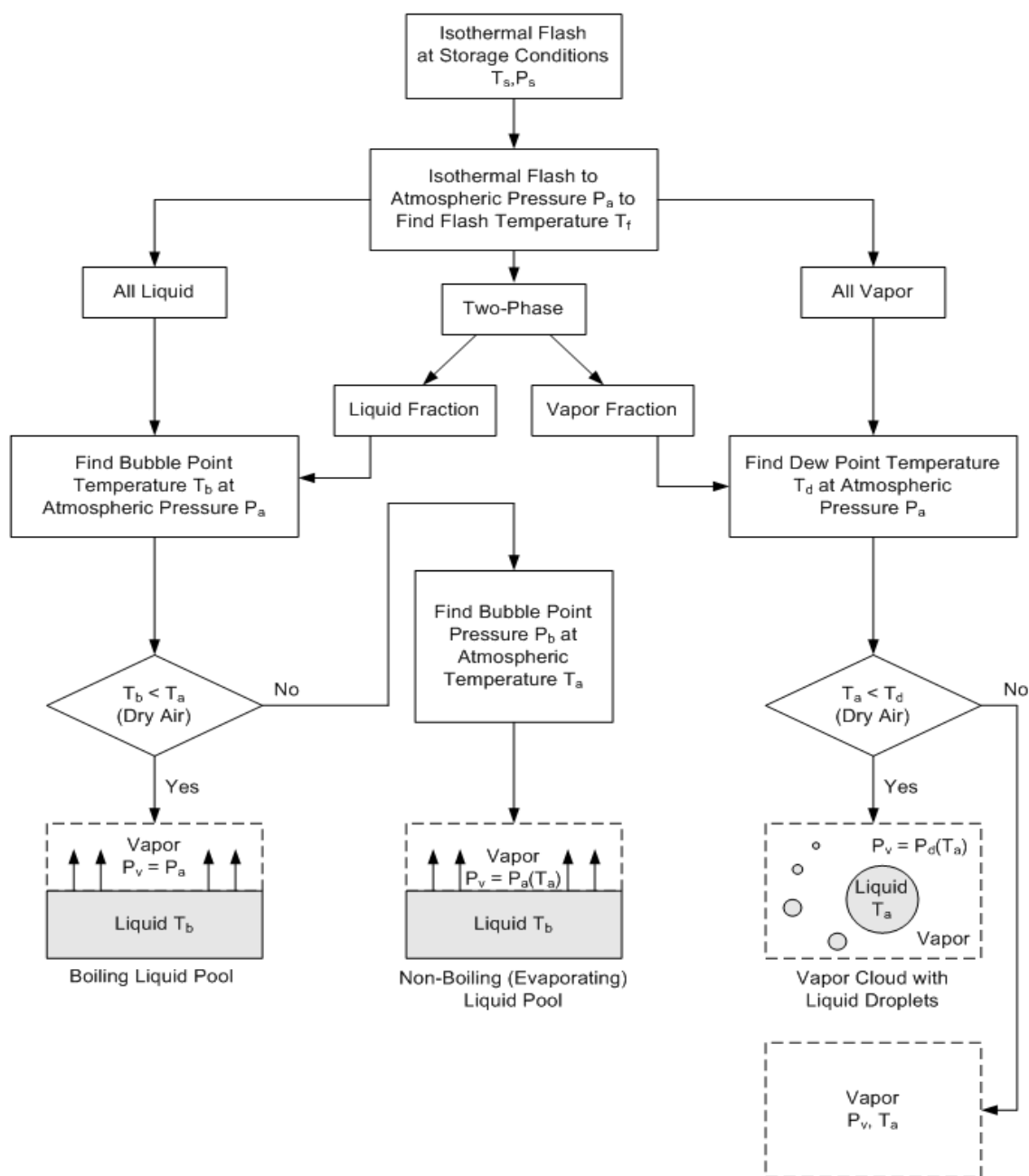
Thermodynamic Calculations Used in Consequence Analysis

Figure 5.1—Source Term Modeling—Thermodynamic Modeling

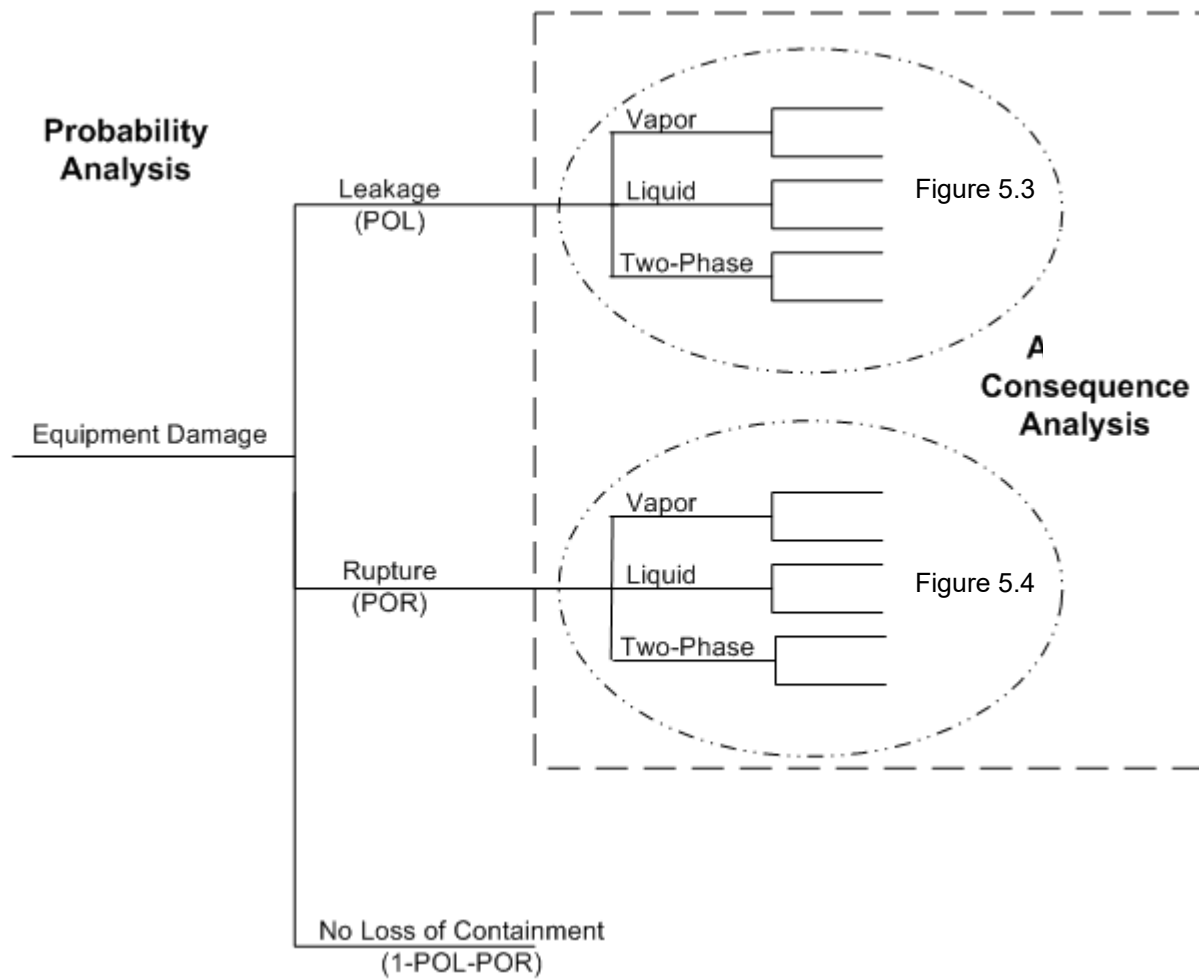
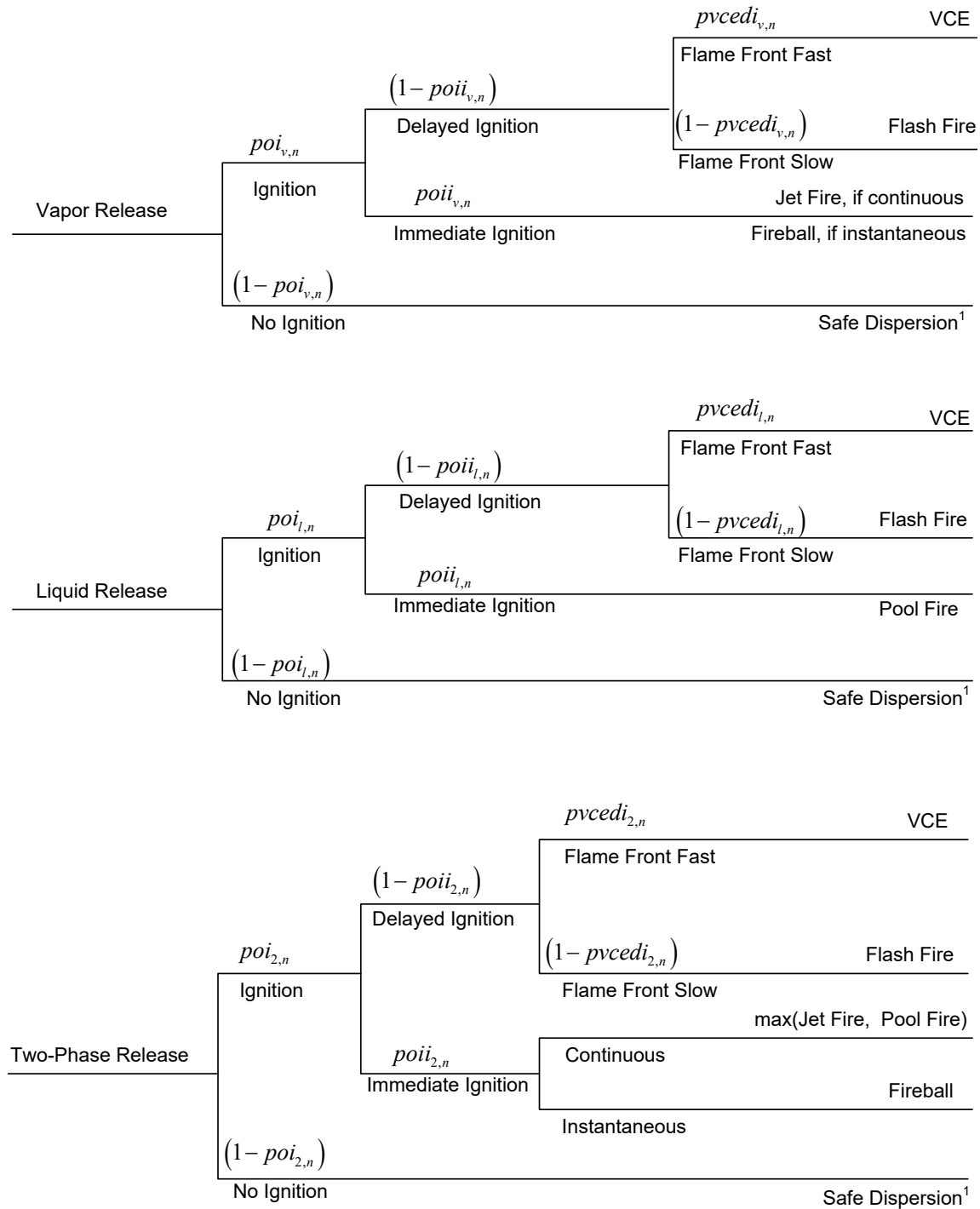
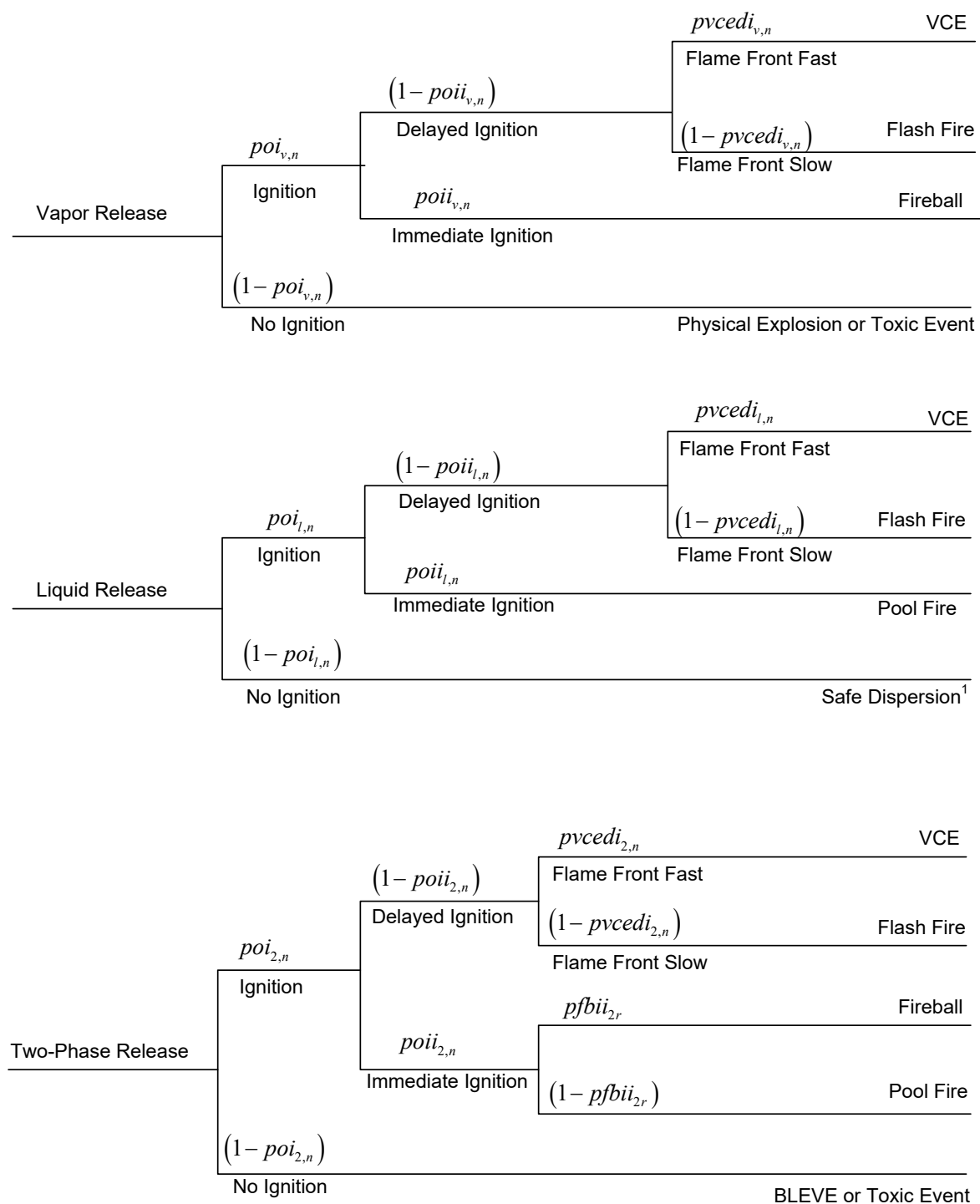


Figure 5.2—Overall Event Tree



¹ If released fluid is toxic, or could result in steam burns or acid splashes, these consequences are considered before a safe dispersion.

Figure 5.3—Level 2 Consequence Analysis Event Tree for Leakage Case



¹ If released fluid is toxic, or could result in steam burns or acid splashes, these consequences are considered before a safe dispersion.

Figure 5.4—Level 2 Consequence Analysis Event Tree for Rupture Case

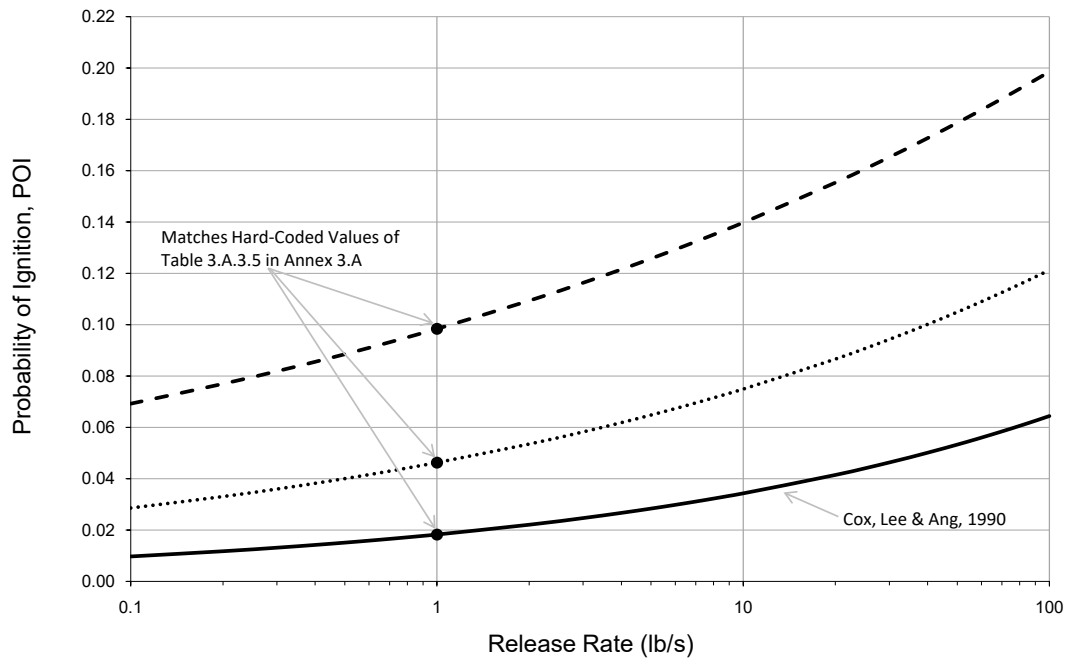


Figure 5.5—Probability of Ignition for Liquids (U.S. Customary Units)

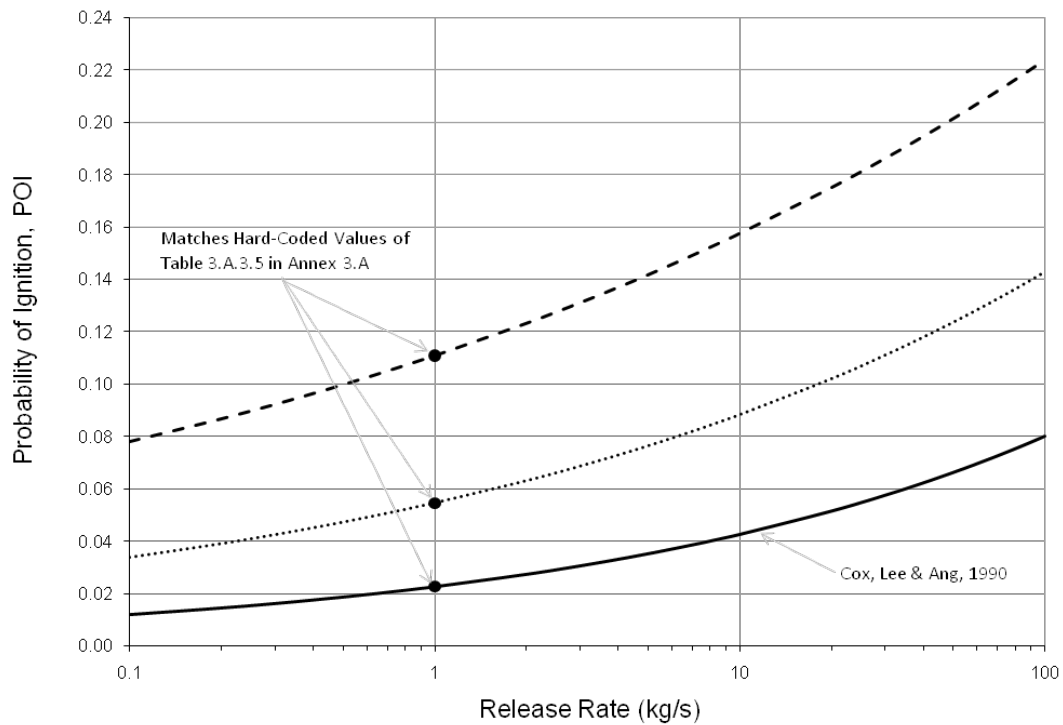


Figure 5.5M—Probability of Ignition for Liquids (Metric Units)

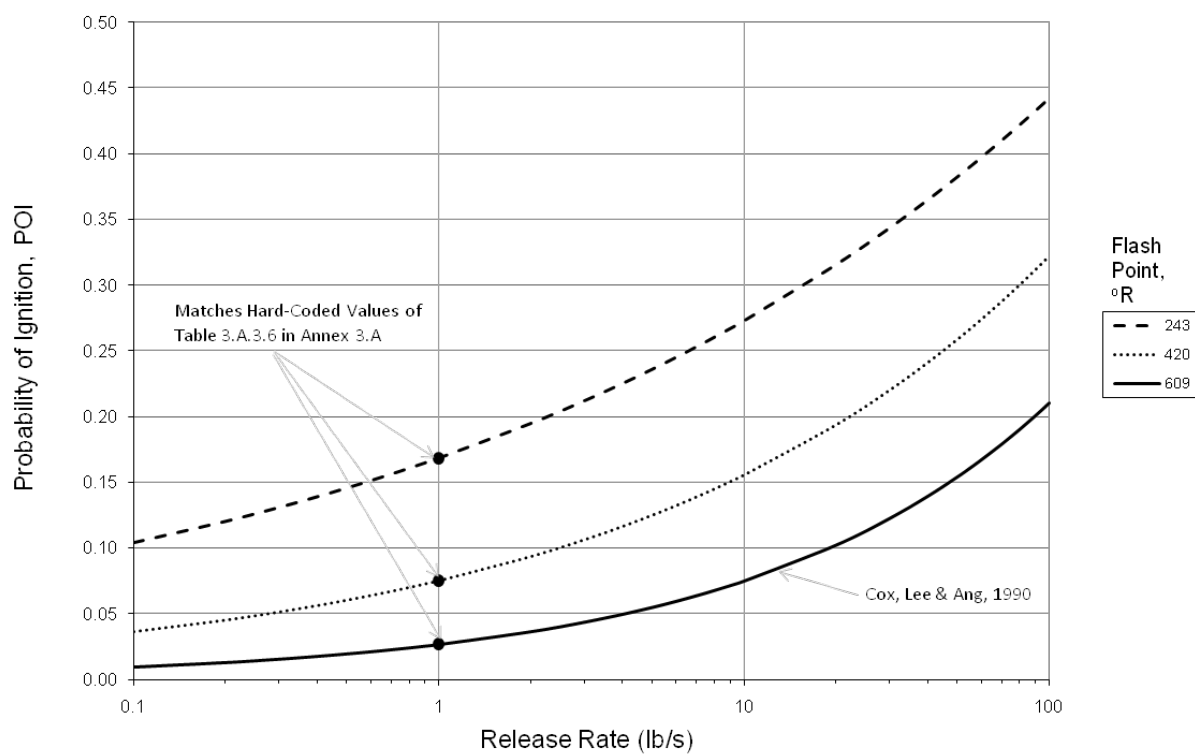


Figure 5.6—Probability of Ignition for Vapors (U.S. Customary Units)

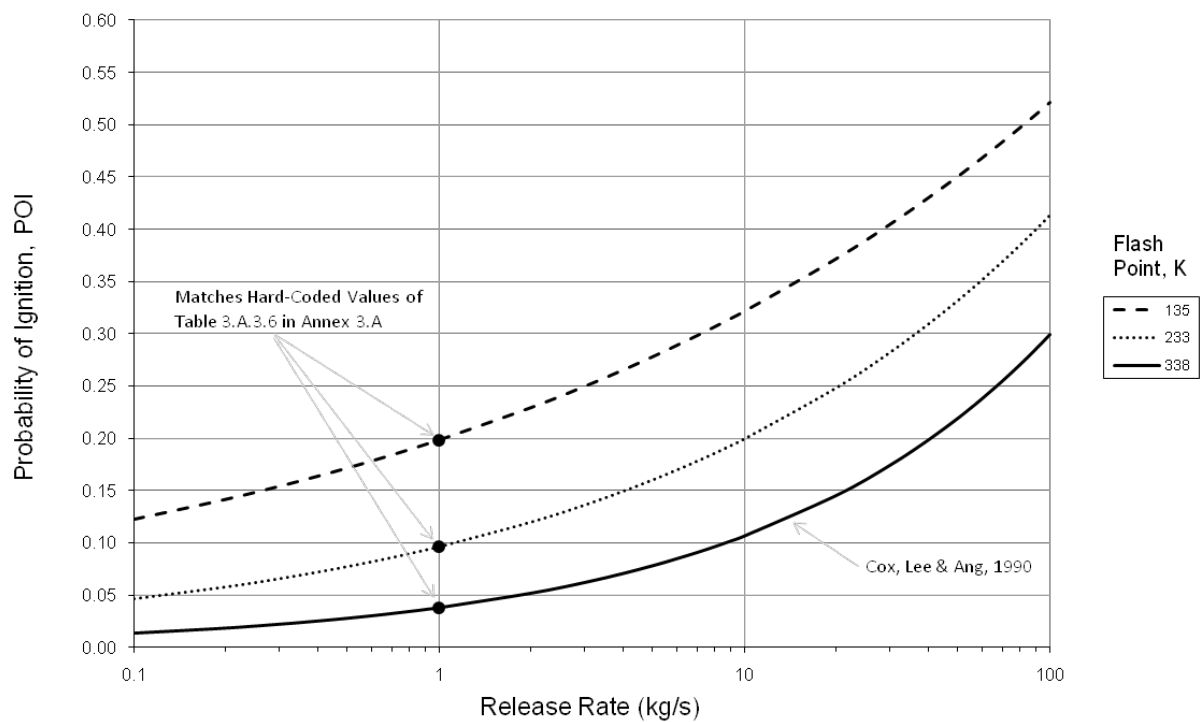


Figure 5.6M—Probability of Ignition for Vapors (Metric Units)

Part 3, Annex 3.A—Basis for Consequence Methodology

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Risk-based Inspection Methodology

Part 3—Consequence of Failure Methodology

Annex 3.A—Basis for Consequence Methodology

3.A.1 General

The consequence analysis is performed to aid in establishing a relative ranking of equipment items on the basis of risk. The consequence methodologies presented in [Part 3](#) of this document are intended as simplified methods for establishing relative priorities for inspection programs. If more accurate consequence estimates are needed, the analyst should refer to more rigorous analysis techniques, such as those used in quantitative risk assessments.

This annex provides background and supplemental information to the specific procedures for conducting the consequence analysis provided in [Part 3](#).

3.A.2 References

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 1—Introduction to Risk-Based Inspection Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 3—Consequence of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 4—Inspection Planning Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 5—Special Equipment*

API, *A Survey of API Members' Aboveground Storage Tank Facilities*, 1994

OFCM ¹, *Directory of Atmospheric Transport and Diffusion Consequence Assessment Models* (FC-13-1999), published by the Office of the Federal Coordinator for Meteorological Services and Supporting Research (OFCM) with the assistance of SCAPA members.

3.A.3 Level 1 Consequence Methodology

3.A.3.1 Representative Fluid and Associated Properties

3.A.3.1.1 Overview

In the Level 1 consequence analysis, a representative fluid that most closely matches the fluid contained in the pressurized system being evaluated is selected from the representative fluids shown in [Table 3.A.3.1](#). Because very few refinery and chemical plant streams are pure materials, the selection of a representative fluid involves making assumptions. The assumptions and the sensitivity of the results are dependent on the type of consequences being evaluated. If assumptions are not valid or the fluid in question is not properly represented by the fluids provided in [Table 3.A.3.1](#), a Level 2 consequence analysis is recommended using the methodology in [Part 3, Section 5](#).

¹ Office of the Federal Coordinator for Meteorological Services and Supporting Research, now known as the Interagency Council on Advancing Meteorological Services (ICAMS), Silver Spring, MD, www.icams-portal.gov.

3.A.3.1.2 Choice of Representative Fluids for Mixtures

3.A.3.1.2.1 General

For mixtures, the choice of the representative material should primarily be based on the NBP and the MW, and secondly on the density. If these values are unknown, an estimated property value for the mixture can be calculated using [Equation \(3.A.1\)](#) to assist in representative fluid selection using mole fraction weighting.

$$Property_{\text{mix}} = \sum x_i \cdot Property_i \quad (3.A.1)$$

It is important to note that the flammable consequence results are not highly sensitive to the exact material selected, provided the MWs are similar, because air dispersion properties and heats of combustion are similar for all hydrocarbons with similar MWs. This is particularly true for straight chain alkanes but becomes less true as the materials become less saturated or aromatic. Therefore, caution should be used when applying the Level 1 consequence analysis table lookups to materials (such as aromatics, chlorinated hydrocarbons, etc.) not explicitly defined in the representative fluid groups of [Table 3.A.3.1](#). In such cases, a Level 2 consequence analysis may be performed using a fluid property solver to determine the consequences of release.

3.A.3.1.2.2 Example

As an example of determining the various properties of mixtures, by applying [Equation \(3.A.1\)](#), a material containing 10 mol % C₃, 20 mol % C₄, 30 mol % C₅, 30 mol % C₆, and 10 mol % C₇ would have the following average key properties:

- a) MW = 74.8;
- b) AIT = 629.8 °F (322.1 °C) ;
- c) NBP = 102.6 °F (39.2 °C);
- d) density = 38.8 lb/ft³ (621.5 kg/m³).

The best selection from the materials in the representative fluids list of [Table 3.A.3.1](#) would be C₅, since the property of first importance is the NBP, and C₅ has a NBP of 97 °F (36 °C), which is lower than the calculated NBP of our example mixture. It is nonconservative to select a representative fluid with a higher NBP than the fluid being considered (e.g. C₆–C₈) when modeling a fluid with a weighted NBP of 210 °F (99 °C).

3.A.3.1.2.3 Example with a Mixture

If a mixture contains inert materials such as CO₂ or water, the choice of representative fluid may be based on the flammable/toxic materials of concern, excluding these materials. This is a conservative assumption that will result in higher COF results, but it is sufficient for risk prioritization. For example, if the material is 93 mol % water and 7 mol % C₂₀, using C₂₀ and the corresponding inventory of the hydrocarbon provides a conservative COF. A Level 2 consequence methodology may be used to more quantitatively model the release.

3.A.3.1.2.4 Toxic Mixture

If the mixture contains toxic components and a toxic consequence analysis is required, a flammable representative fluid is still required, even when the toxic component is a small fraction of the mixture. In this situation, the representative fluid is selected, as described in [Section 3.A.3.1.2.1](#) and [Equation \(3.A.1\)](#).

3.A.3.1.3 Fluid Properties

Representative fluid properties for the Level 1 consequence analysis are provided in [Table 3.A.3.1](#). The properties of fluids (or individual components of mixtures) can be found in standard chemical reference books.

3.A.3.2 Release Hole Size Selection

3.A.3.2.1 Overview

Part 3 of this document defines release hole sizes that represent small, medium, large, and rupture cases for various components or equipment types. This predefined set of release hole sizes are based on failure size distributions observed in piping and pressure vessels. The range of release hole sizes were chosen to address potential on-site and off-site consequences. For on-site effects, small and medium hole size cases usually dominate the risk due to a higher likelihood and potential for on-site consequences.

For off-site effects, medium and large hole size cases dominate risk. To address both on-site and off-site consequences and provide discrimination between components, four release hole sizes per component are used. The following sections discuss the criteria for selecting release hole sizes for specific equipment types.

3.A.3.2.2 Piping

Piping uses the standard four release hole sizes ($\frac{1}{4}$ in., 1 in., 4 in., and rupture), provided that the diameter of the leak is less than or equal to the diameter of the pipe. For example, an NPS 1 pipe has $\frac{1}{4}$ -in. and rupture release hole sizes, because the diameter is equal to a 1-in. release hole size. An NPS 4 pipe will have $\frac{1}{4}$ -in., 1-in., and rupture release hole sizes because the diameter is equal to a 4-in. hole size.

3.A.3.2.3 Pressure Vessels

The standard four release hole sizes are assumed for all sizes and pressure vessel types. Equipment types included in this general classification are as follows.

- a) Vessel—standard pressure vessels such as knock-out (KO) drums, accumulators, and reactors.
- b) Filter—standard types of filters and strainers.
- c) Column—distillation columns, absorbers, strippers, etc.
- d) Heat exchanger shell—shell side of reboilers, condensers, heat exchangers.
- e) Heat exchanger tube—tube side of reboilers, condensers, heat exchangers.
- f) Fin/fan coolers—fin/fan-type heat exchangers.

3.A.3.2.4 Pumps

Pumps are assumed to have $\frac{1}{4}$ -in., 1-in., and 4-in. possible release hole sizes. If the suction line is less than NPS 4, the release hole size should be the full diameter of the suction line. The use of three release hole sizes for pumps is consistent with historical failure data and ruptures are not modeled for pumps.

3.A.3.2.5 Compressors

Both centrifugal and reciprocating compressors use 1-in. and 4-in. (or suction line full bore rupture, whichever is smaller) release hole sizes. The selection of only two release hole sizes is consistent with historical failure data.

3.A.3.3 Fluid Inventory Available for Release

3.A.3.3.1 Overview

The consequence analysis requires an upper limit for the amount of fluid inventory that is available for release from a component. In theory, the total amount of fluid that can be released is the amount that is held within pressure-containing equipment between isolation valves that can be quickly closed. In reality, emergency

operations can be performed over time to close manual valves, de-inventory sections, or otherwise stop a leak. In addition, piping restrictions and differences in elevation can serve to slow or stop a leak. The inventory calculation as presented here is used as an upper limit and does not indicate that this amount of fluid would be released in all leak scenarios.

The Level 1 COF methodology is based on a procedure that determines the mass of fluid that could realistically be released in the event of a leak. When a component or equipment type is evaluated, the inventory of the component is combined with inventory from associated equipment that can contribute fluid mass to the leaking component. These items together form an *Inventory Group*. The procedure calculates the release mass as the lesser of the:

- a) mass of the component plus a 3-minute release through the hole to a maximum rupture hole size of 8 in. using the calculated release rate;
- b) total mass of the inventory group.

A 3-minute release time is based on the dynamics of a large leak scenario, where the leaking component will de-inventory and adjacent equipment provides additional inventory for the leak. Large leaks are detected within a few minutes because of the operational indications that a leak exists. The amount of time that a large leak or rupture will be fed is expected to range from 1 to 5 minutes, with 3 minutes selected as the midpoint of the range.

The 3-minute assumption is not as applicable to small leaks, since it is far less likely that small leaks will persist long enough to empty the inventory from the leaking component and additional inventory from other components in the inventory group. In these situations, plant detection, isolation, and mitigation techniques will limit the duration of the release so that the actual mass released to atmosphere will be significantly less than the available mass as determined above.

Calculating the inventories for equipment and piping can be done using the guidelines provided in [Section 3.A.3.3.2](#) through [Section 3.A.3.3.4](#).

3.A.3.3.2 Liquid Inventory

Liquid inventories for components are calculated using the assumptions presented in [Table 3.A.3.2](#) (normal operating levels should be used, if known). Common equipment and piping groups for liquid systems include:

- a) the bottom half of a distillation column, reboiler, and the associated piping,
- b) accumulators and liquid outlet piping,
- c) feed pipeline,
- d) storage tanks and outlet piping, and
- e) series of heat exchangers and associated piping.

Once the liquid inventory groups are established, the inventory for each component is added to obtain the total group inventory. The liquid inventory determined in this manner is used for each component in the group.

3.A.3.3.3 Vapor Inventory

Common equipment and piping groups for vapor systems include:

- a) the top half of the distillation column, overhead piping, and the overhead condenser, and
- b) vent header line, KO pot, and exit line.

The inventory for vapor systems is governed by the flow or charge rate through the system rather than inventory. A method for determining inventory is to use the flow rate for a specified time (e.g. 60 minutes) to calculate release mass. If this rate is not known, the upstream group liquid inventory can be used since flashing occurs from the liquid system. Using the upstream group liquid inventory will result in a conservative inventory calculation.

3.A.3.3.4 Two-phase Systems

Two-phase systems can be modeled as a liquid or vapor. The conservative assumption is that the release occurs in the lower portion of the component and results in a liquid release. If the upstream system is primarily liquid, only the liquid inventory can be calculated and this limits the conservativeness of modeling a two-phase system as liquid. Conversely, if the upstream inventory is primarily vapor, the vapor inventory can be calculated with an adjustment for the liquid portion.

3.A.3.4 Determination of the Release Type (Instantaneous or Continuous)

Different analytical models and methods are used to estimate the effects of an instantaneous versus a continuous type of release. The COF can differ greatly, depending on the analytical model chosen to represent a release. Therefore, it is very important that a release is properly categorized into one of the two release types.

An example of the importance of proper model selection is a vapor cloud explosion (VCE). A review of historical data on fires and explosions shows that *unconfined* VCEs are more likely to occur for an instantaneous vapor release than a continuous release. An instantaneous release is defined as the release of more than 10,000 lb (4,536 kg) of mass in a short period of time. Using this definition for a continuous release reflects the tendency for mass released in a short period of time, less than 10,000 lb (4,536 kg), to result in a flash fire rather than a VCE.

In the Level 1 consequence procedure, the continuous release model uses a lower probability for a VCE following a leak and the probability of a VCE is a function of release type, not release rate. Level 1 consequence procedure event probabilities are provided in [Tables 3.A.3.3](#) through [3.A.3.6](#). The Level 2 procedure determines event probabilities as a function of release type and release rate (see [Part 3, Section 5.8.1](#) for determining event probabilities for a Level 2 consequence procedure).

3.A.3.5 Determination of Flammable and Explosive Consequences

3.A.3.5.1 Overview

Consequence is measured in terms of the area affected by the ignition of a flammable release. There are several potential consequence outcomes for any release involving a flammable material; however, a single combined COF is calculated as the probability weighted average of all possible consequence outcomes. The probability of a consequence outcome is different from, and should not be confused with, the POF discussed in [Part 2](#), which involves evaluation of the component damage state that affects equipment integrity.

The probability of a consequence outcome is the probability that a specific physical phenomenon (outcome) will be observed after the release has occurred. Potential release consequence outcomes for flammable materials are:

- a) safe dispersion,
- b) jet fire,
- c) VCE,
- d) flash fire,

- e) fireball, and
- f) liquid pool fire.

A description of each event outcome is provided in [Part 3, Section 5.8](#).

3.A.3.5.2 Assumptions and Limitations

The consequence procedure is a simplified approach to a relatively complex discipline. A large number of assumptions are implicit in the procedure in addition to the assumptions that would be part of a more in-depth analysis. This section is intended to highlight a few of the more important assumptions related to the simplified approach but does not attempt a comprehensive discussion.

- a) The consequence area does not reflect where the damage occurs. Jet and pool fires tend to have damage areas localized around the point of the release, but VCE and flash fires may result in damage far from the release point.
- b) The use of a fixed set of conditions for meteorology and release orientations was chosen to represent a conservative basis for the consequence modeling. Meteorological and release orientations are site and situation specific. Quantitative risk assessment calculations allow for customization due to actual site condition since it significantly impacts the results.
- c) The probabilities associated with potential release event outcomes can be situation and site specific. Standardized event trees, including ignition probabilities, were chosen to reflect typical conditions expected for the refining and petrochemical industries. Quantitative risk assessment calculations allow for customization of event probabilities since they significantly impact the results.

3.A.3.5.3 Basis for Flammable Consequence Area Tables

3.A.3.5.3.1 General

For representative fluids shown in [Table 3.A.3.1](#), flammable consequences are determined by using the equations presented in lookup tables, allowing the RBI analyst to establish approximate consequence measures using the following information:

- a) representative fluid and properties,
- b) release type (continuous or instantaneous) and phase of dispersion, and
- c) release rate or mass, depending on the type of dispersion and the effects of detection, isolation, and mitigation measures.

3.A.3.5.3.2 Predicting Probabilities of Flammable Outcomes

Each flammable event outcome is the result of a chain of events. Event trees, as shown in [Figure 3.A.3.1](#), are used to visually depict the possible chain of events that lead to each outcome. The event trees also are used to show how various individual event probabilities should be combined to calculate the probability for the chain of events.

For a given release type, the two main factors that define the outcome of the release of flammable material are the probability of ignition and the timing of ignition. The three possibilities depicted in the outcome event trees are no ignition, early ignition, and late ignition. The event tree outcome probabilities used in the Level 1 consequence analysis for all release types are presented in [Tables 3.A.3.3 through 3.A.3.6](#) according to the release type and representative fluid. Each row within the tables contains probabilities for the potential outcome, according to the representative fluid. Event trees developed for standard risk analyses were used to develop the relative outcome probabilities. Ignition probabilities were based on previously developed correlations. In general, ignition probabilities are a function of the following fluid parameters:

- a) AIT,
- b) flash temperature,
- c) NFPA Flammability Index, and
- d) flammability range (difference between upper and lower flammability limits).

Fluids that are released well above their AITs will have markedly different ignition probabilities ([Table 3.A.3.3](#) and [Table 3.A.3.4](#)) than those released near or below their AITs ([Table 3.A.3.5](#) and [Table 3.A.3.6](#)).

3.A.3.5.3.3 Calculating Consequences for Each Outcome

A set of materials were run through a hazards analysis screening to determine the consequence areas for all potential outcomes. The consequence areas were then plotted as a function of release rate or mass to generate graphs. When plotted on a log/log scale, the consequence curves formed straight lines that were fit to an equation relating consequence area to the release rate or mass. The consequence equations are presented in the following generic form:

$$CA_f = x(\text{rate})^y \quad \text{for a continuous release} \quad (3.A.2)$$

$$CA_f = x(\text{mass})^y \quad \text{for an instantaneous release} \quad (3.A.3)$$

The consequence of a release of flammable materials is not strongly dependent on the duration of the release because most fluids reach a steady state size, or footprint, within a short period of time if released into the atmosphere. The only exception to this generalization is a pool fire resulting from the continuous release of a liquid. If flammable liquids are released in a continuous manner, the consequences associated with a pool fire will depend on the duration and the total mass of the release.

3.A.3.5.3.4 Calculation of the Combined Consequence Area

An equation that represents a single consequence area for the combination of possible outcomes can be derived for each of the four combinations of release types and final phase cases. The combined consequence area is determined by a two-step process.

- a) Step 1—Multiply the consequence area for each outcome [calculated from [Equation \(3.A.2\)](#)] by the associated event tree probabilities (taken from the appropriate [Tables 3.A.3.3 through 3.A.3.6](#)). If the impact criterion uses only a portion of the consequence area (for instance, flash fires use only 25 % of the area within the LFL for equipment damage), include this in the probability equation.
- b) Step 2—Sum all of the consequence-probability products found in Step 1.

The equation that summarizes the result of the process is as follows:

$$CA_{f,comb} = \sum p_i CA_{f,i} \quad (3.A.4)$$

The procedure for combining consequence equations for all the potential outcomes was performed for a set of representative fluids (see [Table 3.A.3.1](#)). The results of this exercise are the equations given in [Part 3](#), [Tables 4.8](#) and [4.9](#).

3.A.3.5.3.5 Consequence Analysis Dispersion Modeling

The computer modeling necessary to determine consequence areas associated with cloud dispersion (flash fires, VCEs, toxic releases) requires specific input regarding meteorological and release conditions. For the Level 1 consequence analysis, meteorological conditions representative of the Gulf Coast annual averages were used. These conditions can also be used when performing a Level 2 consequence analysis. The meteorological input assumptions were as follows:

- c) atmospheric temperature 70 °F (21 °C),
- d) RH 75 %,
- e) wind speed 8 mph (12.9 km/h),
- f) Stability Class D, and
- g) surface roughness parameter 1.2 in. (30.5 mm) for typical for processing plants.

Additional constants were used as part of the Level 1 consequence analysis as follows:

- a) initial pressure typical of medium-pressure processing conditions with a refinery 100 psig (0.69 MPa),
- b) initial temperatures representing a range from low-temperature [below autoignition, i.e. 68 °F (20 °C)] to high-temperature (near autoignition) conditions,
- c) range of release hole sizes from 0.25 in. to 16 in. (6.35 mm to 406 mm) diameter for continuous events,
- d) range of release masses from 100 lb to 100,000 lb (45.4 kg to 453,592 kg), and
- e) both vapor and liquid releases from a component containing saturated liquid, with release orientation horizontal downwind at an elevation of 10 ft over a concrete surface.

Analysis has shown that these assumptions are satisfactory for a wide variety of plant conditions. Where these assumptions are not suitable, the analyst should consider performing a Level 2 consequence analysis.

3.A.3.6 Determination of Toxic Consequences

3.A.3.6.1 Overview

As with the flammable consequence analysis, dispersion analysis has been performed to evaluate the consequence areas associated with the release of toxic fluids to the atmosphere. The assumptions made for the cloud dispersion modeling are as described in [Section 3.A.3.5.3.5](#). Toxic consequences are determined by using the equations presented in lookup tables similar to the flammable consequence analysis described in [Section 3.A.3.5](#).

3.A.3.6.2 Background for Calculation of Toxic Consequences

The development of the toxic consequence area equations for the Level 1 consequence analysis considers exposure time and concentration. These two components combine to result in an exposure that is referred to as the toxic dose. The degree of injury from a toxic release is directly related to the toxic dose. Level 1 consequence methodology relates dose to injury using probits.

For toxic vapor exposure, the probit (a shortened form of probability unit) is represented as follows:

$$Pr = A + B \cdot \ln \left[C^n_t \right] \quad (3.A.5)$$

Example constants for the probit equation are provided in [Part 3, Table 4.14](#) for various toxic fluids. A single fixed probability of fatality (50 % probability of fatality) is used to determine the toxic impact. This level corresponds to a probit value of 5.0.

3.A.3.6.3 Toxic Continuous Releases

A cloud dispersion model is used to analyze a continuous release (plume model) to the atmosphere. The cloud footprint or plan area is approximated as the shape of an ellipse, as shown in [Figure 3.A.3.2](#), and is calculated using [Equation \(3.A.6\)](#).

$$A = \pi ab \quad (3.A.6)$$

3.A.3.6.4 Toxic Instantaneous Releases

For instantaneous releases (puff model), the dispersion of the cloud over time is shown in [Figure 3.A.3.3](#). The plan area covered by the cloud is conservatively assumed to be an ellipse, except that the y-distance (a) is taken as one-half of the maximum cloud width as determined from the dispersion results. As part of a Level 2 consequence methodology, cloud dispersion modeling software exists that provides a more accurate plot area as a function of concentration than the elliptical area assumptions made above.

3.A.3.6.5 Development of Toxic Consequence Areas for HF Acid

3.A.3.6.5.1 General

HF is typically stored, transferred, and processed in liquid form. However, the toxic impact associated with a release of liquid HF into the atmosphere is due to the dispersion of the toxic vapor cloud. A toxic vapor cloud of HF can be produced by flashing of the liquid upon release or evaporation from a liquid pool. For the Level 1 consequence analysis, the initial state of HF is assumed to be liquid; the models for calculating the toxic impact areas for HF liquid releases take into account the possibility of flashing and pool evaporation. For HF releases, the Level 1 consequence analysis uses the following guidelines to determine the release rate or mass of mixtures containing HF.

- The mass fraction of HF is calculated if the released material contains HF as a component in a mixture.
- The liquid release rate (or mass) of the HF component is used to calculate the toxic impact area.
- The release rate is calculated for a continuous release of the fluid using the closest matching representative fluid and with the equations provided in [Part 3, Section 4.3](#). If the released fluid contains a toxic component, the toxic release rate is calculated as the product of the toxic component mass fraction and the release rate for the mixture.

A consequence analysis software program (PHAST) was used to generate a range of release rates and durations to obtain graphs of toxic consequence areas. Release durations of instantaneous (less than 3 minutes), 5 minutes (300 seconds), 10 minutes (600 seconds), 30 minutes (1800 seconds), 40 minutes (2400 seconds), and 1 hour (3600 seconds) were evaluated to obtain toxic consequence areas for varying release rates. Toxic impact criteria used was for a probit value of 5.0 using the probit [Equation \(3.A.5\)](#) and probit values listed in [Part 3, Table 4.14](#) for HF.

3.A.3.6.5.2 Continuous Releases

The results of the dispersion analyses showed that the clouds modeled in accordance with the approximated shapes of [Section 3.A.3.6.3](#) could be correlated as functions of release rate for continuous releases in accordance with [Equation \(3.A.7\)](#).

$$CA_f = C_8 \cdot 10^{(c \cdot \log_{10}[C_4 \cdot \text{rate}] + d)} \quad (3.A.7)$$

For continuous releases, the values of the constants c and d are functions of the release duration and provided for HF in [Part 3, Table 4.11](#).

3.A.3.6.5.3 Instantaneous Releases

The results of the dispersion analyses showed that the clouds modeled in accordance with the approximated shapes of [Section 3.A.3.6.4](#) could be correlated as functions of release mass for instantaneous releases in accordance with [Equation \(3.A.8\)](#).

$$CA_f = C_8 \cdot 10^{(c \cdot \log_{10}[C_4 \cdot \text{mass}] + d)} \quad (3.A.8)$$

For instantaneous releases, the values of the constants c and d are provided for HF and H₂S in [Part 3, Table 4.11](#).

3.A.3.6.6 Development of Toxic Consequence Areas for H₂S

3.A.3.6.6.1 General

H₂S is processed as a vapor or when processed under high pressures, quickly flashes upon release due to its low boiling point. In either case, the release of H₂S to the atmosphere results in the quick formation of a toxic vapor cloud. For H₂S releases, the Level 1 consequence analysis uses the following guidelines to determine the release rate or mass of mixtures containing H₂S.

- a) If the released material contains H₂S as a component in a mixture, the mass fraction of H₂S is obtained, and If the initial state of the material is a vapor, the mass fraction of H₂S is used to obtain the vapor discharge rate (or mass) of only H₂S; this rate (or mass) is used to determine the impact area.
- b) If the initial state of the material is a liquid, the mass fraction of H₂S is used to obtain the vapor flash rate (or mass) of only the H₂S; this rate (or mass) is used to determine the impact.
- c) If the initial phase of a material being released is 1 wt % H₂S in gas oil, the material has the potential for both toxic and flammable outcomes from the vapor and flammable outcomes from the liquid. Therefore, the following procedure is followed, using C₁₇–C₂₅ as the representative material.
 - 1) Calculate the liquid discharge rate for C₁₇–C₂₅ as described in [Part 3, Section 4.3](#).
 - 2) When estimating flammable consequences, calculate the potential flammable consequence areas as in [Part 3, Section 4.3](#) and take the worst case between:
 - i) the flammable effects of C₁₇–C₂₅ using 100 % of the release rate,
 - ii) the flammable effects of H₂S based on 1 % of the release rate.
 - 3) Calculate the toxic effects of H₂S, using 1 % of the release rate.

For instantaneous releases, use the above procedure, substituting inventory mass for release rate.

The release durations used to model the consequences of the H₂S release were identical to those assumed for HF acid as discussed in [Section 3.A.3.6.5.2](#).

3.A.3.6.6.2 Continuous Releases

The results of the dispersion analyses showed that the clouds modeled in accordance with the approximated shapes of [Section 3.A.3.6.3](#) could be correlated as functions of release rate for continuous releases in accordance with [Equation \(3.A.7\)](#).

The values of the constants c and d are functions of the release duration and provided for H₂S in [Part 3, Table 4.11](#).

3.A.3.6.6.3 Instantaneous Releases

The results of the dispersion analyses showed that the clouds modeled in accordance with the approximated shapes of [Section 3.A.3.6.4](#) could be correlated as functions of release mass for instantaneous releases in accordance with [Equation \(3.A.8\)](#).

For instantaneous releases, the values of the constants c and d are provided for H₂S in [Part 3, Table 4.11](#).

3.A.3.6.7 Development of Toxic Consequence Areas for Ammonia

3.A.3.6.7.1 General

To estimate the consequence area for ammonia, the dispersion analyses was performed using a saturated liquid at ambient temperature [5 °F (24 °C)], with liquid being released from a low pressure storage tank. The tank head was set at 10 ft (3.05 m).

3.A.3.6.7.2 Continuous Releases

To determine an equation for the continuous area of a release of ammonia, four release hole sizes (¹/₄ in., 1 in., 4 in., and 16 in.) were run for various release durations (10, 30, and 60 minutes). Again, toxic consequences were calculated using a software package containing atmospheric dispersion routines.

Toxic impact criteria used was for a probit value of 5.0 using the probit [Equation \(3.A.5\)](#) and probit values listed in [Part 3, Table 4.17](#) for ammonia. The results showed that the clouds modeled in accordance with the approximated shapes of [Section 3.A.3.6.3](#) could be correlated as functions of release rate for continuous releases in accordance with [Equation \(3.A.9\)](#).

$$CA_f = e(rate)^f \quad (3.A.9)$$

For continuous releases, the values of the constants e and f are functions of the release duration and provided for ammonia in [Part 3, Table 4.12](#).

3.A.3.6.7.3 Instantaneous Releases

For instantaneous release cases, four release masses of ammonia were modeled (10 lb, 100 lb, 1,000 lb, and 10,000 lb), and the relationship between release mass and consequence area to a probit value of 5.0 were correlated. The results in ft² for ammonia are provided in [Equation \(3.A.10\)](#).

$$CA_f = 14.17(mass)^{0.9011} \quad (3.A.10)$$

3.A.3.6.8 Development of Toxic Consequence Areas for Chlorine

3.A.3.6.8.1 General

To estimate the consequence area for chlorine, the dispersion analyses were performed using the identical procedure for ammonia as described in [Section 3.A.3.6.7.1](#) and [Section 3.A.3.6.7.2](#).

3.A.3.6.8.2 Continuous Releases

The results of the cloud modeling for chlorine showed that the consequence areas could be correlated as functions of release rate for continuous releases in accordance with [Equation \(3.A.9\)](#).

For continuous releases, the values of the constants e and f are functions of the release duration and provided for chlorine in [Part 3, Table 4.12](#).

3.A.3.6.8.3 Instantaneous Releases

For instantaneous release cases, the consequence areas in ft² for chlorine could be correlated using [Equation \(3.A.11\)](#).

$$A = 14.97 (mass)^{1.117} \quad (3.A.11)$$

3.A.3.6.9 Development of Toxic Consequence Areas for Common Chemicals

3.A.3.6.9.1 General

Procedures to perform Level 1 consequence analysis have been completed for 10 additional toxic chemicals:

- a) aluminum chloride (AlCl₃),
- b) carbon monoxide (CO),
- c) hydrogen chloride (HCl),
- d) nitric acid,
- e) nitrogen dioxide (NO₂),
- f) phosgene,
- g) toluene diisocyanate (TDI),
- h) ethylene glycol monoethyl ether (EE),
- i) ethylene oxide (EO), and
- j) propylene oxide (PO).

The Level 1 consequence analysis equations for these chemicals have been developed using the same approach as for ammonia and chlorine, described in [Section 3.A.3.6.7](#) and [Section 3.A.3.6.8](#).

3.A.3.6.9.2 Continuous Releases

For continuous releases, the consequence area can be approximated as a function of duration using [Equation \(3.A.9\)](#) with the constants e and f provided in [Part 3, Table 4.12](#).

3.A.3.6.9.3 Instantaneous Releases

Toxic consequences of an instantaneous release for the toxic chemicals listed in [Section 3.A.3.6.9.1](#) estimated smaller (or 0) affected areas than equivalent continuous releases. A conservative curve was calculated using a short duration continuous release toxic consequence curve instead of a less conservative instantaneous release area.

3.A.3.7 Nomenclature

The following lists the nomenclature used in [Section 3.A.3](#). The coefficients C_1 through C_{41} that provide the metric and U.S conversion factors for the equations are provided in [Annex 3.B](#).

A	is a constant for the probit equation
a	is one-half of the cloud width (minor axis), taken at its largest point (within the 50 % probability of fatality dose level)
B	is a constant for the probit equation
b	is one-half of the downwind dispersion distance (major axis), taken at the 50 % probability of fatality dose level
C	is the toxic concentration in the probit equation, ppm
CA_f	is the consequence area, ft ² (m ²)
$CA_{f,comb}$	is the combined/probability weighted consequence area, ft ² (m ²)
$CA_{f,i}$	is the individual outcome consequence area for the i^{th} event outcome, ft ² (m ²)
c	is a constant for the specific consequence area equations for HF acid and H ₂ S
d	is a constant for the specific consequence area equations for HF acid and H ₂ S
e	is the constant for the specific consequence area equations for ammonia and chlorine
f	is the exponent for the specific consequence area equations for ammonia and chlorine
$mass$	is the release mass, lb (kg)
n	is the exponent in the probit equation
Pr	is the probit value, typically 5.0, which is defined as 50 % probability
p_i	is the specific event probability for the i^{th} event outcome; see Tables 3.A.3.3 , 3.A.3.4 , 3.A.3.5 , or 3.A.3.6
$rate$	is the release rate, lb/s (kg/s)
t	is the toxic dosage in the probit equation, seconds
x	is the constant for the generic consequence area equation
y	is the exponent for the generic consequence area equation

3.A.3.8 Tables

Table 3.A.3.1—List of Representative Fluids Available for Level 1 Consequence Methodology

Representative Fluid	Examples of Applicable Materials	MW	NBP		AIT	
			°C	°F	°C	°F
C ₁ –C ₂	Methane, ethane, ethylene, LNG, fuel gas	23	–125	–193	558	1,036
C ₃ –C ₄	Propane, butane, isobutane, LPG	51	–21	–6.3	369	696
C ₅	Pentane	72	36	97	284	544
C ₆ –C ₈	Gasoline, naphtha, light straight run, heptane	100	99	210	223	433
C ₉ –C ₁₂	Diesel, kerosene	149	184	364	208	406
C ₁₃ –C ₁₆	Jet fuel, kerosene, atmospheric gas oil	205	261	502	202	396
C ₁₇ –C ₂₅	Gas oil, typical crude	280	344	651	202	396
C ₂₅₊	Residuum, heavy crude, lube oil, seal oil	422	527	981	202	396
Water	Water	18	100	212	N/A	N/A
Steam	Steam	18	100	212	N/A	N/A
Acid	Acid, caustic	18	100	212	N/A	N/A
H ₂	Hydrogen only	2	–253	–423	400	752
H ₂ S	Hydrogen sulfide only	34	–59	–75	260	500
HF	Hydrogen fluoride	20	20	68	17,760	32,000
CO	Carbon monoxide	28	–191	–312	609	1,128
DEE	Diethyl ether	74	35	95	160	320
HCl	Hydrogen chloride	36	–85	–121	N/A	N/A
Nitric acid	Nitric acid	63	121	250	N/A	N/A
NO ₂	Nitrogen dioxide	90	135	275	N/A	N/A
Phosgene	Phosgene	99	83	181	N/A	N/A
TDI	Toluene diisocyanate	174	251	484	620	1,148
Methanol	Methanol	32	65	149	464	867
PO	Propylene oxide	58	34	93	449	840
Styrene	Styrene	—	—	—	—	—
EEA	Ethylene glycol monoethyl ether acetate	132	156	313	379	715
EE	Ethylene glycol monoethyl ether	90	135	275	235	455
EG	Ethylene glycol	62	197	387	396	745
EO	Ethylene oxide	44	11	51	429	804

Table 3.A.3.2—Assumptions Used when Calculating Liquid Inventories Within Equipment

Equipment Description	Component Type	Examples	Default Liquid Volume (LV) %
Process columns (may be treated as two or three items) — top half — middle section — bottom half	COLTOP COLMID COLBTM	Distillation columns, FCC main fractionator, splitter tower, debutanizer, packed columns (see Note 1), liquid/liquid columns (see Note 2)	25 % 25 % 37 % These default values are typical of trayed distillation columns and consider liquid holdup at the bottom of the vessel as well as the presence of chimney trays in the upper sections
Accumulators and drums	DRUM	Overhead accumulators, feed drums, high-pressure/low-pressure (HP/LP) separators, nitrogen storage drums, steam condensate drums, three-phase separators (see Note 3)	50 % liquid Typically, two-phase drums are liquid level controlled at 50 %
KO pots and dryers	KODRUM	Compressor KOs, fuel gas KO drums, flare drums, air dryers (see Note 5)	10 % liquid Much less liquid inventory expected in KO drums
Compressors	COMPC COMPR	Centrifugal and reciprocating compressors	Negligible, 0 %
Pumps	PUMP1S PUMP2S PUMPR	Pumps	100 % liquid
Heat exchangers	HEXSS HEXTS	Shell and tube exchangers	50 % shellside, 25 % tubeside
Fin fan air coolers	FINFAN TUBE FINFAN HEADER	Total condensers, partial condensers, vapor coolers, and liquid coolers (see Note 4)	25 % liquid
Filters	FILTER		100 % full
Piping	PIPE-xx		100 % full, calculated for Level 2 methodology
Reactors	REACTOR	Fluid reactors (see Note 6), fixed-bed reactors (see Note 7), mole-sieves	15 % liquid

NOTE 1 Packed columns will typically contain much less liquid traffic than trayed columns. Typical LV percentages for packed columns are 10 % to 15 %.

NOTE 2 For liquid/liquid columns, such as amine contactors, caustic contactors, and lube or aromatics extractors, where a solvent or other fluid is brought into direct contact with the process fluid (e.g. TEG and BTX in an aromatics extractor), the LV % will be much higher. Consideration should be given to the amount of each fluid in the vessel and whether or not the fluid composition includes both fluids in the mixture composition.

NOTE 3 For three-phase separators, such as desalters and overhead drums with water boots, the LV % may be lower than 50 %, depending on how much of the second liquid phase (typically water) is present and whether or not the fluid composition includes both liquid phases in the mixture composition.

NOTE 4 Most air coolers are two-phase and only partially condense vapors. Even A/Cs that totally condense the vapor stream require the majority of the heat transfer area (and volume) to cool the vapors to their dew point and condense to liquid. Typically, only the final pass (less rows of tubes than other passes) will be predominately liquid. A LV % of 25 % should still be conservative for all A/Cs except liquid coolers where a LV of 100 % should be used.

NOTE 5 For flue gas KO drums and air dryers, the LV % is typically negligible. Consideration should be given to reducing LV % to 0 %.

NOTE 6 Fluidized reactors can have up to 15 % to 25 % of the available vessel volume taken up by catalyst. The remaining available volume is predominately vapor. A LV % of 15 % should still be conservative.

NOTE 7 Fixed-bed reactors can have up to 75 % of the available vessel volume taken up by hardware and catalyst. The remaining volume will typically be 50 % liquid and 50 % vapor. An assumed LV of 15 % of the overall available vessel volume should still be conservative.

Table 3.A.3.3—Specific Event Probabilities—Continuous Release Autoignition Likely

Final Liquid State—Processed Above AIT						
Fluid	Probability of Ignition	Probabilities of Outcome				
		VCE	Fireball	Flash Fire	Jet Fire	Pool Fire
C ₁ –C ₂						
C ₃ –C ₄						
C ₅						
C ₆ –C ₈	1				1	
C ₉ –C ₁₂	1				1	
C ₁₃ –C ₁₆	1				0.5	0.5
C ₁₇ –C ₂₅	1				0.5	0.5
C ₂₅₊	1					1
H ₂						
H ₂ S						
Styrene	1				1	
Final Gas State—Processed Above AIT						
Fluid	Probability of Ignition	Probabilities of Outcome				
		VCE	Fireball	Flash Fire	Jet Fire	Pool Fire
C ₁ –C ₂	0.7				0.7	
C ₃ –C ₄	0.7				0.7	
C ₅	0.7				0.7	
C ₆ –C ₈	0.7				0.7	
C ₉ –C ₁₂	0.7				0.7	
C ₁₃ –C ₁₆						
C ₁₇ –C ₂₅						
C ₂₅₊						
H ₂	0.9				0.9	
H ₂ S	0.9				0.9	
Styrene	1				1	

NOTE 1 Shaded areas represent outcomes that are not possible.

NOTE 2 Must be processed at least 80 °F (27 °C) above AIT.

Table 3.A.3.4—Specific Event Probabilities—Instantaneous Release Autoignition Likely

Final Liquid State—Processed Above AIT						
Fluid	Probability of Ignition	Probabilities of Outcome				
		VCE	Fireball	Flash Fire	Jet Fire	Pool Fire
C ₁ –C ₂	0.7		0.7			
C ₃ –C ₄	0.7		0.7			
C ₅	0.7		0.7			
C ₆ –C ₈	0.7		0.7			
C ₉ –C ₁₂	0.7		0.7			
C ₁₃ –C ₁₆						
C ₁₇ –C ₂₅						
C ₂₅₊						
H ₂	0.9		0.9			
H ₂ S	0.9		0.9			
Styrene	1					1
Final Gas State—Processed Above AIT						
Fluid	Probability of Ignition	Probabilities of Outcome				
		VCE	Fireball	Flash Fire	Jet Fire	Pool Fire
C ₁ –C ₂	0.7		0.7			
C ₃ –C ₄	0.7		0.7			
C ₅	0.7		0.7			
C ₆ –C ₈	0.7		0.7			
C ₉ –C ₁₂	0.7		0.7			
C ₁₃ –C ₁₆						
C ₁₇ –C ₂₅						
C ₂₅₊						
H ₂	0.9		0.9			
H ₂ S	0.9		0.9			
Styrene	1		1			

NOTE 1 Shaded areas represent outcomes that are not possible.

NOTE 2 Must be processed at least 80 °F (27 °C) above AIT.

Table 3.A.3.5—Specific Event Probabilities—Continuous Release Autoignition Not Likely

Final Liquid State—Processed Below AIT						
Fluid	Probability of Ignition	Probabilities of Outcome				
		VCE	Fireball	Flash Fire	Jet Fire	Pool Fire
C ₁ –C ₂						
C ₃ –C ₄						
C ₅	0.1				0.02	0.08
C ₆ –C ₈	0.1				0.02	0.08
C ₉ –C ₁₂	0.05				0.01	0.04
C ₁₃ –C ₁₆	0.05				0.01	0.04
C ₁₇ –C ₂₅	0.020				0.005	0.015
C ₂₅₊	0.020				0.005	0.015
H ₂						
H ₂ S						
DEE	1.0				0.18	0.72
Methanol	0.4				0.08	0.32
PO	0.4				0.08	0.32
Styrene	0.1				0.02	0.08
EEA	0.10				0.02	0.08
EE	0.10				0.02	0.08
EG	0.10				0.02	0.08
Final Gas State—Processed Below AIT						
Fluid	Probability of Ignition	Probabilities of Outcome				
		VCE	Fireball	Flash Fire	Jet Fire	Pool Fire
C ₁ –C ₂	0.2	0.04		0.06	0.1	
C ₃ –C ₄	0.1	0.03		0.02	0.05	
C ₅	0.1	0.03		0.02	0.05	
C ₆ –C ₈	0.1	0.03		0.02	0.05	
C ₉ –C ₁₂	0.05	0.01		0.02	0.02	
C ₁₃ –C ₁₆						
C ₁₇ –C ₂₅						
C ₂₅₊						
H ₂	0.9	0.4		0.4	0.1	
H ₂ S	0.9	0.4		0.4	0.1	
CO	0.899	0.4		0.4	0.099	
DEE	0.899	0.4		0.4	0.099	
Methanol	0.4	0.104		0.104	0.192	
PO	0.4	0.178		0.178	0.044	
Styrene	0.1	0.026		0.026	0.048	
EEA	0.1	0.026		0.026	0.048	
EE	0.1	0.026		0.026	0.048	
EG	0.1	0.026		0.026	0.048	
EO	0.9	0.4		0.4	0.1	

NOTE 1 Shaded areas represent outcomes that are not possible.
NOTE 2 Must be processed at least 80 °F (27 °C) below AIT.

Table 3.A.3.6—Specific Event Probabilities—Instantaneous Release Autoignition Not Likely

Final Liquid State—Processed Below AIT						
Fluid	Probability of Ignition	Probabilities of Outcome				
		VCE	Fireball	Flash Fire	Jet Fire	Pool Fire
C ₁ –C ₂						
C ₃ –C ₄						
C ₅	0.1					0.1
C ₆ –C ₈	0.1					0.1
C ₉ –C ₁₂	0.05					0.05
C ₁₃ –C ₁₆	0.05					0.05
C ₁₇ –C ₂₅	0.02					0.02
C ₂₅₊	0.02					0.02
H ₂						
H ₂ S						
DEE	0.9					0.9
Methanol	0.4					0.4
PO	0.4					0.4
Styrene	0.1					0.1
EEA	0.1					0.1
EE	0.1					0.1
EG	0.1					0.1
Final Gas State—Processed Below AIT						
Fluid	Probability of Ignition	Probabilities of Outcome				
		VCE	Fireball	Flash Fire	Jet Fire	Pool Fire
C ₁ –C ₂	0.2	0.04	0.01	0.15		
C ₃ –C ₄	0.1	0.02	0.01	0.07		
C ₅	0.1	0.02	0.01	0.07		
C ₆ –C ₈	0.1	0.02	0.01	0.07		
C ₉ –C ₁₂	0.04	0.01	0.005	0.025		
C ₁₃ –C ₁₆						
C ₁₇ –C ₂₅						
C ₂₅₊						
H ₂	0.9	0.4	0.1	0.4		
H ₂ S	0.9	0.4	0.1	0.4		
CO	0.899	0.4	0.099	0.4		
DEE	0.899	0.4	0.099	0.4		
Methanol	0.4	0.099	0.038	0.263		
PO	0.4	0.178	0.044	0.178		
Styrene	0.101	0.025	0.01	0.066		
EEA	0.101	0.01	0.066	0.025		
EE	0.101	0.01	0.066	0.025		
EG	0.101	0.01	0.066	0.025		
EO	0.9	0.4	0.1	0.4		

NOTE 1 Shaded areas represent outcomes that are not possible.
NOTE 2 Must be processed at least 80 °F (27 °C) above AIT.

3.A.3.9 Figures

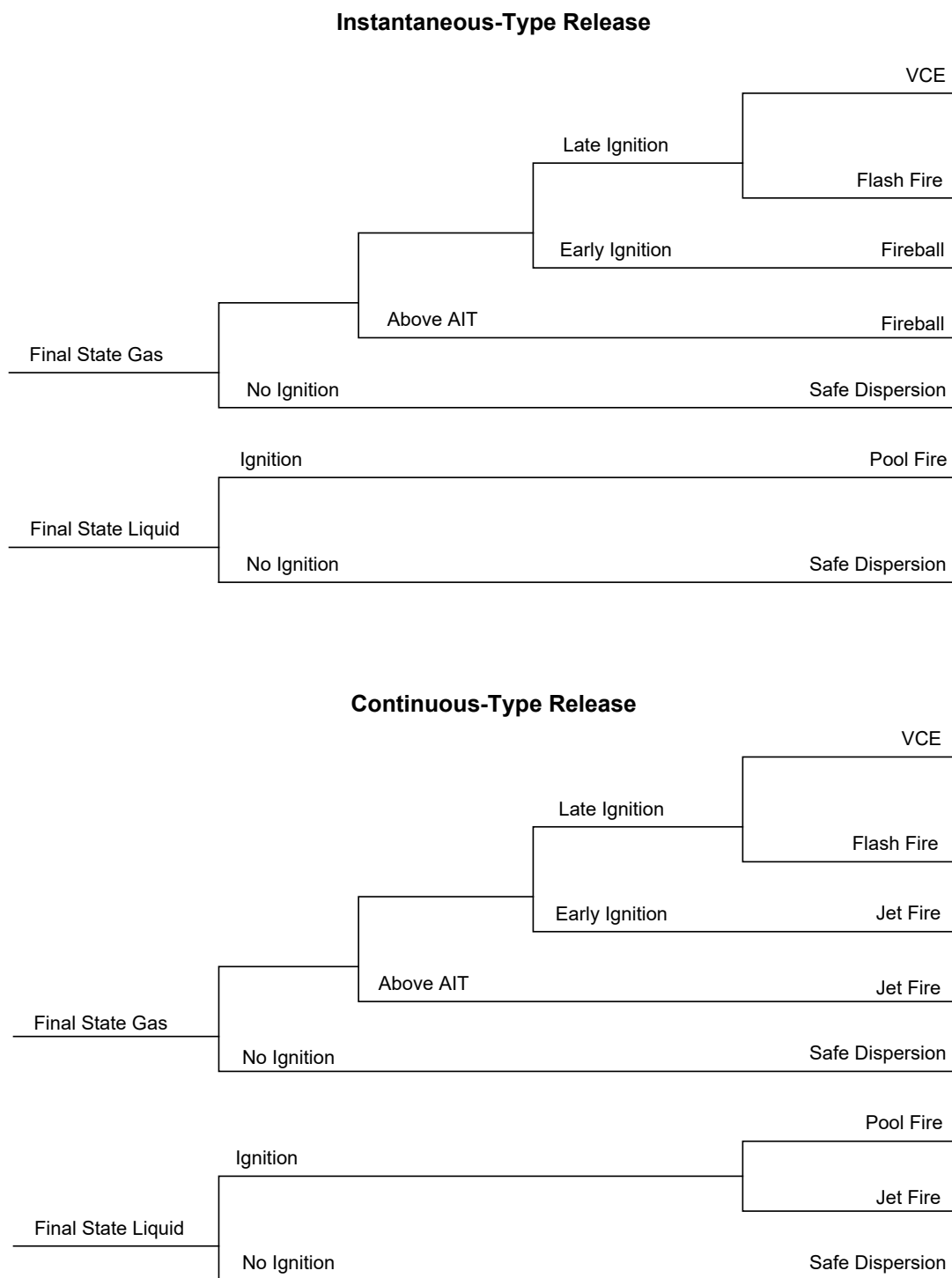


Figure 3.A.3.1—Level 1 Consequence Methodology Event Tree

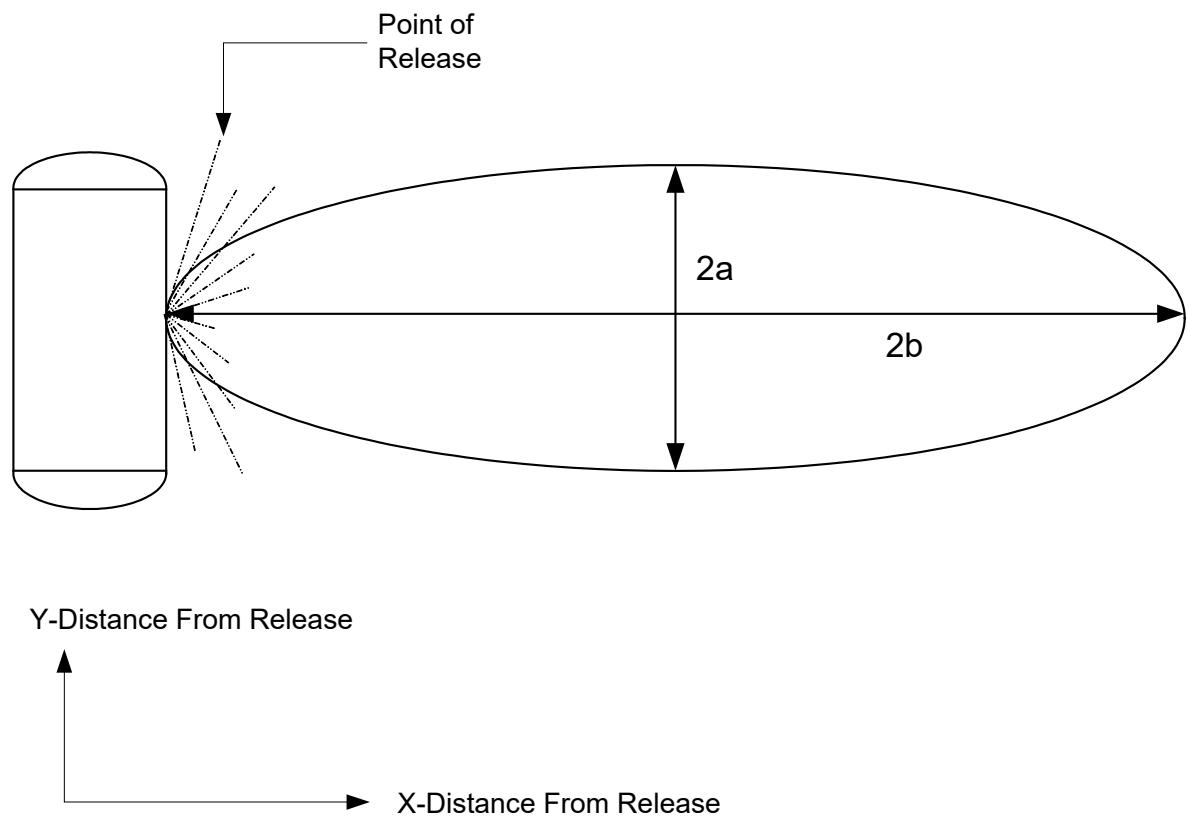


Figure 3.A.3.2—Approximated Cloud Shape for Toxic Plume from a Continuous Release

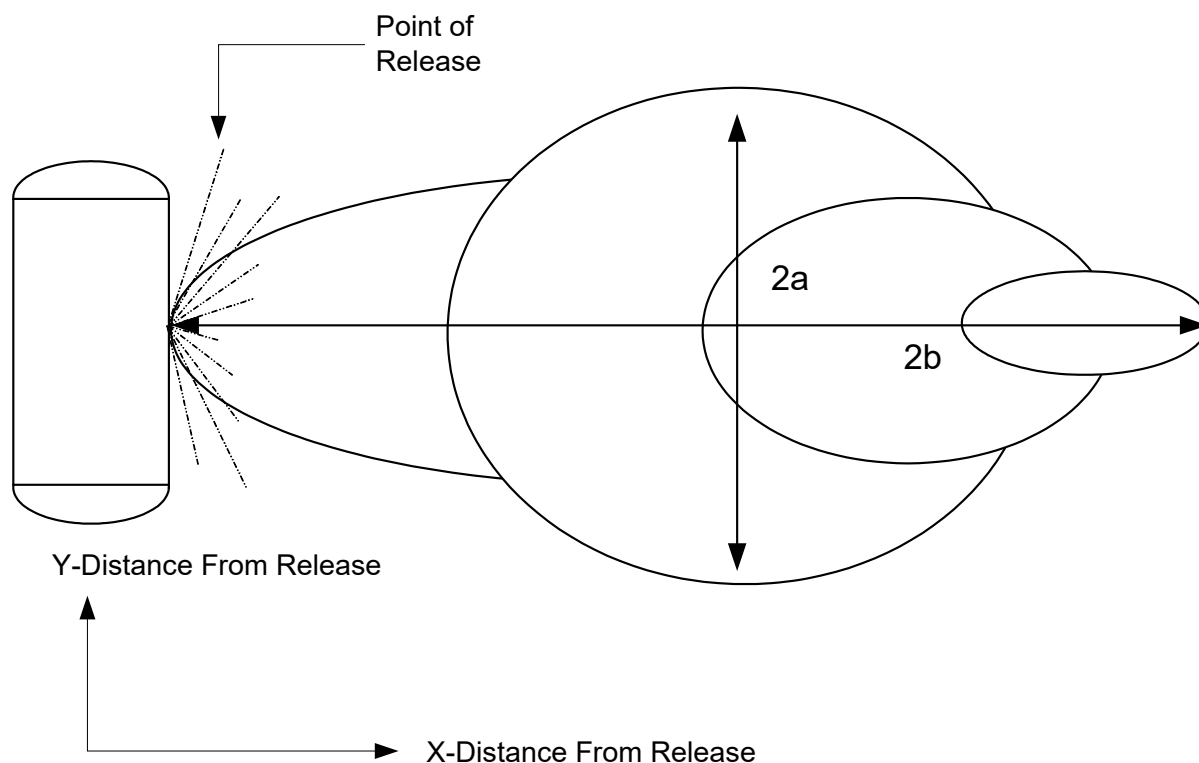


Figure 3.A.3.3—Approximated Cloud Shape for Toxic Puff from an Instantaneous Release

3.A.4 Level 2 Consequence Methodology

3.A.4.1 General

The use of event trees and semi-quantitative effects analysis forms the basis for the Level 2 consequence methodology provided in [Part 3, Section 5](#) with the details for calculating event tree probabilities and the effects of pool fires, jet fires, flash fires, fireballs, VCEs, and BLEVEs are provided. [Part 3](#) provides the impact of most of these events with the closed-form equations.

3.A.4.2 Cloud Dispersion Analysis

Some events, such as VCEs and flash fires, require the use of sophisticated dispersion analysis software to model how the flammable or toxic releases mix and disperse with air as they are released to the atmosphere.

There are several commercially available software packages that enable the user to perform dense gas dispersion consequence modeling. Examples include, such as SLAB, DEGADIS and PHAST, some of which are available in the public domain, while others are commercially available. A study contracted by the U.S. Department of Energy provides a comparison of many different software packages, and recommendations are provided to help select the appropriate package for a particular application.

In general, packages that perform dense gas dispersion modeling should be chosen as opposed to neutrally buoyant models because hazardous releases typically will be materials with MWs heavier than air. Even light hydrocarbons can be modeled accurately using dense gas modeling since the temperature of the releases will result in releases with densities heavier than air.

Dispersion models will provide a cloud concentration profile. For flammables releases, the concentration profile is used to assess which portions of the cloud are in the flammable range. For flash fires, the impact area at grade is determined to be the area in the cloud that has flammable concentrations between the released fluid's LFL and UFL. For VCEs, a volumetric calculation is required since the total amount of flammable volume and mass is required to assess the magnitude of the explosion.

3.A.5 Consequence Methodology for Storage Tanks

3.A.5.1 Overview

The consequence model for storage tanks is based on a modification of the Level 1 consequence analysis. Only a financial consequence analysis is provided for the storage tank bottom.

3.A.5.2 Representative Fluid and Associated Properties

A representative fluid that most closely matches the fluid contained in the storage tank system being evaluated is selected from the representative fluids shown in [Part 5, Table 4.5](#). The required fluid properties for the consequence analysis are also contained in this table.

In addition to selecting a fluid, a soil type must also be specified because the consequence model depends on soil properties. Representative soil conditions and the associated soil properties required for the consequence analysis is provided in [Part 5, Table 4.7](#).

3.A.5.3 GFFs and Release Holes Sizes

3.A.5.3.1 Storage Tank Bottom

The base failure frequency for the leak of an storage tank bottom was derived primarily from an analysis of a portion of the API publication *A Survey of API Members' Aboveground Storage Tank Facilities*, published in July 1994. The survey covered refining, marketing, and transportation storage tanks, each compiled separately. The survey included the years 1983 to 1993, and summary failure data are shown in [Table 3.A.5.1](#). The base failure frequencies obtained from this survey are shown in [Part 2, Table 3.1](#). One of the most significant findings was that tank bottom leaks contributing to soil contamination had been cut in half in the last 5 years compared to the first 5 years covered by the survey. This was attributed to an increased awareness of the seriousness of the problem and to the issuance of the API 653 standard for aboveground storage tank inspection.

A bottom leak frequency of $7.2\text{E-}03$ leaks per year was chosen as the base leak frequency for an storage tank bottom. Although the leak frequency data in [Part 2, Table 3.1](#) indicate that storage tanks less than 5 years old had a much lower leak frequency, it was decided to use the whole survey population in setting the base leak frequency. The age of the storage tank was accounted for elsewhere in the model since the percent of wall loss in the model is a function of the storage tank age, corrosion rate, and original wall thickness. The percent of wall loss was selected as the basis for the modifier on the base leak frequency; thus, a very young storage tank with minimal corrosion would have a frequency modifier of less than 1, which lowers the leak frequency accordingly.

It should be noted that the DF for storage tank bottoms in [Part 2](#) was originally developed based on a GFF of equal to $7.2\text{E-}03$, which equates to a range in DFs from less than 1 to 139. In order to be consistent with the other components in [Part 2](#), the range of DFs was adjusted to a range of 1 to 1390. This adjustment in the DF required a corresponding change of the GFF to a value of $7.2\text{E-}04$, and this is the value shown in [Part 2, Table 3.1](#).

The survey did not report the size of leaks, but a survey of the sponsors for the storage tank RAP project indicated that leak sizes of less than or equal to $\frac{1}{2}$ in. in diameter would adequately describe the vast majority of tank bottom leaks. An $\frac{1}{8}$ -in. release hole size is used if a RPB is present, and a $\frac{1}{2}$ -in. hole size is used for storage tank bottoms without an RPB. A GFF of $7.2\text{E-}04$ is assigned to this hole size in the consequence

analysis. In addition, the number of release holes in an storage tank bottom is determined as a function of the storage tank bottom area; see [Part 5, Table 4.9](#).

3.A.5.3.2 Tank Courses

The generic failure rate for rapid shell failures was determined based on actual incidents. A review of literature produced reports of two rapid shell failures in the U.S. petroleum industry over the last 30 years:

- a) 1971 (location unknown), brittle fracture caused loss of 66,000 bbl crude oil;
- b) 1988 Ashland Oil, PA, brittle fracture caused loss of 96,000 bbl diesel.

The number of tanks that provided the basis for the two failures was estimated from the literature to be about 33,300 large storage tanks. This value was based on a 1989 study carried out for API by Entropy Ltd. In this case, large is defined as having a capacity greater than 10,000 bbl. The number of tanks represents the United States total for the refining, marketing, transportation, and production sectors, thus the total number of tank years was found to be approximately 1,000,000. Dividing the number of failures by the number of tank years yields a rapid shell failure frequency of $2\text{E-}06$ per tank year. API 653 requires tank evaluations for susceptibility to brittle fracture. A hydrostatic test or re-rating of the tank is required for continued service. As a result, API 653 provides protection against brittle fracture. Assuming that one-half of the tanks are not maintained to API 653, the base leak frequencies for rapid shell failures would be $4\text{E-}06$ per tank year. Because the committee team members had no available documented cases of rapid shell failures for a tank that was operated, maintained, inspected, and altered in accordance with API 653, the failure frequency was believed to be significantly better than the calculated average result and the committee selected a frequency of $1\text{E-}07$ per tank year.

The total GFF for leakage events in storage tank courses is set at $1\text{E-}04$. The GFFs for the small, medium, and large holes size is determined by allocating the total GFF for leakage on a 70 %, 25 %, and 5 % basis for these release hole sizes, respectively. The resulting generic failure requires are shown in [Part 2, Table 3.1](#).

3.A.5.4 Estimating the Fluid Inventory Available for Release

The consequence calculation requires an upper limit for the amount of fluid or fluid inventory that is available for release from a component. The total amount of fluid available for release is taken as the amount of product located above the release hole size being evaluated. Flow into and out of the storage tank is not considered in the consequence methodology.

3.A.5.5 Determination of the Release Type (Instantaneous or Continuous)

The release type for the storage tank bottom is assumed to be continuous.

3.A.5.6 Determination of Flammable and Explosive Consequences

Flammable and explosive consequences are not included in the storage tank bottom consequence methodology.

3.A.5.7 Determination of Toxic Consequences

Toxic consequences are not included in the storage tank bottom consequence methodology.

3.A.5.8 Determination of Environmental Consequences

Environmental consequences for storage tank bottoms are driven by the volume and type of product spilled, the property impacted, and the cost associated with cleanup. The consequence methodology includes the potential environmental impact to the locations shown below; see [Part 5](#), [Figure 4.1](#).

- a) **Diked Area**—A release of petroleum products is contained within a diked area or other secondary containment system such as a RPB, spill catch basin, or spill tank. The “diked area” impacted media assumes the spill is of a size and physical characteristics to be contained within a system that is sufficiently impermeable to prevent migration of the spill off-site, prevent contamination of groundwater and surface water, and minimize the volume of impacted on-site soil. Minimal on-site soil impact is defined as less than 1 ft (0.30 m) depth of soil contamination in a 72-hour period. An earthen secondary containment system that contains a release of petroleum may be considered a “diked area” if the soil permeability and stored material properties are sufficient to meet the above definition. For example, a secondary containment system constructed from a uniform sandy soil containing asphalt or other heavy petroleum products would be considered “diked” because a release into the containment is not expected to impact other media (e.g. limited on-site soil impact, no off-site soil, no groundwater or surface water impacts). Conversely, the same system containing gasoline may not meet this definition.
- b) **On-site Soil**—A release of petroleum products is limited to contaminating on-site surficial soils. On-site refers to the area within the physical property boundary limits of the facility. Surface soils refer to the upper 0.61 m (2 ft) of soil that could be readily removed in the event of a spill. The volume spilled, location of spill, site grade, size of the property, soil permeability, and stored material properties are important in determining whether a spill will be contained on-site. For example, a flange leak on a section of aboveground piping may be limited to impacting a small section of on-site soils.
- c) **Off-site Soil**—A release of petroleum products contaminates off-site surface soils. Off-site refers to the property outside of the physical property boundary limits of the facility. Surface soils refer to the upper 2 ft (0.61 m) of soil that could be readily removed in the event of a spill. The volume released location of spill, site grade, land use of the off-site impacted property, soil permeability, and stored material properties are important in determining the impacts to off-site property.
- d) **Subsurface Soil**—A release of petroleum products contaminates subsurface soils. Subsurface impacts may or may not be contained within the physical property boundary limits of the facility. Subsurface soils refer to soils deeper than 2 ft (0.61 m) in depth or those soils that cannot be readily removed in the event of a spill, such as soils beneath a field erected tank or building slab. The soil permeability, stored material properties, and location of the spill are important in determining the extent of the environmental consequences associated with subsurface soil impacts. For example, a release of petroleum from an storage tank bottom that rests on native clay soils will have minor subsurface impacts relative to the same storage tank that is located on native sand soil.
- e) **Groundwater**—A release of petroleum products contaminates groundwater. Groundwater refers to the first encountered phreatic water table that may exist subsurface at a facility. Groundwater elevation may fluctuate seasonally and different groundwater tables may exist at a site (e.g. possible shallow soil water table and a deep bedrock water table). The soil permeability, stored material properties, and location of the spill are important in determining the extent of the environmental consequences associated with groundwater impacts. The nature of the subsurface soils will dictate the time required for a spill to impact the groundwater and the severity of the impact.
- f) **Surface Water**—A release of petroleum products contaminates off-site surface water. Conveyance of spilled product to surface waters is primarily by overland flow, but may also occur through subsurface soils. Surface water refers to non-intermittent surficial waters from canals, lakes, streams, ponds, creeks, rivers, seas, or oceans and includes both fresh and salt water. Surface waters may or may not be navigable. The stored material properties, type of surface water, and response capabilities are important in determining the extent of the environmental consequences associated with surface water impacts.

The cleanup costs associated with these environmental impacts are provided in [Part 5, Table 4.6](#) as a function of environmental sensitivity. The environmental sensitivity is given as Low, Medium, or High and determines the expected cost factor per barrel of spilled fluid for environmental cleanup in a worst-case scenario.

3.A.5.9 Tables

Table 3.A.5.1—Summary of API Members' Aboveground Storage Tank Facilities Relative to Tank Bottom Leakage

Population Description	Number of Tanks	Percent with Bottom Leaks in Last 5 Years	Number with Bottom Leaks in Last 5 Years	Tank Years (see Note)	Bottom Leak Frequency (1988 to 1993)
Tanks < 5 years old	466	0.9%	4	2,330	1.7×10^{-3}
Tanks 6 to 15 years old	628	3.8%	24	3,140	7.6×10^{-3}
Tanks > 15 years old	9,204	3.8%	345	46,020	7.5×10^{-3}
All tanks in survey	10,298	3.6%	373	51,490	7.2×10^{-3}
NOTE Tank years = number of tanks × average number of years in service.					

Part 3, Annex 3.B—SI and U.S. Customary Conversion Factors

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Part 3—Consequence of Failure Methodology
Annex 3.B—SI and U.S. Customary Conversion Factors

3.B.1 General

The SI and U.S. customary unit conversion factors for equations that appear throughout [Part 3](#) of this document are provided in [Table 3.B.2.1](#) of this annex.

3.B.2 Tables

Table 3.B.2.1—SI and U.S. Customary Conversion Factors for Equations in Part 3

Conversion Factor	Equation Reference	SI Units	U.S. Customary Units
C_1	(3.3)	$31,623 \frac{\text{mm}^2}{\text{m}^2}$	$12 \frac{\text{in.}}{\text{ft}}$
C_2	(3.6) , (3.7)	$1,000 \frac{\text{mm}^2}{\text{m}^2}$	1
C_3		4,536 kg	10,000 lb
C_{4A}	(3.17)	$2.205 \frac{1}{\text{kg}}$	$1 \frac{1}{\text{lb}}$
C_{4B}	(3.109) , (3.110)	$2.205 \frac{\text{s}}{\text{kg}}$	$1 \frac{\text{s}}{\text{lb}}$
C_5	(3.18) , (3.70)	$25.2 \frac{\text{kg}}{\text{s}}$	$55.6 \frac{\text{lb}}{\text{s}}$
C_6	(3.23) , (3.24) , (3.25)	55.6 K	100 °R
C_8	(3.62) , (3.63) , (3.A.7) , (3.A.8)	0.0929 m^2	1 ft^2
C_9	(3.68)	$0.123 \frac{\text{m}^2 \cdot \text{s}}{\text{kg}}$	$0.6 \frac{\text{ft}^2 \cdot \text{s}}{\text{lb}}$
C_{10}		$9.744 \frac{\text{m}^2}{\text{kg}^{0.06384}}$	$63.32 \frac{\text{ft}^2}{\text{kg}^{0.06384}}$
C_{12}	(3.89) , (3.109) , (3.110)	$1.8 \frac{1}{\text{K}}$	$\frac{1}{^\circ\text{R}}$
C_{13}	(3.90) , (5.11) , (5.41)	$6.29 \frac{\text{bbl}}{\text{m}^3}$	$0.178 \frac{\text{bbl}}{\text{ft}^3}$

Conversion Factor	Equation Reference	SI Units	U.S. Customary Units
C_{14}	(3.103), (3.138), (3.152), (3.162)	1	$3,600 \frac{\text{s}}{\text{hr}}$
C_{15}	(3.105)	$4.685 \frac{\text{m}^{0.33}}{\text{s}^{0.22}}$	$1 \frac{\text{in.}^2}{\text{ft}^{1.67} \text{s}^{0.22}}$
C_{16}	(3.113), (3.114), (3.116), (3.117)	294.44 K	530 °R
C_{17}	(3.128), (3.129)	$0.001 \frac{\text{kg}}{\text{m}^2 \cdot \text{s}}$	$2.048 \times 10^{-4} \frac{\text{lb}}{\text{ft}^2 \cdot \text{s}}$
C_{18}	(3.132)	0.0050 m	0.0164 ft
C_{19}	(3.140)	$1.085 (\text{kPa} \cdot \text{m})^{0.092}$	$1.015 (\text{psia} \cdot \text{ft})^{0.092}$
C_{20}	(3.141)	1.013 kPa	0.147 psia
C_{21}	(3.141)	5,328 K	9,590 °R
C_{22}	(3.158)	$5.8 \frac{\text{m}}{\text{kg}^{0.333}}$	$14.62 \frac{\text{ft}}{\text{lb}^{0.333}}$
C_{23}	(3.160)	$0.45 \frac{\text{s}}{\text{kg}^{0.333}}$	$0.346 \frac{\text{s}}{\text{lb}^{0.333}}$
C_{24}	(3.161)	$2.6 \frac{\text{s}}{\text{kg}^{0.167}}$	$2.279 \frac{\text{s}}{\text{lb}^{0.167}}$
C_{25}	(3.163)	$0.0296 \frac{1}{\text{kPa}^{0.32}}$	$0.0549 \frac{1}{\text{psia}^{0.32}}$
C_{26}	(3.170)	$100 \frac{\text{kPa}}{\text{bar}}$	$14.5 \frac{\text{psi}}{\text{bar}}$
C_{27}	(3.171)	$1 \frac{\frac{1}{\text{kg}^3}}{\text{m} \cdot \text{s}^3}$	$0.3967 \frac{\frac{\text{lbm}}{\text{ft}^3}}{\text{ft} \cdot \text{s}^3}$
C_{28}	(3.172)	$1,000 \frac{1}{\text{kPa}}$	$6,895 \frac{1}{\text{psia}}$
C_{29}	(3.192)	$4.303 \times 10^{-4} \frac{\text{s}^2}{\text{m}^2}$	$1.85 \times 10^{-4} \frac{\text{lbm}}{\text{psi} \cdot \text{ft}^3}$
C_{30}	(3.195)	$2.150 \times 10^{-7} \frac{\text{kg}}{\text{J}}$	$6.43 \times 10^{-7} \frac{1}{\text{lbf} \cdot \text{ft}}$
C_{31}	(5.35)	$864 \frac{\text{s} \cdot \text{m}}{\text{cm} \cdot \text{day}}$	$7,200 \frac{\text{s} \cdot \text{ft}}{\text{in.} \cdot \text{day}}$

Conversion Factor	Equation Reference	SI Units	U.S. Customary Units
C_{32}	(5.5)	$0.543 \frac{\text{s} \cdot \text{bbl}}{\text{day} \cdot \text{mm}^2 \cdot \text{m}}$	$106.8 \frac{\text{s} \cdot \text{bbl}}{\text{day} \cdot \text{in.}^2 \cdot \text{ft}}$
C_{33}	(5.37)	$0.0815 \frac{\text{s} \cdot \text{bbl}}{\text{day} \cdot \text{mm}^2 \cdot \text{m}}$	$16.03 \frac{\text{s} \cdot \text{bbl}}{\text{day} \cdot \text{in.}^2 \cdot \text{ft}}$
C_{34}	(5.37)	$86.4 \frac{\text{m}}{\text{day} \cdot \text{mm}^2}$	$1.829 \times 10^5 \frac{\text{ft}}{\text{day} \cdot \text{in.}^2}$
C_{35}	(5.38)	$29.6195 \frac{\text{bbl}}{\text{day}^{0.26} \cdot \text{mm}^{0.2} \cdot \text{m}^{1.64}}$	$8.0592 \frac{\text{bbl}}{\text{day}^{0.26} \cdot \text{in.}^{0.2} \cdot \text{ft}^{1.64}}$
C_{36}	(5.53)	30.5 m	100 ft
C_{37}	(5.38)	$1.408 \times 10^{-8} \frac{\text{m}^{1.4}}{\text{day} \cdot \text{mm}^{1.8}}$	$6.995 \times 10^{-5} \frac{\text{ft}^{1.4}}{\text{day} \cdot \text{in.}^{1.8}}$
C_{38}	(5.39)	1.1341	403.95
C_{39}	(5.39)	3.9365	7.2622
C_{40}	(5.39)	5.9352	5.0489
C_{41}	(3.89)	32 °C	0 °F

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Annex 3.C—Bibliography

3.C.1 General

The references for [Part 3](#) of this document are provided in [Section 3.C.2](#) of this annex.

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Risk-based Inspection Methodology

Part 4—Inspection Planning Methodology

1 Scope

The calculation of risk outlined in API 581 involves the determination of a POF combined with the COF. Failure is defined as a loss of containment from the pressure boundary. Risk increases as damage accumulates during in-service operation as the risk tolerance or risk target is approached and an inspection is recommended of sufficient effectiveness to better quantify the damage state of the component. The inspection action itself does not reduce the risk; however, it does reduce uncertainty and therefore allows more accurate quantification of the damage present in the component.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 580, *Elements of a Risk-Based Inspection*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 1—Introduction to Risk-Based Inspection Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 2—Probability of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 3—Consequence of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 5—Special Equipment*

3 Inspection Planning Based on Risk

3.1 Overview

Inspection planning based on risk assumes that at some point in time, the risk as defined by [Part 1, Equation \(1.7\)](#) and [Part 1, Equation \(1.8\)](#) will reach or exceed a user-defined area or financial risk target. When or before the user-defined risk target is reached, an inspection of the equipment is recommended based on the component damage mechanisms with the highest DFs. The user may set additional targets to initiate an inspection, such as POF, DF, COF, inspection interval, or thickness. In addition, inspection may be conducted solely to gather information to reduce uncertainty in the component condition or based on an engineering evaluation of the fitness for continued service rather than the RBI results.

Although inspection of a component does not reduce the inherent risk, inspection provides improved knowledge of the current state of the component and therefore reduces uncertainty. The probability that loss of containment will occur is directly related to the known condition of the component based on information from inspection and the ability to accurately quantify damage.

Reduction in uncertainty in the damage state of a component is a function of the effectiveness of the inspection to identify the type and quantify the extent of damage. Inspection plans are designed to detect and quantify the specific types of damage expected such as local or general thinning, cracking, and other types of damage. An inspection strategy that is appropriate for general thinning may not be effective in detecting and quantifying damage due to local thinning or cracking. Therefore, the inspection effectiveness is a function of the inspection method and extent of coverage used for detecting the type of damage expected.

Risk is a function of time, as shown in [Part 1, Equation \(1.7\)](#), [Part 1, Equation \(1.8\)](#), and [Part 1, Equation \(1.9\)](#), as well as a function of the knowledge of the current state of the component determined from past inspections. When inspection effectiveness is introduced into risk, [Part 1, Equation \(1.7\)](#), [Part 1, Equation \(1.8\)](#), and [Part 1, Equation \(1.9\)](#) can be rewritten as [Equation \(4.1\)](#), [Equation \(4.2\)](#), and [Equation \(4.3\)](#):

$$R(t, I_E) = P_f(t, I_E) \cdot CA_f^{\text{area}} \quad \text{for area-based risk} \quad (4.1)$$

$$R(t, I_E) = P_f(t, I_E) \cdot CA_f^{\text{fin}} \quad \text{for financial-based risk} \quad (4.2)$$

$$R(t, I_E) = P_f(t, I_E) \cdot CA_f^{\text{inj}} \quad \text{for safety-based risk} \quad (4.3)$$

3.1.1 Targets

A target is defined as the maximum level acceptable for continued operation without requiring a mitigating action. Once the target has been met or exceeded, an activity such as inspection is triggered. Several targets can be defined in an RBI program to initiate and define risk mitigation activities, as follows.

- a) **Risk Target**—A level of acceptable risk that triggers the inspection planning process. The risk target may be expressed in area, C_f^{area} (ft²/yr), financial, C_f^{fin} (\$/yr), or safety, C_f^{inj} (injuries/yr) terms, based on the owner–operator preference. One or more risk targets may be set manage the mechanical integrity risk of components within defined acceptable limits.
- b) **POF Target**—A frequency of failure or leak (#/yr) that is considered unacceptable and triggers the inspection planning process. A POF target may be set drive inspection for components with a very low COF and risk but where frequent, nuisance leaks are undesirable.
- c) **DF Target**—A damage state that reflects an unacceptable failure frequency factor greater than the generic and triggers the inspection planning process. Similar to a POF target, a maximum DF target may be set to drive inspection for components with very low COF and risk but where frequent, nuisance leaks are undesirable. Minimum DF targets may be set by damage mechanism type to prevent inspection recommendations for components with very low DF but high COF and risk where inspection will not effectively reduce risk.
- d) **Minimum DF Target**—A minimum DF where inspection will not effectively reduce risk. In this case, risk is consequence driven and other mitigation methods are recommended.
- e) **COF Target**—A level of unacceptable consequence in terms of consequence area (C_f^{area}), financial consequence (C_f^{fin}), or safety consequence (C_f^{inj}) based on owner–operator preference. Because risk driven by COF is not reduced by inspection activities, risk mitigation activities to reduce release inventory or ignition are required.
- f) **Thickness Target**—A specific thickness, often the minimum required thickness, t_{min} , considered unacceptable, triggering the inspection planning process. A minimum thickness target may be set to drive inspection for components at a predetermined thickness (e.g. $1/2$ wall or 0.100 in.), independent of DF, POF, or risk.
- g) **Maximum Inspection Interval Target**—A specific inspection frequency considered unacceptable, triggering the inspection planning process. A maximum inspection interval may be set by the owner–operator's corporate standards or may be set based on a jurisdictional requirement. A maximum inspection interval may be set to require an inspection be performed at a specified maximum interval, independent of DF, POF, or risk.

It is important to note that defining targets is the responsibility of the owner–operator, and the specific target criteria is not provided within this document. The above targets should be developed based on owner–operator internal guidelines and overall risk tolerance. Owner–operators often have corporate risk criteria defining acceptable and prudent levels of safety, environmental, and financial risks. These owner–operator criteria should be used when making RBI decisions since acceptable risk levels and risk management decision-making will vary among companies.

3.1.2 Inspection Effectiveness—The Value of Inspection

An estimate of the POF for a component depends on how well the independent variables of the limit state are known (see API 579-1/ASME FFS-1) and understood. Using examples and guidance for inspection effectiveness provided in [Part 2, Annex 2.F](#), an inspection plan is developed as risk results require. The inspection strategy is implemented to obtain the necessary information to decrease uncertainty about the actual damage state of the equipment by confirming the presence of damage, obtaining a more accurate estimate of the damage rate, and evaluating the extent of damage.

An inspection plan is the combination of NDE methods (i.e. VT, UT, RT, etc.), frequency of inspection, and the location and coverage of an inspection to find a specific type of damage. Inspection plans vary in their overall effectiveness for locating and sizing specific damage and understanding the extent of the damage.

Inspection effectiveness is introduced into the POF calculation using Bayesian analysis, which updates the POF when additional data are gathered through inspection. The extent of reduction in the POF depends on the effectiveness of the inspection to detect and quantify a specific damage type of damage mechanism. Therefore, higher inspection effectiveness levels will reduce the uncertainty of the damage state of the component and reduce the POF. The POF and associated risk may be calculated at a current and/or future time period using [Equation \(4.1\)](#), [Equation \(4.2\)](#), or [Equation \(4.3\)](#).

Examples of the levels of inspection effectiveness categories for various damage mechanisms and the associated generic inspection plan (i.e. NDE techniques and coverage) for each damage mechanism are provided in [Part 2, Annex 2.F](#). These tables provide examples of the levels of generic inspection plans for a specific damage mechanism. The tables are provided as a matter of example only, and it is the responsibility of the owner–operator to create, adopt, and document their own specific levels of inspection effectiveness tables.

3.1.3 Calculation of Inspection Plan

The following procedure is used to determine the inspection required to achieve risk target prior to the plan date.

NOTE This procedure applies to pressure vessels, piping, and storage tanks. The inspection planning process for heat exchanger bundles and PRDs are provided in [Part 5, Section 5](#) and [Section 6](#), respectively.

- a) Step 1—Assign dates to define the plan period.
 - 1) Define the RBI date (normally set to current date).
 - 2) Define the plan date (normally the RBI date + 10 years or two turnaround periods).
 - 3) Cracking inspection date (normally set to the midpoint between the RBI date and plan date or next turnaround).
- b) Step 2—Assign one or more targets as criteria for risk calculation and inspection recommendations (see [Part 1, Section 4.3.1](#)). If more than one target is used, indicate the priority of target analysis.
 - 1) Risk Target.
 - i) Area risk in ft^2/yr , $R(t)_{\text{area-target}}$.

ii) Financial risk in \$/yr, $R(t)_{\text{fin-target}}$.

iii) Safety risk in injuries/yr, $R(t)_{\text{inj-target}}$.

2) POF Target, $P_f(t)_{\text{target}}$.

3) DF Target.

i) Maximum DF target, $D_{f\text{-total,Max}}$.

ii) Minimum DF target.

$$\text{— } D_{f\text{-min}}^{\text{thin}} .$$

$$\text{— } D_{f\text{-min}}^{\text{SCC}} .$$

$$\text{— } D_{f\text{-min}}^{\text{extd}} .$$

4) Thickness Target, t_{target} .

5) Maximum Inspection Interval, $Intvl_{\text{target}}$.

c) Step 3—Determine age_{tk} for each active damage mechanism and t_{rdi} for thinning and/or t_{rde} external for external damage mechanisms.

d) Step 4—Calculate age_{tk} at the RBI date and at 0.5 year intervals from the RBI date through the plan date starting at age_{tk} from Step 3.

e) Step 5—Using the calculation steps in [Part 2](#), calculate the DF for each active damage mechanism at 0.5 year intervals from the RBI date through the plan date.

f) Step 6—Using the calculation steps in [Part 2](#), calculate t_{rdi} and/or t_{rde} at 0.5 year intervals from the RBI date through the plan date.

g) Step 7—Using the calculation steps in [Part 2](#), [Section 3.4.2](#), calculate $D_{f\text{-total}}$ at 0.5 year intervals from the RBI date through the plan date using DFs calculated in Step 5.

$$\text{Set } D_f(t)_{f\text{-total}}^{\text{woplan}} = D_f(t)_{f\text{-total}} @ \text{Plan Date} .$$

h) Step 8—Using the equations in [Part 2](#), [Section 3](#), calculate $P_f(t)$ at 0.5 year intervals from the RBI date to the plan date using $D_{f\text{-total}}$ calculated in Step 7 and gff_{total} from [Part 2](#), [Table 3.1](#).

$$\text{Set } P_f(t)^{\text{woplan}} = P_f(t) @ \text{Plan Date} .$$

i) Step 9—Using the equations in [Part 1](#), [Section 4.3](#), calculate the area risk over time, $R(t)_{\text{area}}$, the financial risk, $R(t)_{\text{fin}}$, and safety risk, $R(t)_{\text{inj}}$, at 0.5 year intervals from the RBI date to the plan date using $P_f(t)$ calculated in Step 8, C_f ([Part 3](#), [Section 4](#) or [Section 5](#)) and C_f^{fin} ([Part 3](#), [Section 4.12](#)).

$$\text{Set } R_f(t)_{\text{safety}}^{\text{woplan}} = R_f(t) @ \text{Plan Date} \text{ and } R_f(t)_{\text{fin}}^{\text{woplan}} = R_f(t) @ \text{Plan Date} .$$

- j) Step 10—Based on the criteria selected in Step 2, use the following logic to determine if inspection is required:
- 1) If $R_f(t)_{\text{area}}^{\text{woplan}} \leq R(t)_{\text{area-target}}$, no inspection is required based on risk. Go to next target criteria. If $R_f(t)_{\text{area}}^{\text{woplan}} > R(t)_{\text{area-target}}$, inspection is required based on safety risk.
 - i) Calculate the target date based on the date the risk target is reached in Step 9. The target date is calculated based on interpolating between 0.5 years points where $R(t)_{\text{area-target}}$ is reached in Step 9.
 - 2) If $R_f(t)_{\text{fin}}^{\text{woplan}} \leq R(t)_{\text{fin-target}}$, no inspection is required based on risk. Go to next target criteria. If $R_f(t)_{\text{fin}}^{\text{woplan}} > R(t)_{\text{fin-target}}$, inspection is required based on financial risk.
 - i) Calculate the target date based on the date the risk target is reached in Step 9. The target date is calculated based on interpolating between 0.5 years points where $R(t)_{\text{fin-target}}$ is reached in Step 9.
 - 3) If $R_f(t)_{\text{inj}}^{\text{woplan}} \leq R(t)_{\text{inj-target}}$, no inspection is required based on risk. Go to next target criteria. If $R_f(t)_{\text{inj}}^{\text{woplan}} > R(t)_{\text{inj-target}}$, inspection is required based on injury risk.
 - i) Calculate the target date based on the date the risk target is reached in Step 9. The target date is calculated based on interpolating between 0.5 years points where $R(t)_{\text{inj-target}}$ is reached in Step 9.
 - 4) If $P_f(t)^{\text{woplan}} \leq P(t)_{\text{target}}$, no inspection is required based on risk. Go to next target criteria. If $P_f(t)^{\text{woplan}} > P(t)_{\text{target}}$, inspection is required based on POF.
 - i) Calculate the target date based on the date that $P_f(t)_{\text{target}}$ is reached in Step 8. The target date is calculated based on interpolating between 0.5 years points where $P_f(t)_{\text{target}}$ is reached in Step 8.
 - 5) If $D_f(t)_{\text{f-total}}^{\text{woplan}} \leq D_{\text{f-total,Max}}$, no inspection is required based on risk. Go to next target criteria. If $D_f(t)_{\text{f-total}}^{\text{woplan}} > D_{\text{f-total,Max}}$, inspection is required based on DF.
 - i) Calculate the target date based on the date that $D_{\text{f-total,Max}}$ is reached in Step 7. The target date is calculated based on interpolating between 0.5 years points where $D_{\text{f-total,Max}}$ is reached in Step 7.
 - 6) If $t_{\text{rdi}} @ \text{Plan Date} > t_{\text{target}}$, no inspection during plan period is required. Go to next target criteria. If $t_{\text{rdi}} \leq t_{\text{target}}$, inspection is required based on thickness.
 - i) Calculate the target date based on the date that t_{rdi} is reached in Step 6. The target date is calculated based on interpolating between 0.5 years points where t_{target} is reached in Step 6.

ii) Calculate the date for inspection based on the remaining life fraction from the target date.

7) If $age_{tk} @ Plan Date \leq Intvl_{target}$, no inspection during plan period is required. Go to next target criteria.. If $age_{tk} @ Plan Date > Intvl_{target}$, a user defined inspection is required based on interval and go to Step 12.

i) Calculate the target date based on the date that $Intvl_{target}$ is reached in Step 4. The target date is calculated based on interpolating between 0.5 years points where $Intvl_{target}$ is reached in Step 4.

8) If the component passes all of the applicable above criteria, set:

$$i) R_f(t)_{area,plan} = R_f(t)_{area}^{woplan};$$

$$ii) R_f(t)_{fin,plan} = R_f(t)_{fin}^{woplan};$$

$$iii) R(t)_{inj-target} = R_f(t)_{inj}^{woplan};$$

$$iv) P_f(t)_{plan} = P_f(t)^{woplan};$$

$$v) D_{f-total}^{plan} = D_{f-total}^{woplan}.$$

Go to Step 14.

k) Step 11— Calculate inspection requirements during plan period.

1) If $D_{f-gov}^{thin} \leq D_{f-min}^{thin}$, $D_{f-gov}^{scc} \leq D_{f-min}^{scc}$, and $D_{f-gov}^{extd} \leq D_{f-min}^{extd}$, risk is consequence driven and inspection will not effectively mitigate risk. Another mitigation method is recommended, go to Step 13.

2) Select the highest DF for each active damage mechanism type from Step 5 and calculate DF, D_{f-gov} , $P(t)^{plan}$, $R_f(t)_{area,plan}$, $R_f(t)_{fin,plan}$, and $R(t)_{inj,plan}$, assuming a C level inspection will be conducted at the target date. If the damage mechanism is an SCC mechanism, use age_{tk} calculated using the cracking inspection date from Step 1.

i) If $D_{f-gov}^{thin} \leq D_{f-min}^{thin}$, $D_{f-gov}^{scc} \leq D_{f-min}^{scc}$, and $D_{f-gov}^{extd} \leq D_{f-min}^{extd}$, no further inspection mitigation is required, go to Step 13.

ii) If $R_f(t)_{area}^{plan} \leq R(t)_{area-target}$, $R_f(t)_{fin}^{plan} \leq R(t)_{fin-target}$, $R_f(t)_{inj}^{plan} \leq R(t)_{inj-target}$, and $D_{f-total} < D_{f-min}$, the inspection is sufficient to satisfy the target and go to Step 13.

- 3) Select the D_{f-gov} of the active damage mechanism type from the previous calculation and repeat the calculation with a C level inspection or next highest inspection category. Calculate $D_{f-total}$, $P(t)^{plan}$, $R_f(t)_{area,plan}$, $R_f(t)_{fin,plan}$, and $R_f(t)_{inj,plan}$ assuming the inspection will be performed at the target date. If the damage mechanism is an SCC mechanism, use age_{tk} calculated using the cracking inspection date from Step 1.
 - i) If $D_f^{thin} \leq D_{f-min}^{thin}$, $D_f^{scc} \leq D_{f-min}^{scc}$, and $D_f^{extd} \leq D_{f-min}^{extd}$, no further inspection mitigation is required, go to Step 12.
 - ii) If $R_f(t)_{area}^{plan} \leq R(t)_{area-target}$, $R_f(t)_{fin}^{plan} \leq R(t)_{fin-target}$, $R_f(t)_{inj}^{plan} \leq R(t)_{inj-target}$, and $D_{f-total} < D_{f-min}$, the inspection is sufficient to satisfy the target and go to Step 13.
- 4) Repeat the calculation procedure above for the D_{f-gov} of the active damage mechanism type from the previous step and calculate $R_f(t)_{area}^{plan} \leq R(t)_{area-target}$, $R_f(t)_{fin}^{plan} \leq R(t)_{fin-target}$, $R_f(t)_{inj}^{plan} \leq R(t)_{inj-target}$, and $D_{f-total} < D_{f-min}$ until the inspection is sufficient to satisfy the target or an A level inspection has been reached for each active mechanism.
- 5) Apply the highest level of inspection identified for the D_{f-gov} of all active damage mechanisms types.
 - l) Step 12—Calculate D_{f-gov} , $P(t)^{plan}$, $R_f(t)_{area,plan}$, $R_f(t)_{fin,plan}$, and $R_f(t)_{inj,plan}$ for all active damage mechanism types after applying the inspection defined in Step 11.
 - m) Step 13—Calculate, $D_{f-total}^{plan}$, $P(t)^{plan}$, $R(t)_{area}^{plan}$, $R(t)_{fin}^{plan}$, and $R(t)_{inj}^{plan}$ at the plan date using the inspection recommended in Step 11, performed at the target date.
 - n) Step 14—Calculate the final target date:
 - 1) If no inspection is required, set *Target Date* = *Plan Date*.
 - 2) If inspection is required, use the recommended inspection plan (A, B, or C inspection effectiveness) and target date defined in Step 11 for the applicable criteria using the minimum date for the applicable criteria in Steps 4 and 6 through 10.

3.1.4 Inspection Planning

An inspection plan date covers a defined plan period and includes one or more future maintenance turnarounds. Within this plan period, three cases are possible based on predicted risk and the risk target.

- a) Case 1—Risk Target is Exceeded During the Plan Period—As shown in [Figure 4.1](#), the inspection plan will be based on the inspection effectiveness required to reduce the risk and maintain it below the risk target through the plan period.
- b) Case 2—Risk Exceeds the Risk Target at the Time the RBI Date—As shown in [Figure 4.2](#), the risk at the start time of the RBI analysis, or RBI date, exceeds the risk target. An inspection is recommended as soon as practical. The plan should be sufficient to reduce the risk so that the risk after inspection remains below the risk target at the plan date. In addition, elevated risk levels should be communicated with management and a risk mitigation plan should be developed and implemented within an acceptable time period.

- c) Case 3—Risk at the Plan Date Does Not Exceed the Risk Target—As shown in [Figure 4.3](#), the risk at the plan date does not exceed the risk target and therefore no inspection is required during the plan period. In this case, the inspection due date for inspection scheduling purposes may be set to the plan date so that reanalysis of risk will be performed by the end of the plan period.

The concept of how the different inspection techniques with different effectiveness levels can reduce risk is shown in [Figure 4.1](#). In the example shown, a minimum of a B level inspection was recommended at the target date. This inspection level was sufficient since the risk predicted after the inspection was performed was determined to be below the risk target at the plan date.

NOTE In [Figure 4.1](#), a C Level inspection at the target date would not have been sufficient to satisfy the risk target criteria.

3.2 Nomenclature

age_{tk}	is the time since the last A or B effective lining inspection
C_f	is the COF, ft ² (m ²), \$ or injuries
C_f^{area}	is the consequence impact area, ft ² (m ²)
C_f^{fin}	is the financial consequence, \$
C_f^{inj}	is the safety consequence, injuries
D_{f-gov}^{extd}	is the governing DF external damage
D_{f-gov}^{SCC}	is the governing DF for SCC
D_{f-gov}^{thin}	is the governing DF for thinning
D_{f-min}^{extd}	is the governing external DF minimum target for inspection planning
D_{f-min}^{SCC}	is the governing DF SCC minimum target for inspection planning
D_{f-min}^{thin}	is the governing DF thinning minimum target for inspection planning
$D_{f-total}$	is total DF for POF calculation
$D_{f-total}^{plan}$	is the DF at the plan date with inspection
$D_{f-total,Max}$	is maximum total DF target for inspection planning
$D_f(t)$	is the DF as a function of time, equal to $D_{f-total}$ evaluated at a specific time
D_f^{SCC}	is the DF for stress corrosion cracking
$D_{f-total}^{woplan}(t)$	is the DF at the plan date without inspection

gff_{total}	is the total GFF, failures/yr
$Intvl_{\text{target}}$	is the interval target for inspection planning
plan date	is the date set by the owner–operator that defines the end of plan period
$P_f(t)$	is the POF as a function of time, failures/yr
$P_f(t)_{\text{plan}}$	is the POF at the plan date before the planned inspection, failures/yr
$P_f(t)_{\text{target}}$	is the POF target for inspection planning, failures/yr
$P_f(t)^{\text{woplan}}$	is the POF at the plan date after the planned inspection, failures/yr
$P_f(t, I_E)$	is the POF as a function of time and inspection effectiveness, failures/yr
RBI date	is date set by the owner–operator that defines the start of a plan period
$R_f(t)_{\text{area,plan}}$	is the safety risk at the plan date before the planned inspection, ft ² /yr (m ² /yr)
$R_f(t)_{\text{area}}^{\text{woplan}}$	is the safety risk at the plan date after the planned inspection, ft ² /yr (m ² /yr)
$R(t)$	is the risk as a function of time, ft ² /yr (m ² /yr), \$/yr, or injuries/yr
$R(t)_{\text{area}}$	is the area risk as a function of time, ft ² /yr (m ² /yr)
$R(t)_{\text{area-target}}$	is the level of acceptable safety risk that triggers the inspection planning process, ft ² /yr (m ² /yr)
$R_f(t)_{\text{fin,plan}}$	is the financial risk at the plan date before the planned inspection, \$/yr
$R(t)_{\text{fin-target}}$	is the level of acceptable financial risk that triggers the inspection planning process, \$/yr
$R_f(t)_{\text{fin}}^{\text{woplan}}$	is the financial risk at the plan date after the planned inspection, \$/yr
$R(t)_{\text{inj}}$	is the safety risk as a function of time, injuries/yr
$R(t)_{\text{inj-target}}$	is the level of acceptable safety risk that triggers the inspection planning process, injuries/yr
$R_f(t)_{\text{inj,plan}}$	is the safety risk at the plan date before the planned inspection, injuries/yr
$R_f(t)_{\text{inj}}^{\text{woplan}}$	is the safety risk at the plan date after the planned inspection, injuries/yr

$R(t)_{\text{fin}}$	is the financial risk as a function of time, \$/yr
$R(t, I_E)$	is the risk as a function of time and inspection effectiveness, ft^2/yr (m^2/yr), \$/yr, injuries/yr
target date	is the date where the risk target is expected to be reached and is the date at or before the recommended inspection should be performed
t_{rde}	is the measured thickness reading from previous inspection with respect to wall loss associated with external corrosion
t_{rdi}	the furnished thickness, t , or measured thickness reading from previous inspection, only if there is a high level of confidence in its accuracy, with respect to wall loss associated with internal corrosion
t_{target}	is the thickness target for inspection planning

3.3 Figures

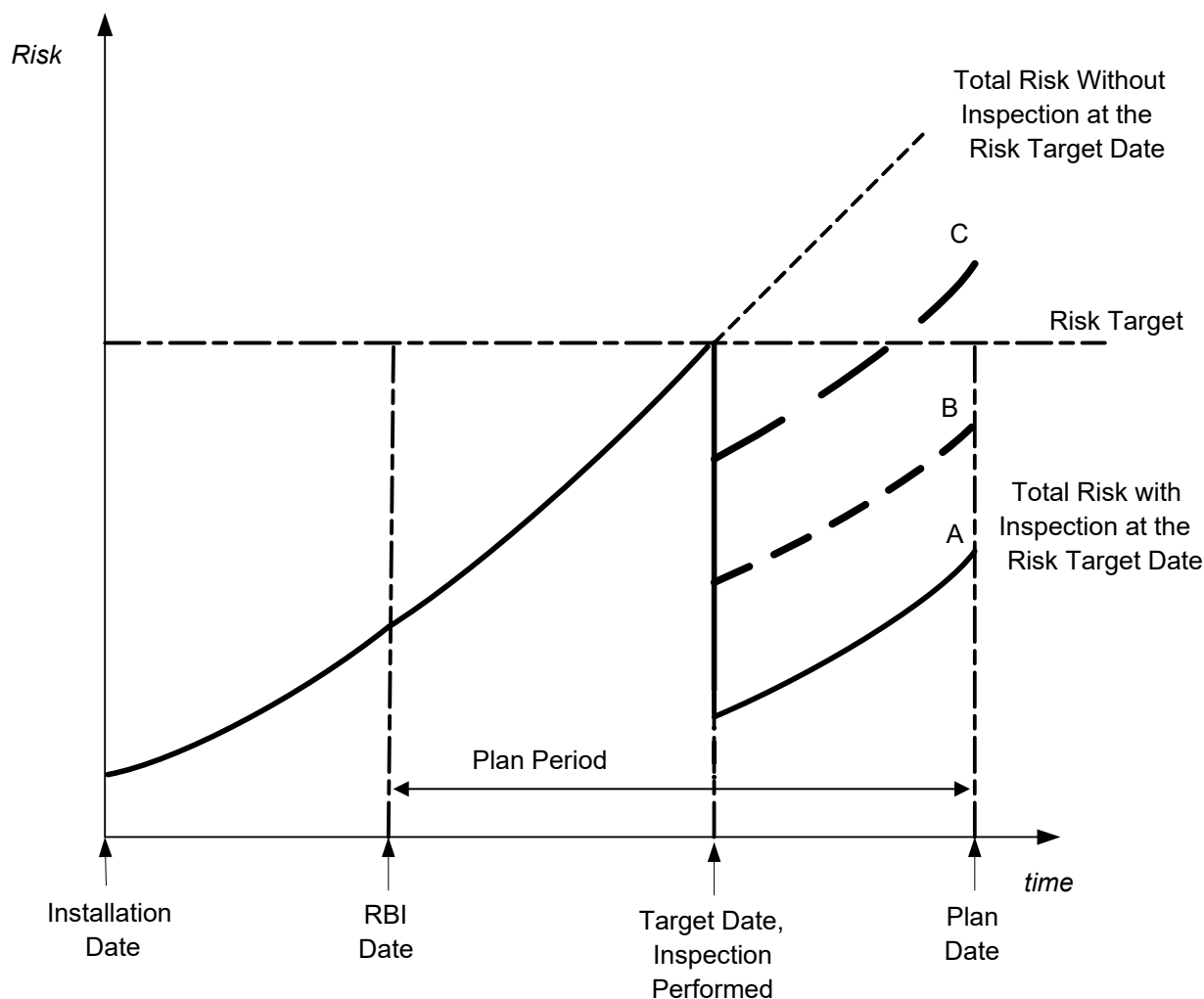


Figure 4.1—Case 1: Inspection Planning when the Risk Target Is Exceeded During the Plan Period

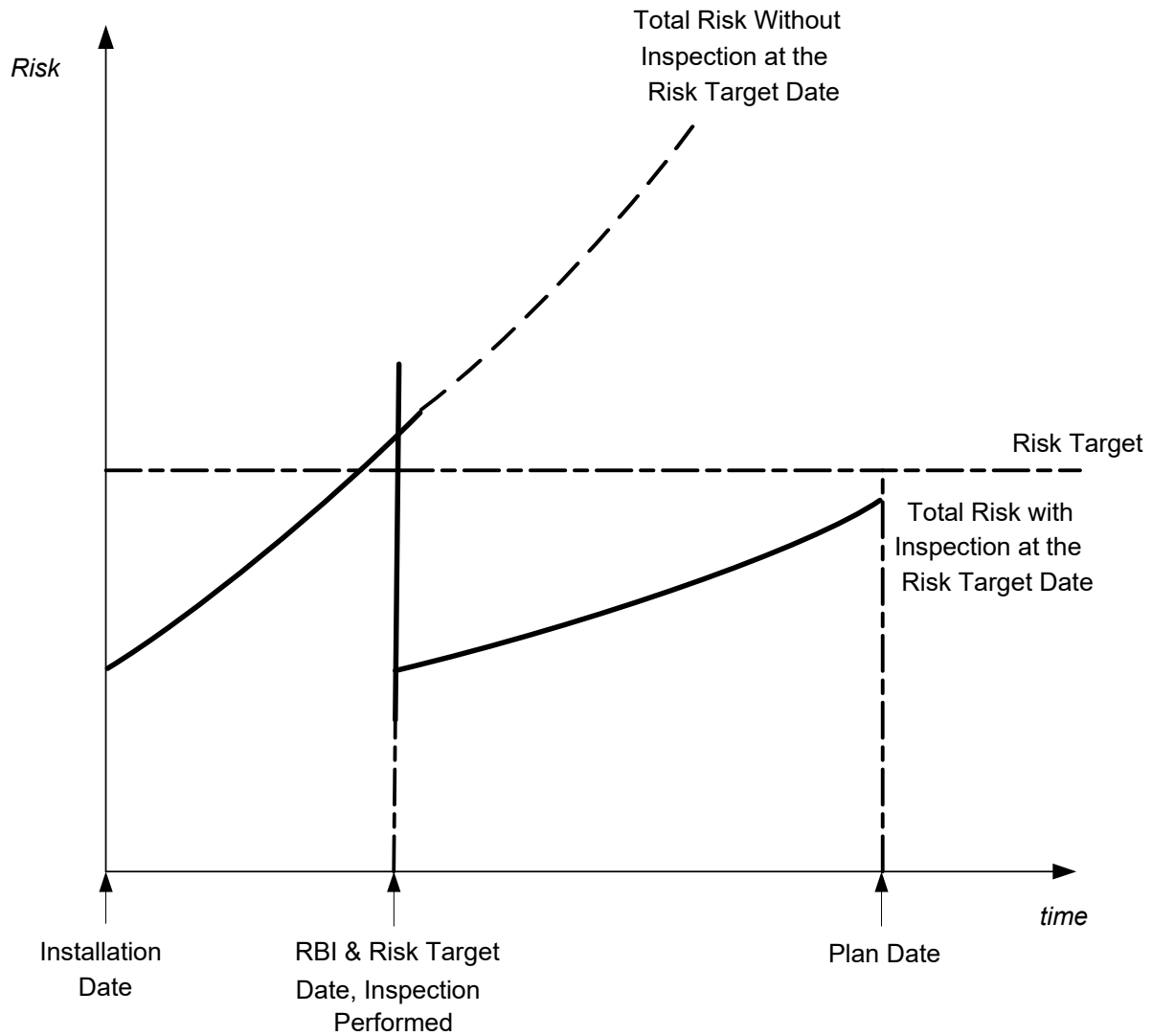


Figure 4.2—Case 2: Inspection Planning when the Risk Target Has Been Exceeded at or Prior to the RBI Date

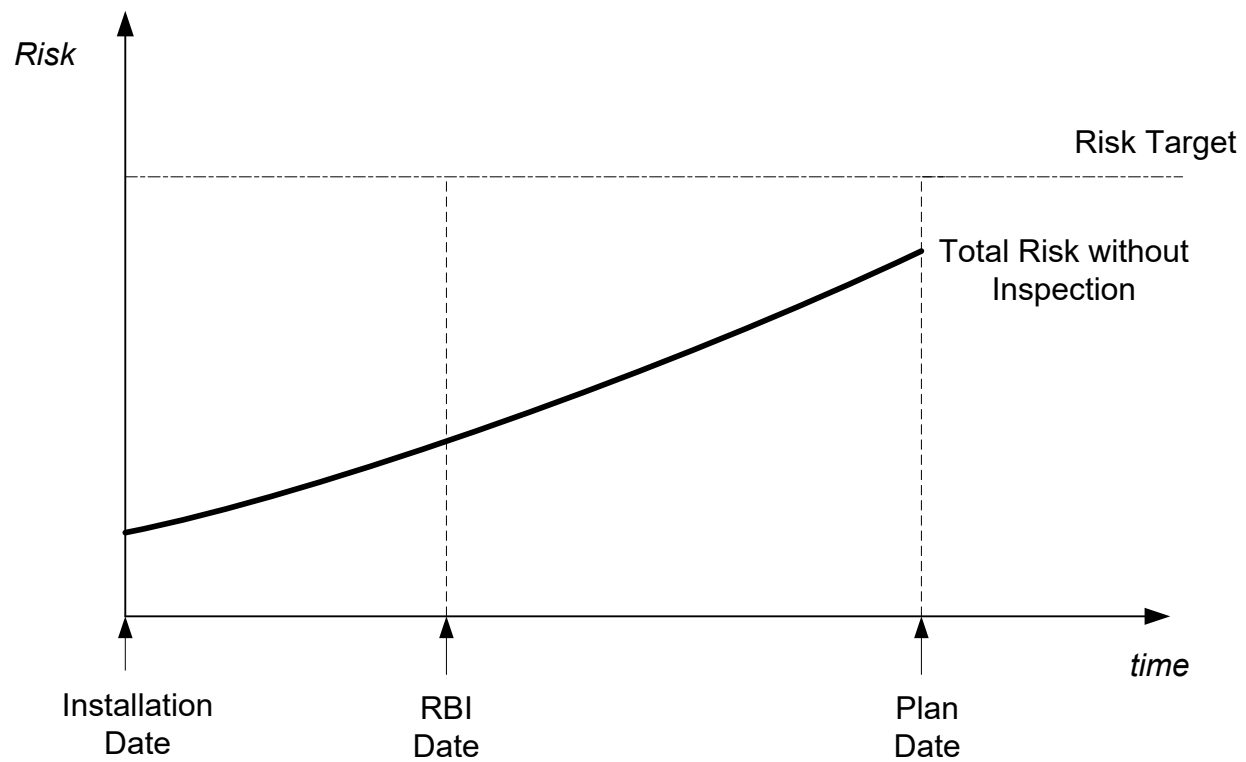


Figure 4.3—Case 3: Inspection Planning when Risk Target Is Not Exceeded During the Plan Period

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Risk-based Inspection Methodology

Part 5—Special Equipment

1 Scope

1.1 Purpose

This recommended practice, API 581, provides semiquantitative procedures to establish an inspection program using risk-based methods for pressurized fixed equipment, including pressure vessel, piping, tankage, PRDs, and heat exchanger tube bundles. API 580, *Risk-Based Inspection*, provides guidance for developing RBI programs on fixed equipment in refining, petrochemical, chemical process plants, and oil and gas production facilities. The intent is for API 580 to introduce the principles and present minimum general guidelines for RBI, while the API 581 recommended practice provides semiquantitative calculation methods to calculate risk and develop an inspection plan.

1.2 Introduction

The calculation of risk outlined in API 581 involves the determination of a probability of failure (POF) combined with the consequence of failure (COF). Failure is defined as a loss of containment from the pressure boundary resulting in leakage to the atmosphere or rupture of a pressurized component. Risk increases as damage accumulates during in-service operation as the risk tolerance or risk target is approached and an inspection is recommended of sufficient effectiveness to better quantify the damage state of the component. The inspection action itself does not reduce the risk; however, it does reduce uncertainty and therefore allows more accurate quantification of the damage present in the component.

1.3 Risk Management

In most situations, once risks have been identified, alternate opportunities are available to reduce them. However, nearly all major commercial losses are the result of a failure to understand or manage risk. In the past, the focus of a risk assessment has been on-site safety-related issues. Presently, there is an increased awareness of the need to assess risk resulting from:

- a) on-site risk to employees,
- b) off-site risk to the community,
- c) business interruption risks, and
- d) risk of damage to the environment.

Any combination of these types of risks may be factored into decisions concerning when, where, and how to inspect equipment.

The overall risk of a plant may be managed by focusing inspection efforts on the process equipment with higher risk. API 581 provides a basis for managing risk by making an informed decision on inspection frequency, level of detail, and types of NDE. It is a consensus document containing methodology that owner-operators may apply to their RBI programs. In most plants, a large percent of the total unit risk will be concentrated in a relatively small percent of the equipment items. These potential higher risk components may require greater attention, perhaps through a revised inspection plan. The cost of the increased inspection effort can sometimes be offset by reducing excessive inspection efforts in the areas identified as having lower risk. Inspection will continue to be conducted as defined in existing working documents, but priorities, scope, and frequencies can be guided by the methodology contained in API 581.

This approach can be made cost-effective by integration with industry initiatives and government regulations, such as *Process Safety Management of Highly Hazardous Chemicals* (OSHA 29 CFR 1910.119) or the EPA risk management programs for chemical accident release prevention.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 580, *Elements of a Risk-Based Inspection*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 1—Introduction to Risk-Based Inspection Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 2—Probability of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 3—Consequence of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 4—Inspection Planning Methodology*

3 Pressure Vessels and Piping

3.1 POF

The procedures for POF calculations to be used are provided in [Part 2](#). The POF as a function of time and inspection effectiveness is determined using a GFF, a management systems factor, and DFs for the applicable active damage mechanisms as described in [Section 4.1](#).

3.2 COF

COF calculation procedures for two levels of consequence analysis are provided in [Part 3](#), as described in [Section 4.2](#). In both methods, the consequence analysis may be determined in consequence area or in financial consequence. Consequences from flammable and explosive events, toxic releases, and nonflammable and nontoxic events are considered based on the process fluid and operating conditions.

3.3 Risk Analysis

Risk as a function of time is calculated in accordance with [Section 4.3.1](#). The distribution of risks for different components may be plotted on a risk matrix or iso-risk plot, as described in [Section 4.3.2](#) and [Section 4.3.2.3](#), respectively.

3.4 Inspection Planning Based on Risk Analysis

The procedure to determine an inspection plan is provided in Part 4. This procedure may be used to determine both the time and type of inspection to be performed based on the process fluid and design conditions, component type and materials of construction, and the active damage mechanisms.

4 Storage Tanks

4.1 General

The calculation of the consequence of a leak or rupture of an API 620 low-pressure and API 650 atmospheric storage tank bottom, edge, and course components are covered in this section. The primary liquid container should be evaluated for risk with the secondary container purpose as leak isolation for API 620 double-walled tanks (tank-in-tank systems). The DF and POF calculation use a methodology similar to the approach outlined in [Part 2](#). The methodology for consequence analysis specialized for storage tanks is provided for the COF calculation. The background on the GFFs for tank bottoms and courses are provided in [Part 3, Section 3.A.5.3.1](#).

4.2 POF

POF calculation procedures for storage tank bottom components are provided in this section. Follow calculating procedures outlined in [Part 2](#) for tank course POF. The tank bottom component POF as a function of time and inspection effectiveness is determined using a GFF, a management systems factor, and DFs for the applicable active damage mechanisms.

The soil-side plates of the tank bottom edge (under-shell) may have a different corrosive environment and foundation conditions than the remainder of the bottom component in tanks with annular rings. Product-side corrosion in the perimeter area of the tank may be different than the remainder of the tank bottom due to the as-built or settled profile, edge sump(s), mixers, or other appurtenances. In addition, the stresses in the tank bottom edge differs from the tank bottom and the $t_{\min}$ calculation in the critical zone are calculated using API 620 and API 650.

4.3 Determination of the Tank Bottom DF

4.3.1 General

The calculation procedure for the tank bottom component thinning DF calculation is provided in this section. DFs for other active damage mechanisms are calculated using [Part 2, Section 5](#) through [Section 24](#).

4.3.2 Determination of the Tank Bottom Thinning DF

- a) Step 1.1—Determine the furnished thickness, t , and age, age , for the tank component from the installation date. If the tank has an internal liner, determine the liner age, age_{liner} from the liner installation date.
- b) Step 1.2—Determine the corrosion rate for the base material, $C_{r,bm}$, based on the material of construction and process environment, using guidance from [Part 2, Section 4.5.2](#) and examples in [Part 2, Annex 2.B](#) for establishing corrosion rates.
- c) Step 1.3—Determine the inspection effectiveness, N_A^{Thin} , N_B^{Thin} , N_C^{Thin} , and N_D^{Thin} , for the last inspection performed using [Part 2, Section 4.5.6](#) for guidance.
- d) Step 1.4—Determine the time in service, age_{tk} , since the last inspection known thickness, t_{rdi} , where t_{rdi} is the starting thickness with respect to wall loss associated with internal corrosion (see [Part 2, Section 4.5.5](#)).
 - 1) Determine the date of the last inspection with a measured thickness and calculate the service age since the inspection, age_{tk} , and the measured thickness, t_{rdi} . If no measured thickness is available, set $t_{rdi} = t$ and $age_{tk} = age$.
 - 2) For tank components with internal liners, determine the lining type and age using [Table 4.1](#) or using the remaining life of the internal liner, condition of liner, F_{LC} , at last inspection using [Table 4.2](#), and

online monitoring factor, F_{OM} , using Equation (5.1). If component does not contain an internal liner, $age_{rc} = 0$.

$$age_{f,rc} = \frac{age_{rc}}{F_{LC}} \cdot F_{OM} \quad (5.1)$$

Online monitoring adjustment factor, F_{OM} —Some lined components have monitoring to allow early detection of a leak or other failure of the lining. The monitoring allows orderly shutdown of the component before failure occurs. If online monitoring is used and it is known to be effective at detecting lining deterioration, $F_{OM} = 0.1$; otherwise, $F_{OM} = 1.0$. Examples of monitoring systems include thermography or heat sensitive paint (refractory linings), weep holes with detection devices (loose alloy linings), and electrical resistance detection (glass linings).

e) Step 1.5—Determine t_{min} using one of the following methods:

- 1) For the API 620 and API 650 tank courses, determine the allowable stress, S and weld joint efficiency, E , and calculate the minimum required thickness, t_{min} , using component type in Part 2, Table 4.2, geometry type in Part 2, Table 4.3, and per the original construction code or API 579-1/ASME FFS-1 [24] or API 620, as applicable.
- 2) API 650 tank bottoms can be modeled with two components. If the component type is Tank650 TANKBOTTOM, use $t_{min} = 0.1$ in. if the storage tank does not have an RPB or $t_{min} = 0.05$ in. if the storage tank has an RPB, in accordance with API 653 [2]. If the component is a Tank650 TANKBOTEDGE, use the minimum thickness for an annular ring or the critical zone (for tanks without annular rings), whichever is applicable, in accordance with API 653.
- 3) API 620 tank bottom t_{min} is determined by using API 620. If the component is a Tank620 TANKBOTEDGE, use the minimum thickness for an annular ring or the critical zone (for tanks without annular rings), whichever is applicable, in accordance with API 653.
- 4) A specific t_{min} calculated by another method and documented in the asset management program may be used at the owner–operator's discretion.

f) Step 1.6—Determine the tank bottom component A_{rt} parameter using Equation (5.2) based on t from Step 1, $C_{r,bm}$ from Step 1.2, and age_{tk} and t_{rdi} from Step 1.4.

NOTE The age parameter in these equations is equal to age_{tk} from Step 1.4.

- 1) For tank courses, go to Steps 7 through 15 in Part 2, Section 4.5.7 and skip to Step 1.8.
- 2) For tank bottom components, calculate the A_{rt} parameter using Equation (5.2).

$$A_{rt} = \max \left[\left(1 - \frac{t_{rdi} - (C_{r,bm} \cdot (age_{tk} - age_{f,rc}))}{t_{min} + CA} \right), 0.0 \right] \quad (5.2)$$

g) Step 1.7—For tank bottom components, determine the base DF for thinning, D_{fB}^{thin} , using Table 4.3 and based on the A_{rt} parameter from Step 1.6 and inspection effectiveness from Step 1.3.

h) Step 1.8—Determine the DF for thinning, $D_f^{\text{Tank, Thin}}$, using Equation (5.3).

$$D_f^{\text{Tank, Thin}} = \max \left[\left(D_{fB}^{\text{Thin}} \cdot F_{WD} \cdot F_{AM} \cdot F_{SM} \right), 0.1 \right] \quad (5.3)$$

The adjustment factors in are determined as described below.

- 1) Adjustment for Welded Construction, F_{WD} —If the component is welded (i.e. not riveted), then $F_{WD} = 1$; otherwise, $F_{WD} = 10$.
- 2) Adjustment for Maintenance in Accordance with API 653, F_{AM} —If the storage tank is maintained in accordance with API 653, then $F_{AM} = 1$; otherwise, $F_{AM} = 5$.
- 3) Adjustment for Settlement, F_{SM} —It is determined based on the following criteria.
 - Recorded settlement exceeds API 653 criteria— $F_{SM} = 2$.
 - Recorded settlement meets API 653 criteria— $F_{SM} = 1$.
 - Settlement never evaluated— $F_{SM} = 1.5$.
 - Concrete foundation, no settlement— $F_{SM} = 1$.

4.3.3 Determination of the SCC DFs

Follow calculating procedures outlined in Part 2, Section 5 through Section 14 for SCC of storage tank courses, if applicable.

4.3.4 Determination of the External DFs

Follow calculating procedures outlined in Part 2, Section 15 through Section 18 for external damage of storage tank courses, if applicable.

4.3.5 Determination of the Brittle Fracture DFs

Follow calculating procedures outlined in Part 2, Section 21 for brittle fracture of storage tank courses, if applicable.

4.3.6 DF Combination for Multiple Damage Mechanisms

Follow calculating procedures outlined in Part 2, Section 3.4.2 for combining DFs or multiple damage mechanisms of storage tank courses.

4.4 COF

The COF is calculated in terms of affected area or in financial consequence. Consequences from flammable and explosive events, toxic releases, and nonflammable/nontoxic events are considered in both methods based on the process fluid and operating conditions. Financial consequences from component damage, product loss, financial impact, and environmental penalties are considered.

The COF methodology is performed to aid in establishing a ranking of equipment items on the basis of risk. The consequence measures are intended to be used for establishing priorities for inspection programs. Methodologies for two levels of analysis are provided. A special COF methodology is provided for low-pressure and atmospheric storage tanks and is covered in this section.

4.5 COF Methodology for Storage Tank Courses

The COF associated with storage tanks is concerned primarily with the financial losses due to leakage and/or rupture of a storage tank course. Safety/area-based consequences are addressed for the courses following the Level 1 or Level 2 consequence analysis methods provided in [Part 3, Section 4](#) or [Section 5](#). Detailed procedures for calculating the financial COF for courses are provided in [Section 2.5](#) through [Section 2.16](#).

The procedure for determining COF of storage tank course components includes calculations for both area- and financial-based methods.

4.6 Required Properties at Storage Conditions

4.6.1 General

Fluid properties should be determined for the COF calculation. When calculating the safety COF area for tank courses, see [Part 3, Section 5.1.2](#) Level 1 or 2 COF methodology. See [Part 3, Section 5.1.2](#) for detailed description of required properties at storage conditions. The financial COF for fluids other than those in [Table 4.5](#) may be modeled if the stored as liquid data required in [Table 4.5](#) and [Part 3, Table 4.2](#) are provided by the user.

NOTE The flammable COF would be calculated based on the equation constants in [Part 3, Table 4.8](#) and [Part 3, Table 4.9](#) for the fluid closest matching the MW and NBP.

Fluid properties at storage conditions are necessary to calculate the financial- and area-based Level 1 and Level 2 COF. Refer to the following sections for a detailed description of the required properties at storage conditions for tank course components.

- a) Level 1 COF methodology, see [Part 3, Section 4.1.2](#).
- b) Level 2 COF methodology see [Part 3, Section 5.1.2](#).

4.6.2 Required Properties at Flash Conditions

Fluid properties are determined for a safety based COF for use in the Level 1 or 2 COF methodology. See [Part 3, Section 5.1.3](#) for detailed description of required properties at flashed conditions.

4.7 Release Hole Size Selection

4.7.1 General

A discrete set of release events or release hole sizes are used for consequence analysis as outlined in [Table 4.4](#).

4.7.2 Calculation of Release Hole Sizes

The following procedure may be used to determine the release hole size and the associated GFFs.

- a) Step 2.1—Determine the release hole size, $d_n = 1$, from [Table 4.4](#) for storage tank courses.
- b) Step 2.2—Determine the generic failure frequency, gff_n , for the d_n release hole size and the total generic failure frequency from [Part 2, Table 3.1](#) or from [Equation \(5.4\)](#).

$$gff_{\text{total}} = \sum_{n=1}^4 gff_n \quad (5.4)$$

4.8 Release Rate Calculation

4.8.1 General

Release rate calculations are provided for a leak in a storage tank course. The liquid head of the product is assumed to be constant over time, and the leak is to atmospheric pressure for a course leak.

4.8.2 Storage Tank Course

The discharge of a liquid through a sharp-edged orifice in a storage tank course with a liquid height above the orifices may be calculated using Equation (5.5).

$$W_n = C_{32} \cdot C_d \cdot A_n \sqrt{2 \cdot g \cdot LHT_{\text{above},i}} \quad (5.5)$$

In Equation (5.5), the discharge coefficient, C_d , for fully turbulent liquid flow from sharp-edged orifices is in the range of $0.60 \leq C_d \leq 0.65$. A value of $C_d = 0.61$ is recommended.

4.8.3 Calculation of Storage Tank Course Release Rate

- a) Step 3.1—Determine the height of the liquid, h_{liq} , above the release hole size, d_n , for each hole size.
- b) Step 3.2—Determine the hole area, A_n , for each hole size using Equation (5.6).

$$A_n = \frac{\pi d_n^2}{4} \quad (5.6)$$

- c) Step 3.3—Determine the liquid height above the i^{th} course where h_{liq} is the maximum fill height in the tank and CHT is the height of each course.

$$LHT_{\text{above},i} = [h_{\text{liq}} - (i-1) \cdot CHT] \quad (5.7)$$

- d) Step 3.3—Determine the flow rate, W_n , for each hole size using Equation (5.5) based on h_{liq} from Step 3.1 and A_n from Step 3.2.

4.9 Estimate the Inventory Volume and Mass Available for Release

4.9.1 General

The inventory in the storage tank available for release depends on the component being evaluated. The available inventory for courses is a function of the location of the release hole and is calculated as the volume of fluid above the release hole.

4.9.2 Calculation of Storage Tank Course Inventory Mass

The amount of fluid inventory used in the course consequence analysis is the amount of fluid that is above the lower elevation of the course under evaluation.

- a) Step 4.1—Determine the liquid height above the i^{th} course where h_{liq} is the maximum fill height in the tank and CHT is the height of each course.

$$LHT_{\text{above},i} = [h_{\text{liq}} - (i-1) \cdot CHT] \quad (5.8)$$

- b) Step 4.2—Determine the volume above the course being evaluated.

$$Lvol_{above,i} = \left(\frac{\pi D_{\text{tank}}^2}{4} \right) \cdot LHT_{above,i} \quad (5.9)$$

- c) Step 4.3—Calculate the available volume of the release.

NOTE The release hole should be assumed to be at the bottom of the course.

$$Lvol_{avail,n} = Lvol_{above,i} \quad (5.10)$$

- d) Step 4.4—Calculate the storage tank volume in barrels using Equation (5.11).

$$Bbl_{avail,n} = Lvol_{avail,n} \cdot C_{13} \quad (5.11)$$

- e) Step 4.5—Calculate the storage tank mass using liquid density, ρ_l , from Table 4.5 and using Equation (5.12).

$$mass_{avail,n} = Lvol_{avail,n} \cdot \rho_l \quad (5.12)$$

4.10 Determine the Type of Release

The type of release for a storage tank is assumed to be continuous.

4.11 Estimate the Impact of Detection and Isolation Systems on Release Magnitude

Detection and isolation systems are not accounted for in a storage tank course consequence analysis.

4.12 Determine the Release Rate and Volume for the COF Analysis

4.12.1 General

The storage tank course release is assumed to be continuous and the release rate is calculated from Equation (5.13), where W_n is determined in Section 2.7.2.

$$rate_n = W_n \quad (5.13)$$

4.12.2 Calculation for Storage Tank Course Release Volume

A step-by-step methodology for determining the release rate and volume is in accordance with the modeling in Part 3, Section 4 for Level 1 COF and Part 3, Section 5 for Level 2 COF with the following differences.

- The pool fire area should not exceed the area of the dike.
- The release volume should be calculated with the following steps.

- a) Step 5.1—Determine the release rate, $rate_n$, for each hole size in bbl/day using Equation (5.13) where the release rate, W_n , is from Step 3.3.

- b) Step 5.2—Determine the leak detection time, t_{ld} , as follows:

$$t_{ld} = 7 \text{ days for } d_n \leq 0.125 \text{ in. (3.17 mm)}$$

$$t_{ld} = 1 \text{ day for } d_n > 0.125 \text{ in. (3.17 mm)}$$

- c) Step 5.3—Calculate the leak duration, ld_n , of the release for each hole size using Equation (5.14) based on the release rate, $rate_n$, from Step 5.1, the leak detection time, t_{ld} , from Step 5.2, and the storage tank volume, $Bbl_{avail,n}$, from Step 4.4.

$$ld_n = \min \left[\left\{ \frac{Bbl_{avail,n}}{rate_n} \right\}, 7 \text{ days} \right] \quad \text{for } d_n \leq 0.125 \text{ in. (3.17 mm)} \quad (5.14)$$

- d) Step 5.4—Calculate the release volume from leakage, Bbl_n^{leak} , for each hole size using Equation (5.15) based on the release rate, $rate_n$, from Step 5.1, the leak duration, ld_n , from Step 5.3, and available volume, $Bbl_{avail,n}$, from Step 4.4.

$$Bbl_n^{leak} = \min \left[\{ rate_n \cdot ld_n \}, Bbl_{avail,n} \right] \quad (5.15)$$

- e) Step 5.5—Calculate the release mass from leakage, $mass_n^{leak}$, for each hole size using Equation (5.16) based on the available volume, Bbl_n^{leak} , from Step 5.4.

$$mass_n^{leak} = Bbl_n^{leak} \quad (5.16)$$

- f) Step 5.6—Calculate the release volume from a rupture, $Bbl_n^{rupture}$, for each hole size using Equation (5.17) based on the available volume, $Bbl_{avail,n}$, from Step 4.4.

$$Bbl_n^{rupture} = Bbl_{avail,n} \quad (5.17)$$

- g) Step 5.7—Calculate the mass from a rupture, $mass_n^{rupture}$, for each hole size using Equation (5.18) based on the available volume, $Bbl_n^{rupture}$, from Step 5.6.

$$mass_n^{rupture} = Bbl_n^{rupture} \quad (5.18)$$

4.13 Determine Flammable and Explosive Consequences for Storage Tank Courses

4.13.1 General

Flammable and explosive consequences for storage tanks courses are determined using a similar approach as implemented for Level 1 and 2 consequence analysis.

4.13.2 Calculation of Flammable and Explosive Consequences

The step-by-step procedure for determining the flammable and explosive consequences are in accordance with the level of consequence analysis; see Part 3, Section 4.8 for Level 1 analysis and Part 3, Section 5.8.9 for Level 2 COF analysis.

4.14 Determine Toxic Consequences for Storage Tank Courses

4.14.1 General

Toxic consequences for storage tank courses are determined using a similar approach as implemented for Level 1 and 2 consequence analysis.

4.14.2 Calculation of Toxic Consequences for Storage Tank Courses

The step-by-step methodology for determining the toxic consequences are in accordance with the Level 1 and 2 consequence analysis; see [Part 3, Section 4.9](#) and [Part 3, Section 5.9.8](#).

4.15 Determine Nonflammable, Nontoxic Consequences

Nonflammable, nontoxic consequences are not determined for storage tanks.

4.16 Determine Component Damage and Personnel Injury Consequences for Storage Tank Courses

4.16.1 General

Flammable and explosive consequences for storage tank courses are determined using a similar approach as implemented for Level 1 and 2 consequence analysis.

4.16.2 Calculation for Component Damage and Personnel Injury Consequences

The step-by-step procedure for determining the flammable and explosive consequences are in accordance with the Level 1 COF in [Part 3, Section 4.8](#) and Level 2 COF in [Part 3, Section 5.11.5](#).

4.17 Determine the Financial Consequences

4.17.1 General

The financial consequence is determined in accordance with the Level 1 COF in [Part 3, Section 4.12](#).

4.17.2 Calculation of Storage Tank Course Financial Consequence

The step-by-step procedure for estimating the financial consequence is in accordance with [Section 4.12.7](#), except when calculating the environmental financial consequence. The storage tank course financial consequence can be calculated following the approach in sections defined below using the hole sizes defined in [Table 4.8](#).

- Component damage cost in accordance with [Section 4.12.2](#).
- Damage cost to surrounding equipment in accordance with [Section 4.12.3](#).
- Business interruption costs in accordance with [Section 4.12.4](#).
- Potential injury costs in accordance with [Section 4.12.5](#).

The storage tank environmental financial consequence for courses is calculated following the steps provided below.

a) Step 6.1—Determine the following parameters.

- 1) P_{ldike} —percentage of fluid leaving the dike.
- 2) P_{onsite} —percentage of fluid that leaves the dike area but remains on-site.
- 3) P_{offsite} —percentage of fluid that leaves the dike area but does not enter nearby water.

b) Step 6.2—Determine the environmental sensitivity used to establish C_{indike} , $C_{\text{ss-onsite}}$, $C_{\text{ss-offsite}}$, and C_{water} from [Table 4.6](#).

c) Step 6.3—Determine the probability weighted total barrels of fluid released by leakage, $Bbl_{\text{release}}^{\text{leak}}$.

$$Bbl_{\text{release}}^{\text{leak}} = \frac{\sum_{n=1}^3 (Bbl_n^{\text{leak}} \cdot gff_n)}{gff_{\text{total}}} \quad (5.19)$$

d) Step 6.4—Calculate the total barrels of fluid within the dike from leakage, $Bbl_{\text{indike}}^{\text{leak}}$, the total barrels of fluid in the on-site surface soil, $Bbl_{\text{ss-onsite}}^{\text{leak}}$, the total barrels of fluid in the off-site surface soil, $Bbl_{\text{ss-offsite}}^{\text{leak}}$, and the total barrels of fluid that reach water, $Bbl_{\text{water}}^{\text{leak}}$, using [Equation \(5.20\)](#) through [Equation \(5.23\)](#), respectively.

$$Bbl_{\text{indike}}^{\text{leak}} = Bbl_{\text{release}}^{\text{leak}} \left(1 - \frac{P_{\text{ldike}}}{100} \right) \quad (5.20)$$

$$Bbl_{\text{ss-onsite}}^{\text{leak}} = \frac{P_{\text{onsite}}}{100} (Bbl_{\text{release}}^{\text{leak}} - Bbl_{\text{indike}}^{\text{leak}}) \quad (5.21)$$

$$Bbl_{\text{ss-offsite}}^{\text{leak}} = \frac{P_{\text{offsite}}}{100} (Bbl_{\text{release}}^{\text{leak}} - Bbl_{\text{indike}}^{\text{leak}} - Bbl_{\text{ss-onsite}}^{\text{leak}}) \quad (5.22)$$

$$Bbl_{\text{water}}^{\text{leak}} = Bbl_{\text{release}}^{\text{leak}} - (Bbl_{\text{indike}}^{\text{leak}} + Bbl_{\text{ss-onsite}}^{\text{leak}} + Bbl_{\text{ss-offsite}}^{\text{leak}}) \quad (5.23)$$

e) Step 6.5—Calculate the financial environmental cost from leakage, $FC_{\text{environ}}^{\text{leakage}}$.

$$FC_{\text{environ}}^{\text{leak}} = Bbl_{\text{indike}}^{\text{leak}} \cdot C_{\text{indike}} + Bbl_{\text{ss-onsite}}^{\text{leak}} \cdot C_{\text{ss-onite}} + Bbl_{\text{ss-offsite}}^{\text{leak}} \cdot C_{\text{ss-offite}} + Bbl_{\text{water}}^{\text{leak}} \cdot C_{\text{water}} \quad (5.24)$$

f) Step 6.6—Determine the total barrels of fluid released by a course rupture, $Bbl_{\text{release}}^{\text{rupture}}$.

$$Bbl_{\text{release}}^{\text{rupture}} = \frac{Bbl_n^{\text{rupture}} \cdot gff_4}{gff_{\text{total}}} \quad (5.25)$$

- g) Step 6.7—Calculate the total barrels of fluid within the dike from a rupture, $Bbl_{indike}^{rupture}$, the total barrels of fluid in the on-site surface soil, $Bbl_{ss-onsite}^{rupture}$, the total barrels of fluid in the off-site surface soil, $Bbl_{ss-offsite}^{rupture}$, and the total barrels of fluid that reach water, Bbl_{water}^{leak} , using Equation (5.26) through Equation (5.29), respectively.

$$Bbl_{indike}^{rupture} = Bbl_{release}^{rupture} \left(1 - \frac{P_{ldike}}{100} \right) \quad (5.26)$$

$$Bbl_{ss-onsite}^{rupture} = \frac{P_{onsite}}{100} \left(Bbl_{release}^{rupture} - Bbl_{indike}^{rupture} \right) \quad (5.27)$$

$$Bbl_{ss-offsite}^{rupture} = \frac{P_{offsite}}{100} \left(Bbl_{release}^{rupture} - Bbl_{indike}^{rupture} - Bbl_{ss-onsite}^{rupture} \right) \quad (5.28)$$

$$Bbl_{water}^{rupture} = Bbl_{release}^{rupture} - \left(Bbl_{indike}^{rupture} + Bbl_{ss-onsite}^{rupture} + Bbl_{ss-offsite}^{rupture} \right) \quad (5.29)$$

- h) Step 6.8—Calculate the financial environmental cost for a course rupture, $FC_{environ}^{rupture}$.

$$FC_{environ}^{rupture} = Bbl_{indike}^{rupture} \cdot C_{indike} + Bbl_{ss-onsite}^{rupture} \cdot C_{ss-onsite} + Bbl_{ss-offsite}^{rupture} \cdot C_{ss-offsite} + Bbl_{water}^{rupture} \cdot C_{water} \quad (5.30)$$

- i) Step 6.9—Calculate the total financial environmental cost from a leak and a rupture, $FC_{environ}$, where $FC_{environ}^{leak}$ is from Step 12.5 and $FC_{environ}^{rupture}$ is from Step 12.8.

$$FC_{environ} = FC_{environ}^{leak} + FC_{environ}^{rupture} \quad (5.31)$$

- j) Step 6.10—Calculate the total financial COF, FC_{total} , using Equation (5.32).

$$FC_{total} = FC_{environ} + FC_{cmd} + FC_{prod} + FC_{affa} + FC_{inj} \quad (5.32)$$

4.18 Determination of Safety Consequences

Safety consequences, SC_f , for storage tank courses are calculated the approach outlined in Part 3, Section 5.13. The injury area, CA_{inj} , for a course release is outlined in Section 3.15.1.

4.19 COF Methodology for Storage Tank Bottoms

4.19.1 General

The COF associated with storage tanks is concerned primarily with the financial losses due to loss of containment and leakage through the storage tank bottoms. Area-based consequences are not calculated for storage tank bottoms. Detailed procedures for calculating the financial COF for bottom plates are provided in this section.

The procedure for determining the COF for storage tank bottom components consists of calculations for financial COF based on environmental consequences, component damage cost, and business interruption cost. storage tank consequence analysis for flammable and/or explosive or toxic are not calculated for storage tank bottoms.

4.19.2 Required Properties at Storage Conditions

The tank bottom financial COF is calculated using one of the following approaches.

- Select the representative fluid from [Table 4.5](#) that most closely matches the stored fluid.
- Determine the dynamic viscosity and density of the stored fluid.

4.19.3 Hydraulic Conductivity for Storage Tank Bottom

The amount and rate of leakage from storage tank bottoms is dependent on the type of soil and its properties as well as whether or not the storage tank bottom has an RBP. A list of soil types and properties used in the storage tank consequence analysis routine is shown in [Table 4.7](#).

The fundamental soil property required in the analysis is the soil hydraulic conductivity, k_h . The hydraulic conductivity as a function of soil type is provided in [Table 4.7](#) based on water. The hydraulic conductivity for other fluids can be estimated based on the hydraulic conductivity, density, and dynamic viscosity of water, denoted as $k_{h,water}$, ρ_w , and μ_w , respectively, and the density and dynamic viscosity of the actual fluid using [Equation \(5.33\)](#).

$$k_{h,prod} = k_{h,water} \left(\frac{\rho_l}{\rho_w} \right) \left(\frac{\mu_w}{\mu_l} \right) \quad (5.33)$$

4.19.4 Fluid Seepage Velocity for Storage Tank Bottom

The seepage velocity of the fluid in the storage tank bottom or product through the soil is given by [Equation \(5.34\)](#), where k_h is the soil hydraulic conductivity and p_s is the soil porosity.

$$vel_{s,prod} = \frac{k_{h,prod}}{p_s} \quad (5.34)$$

4.19.5 Calculation of Fluid Seepage Velocity for Storage Tank Bottom

- Step 7.1—Determine properties including density, ρ_l , and dynamic viscosity, μ_l , of the stored fluid. If a Level 1 analysis is being performed, select the representative fluid properties from [Table 4.5](#).
- Step 7.2—Calculate the hydraulic conductivity for water by averaging the upper and lower bound hydraulic conductivities provided in [Table 4.7](#) for the soil type selected using [Equation \(5.35\)](#).

$$k_{h,water} = C_{31} \frac{(k_{h,water-lb} + k_{h,water-ub})}{2} \quad (5.35)$$

- Step 7.3—Calculate the fluid hydraulic conductivity, $k_{h,prod}$, for the fluid stored in the storage tank using [Equation \(5.33\)](#) based on the density, ρ_l , and dynamic viscosity, μ_l , from Step 7.1 and the hydraulic conductivity for water, $k_{h,water}$, from Step 7.2.
- Step 7.4—Calculate the product seepage velocity, $vel_{s,prod}$, for the fluid stored in the storage tank using [Equation \(5.34\)](#) based on fluid hydraulic conductivity, $k_{h,prod}$, from Step 7.3 and the soil porosity provided in [Table 4.7](#).

4.20 Release Hole Size Selection

4.20.1 General

A discrete set of release events or release hole sizes are used for consequence analysis as outlined in [Table 4.8](#).

4.20.2 Calculation of Release Hole Sizes

The following procedure may be used to determine the release hole size and the associated GFFs.

- Step 8.1—Determine the release hole size, d_n , from [Table 4.8](#) for storage tank bottoms.
- Step 8.2—Determine the generic failure frequency, gff_n , for the d_n release hole size and the total generic failure frequency from [Part 2, Table 3.1](#) or from [Equation \(5.36\)](#).

$$gff_{\text{total}} = \sum_{n=1}^4 gff_n \quad (5.36)$$

4.21 Release Rate Calculation

4.21.1 General

Release rate calculations are provided for a leak in a storage tank bottom plate. The liquid head is assumed to be constant in time, and the leak is into the ground that is modeled as a continuous porous media approximated by soil properties typically used for storage tank foundations.

4.21.2 Storage Tank Bottom Release Rate

The product leakage flow rate through a small hole in the storage tank bottom is a function of the soil and fluid properties as well as the liquid head (fill height) above the bottom. The flow rate equations can be found in Rowe [3]. The flow rate through a storage tank bottom into a porous media is calculated using the Bernoulli in [Equation \(5.37\)](#), Giroud in [Equation \(5.38\)](#), or [Equation \(5.39\)](#) based on the hydraulic conductivity, $k_{h,\text{prod}}$, and release hole size, d_n .

$$W_n = C_{33} \cdot \pi \cdot d_n^2 \sqrt{2 \cdot g \cdot h_{\text{liq}}} \cdot n_{\text{rh},n} \quad \text{for } k_{h,\text{prod}} > C_{34} \cdot d_n^2 \quad (5.37)$$

$$W_n = C_{35} \cdot C_{\text{qo}} \cdot d_n^{0.2} \cdot h_{\text{liq}}^{0.9} \cdot k_{h,\text{prod}}^{0.74} \cdot n_{\text{rh},n} \quad \text{for } k_{h,\text{prod}} \leq C_{37} \cdot \left[\frac{d_n^{1.8}}{C_{\text{qo}} \cdot h_{\text{liq}}^{0.4}} \right]^{\frac{1}{0.74}} \quad (5.38)$$

$$W_n = C_{38} \cdot 10^{2 \cdot \log(d_n) + 0.5 \cdot \log(h_{\text{liq}}) - 0.74 \cdot \left(\frac{C_{39} + 2 \cdot \log(d_n) - \log(k_{h,\text{prod}})}{m} \right)^m} \cdot n_{\text{rh},n} \quad \text{for all other cases} \quad (5.39)$$

where

$$m = C_{40} - 0.4324 \cdot \log(d_n) + 0.5405 \cdot \log(h_{\text{liq}}).$$

In [Equation \(5.38\)](#), the parameter C_{qo} is an adjustment factor for degree of contact with soil and ranges from $C_{qo} = 0.21$ for good contact to $C_{qo} = 1.15$ for poor contact. A value of $C_{qo} = 0.21$ is recommended in the consequence analysis.

If the storage tank bottom has an RBP, then the liquid height, h_{liq} , to be used in the flow rate calculations is set to 0.25 ft (0.0762 m). If the storage tank does not have an RPB, the liquid height, h_{liq} , to be used in the flow rate calculations is the actual height of the stored product.

The number of release holes, $n_{rh,n}$, for each release hole size is a function of the storage tank diameter and is shown in [Table 4.9](#).

4.21.3 Calculation for Storage Tank Bottom Release Hole Size

- a) Step 9.1—For each release hole size, determine the number of release holes, $n_{rh,n}$, from [Table 4.9](#).
- b) Step 9.2—Determine the hole area, A_n , for each hole size from Step 8.1 using [Equation \(5.6\)](#).
- c) Step 9.3—Determine the hydraulic conductivity of the stored liquid, $k_{h,prod}$, from Step 1.4.
- d) Step 9.4—For each release hole size, determine the flow rate, W_n , using [Equation \(5.37\)](#), [Equation \(5.38\)](#), or [Equation \(5.39\)](#), as applicable. The liquid height, h_{liq} , to use in this calculation is determined as follows.
 - 1) The storage tank has an RPB: $h_{liq} = 0.25 \text{ ft (0.0762 m)}$.
 - 2) The storage tank does not have an RPB: $h_{liq} = \text{Actual Product Height}$.

4.22 Inventory Volume and Mass Available for Release

4.22.1 General

The amount of inventory in the storage tank available for release depends on the component being evaluated. The available inventory is the entire contents of the storage tank for bottom components unless the tank has an RPB.

4.22.2 Calculation of Storage Tank Bottom Inventory Mass

The amount of fluid available for release through storage tank bottoms is the fluid level up to the storage tank design fill height or the operating fill height.

- a) Step 10.1—Calculate liquid volume in the storage tank in ft^3 (m^3) using [Equation \(5.40\)](#).

$$Lvol_{total} = \left(\frac{\pi D_{tank}^2}{4} \right) \cdot h_{liq} \quad (5.40)$$

- b) Step 10.2—Calculate the total storage tank volume in barrels using [Equation \(5.41\)](#).

$$Bbl_{total} = Lvol_{total} \cdot C_{13} \quad (5.41)$$

- c) Step 10.3—Calculate the storage tank mass using [Equation \(5.42\)](#).

$$mass_{total} = Lvol_{total} \cdot \rho_l \quad (5.42)$$

4.23 Type of Release

The type of release for the storage tank bottom is assumed to be continuous.

4.24 Impact of Detection and Isolation Systems on Release Magnitude

Detection and isolation systems are not accounted for in the storage tank consequence analysis.

4.25 Release Rate and Volume for the COF Analysis

4.25.1 General

The release for the storage tank is assumed to be continuous, and the release rate is calculated from Equation (5.43) where W_n is determined in Step 9.4.

$$rate_n = W_n \quad (5.43)$$

4.25.2 Storage Tank Bottom Release Volume

A step-by-step procedure for determining the release rate and volume is as follows.

- a) Step 11.1—Determine the release rate, $rate_n$, for each release hole size using Equation (5.43) where the release rate, W_n , is from Step 9.4.
- b) Step 11.2—Determine the leak detection time, t_{ld} , as follows:
 - 1) $t_{ld} = 7$ days for a storage tank on a concrete or asphalt foundation, or
 - 2) $t_{ld} = 30$ days for a storage tank with an RPB, or
 - 3) $t_{ld} = 360$ days for a storage tank without an RPB.
- c) Step 11.3—Calculate the leak duration, ld_n , for each release hole size using Equation (5.44) based on the release rate, $rate_n$, from Step 11.1, the leak detection time, t_{ld} , from Step 11.2, and the total volume, Bbl_{total} , from Step 10.2

$$ld_n = \min \left[\left\{ \frac{Bbl_{total}}{rate_n} \right\}, t_{ld} \right] \quad (5.44)$$

- d) Step 11.4—Calculate the release volume from leakage, Bbl_n^{leak} , for each release hole size using Equation (5.45) based on the release rate, $rate_n$, from Step 11.1, the leak duration, ld_n , from Step 11.3, and the total volume, Bbl_{total} , from Step 10.2.

$$Bbl_n^{leak} = \min \left[\{ rate_n \cdot ld_n \}, Bbl_{total} \right] \quad (5.45)$$

- e) Step 11.5—Calculate the release volume from a rupture, $Bbl_n^{rupture}$, for each release hole size using Equation (5.46) based on the total volume, Bbl_{total} , from Step 10.2.

$$Bbl_n^{rupture} = Bbl_{total} \quad (5.46)$$

4.26 Determine the Financial Consequences

4.26.1 General

The step-by-step procedure for estimating the financial consequence is in accordance with [Section 4.12.7](#). The financial consequences for the storage tank bottom are calculated with the steps provided below.

- Damage cost to surrounding equipment in accordance with [Section 4.12.3](#) is not applicable for storage tank bottom component.
- Business interruption costs in accordance with [Section 4.12.4](#).
- Potential Injury costs in accordance to [Section 4.12.5](#) is not applicable for storage tank bottom component.

4.26.2 Calculation of Storage Tank Bottom Financial Consequence

The step-by-step procedure for determining financial COF is as follows.

- a) Step 12.1—Determine the following parameters.
 - 1) P_{ldike} —percentage of fluid leaving the dike.
 - 2) $P_{\text{ldike-onsite}}$ —percentage of fluid that leaves the dike area but remains on-site.
 - 3) $P_{\text{ldike-offsite}}$ —percentage of fluid that leaves the site area, but does not enter nearby water.
 - 4) The storage tank environmental financial consequence for the bottom can be calculated following the steps provided below.
- b) Step 12.2—Determine the environmental sensitivity to establish C_{indike} , $C_{\text{ss-onsite}}$, $C_{\text{ss-offsite}}$, C_{water} , C_{subsoil} , and $C_{\text{groundwater}}$ from [Table 4.6](#).
- c) Step 12.3—Determine the seepage velocity of the product, $vel_{\text{s-prod}}$, using [Equation \(5.34\)](#).
- d) Step 12.4—Determine the total distance to the groundwater underneath the storage tank, s_{gw} , and the time to initiate leakage to the groundwater, t_{gl} .

$$t_{\text{gl}} = \frac{s_{\text{gw}}}{vel_{\text{s-prod}}} \quad (5.47)$$

- e) Step 12.5—Determine the volume of the product for each hole size in the subsoil and groundwater where the leak detection time, t_{ld} , is determined in Step 11.2.

$$Bbl_{\text{groundwater},n}^{\text{leak}} = Bbl_n^{\text{leak}} \left(\frac{t_{\text{ld}} - t_{\text{gl}}}{t_{\text{ld}}} \right) \quad \text{for } t_{\text{gl}} < t_{\text{ld}} \quad (5.48)$$

$$Bbl_{\text{groundwater},n}^{\text{leak}} = 0 \quad \text{for } t_{\text{gl}} \geq t_{\text{ld}} \quad (5.49)$$

$$Bbl_{\text{subsoil},n}^{\text{leak}} = Bbl_n^{\text{leak}} - Bbl_{\text{groundwater},n}^{\text{leak}} \quad (5.50)$$

- f) Step 12.6—Determine the environmental financial consequence of a leak, $FC_{\text{environ}}^{\text{leak}}$, for each hole size.

$$FC_{\text{environ}}^{\text{leak}} = \frac{\sum_{n=1}^3 \left(Bbl_{\text{groundwater},n}^{\text{leak}} \cdot C_{\text{groundwater}} + Bbl_{\text{subsoil},n}^{\text{leak}} \cdot C_{\text{subsoil}} \right) gff_n}{gff_{\text{total}}} \quad (5.51)$$

- g) Step 12.7—Determine the total barrels of fluid released by a storage tank bottom rupture, $Bbl_{\text{release}}^{\text{rupture}}$.

$$Bbl_{\text{release}}^{\text{rupture}} = \frac{Bbl_{\text{total}} \cdot gff_4}{gff_{\text{total}}} \quad (5.52)$$

- h) Step 12.8—Calculate the total barrels of fluid within the dike from a rupture, $Bbl_{\text{indike}}^{\text{rupture}}$, the total barrels of fluid in the on-site surface soil, $Bbl_{\text{ss-onsite}}^{\text{rupture}}$, the total barrels of fluid in the off-site surface soil, $Bbl_{\text{ss-offsite}}^{\text{rupture}}$, and the total barrels of fluid that reach water, $Bbl_{\text{water}}^{\text{leak}}$, using Equation (5.26) through Equation (5.29), respectively.
- i) Step 12.9—Calculate the financial environmental cost for a storage tank bottom rupture, $FC_{\text{environ}}^{\text{rupture}}$, using Equation (5.30) where $Bbl_{\text{indike}}^{\text{rupture}}$, $Bbl_{\text{ss-onsite}}^{\text{rupture}}$, $Bbl_{\text{ss-offsite}}^{\text{rupture}}$, and $Bbl_{\text{water}}^{\text{leak}}$ are from Step 12.8.
- j) Step 12.10—Calculate the total financial environmental cost from a leak and a rupture, FC_{environ} , using Equation (5.51) where $FC_{\text{environ}}^{\text{leak}}$ is from Step 12.6 and $FC_{\text{environ}}^{\text{rupture}}$ is from Step 12.9.
- k) Step 12.11—Calculate the component damage cost, FC_{cmd} , using Equation (5.53) with the release hole size damage costs from Part 3, Table 4.15 and GFFs for the release hole sizes from Step 2.3. The material cost factor, $matcost$, is obtained from Part 3, Table 4.16.

$$FC_{\text{cmd}} = \left(\frac{\sum_{n=1}^3 gff_n \cdot holecost_n + gff_4 \cdot holecost_4 \cdot \left(\frac{D_{\text{tank}}}{C_{36}} \right)^2}{gff_{\text{total}}} \right) \cdot matcost \quad (5.53)$$

The parameter, $\left(\frac{D_{\text{tank}}}{C_{36}} \right)^2$, is a cost adjustment factor for a storage tank bottom replacement. The cost factor included in Part 3, Table 4.15 is normalized for a storage tank with a diameter of 100 ft (30.5 m), and this factor corrects the cost for other storage tank diameters.

- l) Step 12.12—Calculate the total financial COF, FC_{total} , using Equation (5.54).

$$FC_{\text{total}} = FC_{\text{environ}} + FC_{\text{cmd}} + FC_{\text{prod}} \quad (5.54)$$

4.27 Nomenclature

The following lists the nomenclature used in [Section 2](#). The coefficients C_1 through C_{36} , which provide the metric and U.S conversion factors for the equations, are provided in [Part 3, Annex 3.B](#).

A_n	is the hole area associated with the n^{th} release hole size, in. ² (mm ²)
A_{rt}	is the component wall loss fraction since last inspection thickness measurement or service start date
age	is the in-service time that the damage is applied, years
$age_{\text{f,rc}}$	is the final remaining life of the internal liner after adjusting for liner age factors, years
age_{rc}	is the remaining life of the internal liner associated with the date of the starting thickness, years
age_{tk}	is the component in-service time since the last inspection thickness measurement or service start date, years
$Bbl_{\text{avail},n}$	is the available product volume for the n^{th} release hole size due to a leak, barrels
$Bbl_{\text{groundwater}}^{\text{leak}}$	is the total product volume in the groundwater due to a leak, barrels
$Bbl_{\text{groundwater},n}^{\text{leak}}$	is the product volume for the n^{th} release hole size due to a leak in the groundwater, barrels
$Bbl_{\text{indike}}^{\text{leak}}$	is the total product volume in the dike due to a leak, barrels
$Bbl_{\text{indike}}^{\text{rupture}}$	is the product volume in the dike due to a rupture, barrels
Bbl_n^{leak}	is the product volume for the n^{th} release hole size due to a leak, barrels
Bbl_n^{rupture}	is the product volume for the n^{th} release hole size due to a rupture, barrels
$Bbl_{\text{release}}^{\text{leak}}$	is the total product volume released due to a leak, barrels
$Bbl_{\text{release}}^{\text{rupture}}$	is the product volume in released due to a rupture, barrels
$Bbl_{\text{ss-offsite}}^{\text{leak}}$	is the total product volume released on the surface located off-site due to a leak, barrels
$Bbl_{\text{ss-offsite}}^{\text{rupture}}$	is the product volume on the surface located off-site due to a rupture, barrels
$Bbl_{\text{ss-onsite}}^{\text{leak}}$	is the total product volume released on the surface located on-site due to a leak, barrels
$Bbl_{\text{ss-onsite}}^{\text{rupture}}$	is the product volume on the surface located on-site due to a rupture, barrels

$Bbl_{\text{subsoil}}^{\text{leak}}$	is the total product volume in the subsoil due to a leak, barrels
$Bbl_{\text{subsoil},n}^{\text{leak}}$	is the product volume for the n^{th} release hole size due to a leak in the subsoil, barrels
Bbl_{total}	is the product volume in the storage tank, barrels
$Bbl_{\text{water}}^{\text{leak}}$	is the total product volume in the water due to a leak, barrels
$Bbl_{\text{water}}^{\text{rupture}}$	is the total product volume in the water due to a rupture, barrels
CHT	is the course height of the storage tank, ft (m)
C_d	is the discharge coefficient
C_{indike}	is the environmental cost for product in the dike area, \$/bbl
$C_{\text{groundwater}}$	is the environmental cost for product in the groundwater, \$/bbl
C_{subsoil}	is the environmental cost for product in the subsoil, \$/bbl
$C_{\text{ss-offsite}}$	is the environmental cost for product on the surface located off-site, \$/bbl
$C_{\text{ss-onsite}}$	is the environmental cost for product on the surface located on-site, \$/bbl
C_{water}	is the environmental cost for product in water, \$/bbl
C_{qo}	is the adjustment factor for degree of contact with soil
$C_{\text{r,bm}}$	is the corrosion rate for the base material, in./yr (mm/yr)
CA	is the corrosion allowance, in. (mm)
$D_f^{\text{Tank,Thin}}$	is the DF for thinning
$D_{\text{fB}}^{\text{Thin}}$	is the base value of the DF for thinning
D_{tank}	is the storage tank diameter, ft (m)
d_n	is the diameter of the n^{th} release hole, in. (mm)
E	is the weld joint efficiency or quality code from the original construction code
F_{AM}	is the DF adjustment for AST maintenance per API 653
F_{LC}	is the DF adjustment for lining condition
F_{OM}	is the DF adjustment for online monitoring
F_{SM}	is the DF adjustment for settlement
F_{WD}	is the DF adjustment for welded construction

FC_{affa}	is the financial consequence because of damage to the surrounding equipment on the unit, \$
FC_{cmd}	is the financial consequence of component damage, \$
FC_{environ}	is the financial consequence of environmental cleanup, \$
FC_{inj}	is the financial consequence because of serious personnel injury, \$
$FC_{\text{environ}}^{\text{leak}}$	is the financial consequence of environmental cleanup for leakage, \$
$FC_{\text{environ}}^{\text{rupture}}$	is the financial consequence of environmental cleanup for leakage, \$
FC_{prod}	is the financial consequence of lost production on the unit, \$
FC_{total}	is the total financial consequence, \$
g	is the acceleration due to gravity on earth at sea level = 32.2 ft/s ² (9.81 m/s ²)
gff_n	are the generic failure frequencies for each of the n release hole sizes selected for the type of equipment being evaluated
gff_{total}	is the sum of the individual release hole size generic frequencies
h_{liq}	is the maximum fill height in the storage tank, ft (m)
k_h	is the soil hydraulic conductivity, ft/day (m/day)
$k_{h,\text{prod}}$	is the soil hydraulic conductivity based on the storage tank product, ft/day (m/day)
$k_{h,\text{water}}$	is the soil hydraulic conductivity based on water, ft/day (m/day)
$k_{h,\text{water-lb}}$	is the lower bound soil hydraulic conductivity based on water, in./s (cm/s)
$k_{h,\text{water-ub}}$	is the upper bound soil hydraulic conductivity based on water, in./s (cm/s)
$LHT_{\text{above},i}$	is the liquid height above the i^{th} storage tank course, ft (m)
$Lvol_{\text{above},i}$	is the total liquid volume above the i^{th} storage tank course, ft ³ (m ³)
$Lvol_{\text{above},n}$	is the total liquid volume for the n^{th} release hole size, ft ³ (m ³)
$Lvol_{\text{total}}$	is the total liquid volume in the storage tank, ft ³ (m ³)
ld_n	is the actual leak duration of the release based on the available mass and the calculated release rate, associated with the n^{th} release hole size, day
$mass_{\text{avail},n}$	is the available mass for release for each of the release hole sizes selected, associated with the n^{th} release hole size, lb (kg)
$mass_n^{\text{leak}}$	is the release mass from leakage associated with the n^{th} hole size, bbl/day
$mass_n^{\text{rupture}}$	is the release mass from a rupture associated with the n^{th} hole size, bbl/day
$mass_{\text{total}}$	is the available mass for release, barrels
$matcost$	is the material cost factor
N_A^{Thin}	is the number of A level inspections

N_B^{Thin}	is the number of B level inspections
N_C^{Thin}	is the number of C level inspections
N_D^{Thin}	is the number of D level inspections
n^{th}	is the representative holes sizes
$n_{rh,n}$	is the number of release holes for each release hole size as a function of the storage tank diameter
P_{ldike}	is the percentage of fluid leaving the dike
P_{offsite}	is the percentage of fluid that leaves the dike area, remains off-site, and remains out of nearby water
P_{onsite}	is the percentage of fluid that leaves the dike area but remains on-site
p_s	is the soil porosity
$rate_n$	is the adjusted or mitigated discharge rate used in the consequence calculation associated with the n^{th} release hole size, bbl/day
S	is the allowable stress, psi (MPa)
s_{gw}	is the distance to the groundwater underneath the storage tank, ft (m)
t	is the furnished thickness of the component calculated as the sum of the base material and cladding/weld overlay thickness, as applicable, in. (mm)
t_{gl}	is the time required for the product to reach the groundwater through a leak in the storage tank bottom, days
t_{ld}	is the leak detection time, days
t_{min}	is the minimum required thickness based on the applicable construction code, in. (mm)
t_{rdi}	the furnished thickness, t , or measured thickness reading from previous inspection, only if there is a high level of confidence in its accuracy, with respect to wall loss associated with internal corrosion, in. (mm)
$vel_{s,\text{prod}}$	is the seepage velocity, ft/day (m/day)
W_n	is the discharge rate of the storage tank product through a hole in the course, bbl/day
μ_l	is the dynamic viscosity, (lbf-s)/ft ² [(N-s)/m ²]
μ_w	is the dynamic viscosity of water at storage or normal operating, (lbf-s)/ft ² [(N-s)/m ²]
ρ_l	is the liquid density at storage or normal operating conditions, lb/ft ³ (kg/m ³)
ρ_w	is the density of water at storage or normal operating conditions, lb/ft ³ (kg/m ³)

4.28 Tables

Table 4.1—Internal Liner Types

Internal Liner	Lining Resistance	Expected Age
Alloy strip liner	Subject to failure at seams	5 to 15 years
Organic coating—low-quality immersion grade coating (spray applied, to 40 mils)	Limited life	1 to 3 years
Organic coating—medium-quality immersion grade coating (filled, trowel applied, to 80 mils)	Limited life	3 to 5 years
Organic coating—high-quality immersion grade coating (reinforced, trowel applied, ≥ 80 mils)	Limited life	5 to 10 years
Thermal resistance service: castable refractory plastic refractory refractory brick ceramic fiber refractory refractory/alloy combination	Subject to occasional spalling or collapse	1 to 5 years
Thermal resistance service: castable refractory ceramic tile	Limited life in highly abrasive service	1 to 5 years
Glass liners	Complete protection, subject to failure due to thermal or mechanical shock	5 to 10 years
Acid brick	Partial protection. The brick provides thermal protection but is not intended to keep the fluid away from the base material.	10 to 20 years

Table 4.2—Lining Condition Adjustment

Qualitative Condition	Description	Adjustment Multiplier, F_{LC}
Poor	The lining has either had previous failures or exhibits conditions that may lead to failure in the near future. Repairs to previous failures are not successful or are of poor quality.	3
Average	The lining is not showing signs of excessive attack by any damage mechanisms. Local repairs may have been performed, but they are of good quality and have successfully corrected the lining condition.	2
Good	The lining is in “like new” condition with no signs of attack by any damage mechanisms. There has been no need for any repairs to the lining.	1

Table 4.3—Thinning DFs for Storage Tank Bottom Components

A_{ft}	Inspection Effectiveness				
	E	1 Inspection			
		D	C	B	A
0.00	0.1	0.1	0.1	0.1	0.1
0.05	4	1	0.5	0.4	0.3
0.10	14	3	1	0.7	0.5
0.15	32	8	2	1	0.7
0.20	56	18	6	2	1
0.25	87	32	11	4	3
0.30	125	53	21	9	6
0.35	170	80	36	16	12
0.40	222	115	57	29	21
0.45	281	158	86	47	36
0.50	347	211	124	73	58
0.55	420	273	173	109	89
0.60	500	346	234	158	133
0.65	587	430	309	222	192
0.70	681	527	401	305	270
0.75	782	635	510	409	370
0.80	890	757	638	538	498
0.85	1005	893	789	696	658
0.90	1126	1044	963	888	856
0.95	1255	1209	1163	1118	1098
1.00	1390	1390	1390	1390	1390

Table 4.4—Release Hole Sizes and Areas—Storage Tank Courses

Release Hole Number	Release Hole Size	Range of Hole Diameters (in.)	Release Hole Diameter (in.)
1	Small	0 to $\frac{1}{8}$	$d_1 = 0.125$
2	Medium	$> \frac{1}{8}$ to $\frac{1}{4}$	$d_2 = 0.25$
3	Large	$> \frac{1}{4}$ to 2	$d_3 = 2$
4	Rupture	> 2	$d_4 = 12 \left(\frac{D_{\text{tank}}}{4} \right)$

Table 4.4M—Release Hole Sizes and Areas—Storage Tank Courses

Release Hole Number	Release Hole Size	Range of Hole Diameters (mm)	Release Hole Diameter (mm)
1	Small	0 to 3.175	$d_1 = 3.175$
2	Medium	> 3.175 to 6.35	$d_2 = 6.35$
3	Large	> 6.35 to 50.8	$d_3 = 50.8$
4	Rupture	> 50.8	$d_4 = 1000 \left(\frac{D_{\text{tank}}}{4} \right)$

Table 4.5—Fluids and Fluid Properties for Storage Tank Consequence Analysis

Fluid	Level 1 Consequence Analysis Representative Fluid	MW	Liquid Density (lb/ft ³)	Liquid Dynamic Viscosity (lb _f -s/ft ²)
Gasoline	C ₆ –C ₈	100	42.702	8.383E-05
Light diesel oil	C ₉ –C ₁₂	149	45.823	2.169E-05
Heavy diesel oil	C ₁₃ –C ₁₆	205	47.728	5.129E-05
Fuel oil	C ₁₇ –C ₂₅	280	48.383	7.706E-04
Crude oil	C ₁₇ –C ₂₅	280	48.383	7.706E-04
Heavy fuel oil	C ₂₅₊	422	56.187	9.600E-04
Heavy crude oil	C ₂₅₊	422	56.187	9.600E-04

Table 4.5M—Fluids and Fluid Properties for Storage Tank Consequence Analysis

Fluid	Level 1 Consequence Analysis Representative Fluid	MW	Liquid Density (kg/m ³)	Liquid Dynamic Viscosity (N-s/m ²)
Gasoline	C ₆ –C ₈	100	684.018	4.01E-03
Light diesel oil	C ₉ –C ₁₂	149	734.011	1.04E-03
Heavy diesel oil	C ₁₃ –C ₁₆	205	764.527	2.46E-03
Fuel oil	C ₁₇ –C ₂₅	280	775.019	3.69E-02
Crude oil	C ₁₇ –C ₂₅	280	775.019	3.69E-02
Heavy fuel oil	C ₂₅₊	422	900.026	4.60E-02
Heavy crude oil	C ₂₅₊	422	900.026	4.60E-02

Table 4.6—Cost Parameters Based on Environmental Sensitivity

Location ¹	Description	Environmental Sensitivity		
		Low (US\$/bbl)	Medium (US\$/bbl)	High (US\$/bbl)
1	C_{indike} —Environmental cost for product located in the dike area	10	10	10
2	$C_{\text{ss-onsite}}$ —Environmental cost for product located in surface soil located on-site	50	50	50
3	$C_{\text{ss-offsite}}$ —Environmental cost for product located in surface soil located off-site	100	250	500
4	C_{subsoil} —Environmental cost for product located in subsoil	500	1,500	3,000
5	$C_{\text{groundwater}}$ —Environmental cost for product located in groundwater	1,000	5,000	10,000
6	C_{water} —Environmental cost for product in surface water	500	1,500	5,000
NOTE 1 See Figure 4.1 .				
NOTE 2 The values shown above are estimates. The end user should decide if these values are appropriate for the specific application.				

Table 4.7—Soil Types and Properties for Storage Tank Consequence Analysis

Soil Type	Hydraulic Conductivity for Water Lower Bound (in./s)	Hydraulic Conductivity for Water Upper Bound (in./s)	Soil Porosity
Gravel	3.94E-01	3.94	0.40
Coarse sand	3.94E-03	3.94E-02	0.33
Fine sand	3.94E-04	3.94E-03	0.33
Very fine sand	3.94E-06	3.94E-04	0.33
Silt	3.94E-07	3.94E-06	0.41
Sandy clay	3.94E-08	3.94E-07	0.45
Clay	3.94E-09	3.94E-08	0.50
Concrete-asphalt	3.94E-12	3.94E-11	0.3

Table 4.7M—Soil Types and Properties for Storage Tank Consequence Analysis

Soil Type	Hydraulic Conductivity for Water Lower Bound (cm/s)	Hydraulic Conductivity for Water Upper Bound (cm/s)	Soil Porosity
Gravel	1.00E00	1.00E01	0.40
Coarse sand	1.00E-02	1.00E-01	0.33
Fine sand	1.00E-03	1.00E-02	0.33
Very fine sand	1.00E-05	1.00E-03	0.33
Silt	1.00E-06	1.00E-05	0.41
Sandy clay	1.00E-07	1.00E-06	0.45
Clay	1.00E-08	1.00E-07	0.50
Concrete-asphalt	1.00E-11	1.00E-10	0.3

Table 4.8—Release Hole Sizes and Areas—Storage Tank Bottoms

Release Hole Number	Release Hole Size	RPB?	Range of Hole Diameters (in.)	Release Hole Diameter (in.)
1	Small	Yes	0 to $\frac{1}{8}$	$d_1 = 0.125$
		No	0 to $\frac{1}{2}$	$d_1 = 0.50$
2	Medium	N/A	0	$d_2 = 0$
		N/A	0	
3	Large	N/A	0	$d_3 = 0$
		N/A	0	
4	Rupture	Yes	$> \frac{1}{8}$	$d_4 = 12 \left(\frac{D_{\text{tank}}}{4} \right)$
		No	$> \frac{1}{2}$	

Table 4.8M—Release Hole Sizes and Areas—Storage Tank Bottoms

Release Hole Number	Release Hole Size	RPB?	Range of Hole Diameters (mm)	Release Hole Diameter (mm)
1	Small	Yes	0 to 3.175	$d_1 = 3.175$
		No	0 to 12.7	$d_1 = 12.7$
2	Medium	N/A	0	$d_2 = 0$
		N/A	0	
3	Large	N/A	0	$d_3 = 0$
		N/A	0	
4	Rupture	Yes	> 3.175	$d_4 = 1000 \left(\frac{D_{\text{tank}}}{4} \right)$
		No	> 12.7	

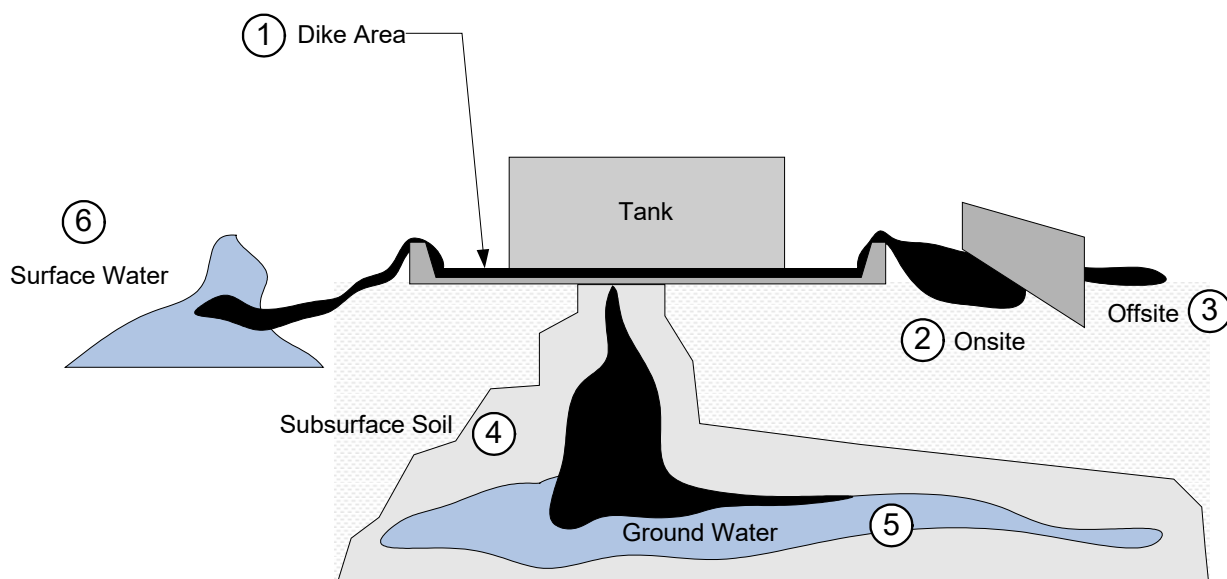
Table 4.9—Number of Release Holes as a Function of Storage Tank Diameter

Storage Tank Diameter [ft (m)]	Number of Release Holes with or Without an RPB		
	Small	Medium	Large
30.5 (100)	1	0	0
61.0 (200)	4	0	0
91.4 (300)	9	0	0

NOTE For intermediate storage tank diameters, the number of small release holes may be calculated using the following equation where the function nint() is defined as the nearest integer. For example, nint(3.2) = 3, nint(3.5) = 4, and nint(3.7) = 4.

$$n_{rh,1} = \max \left[\text{nint} \left[\left(\frac{D}{C_{36}} \right)^2 \right], 1 \right]$$

4.29 Figures

**Figure 4.1—Storage Tank Consequence**

5 Heat Exchanger Tube Bundles

5.1 Overview

This section describes a methodology to assess the reliability and remaining life of heat exchanger bundles. It also provides a methodology for performing cost benefit analysis to assist in making RBI and replacement decisions and to determine the optimal replacement frequency of heat exchanger bundles.

The purpose of the module is to manage heat exchanger bundle inspection and replacement cycles and to reduce annual operating and maintenance costs of heat exchanger bundles. The costs considered include bundle fabrication and installation costs, environmental impact costs, and lost opportunity costs due to unit and plant unplanned shutdowns or unit rate reductions as a result of an unplanned bundle failure.

5.2 Background

Analyzing each heat exchanger bundle service history generally does not consider the financial consequences associated with a bundle failure. Many exchangers experience few or no bundle failures, while some failures may not have occurred at the current operating conditions or practices. In addition, statistically significant data may not exist in order to make an accurate prediction of future performance or POF for the heat exchanger bundle.

5.3 Basis of Model

The application of risk principles to exchanger bundle inspection allows decisions to be made based on the consequences of bundle failure, including costs associated with lost production and environmental impact costs associated with leakage into utility systems and the replacement and maintenance costs associated with bundle replacement.

The combined experience of heat exchanger bundles of similar design and service is combined and statistically analyzed to provide a prediction of future performance. The exchanger bundle under evaluation is matched to similar bundles and statistically analyzed using a Weibayes or similar analysis to estimate the POF of the bundle. The results from the analysis are used to determine if the exchanger bundle will operate safely and reliably until the next scheduled maintenance opportunity. See [Annex 5.A](#) for an explanation on how to determine Weibull parameters.

5.4 Required Data

5.4.1 General

The data listed in [Table 5.1](#) shows the minimum data requirements for each heat exchanger bundle.

5.4.2 Methodology Overview

Calculations for the risk and inspection for heat exchanger bundles are performed following the flow chart shown in [Figure 5.1](#).

An overview of the steps for calculating risk are shown in the following steps.

- a) Step 1.1—Gather and input the bundle basic input data required as defined in [Table 5.1](#).
- b) Step 1.2—Gather and input inspection historical data, if available.
- c) Step 1.3—Determine the maximum acceptable POF, $P_{f,tgt}^{tube}$ based on the calculated C_f^{tube} and the risk target, $Risk_{tgt}$.
- d) Step 1.4—Provide *MTTF* or Weibull parameters for the bundle failure rate curve based on historical bundle failures in the same or similar service using Weibull analysis or some other statistical approach.
- e) Step 1.5—Calculate the POF at the current date, RBI date, plan date, turnaround date 1, and turnaround date 2 using the Weibull data.
- f) Step 1.6—Determine consequences of bundle failure, C_f^{tube} .
- g) Step 1.7—Calculate the risk at the plan date with and without inspection.
- h) Step 1.8—Define a recommended inspection plan.
- i) Step 1.9—Calculate a bundle replacement frequency.

5.5 POF

5.5.1 Definition of Bundle Failure

A definition of bundle failure was established to determine the bundle life (failure) to predict the point in time at which an existing bundle will reach its end of life. A failure is defined as a tube leak for the purposes of RBI.

The current condition or remaining life of a bundle is quantified and expressed as a percent of the original wall thickness when the controlling damage mechanism for the bundle is general corrosion. Inspection data may be used to determine when failure occurred or to predict when a failure is likely to occur if inspection records documenting average remaining wall thickness are available. Other damage mechanisms, such as local corrosion, erosion, or vibration damage, are not easily predicted based on inspection measurements. In these cases, a predicted bundle life is based on a remaining life estimate.

Bundles are often replaced or repaired prior to failure due to a deteriorated condition. An assumed remaining bundle life (25 % remaining life is recommended) for the degraded condition provides an adjustment for a bundle replaced prior to a failure. A degraded condition is a bundle that would not be expected to make another operating cycle without expected tube failures.

5.5.2 POF Using Weibull Distribution

- a) The POF for a heat exchanger bundle is expressed using a two-parameter Weibull distribution in [Equation \(5.55\)](#) [4].

$$P_f^{\text{tube}} = 1 - R(t) = 1 - \exp \left[- \left(\frac{t}{\eta} \right)^\beta \right] \quad (5.55)$$

where $P_{\text{tgt}}^{\text{tube}}$ is the POF as a function of time or the fraction of bundles that have failed at time t , β is the Weibull shape factor that is unitless, η is the Weibull characteristic life in years, and t is the independent variable time in years.

The time to reach a specified POF is calculated by using [Equation \(5.55\)](#) and solving for t , as shown in [Equation \(5.56\)](#).

$$t = \eta \cdot \left(-\ln \left[1 - P_f^{\text{tube}} \right] \right)^{\frac{1}{\beta}} \quad (5.56)$$

- b) POF is calculated as a function of in-service duration using one of the methods below.

- 1) Method 1, Specified Weibull Parameters (see [Part 2, Section 5.5.3.1](#))—The Weibull β and η parameters for the exchanger bundle are provided and used for the POF calculation. A statistical analysis such as Weibayes or other statistical analysis is used to establish the Weibull β and η parameters from an exchanger bundle reliability library or available bundle failure data. [Annex 5.A](#) shows an example of calculating Weibull parameters from an exchanger bundle reliability library.
- 2) Method 2, Specified *MTTF* (see [Part 2, Section 5.5.3.2](#))—An *MTTF* for the bundle is provided for the POF calculation. This approach uses the *MTTF* to calculate a Weibull η parameter using a β value of 3.0. As an option, the Weibull β parameter in addition to the *MTTF* is specified.
- 3) Method 3, Specific Bundle Inspection History (see [Part 2, Section 5.5.3.3](#))—Statistical approaches are outlined to calculate the η parameter for the bundle if sufficient inspection history is available.

5.5.3 POF Calculation

5.5.3.1 POF Using the Supplied Weibull Parameters

The β and η parameters for the exchanger bundle are provided from a statistical analysis and used in [Equation \(5.55\)](#) to determine the POF for the bundle as a function of time.

5.5.3.2 POF Using the Supplied MTTF

An MTTF is calculated if sufficient inspection information exists for a bundle using a Weibull distribution with a known β parameter (default to 3.0 if unknown) and η parameter using the gamma function in [Equation \(5.57\)](#).

$$MTTF = \eta \cdot \Gamma \left[1 + \frac{1}{\beta} \right] \quad (5.57)$$

POF is calculated using [Equation \(5.55\)](#) for β and η .

5.5.3.3 POF Calculated Using Specific Bundle History

5.5.3.3.1 General

Information gained from inspection of the tube bundle is used to assess the actual condition of the bundle and adjust the POF rate. Inspection provides two benefits:

- a reduction in uncertainty due to the effectiveness of the inspection providing a more accurate assessment of the bundle condition and failure rate;
- improved knowledge of the true condition of the bundle by using measured tube wall thicknesses to make an estimate of the remaining life.

Inaccuracies and biases are addressed with uncertainty, as shown in [Part 2, Annex C, Table 2.C.4.1](#). Uncertainty is reduced and the POF decreases through bundle inspection. The level of uncertainty decreases as more effective inspection techniques are used and risk reduction through inspection results in more rigorous inspection techniques as the bundle reaches end of life. Inspection effectiveness is discussed in more detail in [Part 2, Annex 2.C](#). The bundle may reach a time in life when inspection (more data) does little or nothing to lower the risk and repair, replace, coat, or other recommendations are more appropriate. This is typically because it is actually at or near end of life.

5.5.3.3.2 Specific Bundle History

Inspection provides knowledge of the current condition of the bundle. Inspection determines if the bundle is in better or worse condition than predicted by using data from similar service bundles.

If general corrosion is the primary damage mechanism, average measured tube thickness data is used to predict the bundle failure date. When other damage mechanisms (such as vibration or tube end thinning) or when measured thickness data does not exist, a qualitative estimate of the remaining life is used to predict the bundle failure date. Two methods are provided for inspection data use in adjusting the POF calculation.

- Calculated Failure Data Based on Measured Thickness Data—The thinning rate of the tube bundle, t_{rate} , is calculated using the average furnished wall thickness, $\bar{t}_{orig}$, and average measured wall thickness, $\bar{t}_{insp}$, from inspection, and the time in service, t_{dur} , using [Equation \(5.58\)](#):

$$t_{rate} = \frac{\bar{t}_{orig} - \bar{t}_{insp}}{t_{dur}} \quad (5.58)$$

The calculated rate is adjusted, $t_{\text{rate,adj}}$, in Equation (5.59) uses the probabilities and damage state factors used in the thinning DF calculation in Part 2, Section 4.5.7.

$$t_{\text{rate,adj}} = (t_{\text{rate1}} \cdot D_1^{\text{Bundle}}) + (t_{\text{rate2}} \cdot D_2^{\text{Bundle}}) + (t_{\text{rate3}} \cdot D_3^{\text{Bundle}}) \quad (5.59)$$

where t_{rate1} , t_{rate2} , and t_{rate3} are the thinning states based on the measured corrosion rate from inspection, and D_1^{Bundle} , D_2^{Bundle} , and D_3^{Bundle} are the probabilities Part 2, Table 4.5.

The calculated bundle life, PBL_{adj} , is adjusted for inspection using Equation (5.60).

$$PBL_{\text{adj}} = \frac{RWT_f \cdot \bar{t}_{\text{orig}}}{t_{\text{rate,adj}}} \quad (5.60)$$

where the failure point is defined as a fraction of remaining wall thickness, RWT_f .

- b) Calculated Failure Data Based on Estimated Remaining Life—The estimated remaining life, ERL , of the bundle is used to calculate bundle life if tube wall thickness data is not available for calculation of a bundle tube thinning rate or when the damage mechanism is not general corrosion. The ERL is calculated using inspection data combined with accepted FFS calculations based on the damage mechanism known or anticipated and the time in service, t_{dur} .

$$PBL_{\text{adj}} = t_{\text{dur}} + ERL \quad (5.61)$$

5.5.3.3.3 Adjustment to Failure Rate Based on Condition of Bundle

A bundle with a recommended two or more life cycles with inspection data is used to calculate a β parameter for the matching bundle criteria (default to 3.0 if unknown) with a Weibayes analysis. The η parameter is calculated using Equation (5.62).

$$\eta = \left(\frac{\sum_{i=1}^N \frac{t_{\text{dur},i}^{\beta}}{r}}{\beta} \right)^{\frac{1}{\beta}} \quad (5.62)$$

where N is the number of past bundles, $t_{\text{dur},i}$ is the time in service for each bundle in years, r is the number of failed bundles, and β is the Weibull slope parameter. This method assumes that the current operating conditions for the bundle have not changed including changes in metallurgy, process conditions, or bundle design. POF is calculated using Equation (5.55) for β and η .

A modified characteristic life, η_{mod} , for the bundle is calculated using Equation (5.63) if the bundle life is calculated based on the last inspection using Equation (5.60) or Equation (5.63).

$$\eta_{\text{mod}} = \left(\frac{1}{r} \sum_{i=1}^N t_{i,\text{dur}}^{\beta} \right)^{\frac{1}{\beta}} \quad (5.63)$$

where N is the number of past bundles, $t_{\text{dur},i}$ is the time in service for each bundle in years, r is the number of failed bundles, and β is the Weibull slope parameter.

NOTE If the bundle was replaced before failure, a factor of 1.25 is applied to the service duration. This method assumes that the current operating conditions for the bundle have not changed including changes in metallurgy, process conditions, or bundle design. POF is calculated using Equation (5.55) for β and η_{mod} .

The recommended inspection interval at the target POF for the bundle is calculated using Equation (5.64):

$$t_{\text{insp}} = \eta_{\text{mod}} \cdot \left(-\ln \left[1 - P_{\text{f,tgt}}^{\text{tube}} \right] \right)^{\frac{1}{\beta}} \quad (5.64)$$

The adjusted characteristic life, and adjusted POF, $P_{\text{f,adj}}^{\text{tube}}$, of the bundle is calculated using η_{mod} from Equation (5.63) using Equation (5.65).

$$P_{\text{f,adj}}^{\text{tube}} = 1 - \exp \left[- \left(\frac{t}{\eta_{\text{mod}}} \right)^{\beta} \right] \quad (5.65)$$

5.5.3.3.4 Effects of Bundle Life Extension Efforts

Minor repairs and cleaning operations performed on bundles prior to inspection do not affect the life of the bundle. However, there are life extension methods that are often implemented during shutdowns that return the bundle to service in an improved condition. An adjustment is made to the inspection interval based on Table 4.2 for life extension methods and by determining a life extension factor, *LEF*. The adjusted service duration, $t_{\text{adj,dur}}$, is calculated with the *LEF* using Equation (5.66).

$$t_{\text{adj,dur}} = (1 + LEF) \cdot t_{\text{dur}} \quad (5.66)$$

NOTE The actual service duration, t_{dur} , is the time period in years between the bundle installation date and the inspection date that the life extension method was performed, as shown in Equation (5.67).

$$t_{\text{dur}} = \text{Inspect Date} - \text{Install Date} \quad (5.67)$$

The effective installation date, *Bundle Installation Date_{adj}*, is calculated using $t_{\text{adj,dur}}$, as shown in Equation (5.68).

$$\text{Bundle Installation Date}_{\text{adj}} = \text{Inspect Date} - t_{\text{adj,dur}} \quad (5.68)$$

5.6 COF

Bundle failure is defined as a tube leak. Financial COF is determined based on the bundle criticality, which includes costs associated with lost opportunity due to production downtime, environmental impact costs, and costs associated with maintenance and replacement of the bundle. The consequence of an unplanned shutdown due to a bundle tube leak is determined using Equation (5.69).

$$C_{\text{f}}^{\text{tube}} = \left(\text{Unit}_{\text{prod}} \cdot \frac{\text{Rate}_{\text{red}}}{100} \cdot D_{\text{sd}} \right) \cdot \text{Outage}_{\text{mult}} + \text{Cost}_{\text{env}} + (\text{Cost}_{\text{bundle}} \cdot \text{matcost}) + \text{Cost}_{\text{maint}} \quad (5.69)$$

where D_{sd} is the time in days for a planned or unplanned shutdown and *matcost* factor is from Table 4.3.

5.7 Risk Analysis

5.7.1 General

Risk over time is calculated to determine what inspection is required to manage risk. Uncertainty exists when relevant, credible data is lacking. More relevant data reduces the amount of uncertainty in the risk calculation. Information from inspection is often needed to improve confidence in the damage states and damage rates

associated with bundles. Risk for bundles is a function of time is the product of the POF and the COF in financial terms, as shown in Equation (5.70).

$$Risk_f^{tube} = P_f^{tube} \cdot C_f^{tube} \quad (5.70)$$

5.7.2 Risk Matrix

A risk matrix is a valuable visual tool for identifying high risk bundles. The risk of each bundle is characterized by the POF and COF categories, shown in Part 1, Section 4.3.2.2, and enables each bundle to be plotted on the risk matrix as shown in Part 1, Figure 4.2 and Figure 4.3.

The risk matrix is grouped into four areas: high risk, medium high risk, medium risk, and low risk. If an exchanger has been identified as high risk prior to the turnaround, it would require a more rigorous inspection than has been used on that bundle in the past. For example, if the bundle were determined to be a high risk on the risk matrix and past inspections for that bundle were *usually effective*, it is very likely that a *highly effective inspection* would be required at the upcoming shutdown. The benefits of the different levels of inspection are discussed in Section 5.8.

5.8 Inspection Planning Based on Risk Analysis

5.8.1 General

The inspection target date is the date at which the calculated risk using Equation (5.55) exceeds the risk target, $Risk_{tgt}$. An inspection is required prior to the target date to maintain a risk level below the risk target. The target date for the next inspection is calculated using the inspection adjusted Weibull parameters.

5.8.2 Use of Risk Target in Inspection Planning

The risk target is a function of the owner–operator’s corporate philosophy for making risk decisions. Some companies are more risk adverse than others, and this will have a direct impact on the inspection planning results.

Equation (5.71) is used to calculate the target POF for a bundle as a function of the COF and using the target risk:

$$P_{f,tgt}^{tube} = \frac{Risk_{tgt}}{C_f^{tube}} \quad (5.71)$$

A target inspection date is calculated using Equation (5.56). The target date is the date when the bundle risk reaches the target risk.

A user-defined $P_{f,tgt}^{tube}$ is used in place of the calculated $P_{f,tgt}^{tube}$ if a lower risk or probability of bundle failure is required for inspection planning.

The target inspection time is calculated using Equation (5.72). The target time is the number of years from the installation date when the bundle risk reaches the target risk.

$$t_{insp} = \eta_{tgt} \cdot \left(-\ln \left[1 - P_{f,tgt}^{tube} \right] \right)^{\frac{1}{\beta}} \quad (5.72)$$

The target inspection date is calculated using Equation (5.73) using t_{insp} and the installation date. The target date is the date when the bundle risk reaches the target risk.

$$\text{Target Inspection Date} = \text{Bundle Installation Date} + t_{\text{insp}} \quad (5.73)$$

Bundle target characteristic life, η_{tgt} , is calculated using the $P_{\text{f,tgt}}^{\text{tube}}$ and the bundle age at the plan date as shown in Equation (5.74).

$$\eta_{\text{tgt}} = \frac{t_{\text{plan}}}{-\ln \left[1 - P_{\text{f,tgt}}^{\text{tube}} \right]^{\frac{1}{\beta}}} \quad (5.74)$$

5.8.3 Determine Inspection Recommendation

Once a decision has been made to inspect per Equation (5.74), an economic decision can be made as to the appropriate level of inspection with similar techniques as described in Section 5.9.1 by comparing the cost of the various inspection techniques to the reduction in risk expected for the level of inspection.

NOTE No inspection is required if $P_{\text{f,plan}}^{\text{tube}} \leq P_{\text{f,tgt}}^{\text{tube}}$.

The target uncertainty, $AU_{\text{tgt}}\%$, is the level of uncertainty associated with an inspection required to remain below the $P_{\text{f,tgt}}^{\text{tube}}$ at the plan date from Equation (5.75).

$$AU_{\text{tgt}}\% = \frac{\eta_{\text{tgt}}}{\eta_{\text{mod}}} \quad (5.75)$$

The $AU_{\text{tgt}}\%$ is used with Table 4.5 to determine the level of inspection required to achieve target $P_{\text{f,tgt}}^{\text{tube}}$ at the plan date. The inspection plan is defined by using the target inspection date from Equation (5.71) and the recommended inspection from Equation (5.75).

5.8.4 Calculate Characteristic Life at Plan Date

The recommended inspection uncertainty is used calculate the characteristic life at the plan date after inspection using Equation (5.76).

$$\eta_{\text{insp}} = \eta_{\text{mod}} \cdot \left(\frac{1 - AU_{\text{w/insp}}\%}{1 - AU_{\text{w/outinsp}}\%} \right) \quad (5.76)$$

where η_{mod} is defined in Equation (5.62).

5.8.5 Calculation of Risk

The POF at the plan date, $P_{\text{f,w/insp}}^{\text{tube}}$, with inspection is calculated with Equation (5.55), using t_{plan} for time at the plan date, η_{insp} from Equation (5.76), and the original β value.

5.8.6 Calculation of Risk

The risk at the plan date is calculated using Equation (5.70) using $P_{\text{f,w/insp}}^{\text{tube}}$ and $C_{\text{f,plan}}^{\text{tube}}$.

5.9 Bundle Inspect/Replacement Decisions Using Cost Benefit Analysis

5.9.1 General

Weibull parameters are used to predict the optimal replacement frequency for a bundle and determine whether it makes economic sense to inspect or replace a bundle at an upcoming shutdown.

5.9.2 Decision to Inspect or Replace at Upcoming Shutdown

Risk reduction cost benefit is calculated from mitigating actions including various levels of inspection or bundle replacement. The cost benefit calculation includes the cost of the mitigating action to inspect or replace). An optional rate of return, *ROR* (or hurdle cost), is added to the cost of a bundle replacement to prevent excessive bundle replacement for borderline risk determinations that require action. The decision to perform a risk mitigating bundle inspection or bundle replacement at an upcoming turnaround is determined by comparing the incremental risk (\$) associated with deferring the inspection or replacement to the cost associated with the performing the inspection or replacement.

Expected incremental risk, EIR_{t1}^{t2} , associated with deferring the inspection or replacement of a bundle to a later date is calculated using Equation (5.77).

$$EIR_{t1}^{t2} = C_f^{\text{tube}} \cdot \left(1 - \left[\frac{1 - P_f^{\text{tube}}(t_2)}{1 - P_f^{\text{tube}}(t_1)} \right] \right) \quad (5.77)$$

where t_1 is the service duration of the bundle at the next shutdown (turnaround date 1) and t_2 is the service duration of the bundle at the subsequent shutdown (turnaround date 2).

If the cost to inspect or replace is greater than the expected incremental risk using Equation (5.78) and Equation (5.79), that action is recommended.

$$\begin{aligned} &\text{If } (Cost_{\text{insp}} + Cost_{\text{maint}}) \cdot (1 + ROR) < EIR_{t1}^{t2}, \text{ then inspect} \\ &\text{If } (Cost_{\text{insp}} + Cost_{\text{maint}} + Hurdle \text{ Cost}) < EIR_{t1}^{t2}, \text{ then inspect} \end{aligned} \quad (5.78)$$

$$\begin{aligned} &\text{If } (Cost_{\text{bundle}} + Cost_{\text{maint}}) \cdot (1 + ROR) < EIR_{t1}^{t2}, \text{ then replace the bundle} \\ &\text{If } (Cost_{\text{bundle}} + Cost_{\text{maint}} + Hurdle \text{ Cost}) < EIR_{t1}^{t2}, \text{ then replace the bundle} \end{aligned} \quad (5.79)$$

The actual inspection costs should be used when available. Maintenance costs to pull the bundles for inspection should be included in the total inspection costs when using Equation (5.78) and Equation (5.79).

5.9.3 Optimal Bundle Replacement Frequency

Maintenance optimization helps to strike a balance between cost and reliability. The cost per day of a “run to failure” strategy shows low costs early in the life of the equipment and increasing costs as reliability decreases. By overlaying the costs of an associated preventative maintenance to address the failure mode, initial costs are high, but costs per unit time decrease as time progresses. This optimization occurs at a point where the total cost function (sum of the two cost functions) is at a minimum. The time at which the minimum occurs is the optimum time to perform maintenance [5].

The optimum replacement frequency is calculated comparing the cost associated with a bundle failure (increasing with increasing replacement frequency) to the replacement cost associated with periodic planned shutdowns to replace the bundle (decreasing with increasing replacement frequency). The point where the two costs reach a minimum value is the optimum replacement frequency.

The methodology in Shultz, 2001 [6] described below is recommended to determine the optimum bundle replacement frequency.

a) Increasing Risk Cost of Unplanned Outage.

A planned replacement time frequency is defined by the variable, tr_n , and the risk cost associated with an unplanned failure to replace the bundle (including business interruption and bundle replacement costs) is calculated using Equation (5.80).

$$Risk_f^{tube}(tr_n) = C_{f,unplan}^{tube} \cdot P_f^{tube}(tr_n) \quad (5.80)$$

where $C_{f,plan}^{tube}$ is defined in Equation (5.81).

$$C_{f,unplan}^{tube} = \left(Unit_{prod} \cdot \frac{Rate_{red}}{100} \cdot D_{sd,unplan} \right) \cdot Outage_{mult} + Cost_{env} + (Cost_{bundle} \cdot matcost) + Cost_{maint} \quad (5.81)$$

NOTE Equation (5.81) is similar to Equation (5.69) but uses the unplanned outage time, $D_{sd,unplan}$. The consequence of an unplanned frequency due to a tube bundle failure, C_f^{tube} , includes business interruption, the number of days required for bundle replacement during an unplanned outage, $D_{sd,unplan}$ and environmental impact, $Cost_{env}$. The risk cost due to bundle failure increases with time since the POF, $P_f^{tube}(tr_n)$, increases with time.

b) Decreasing Cost of Bundle Replacement.

The bundle replacement costs as a function of planned replacement frequency, tr , is calculated using Equation (5.82).

$$Cost_{pbr}(tr_n) = C_{f,plan}^{tube} \cdot [1 - P_f^{tube}(tr_n)] \quad (5.82)$$

where $C_{f,plan}^{tube}$ is defined in Equation (5.83).

$$C_{f,plan}^{tube} = \left(Unit_{prod} \cdot \frac{Rate_{red}}{100} \cdot D_{sd,plan} \right) \cdot Outage_{mult} + Cost_{env} + (Cost_{bundle} \cdot matcost) + Cost_{maint}$$

$$C_{f,plan}^{tube} = Cost_{env} + (Cost_{bundle} \cdot matcost) + Cost_{maint} \quad (5.83)$$

c) Optimization of Total Cost.

The total cost as a function of replacement time frequency averaged over the service bundle life is calculated using Equation (5.84).

$$Cost_{total}(tr_n) = \frac{Risk_f^{tube}(tr_n) + Cost_{pbr}(tr_n)}{365.25 \cdot ESL_n} \quad (5.84)$$

The estimated service life as a function of replacement time interval may be approximated using an integration technique using Equation (5.85).

$$ESL_n = ESL_{f,n} + ESL_{p,n} \quad (5.85)$$

where the average life of the bundles that would have been expected to fail prior to the planned replacement time, $ESL_{f,n}$, and the average life of the bundles that would not have been expected to fail prior to the planned replacement time, $ESL_{p,n}$ are summed, ESL_n .

The average life of the bundles that would have been expected to fail prior to the planned replacement time is:

$$ESL_{f,n} = ESL_{f,n-1} + tr_n \cdot (P_{f,n}^{\text{tube}} - P_{f,n-1}^{\text{tube}}) \quad (5.86)$$

The average life of the bundles that would have been expected to not fail prior to the planned replacement time is:

$$ESL_{p,n} = tr_n \cdot (1 - P_{f,n}^{\text{tube}}) \quad (5.87)$$

A planned replacement frequency is selected and the costs associated with the frequency calculated to allow optimization of the total cost. The frequency is incrementally increased and the costs are calculated for each incremental step, $n(n = n + 1)$. The point where the costs reach a minimum is the optimum replacement frequency.

- 1) Step 2.1—Select an appropriate time step, t_s , in days (a value for t_s of 7 to 14 days should be sufficient) and an increment of $n = 1$. Subsequent calculations will increase the increment by 1 or $n(n = n + 1)$
- 2) Step 2.2—Calculate the planned replacement frequency, tr_n , by multiplying the increment number, n , by the time step, t_s , as follows:

$$tr_n = n \cdot \frac{t_s}{365.25} \quad (5.88)$$

- 3) Step 2.3—Calculate the POF at the planned replacement frequency at increment n , $P_{f,n}^{\text{tube}}(tr_n)$, using Equation (5.55), the updated Weibull parameters based on the latest inspection of the bundle and the time value to use in Equation (5.56) is tr_n obtained in Step 2.2.

NOTE Time is reported in years.

- 4) Step 2.4—Calculate the average life of the bundles that would have been expected to fail prior to the planned replacement time, $ESL_{f,n}$, using Equation (5.86).
- 5) Step 2.5—Calculate the average life of the bundles that would have not been expected to fail prior to the planned replacement time, $ESL_{p,n}$, using Equation (5.87).
- 6) Step 2.6—Calculate the estimated service life, ESL_n , using Equation (5.83).
- 7) Step 2.7—Calculate the risk cost associated with bundle failure at the replacement frequency, $Risk_f(tr_n)$, using Equation (5.80).
- 8) Step 2.8—Calculate the bundle replacement cost at the replacement frequency, $Cost_{pbr}(tr_n)$, using Equation (5.82).

- 9) Step 2.9—Calculate the total costs at the replacement frequency averaged over the expected life of the bundle, $Cost_{total}(tr_n)$, using Equation (5.84).
- 10) Step 2.10—Increase the increment number by 1 ($n = n + 1$) and repeat Steps 2.2 through 2.9 until a minimum value of $Cost_{total}(tr_n)$ in Step 2.9 is obtained.
- 11) Step 2.11—The optimal bundle replacement frequency, t_{opt} , is where the tr_n is at the minimum $Cost_{total}(tr_n)$.

5.10 Nomenclature

$AU\%$	is the percent additional uncertainty, %
$AU_{tgt}\%$	is the additional inspection uncertainty required to remain below the $P_{f,tgt}^{tube}$ at the plan date, %
$AU_{w/insp}\%$	is the additional inspection uncertainty at the plan date after inspection, %
$AU_{w/outinsp}\%$	is the additional inspection uncertainty at the plan date before inspection, %
C_f^{tube}	is the consequence of bundle failure, \$
$C_{f,plan}^{tube}$	is the consequence of bundle failure based on a planned bundle replacement, \$
$C_{f,unplan}^{tube}$	is the consequence of bundle failure during an unplanned bundle replacement, \$
$Cost_{bundle}$	is the replacement cost of the tube bundle, \$
$Cost_{env}$	is the environmental costs due to a bundle leak, \$
$Cost_{insp}$	is the cost to perform the inspection, \$
$Cost_{maint}$	is the cost of maintenance for bundle inspection or replacement, \$
$Cost_{pbr}(tr_n)$	is the cost per year of bundle replacement at a planned frequency, tr_n , \$/yr
$Cost_{prod}$	is the production losses as a result of shutting down to repair or replace a tube bundle, \$
$Cost_{total}(tr_n)$	is the total cost of a bundle replacement program at a planned frequency, tr_n , \$/yr
D_{sd}	is the number of days required to shut a unit down to repair a bundle during an unplanned shutdown, days
$D_{sd,plan}$	is the number of days required to shut a unit down to repair a bundle during a planned shutdown, days

$D_{sd,unplan}$	is the number of days required to shut a unit down to repair a bundle during an unplanned shutdown, days
D_1^{Bundle}	is the probability adjustment for t_{rate1}
D_2^{Bundle}	is the probability adjustment for t_{rate3}
D_3^{Bundle}	is the probability adjustment for t_{rate4}
EIR_{t1}^{t2}	is the expected incremental risk between turnaround dates t_1 and t_2 , \$/yr
ERL	is the estimated remaining life of the bundle, years
ESL_n	is the estimated service life of a bundle as a function of replacement time interval, years
$ESL_{f,n}$	is the average life of bundles that would have failed at the replacement time interval, years
$ESL_{f,n-1}$	is the average life of bundles that would have failed at the previous replacement time interval ($n - 1$), years
$ESL_{p,n}$	is the average life of bundles that would not have failed at the replacement time interval, years
LEF	is the bundle life extension factor
$MTTF$	is the mean time to failure, years
$matcost$	is the material cost factor for the tube bundle material of construction
N	is the number of bundles in a heat exchangers past history
$Outage_{mult}$	is the outage multiplier factor of the unit
P_f^{tube}	is the probability of the bundle failure, failures/yr
$P_{f,n}^{tube}$	is the probability of bundle failure calculated for the current (n) increment of the optimization procedure, failures/yr
$P_{f,n-1}^{tube}$	is the probability of bundle failure calculated for the previous ($n - 1$) increment of the optimization procedure, failures/yr
$P_{f,w/insp}^{tube}$	is the probability of bundle failure at the plan date with inspection, failures/yr
$P_{f,tgt}^{tube}$	is the maximum acceptable probability of bundle failure based on the owner–operator's risk target, failures/yr
PBL_{adj}	is the predicted bundle life adjusted based on inspection, years

$R(t)$	is the risk as a function of time, ft ² /yr (m ² /yr) or \$/yr
$Risk_f^{tube}$	is the risk of failure of the tube bundle, \$/yr
$Risk_f^{tube}(tr_n)$	is the risk of failure of the tube bundle at a planned bundle replacement frequency, tr_n , \$/yr
$Rate_{red}$	is the production rate reduction on a unit as a result of a bundle being out of service, %
$Risk_{tgt}$	is the risk target, \$/yr
ROR	is the fractional rate of return or hurdle rate
RWT_f	is the failure point defined as a fraction of remaining wall thickness
r	is the number of failed bundles in a heat exchangers past history
t	is time, years
t_{dur}	is the bundle duration or time in service, years
$t_{dur,i}^{\beta}$	is the time in service for the i^{th} bundle in a heat exchanger, years
t_{insp}	is the inspection interval, years
t_{plan}	is the time from the bundle installation date to the plan date, years
t_{rate}	is the thinning rate for the tube bundle, in./yr (mm/yr)
$t_{rate,adj}$	is the probability adjusted corrosion rate
t_{rate1}	is the corrosion rate for damage state 1, in./yr (mm/yr)
t_{rate2}	is the corrosion rate for damage state 2, in./yr (mm/yr)
t_{rate3}	is the corrosion rate for damage state 3, in./yr (mm/yr)
t_s	is the time step used in the optimization routine for bundle replacement frequency, days
t_1	is the service duration of the bundle at the upcoming turnaround (turnaround date 1), years
t_2	is the service duration of the bundle at the subsequent turnaround (turnaround date 2), years
$t_{adj,dur}$	is the bundle duration or time in service adjusted for life extension activities, years
tr_n	is the bundle planned replacement frequency, year
$\bar{t}_{insp}$	is the average measured tube wall thickness, in. (mm)

$\bar{t}_{\text{orig}}$	is the average furnished tube wall thickness, in. (mm)
$Unit_{\text{prod}}$	is the daily production margin on the unit, \$/day
β	is the Weibull shape parameter that represents the slope of the line on a POF vs time plot
Γ	is the gamma function
η	is the Weibull characteristic life parameter that represents the time at which 62.3 % of the bundles are expected to fail, years
η_{insp}	is the Weibull characteristic life parameter at the plan date after inspection, years
η_{mod}	is the Weibull modified characteristic life parameter modified with inspection history, years
η_{tgt}	is the Weibull target characteristic life parameter based on the risk target, years

5.11 Tables

Table 5.1—Basic Data for Exchanger Bundle Risk Analysis

Bundle Remaining Life Methodology	
Specified MTTF	User-specified MTTF for bundle, years to be used in calculation
Specified Weibull, η	User-specified Weibull characteristic life (years) to be used in calculations (β should also be provided)
Specified Weibull, β	User-specified Weibull slope parameter to be used in calculations (η should also be provided)
Bundle life	The life of the bundle under evaluation, years (required for inactive bundles)
Consequences of Bundle Failure	
Financial risk target	User risk target, \$/yr
Tube wall failure fraction	Wall thickness fraction that constitutes bundle failure (0 and 1.0)
Production cost	Unit production costs, \$/day (should be equal to the production rate, bbl/day $\times$ margin (\$/bbl))
Production impact	Production impact, e.g. none, bypass, bypass with rate reduction, shutdown
Rate reduction	Rate reduction, % (required if production impact is bypass with rate reduction)
Planned shutdown days	Number of days required to repair or replace failed exchanger bundle when the shutdown is planned, days
Unplanned shutdown days	Number of days required to repair or replace failed exchanger bundle when the shutdown is unplanned, days (should be a longer duration than a planned shutdown to allow for lead time to mobilize or to purchase a replacement bundle)
Environmental impact	Environmental costs associated with bundle failure that includes damage to cooling water system and towers
Lost opportunity cost	Additional cost beyond production losses or environmental costs as a result of bundle failure, \$
Bundle cost	Cost of replacement bundle, \$
Bundle installation cost	Cost of maintenance required to remove, clean, and re-install exchanger bundle, \$
Hurdle cost	Additional cost above the economic breakeven point at which a decision to inspect or replace a bundle is made, \$
Turnaround date 1	The date for the next scheduled turnaround from the RBI date (used as plan date for calculating risk)
Turnaround date 2	The date for the second scheduled turnaround from the RBI date (used in the cost benefit analysis to make inspection or replacement decisions)

Table 5.2—Effects of Bundle Life Extension Methods

Life Extension Method	Life Extension Factor (LEF) ³
Plug tubes	0.10
180° bundle rotation	0.50
Partial re-tube	0.50
Total re-tube	0.90
Install spare bundle ²	0.50
Install tube ferrules ¹	0.75

NOTE 1 This LEF is only valid when the tube ferrules are installed for protection against localized, tube-end damage due to erosion, corrosion, or impingement.

NOTE 2 The spare bundle condition is known to be good through prior inspection. If the condition of the spare bundle is known to be excellent, a higher LEF can be used.

NOTE 3 LEFs provided in this table are suggestions. It is the responsibility of the owner–operator to define life extensions for use for the bundle life extension methods.

Table 5.3—Bundle Material Cost Factors

Bundle Generic Material	Tube Material Cost Factor, M_f
Carbon steel	1.0
C-1/2 Mo	2.0
1 ¹ / ₄ Cr	2.0
2 ¹ / ₄ Cr	2.8
5Cr	3.2
9Cr	3.3
12Cr	3.4
70/30 CuNi	3.5
90/10 CuNi	3.5
Monel 400*	7.0
Nickel 200	8.5
304/309/310 SS	2.6
304L/321/347 SS	2.8
316 SS	3.0
316L SS	3.0
317L SS	4.2
410/439 SS	2.8
444 SS	3.2
904L	7.0
2205 duplex SS	3.0
2304 duplex SS	2.8
2507 duplex SS	4.0
AL6XN/254 SMO	7.0

Bundle Generic Material	Tube Material Cost Factor, M_f
Seacure/E-Brite*	6.0
Admiralty brass/aluminum brass/red brass/Muntz	2.5
Aluminum alloy	3.0
Alloy 20 Cb3	6.5
Alloy 600	9.5
Alloy 625	11.0
Alloy 800	7.0
Alloy 825	8.0
Alloy C276	11.0
Ferrallium 255	7.0
Bimetallic	4.5
Ceramic	1.0
Plastic	1.0
Titanium Grade 2	6.0
Titanium Grade 12	10.0
Titanium Grade 16	14.0
Zeron 100	4.0
Zirconium alloy	15.0

NOTE The tube material cost factors are generic data, and the user is encouraged to set values based on current material cost factors.
 * These terms are used as examples only, and do not constitute an endorsement of these products by API.

Table 5.4—Numerical Values Associated with POF and Financial-based COF Categories for Exchanger Bundles

Probability Category ¹		Consequence Category ²	
Category	Range	Category	Range (\$)
1	$POF \leq 0.1$	A	$COF \leq \$10,000$
2	$0.1 < POF \leq 0.2$	B	$\$10,000 < COF \leq \$50,000$
3	$0.2 < POF \leq 0.3$	C	$\$50,000 < COF \leq \$150,000$
4	$0.3 < POF \leq 0.5$	D	$\$150,000 < COF \leq \$1,000,000$
5	$0.5 < POF \leq 1.0$	E	$COF > \$1,000,000$

NOTE 1 In terms of the total DF, see [Part 2, Section 2.3](#).
 NOTE 2 In terms of consequence area, see [Part 3, Section 4.11.4](#).

Table 5.5—Inspection Effectiveness and Uncertainty

Inspection Category	Inspection Effectiveness Category	Inspection Confidence	Inspection Uncertainty
A	Highly Effective	> 90 %	< 10 %
B	Usually Effective	> 70 % to 90 %	< 30 % to 10 %
C	Fairly Effective	> 50 % to 70 %	< 50 % to 30 %
D	Poorly Effective	> 40 % to 50 %	< 60 % to 50 %
E	Ineffective	< 40 %	> 60 %

NOTE 1 Inspection cost numbers are not provided in this table but may be used in the methodology regarding a “repair or replace” strategy. It is the responsibility of the owner–operator to determine the cost numbers unique to their particular operation and strategy.

NOTE 2 Refer to [Part 2, Annex C, Section 2.C.4](#) for more information.

NOTE 3 The owner–operator should consider applying confidence/uncertainty based upon the relationship between the following variables:

- amount of the bundle inspected (percentage whole or percentage per pass),
- examination method(s) used and degree of cleanliness,
- metallurgy of the bundle,
- damage mechanism(s) expected/found.

5.12 Figures

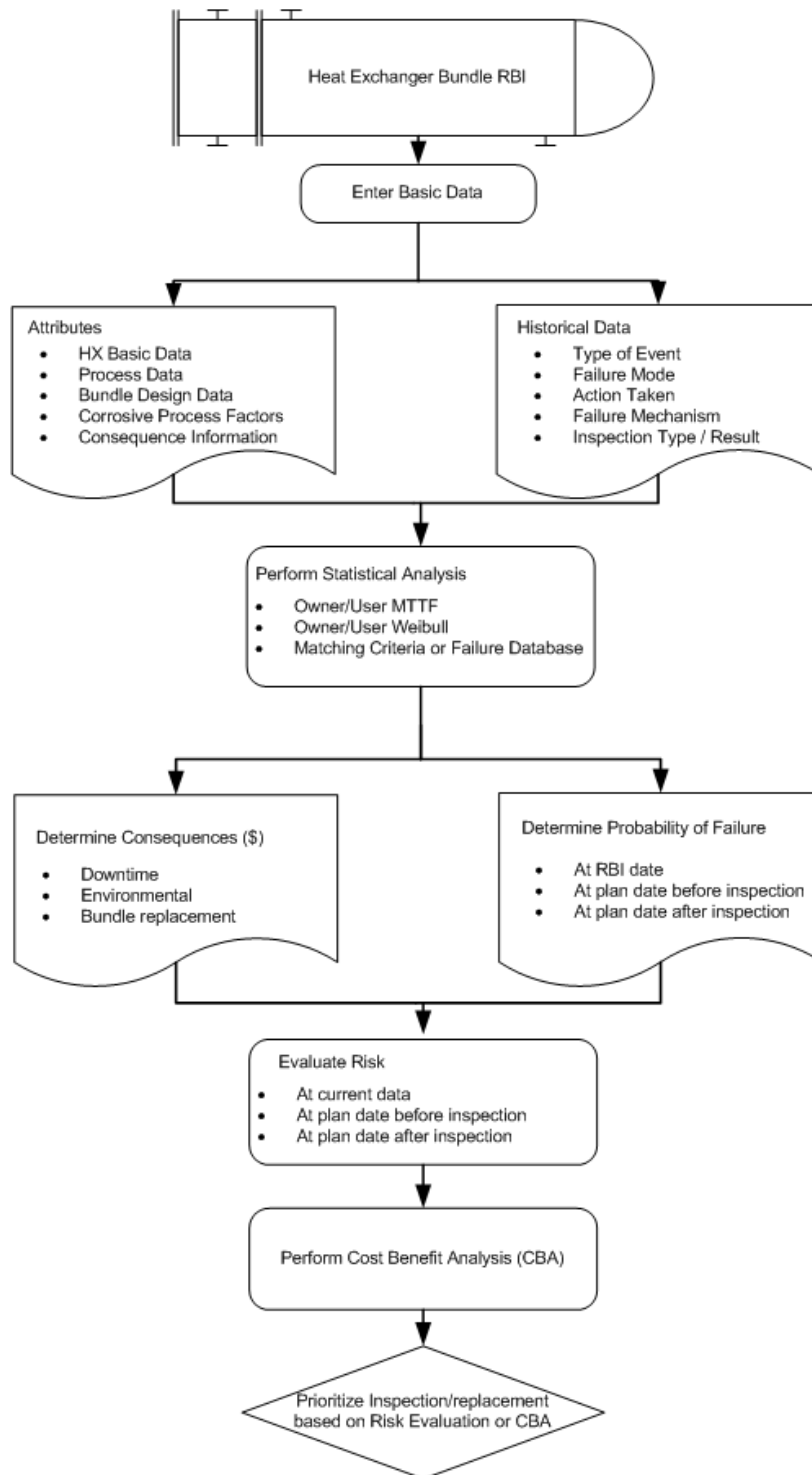


Figure 5.1—Flow Chart of Bundle Calculation Approach

6 PRDs

6.1 General

6.1.1 Overview

PRDs are routinely inspected and tested to assure that the PRDs will relieve properly in overpressure events to prevent a loss of containment of the protected component. The impact of leaks associated with PRDs is also considered.

A risk-based approach to evaluate PRD criticality is covered in this section to set inspection and test intervals. All spring-loaded and pilot-operated PRVs with and without rupture disks are covered. AST pressure/vacuum vents (P/Vs) and explosion hatches may be analyzed using this methodology provided Weibull parameter reliability data are available.

This methodology is not intended to be used to perform or check PRD design or capacity calculations. It is assumed that the owner-operator has completed due diligence and the PRDs have been designed in accordance with API 521 [7] and sized, selected, and installed in accordance with API 520 [8]. It is also assumed that minimum inspection practices in accordance with API 576 [9] are in place.

The methodology outlined uses a demand rate for the PRD combined with a probability of failure on demand (POFOD) determined from plant-specific data, if available, or using conservative default data provided. These inputs are used to generate POF as a function of time with a Weibull statistical approach. The protected component COF if the PRD fails to operate on demand is based on the methodology outlined in [Part 3](#), substituting the operating pressure with the overpressure of each demand case combined with the consequences associated with PRD leakage. The combination of COF with a time-based POF results in an increasing risk value with time between inspection and test, allowing test intervals to be set based on risk targets.

The flow chart shown in [Figure 6.1](#) illustrates the basic methodology required for the determination of an RBI inspection and test schedule. The basic data required for the evaluation are listed in [Table 6.1](#).

6.1.2 Failure Modes

There are several failure modes of significance when evaluating the risks associated with PRD failure. For the PRD, the failure modes are grouped into two categories.

a) Fails to open as designed (FAIL):

- 1) stuck or fails to open (FTO),
- 2) device partially open (DPO),
- 3) opens above set pressure (OASP).

b) Leakage failure (LEAK):

- 1) leakage past device (LPD),
- 2) spurious or premature opening (SPO),
- 3) device stuck open (DSO).

FAIL modes generally causes the potential for the protected equipment overpressure resulting in a loss of containment. Included in FAIL modes is the case of a DPO causing a less severe equipment overpressure.

A PRD OASP is included in the FAIL failure mode. The POF curves are based on bench test data where a failure is defined as any test requiring a pressure greater than 1.3 times the set pressure. A value that opens above set pressure during a test but does not exceed 1.3 times the set pressure is considered a successful test and is not included in the FAIL case.

Consequences associated with the FAIL failure mode include the effects of fires and explosions on personnel and equipment and the exposure of personnel to toxic fluids as a result of loss of containment. These consequences and their effect on personnel and equipment are further described in [Part 3](#).

A secondary concern is failure of a PRD to contain the process while operating at normal conditions. The API 581 methodology groups the remaining three failure modes together into the LEAK category. LPD, SPO, and DSO failures will not result in overpressure or loss of containment from the protected equipment but represent potentially unacceptable leakage from the process system. The consequences of leakage through a PRD can range from a minor nuisance, causing some loss of product, to a more severe consequence resulting in a process shutdown to repair or replace the PRD. If the PRD discharges to the atmosphere, additional consequences may be environmental impact and potential for fires, explosions, and toxic exposure.

6.1.3 Use of Weibull Curves

POFOD and the probability of leakage (POL) is expressed as a function of time for risk-based planning of inspections and tests. Weibull functions are suitable for this task with the added advantage that they may be used to evaluate large populations of data points to seek trends. In the absence of large sets of failure data, the functions are still useful as a starting point since the parameters involved describe both the manner of failure and the time to failure.

Using a two-parameter Weibull distribution [\[4\]](#), The cumulative failure density function, $F(t)$, sometimes referred to as unreliability, is using a two-parameter Weibull distribution as shown in [Equation \(5.90\)](#) and discussed in [Section 6.1.2](#).

The Weibull characteristic life parameter, η , is equivalent to the MTTF when the Weibull β parameter is equal to 1.0. Adjustments to the η parameter are made to increase or decrease the POFOD and POF as a result of environmental factors, PRD types, or available inspection data the PRD. Adjustments to the η parameter may be viewed as an adjustment to the PRD MTTF.

Determination of the default Weibull parameters assumes that PRDs in similar services will have a similar POFOD, P_{fod} , and POL, P_l , and industry failure rate data may be used as a basis to establish the initial or default PRD POF. The POFOD is evaluated for the process and installation conditions, such as process temperature, process corrosivity, and the tendency of the process to foul, polymerize, block the PRD inlet, or prevent the PRD from reseating during operation. Rough handling during transportation and installation and excessive piping vibration are also associated with failures. In addition, increased demand rates and improper installations that result in chatter may also increase the POFOD and POL.

6.1.4 PRD Testing, Inspection, and Repair

Inspection, testing, reconditioning, or replacement of PRDs are recognized safe practices and serve to reduce the POFOD and leakage. This PRD methodology assumes that a bench test performed on a PRD in the as-received condition from a process unit will result in a true determination of the performance of the PRD on the unit.

An effective inspection program for PRDs will track the history of inspection and test of each PRD. The outlined PRD methodology adjusts the POF data for each PRD based on historical data and allows varying degrees of inspection effectiveness. Pass/fail test data are given the highest confidence inspection effectiveness level when a shop bench pre-pop test is performed. A lower confidence inspection effectiveness level is associated with the inspection if a PRD is inspected or overhauled without a pre-test.

6.1.5 PRD Shop Inspection/Overhaul or Replacement Start Date ^[9]

The PRD is assumed to be returned to service in the as-new condition when the PRD is overhauled in the shop. The original install date for the PRD is retained with a last inspection date reflecting the PRD overhaul date or the installation date after overhaul. As a result, the calculated inspection interval and subsequent new due date for the PRD is based on the date the PRD was most recent overhaul or the date the PRD was installed following the most recent overhaul.

The installation date and last inspection date will be the same for a PRD that is replaced rather than overhauled and the calculated inspection interval and next test due date is based on the installation date. The replaced PRD does not necessarily need to be a new valve, it could be a spare or overhauled valve.

It is important to note that there may be a delay between the time of overhaul and the time the PRD is placed in service. This time delay may occur because the PRD has a spare and is currently installed or there is a delay in recommissioning. If there is a delay in between the time of the overhaul and the time the PRD returns to service, consider using the date of return to service date to calculate the inspection interval and subsequent new due date. For example, if the last inspection date with shop inspection/overhaul was in the year 2015, and the PRD was not put back into service until 2018, then consider using 2018 to calculate the next inspection due date.

The impact on the PRDs reliability of a time delay between the testing and installation dates should be considered. Where reliability may have adversely been affected, retesting prior to the installation should be considered. The owner–operator should specify the maximum delay time after which:

- a) the install date is to be used rather than the last overhaul date to calculate the next inspection date, and
- b) a retest should be considered before installation.

Often PRDs are pop-tested either in the field or in the shop without overhauling the PRD. When a PRD is pop-tested in the field or in the shop without performing an overhaul, the PRD has not been returned to service in an as-new condition. The PRD is assumed to remain in the prior test condition, and the POFOD may be adjusted based on the results of the field test (i.e. credit for inspection to reduce uncertainty). In this case, the last overhaul date is unchanged and the PRD will not get the full benefit of an overhaul. In this case, the due date is determined by adding the recommended inspection interval to the last overhaul date (not the last inspection date). For example, if PRD was pop-tested and overhauled in 2005, and then pop-tested, but not overhauled in 2010, and put back into service, the next inspection date is determined by adding the recommended inspection interval (7 years) to 2005, the date of the last overhaul. The next inspection due date is therefore 2012.

6.1.6 Risk Ranking of PRDs

The PRD methodology provides individual PRD risk ranking as well as risk ranking between PRDs and other fixed equipment being evaluated.

The two key drivers for effectively risk ranking between PRDs is the:

- 1) specific PRD reliability for each PRD by selecting a severity of service for the PRDs, establishing a default POF, and modifying the POFOD using the inspection and test history;
- 2) relative importance or criticality of each PRD by defining the relief system design basis and knowledge of the overpressure demand cases applicable for each PRD. The PRD risk rank will increase based on the criticality and demand placed the PRD.

6.1.7 Link to Fixed or Protected Equipment

To effectively characterize the risk associated with PRD failure, the consequence associated with the failure of a PRD to open upon demand should be tied directly to the equipment that the PRD protects by using direct links to the fixed equipment RBI analysis as covered in [Part 2](#) and [Part 3](#). The risk of loss of containment from fixed equipment increases proportionately with the amount of overpressure that occurs when the PRD fails to open on demand. In addition, the calculated risk associated with damaged fixed equipment will be greater than that for undamaged equipment since the actual damage states (i.e. damage factor, D_f , see [Part 2](#)) are used in the calculations.

Although consequences associated with PRD overpressure cases are greater than those associated with the fixed equipment operating at normal pressure, it may be compensated by using realistic PRD demand rates and accurate PRD failure rate data results in a low frequency of occurrence.

6.2 Overpressure Potential for Overpressure Demand Cases

6.2.1 General

The PRD analysis should consider the overpressure demand cases applicable for each PRD. The overpressure demand cases are the potential process upsets that the PRD is designed protect against and the criticality of the protected equipment if a failure on demand occurs. The importance of the criticality of the protected equipment in addition to the PRD failure is demonstrated by the following examples.

EXAMPLE 1 A PRD that protects equipment and piping for the blocked discharge demand case downstream of a pump is less critical than a PRD that is protecting a reactor from a runaway chemical reaction. In the former case, a lower overpressure with a PRD failure to open upon demand would be expected.

EXAMPLE 2 A PRD protecting piping against thermal relief is less critical than a PRD protecting low-pressure equipment from a high-pressure gas breakthrough due to a control valve failure.

The potential overpressure resulting from a PRDs failure to open upon demand may be calculated for most of the overpressure demand cases. The logic for determining the potential overpressure for each of the overpressure demand cases is provided in [Table 6.2](#). The potential overpressure approaches the burst pressure (defined as design margin times MAWP) of the protected equipment in cases where the overpressure demand case is not self-limiting. In other cases, such as a blocked discharge downstream of a centrifugal pump, the potential overpressure is self-limiting as it deadheads at the pump pressure of typically 1.3 times the normal discharge pressure of the pump.

Defining demand case overpressure scenarios for each PRD requires a thorough review of the unit pressure-relief study in conjunction with the P&IDs. The review should be performed by qualified personnel with experience in the design and installation of pressure-relief systems.

The determination of the potential overpressure, P_o , due to a PRDs failure to open upon demand is generally a function of the following.

- a) Type of Upstream Overpressure Source—Centrifugal pumps, steam supply headers, upstream pressure vessels, etc.
- b) Upstream Source Pressures—Steam supply pressure, control valve upstream pressure, pressure from the high-pressure side of a heat exchanger, and deadhead pressure for centrifugal rotating equipment. Additionally, credit for PRDs on upstream equipment can be assumed to be available to limit overpressure.
- c) Heat Sources, Types, and Temperatures—Blocked-in equipment, the heat source supplying energy to the system has a significant impact on the potential overpressure. Examples, a solar heat/energy supplied in a thermal relief scenario may result in flange leaks, limiting the overpressure to the normal operating pressure of the system. Alternatively, the overpressure may increase until a rupture occurs if the heat

source is a fired heater (i.e. overpressure exceeding the burst pressure of the protected equipment). Other heat sources include steam reboilers to towers and the hot side of heat exchangers.

- d) Fluid Bubble Point Pressure—Pressure increase is limited by the bubble point pressure of the contained process fluid at the temperature of the heat/energy source being supplied to the process.

6.2.2 Multiple Relief PRD Installations

The probability is reduced when multiple PRDs are used to manage the relief capacity required since the likelihood that multiple failures would occur is unlikely. In this case, the component POF is lower due to the expectation that some of the PRD capacity will be available on demand and minimize the overpressure experienced. When a component is protected by multiple PRDs, the calculated POFOD of each PRD in the multiple installation does not change. This multiple PRD installation adjustment factor, F_a , adjusts the overpressure that the component is likely to experience with a multiple PRD installation to minimize the potential overpressure.

$$F_a = \sqrt{\frac{A^{\text{prd}}}{A_{\text{total}}^{\text{prd}}}} \quad (5.89)$$

The F_a is a ratio of the area of a single PRD to the total area considering all PRDs in the multiple setup. The multiple PRD installation adjustment factor has a minimum reduction value of 0.25 since PRDs in a multiple PRD installation may have common failure modes. The final component overpressure is reduced by using Equation (5.90):

$$P_{o,j}^{\text{comp}} = F_a \cdot P_{o,j} \quad (5.90)$$

The reduced overpressure should be used when determining the protected component POF but is not used for calculating the overpressure factor, F_{op} .

6.2.3 Calculation Procedure

The following procedure is used to identify the potential PRD overpressure demand case scenarios.

- a) Step 1.1—Determine the list of overpressure scenarios applicable to the piece of equipment being protected by the PRD under evaluation. Table 5.3 provides a list of overpressure demand cases specifically covered. Additional guidance on overpressure demand cases and pressure-relieving system design is provided in API 521 [7].
- b) Step 1.2—Determine the design margin, DM, for the protected component material of construction.
- c) Step 1.3—For each overpressure demand case, estimate the amount of overpressure, $P_{o,j}$, likely to occur during the overpressure event if the PRD were to fail to open.
- d) Step 1.4—Calculate the total PRD orifice area, $A_{\text{total}}^{\text{prd}}$, for all PRDs in a multiple PRD installation.
- e) Step 1.5—Calculate the overpressure adjustment factor, F_a , using Equation (5.89).
- f) Step 1.6—Calculate the final component overpressures determined in Step 1.4 using Equation (5.90).

6.3 PRD POF

6.3.1 Definition

The POF calculations are performed for each overpressure demand case identified for the PRD according to [Section 5.2](#). Failure of a PRD is defined as:

- 1) failure to open during emergency or upset condition causing an overpressure of the protected component and resulting in loss of containment in failures/yr;
- 2) leakage through a PRD ([Section 6.4](#)).

6.3.2 Failure to Open

The calculation for the POF of a PRD failing to open is the product of an estimated overpressure demand case frequency (failures/demand), the probability of the PRD failing to open on demand (failures/demand), and the POF of the protected component at the overpressures.

A PRD protects equipment components from multiple overpressure scenarios. Guidance on overpressure demand cases and pressure relieving system design is provided in API 521 [\[7\]](#). Each of these scenarios (fire, blocked discharge, etc.) may result in a multiple possible overpressure demand case scenarios, $P_{o,j}$. In addition, each overpressure demand case scenario has an associated demand rate, DR_j . Demand cases are discussed in more detail in [Section 6.2](#), [Table 6.2](#), and [Table 6.3](#). The POF of the PRD failing to open for each overpressure demand case scenario is defined in [Equation \(5.91\)](#).

$$P_{f,j}^{\text{prd}} = P_{\text{fod},j} \cdot DR_j \cdot P_{f,j} \quad (5.91)$$

where j is the applicable overpressure demand case scenario for the PRD, $P_{f,j}^{\text{prd}}$.

The protected component POF, $P_{f,j}$, is a function of time and the potential overpressure. The individual parts for the POF of a PRD failing to open in [Equation \(5.91\)](#) are discussed in more detail in the following sections.

- a) [Section 5.3.3](#)—PRD demand rate, DR_f .
- b) [Section 5.3.4](#)—PRD POFOD, $P_{\text{fod},j}$.
- c) [Section 5.3.5](#)—POF of protected component as a result of overpressure, $P_{f,j}$.

6.3.3 PRD Demand Rate

The first step in evaluating the POF of a PRD failing to open is to determine the expected demand rate (demands/yr) placed on the PRD.

- a) Default Initiating Event Frequencies.

Estimated initiating event frequencies, EF_j , are provided based on the types of overpressure demand case scenario assigned. Examples of the initiating event frequencies are provided in [Table 6.3](#), and the background on the default initiating event frequencies is provided in [Table 6.2](#).

- b) Credit for Other Layers of Protection.

The actual PRD demand rate is not necessarily equal to the initiating event frequency. A demand rate reduction factor, $DRRF_j$, accounts for the difference in the overpressure demand case event frequency and the PRD overpressure demand rate.

Pressure vessels often contain control systems, high integrity protective instrumentation, shutdown systems, and other layers of protection to reduce the PRD demand rate. Credit can be taken for additional layers of protection, $DRRF_j$, or operator intervention for by the to reduce the probability of overpressure. The $DRRF_j$ may be determined rigorously for the installation using a layer of protection analysis (LOPA) or use the estimated value provided in [Table 6.3](#).

An example using the $DRRF_j$ credit is for the fire overpressure demand case with an estimated initiating event frequency of 1 every 250 years (0.004 events/yr). However, due to factors such as fire impinging on equipment rarely results in a significant pressure increase causing the PRD to open. As a result, factors reducing the actual PRD demand rate, such as fire proofing, availability of other escape paths for the process fluid, and firefighting efforts at the facility may increase the $DRRF_j$.

c) Calculation of Demand Rate.

The PRD demand rate, DR_j , is calculated as the product of the initiating event frequency and the $DRRF_j$ using [Equation \(5.92\)](#):

$$DR_j = EF_j \cdot DRRF_j \quad (5.92)$$

where j is the applicable overpressure demand case scenario.

A PRD typically protects equipment from several overpressure demand case scenarios, and each overpressure demand case has a unique demand rate. Default EF_j values for each of the overpressure cases are provided in [Table 5.3](#). An overall demand rate on the PRD can be calculated in [Equation \(5.93\)](#):

$$DR_{\text{total}} = \sum_{j=1}^{ndc} DR_j \quad (5.93)$$

Additional guidance on overpressure demand cases and pressure relieving system design is provided in API 521 [\[7\]](#).

If the relief design basis of the PRD installation has not been completed, the list of applicable overpressure demand cases may not be available, and it may be more appropriate to use a simple overall average value of the demand rate for a PRD. An overall demand rate for a particular PRD may usually be estimated from past operating experience for the PRD.

d) Owner–Operator Experience.

The EF_j for the overpressure demand cases as shown in [Table 6.3](#) are default values that may not be applicable in all situations. Owner–operators may have operating experience with a particular process system that may warrant using other event frequencies. Additionally, a PRD that protects multiple components may experience an increased demand for a particular overpressure scenario. For example, a PRD located on a crude distillation tower may also protect the desalted preheat exchanger train. Since the PRD protects equipment encompassing a much greater area of the unit, an increase in the EF_j for the fire case may be appropriate. In general, where a PRD protects multiple components, the EF_j should be evaluated to determine if an increase is justified.

6.3.4 PRD POFOD

The next step is to determine the PRD POFOD in service.

a) Categories of Service Severity.

PRD failure rates are directly related to the process severity of service. Categories of service are established for a PRD based on the process fluid tendency to result in a PRD failure caused by corrosion, fouling, plugging, or other effects. Temperature may also be a factor in determining the severity of service. The categories of service severity (mild, moderate, or severe) are associated with specific failure tendencies and default Weibull cumulative failure distribution curves, as described in [Table 6.4](#).

It is important to note that a process fluid classified as mild service for POFOD is not necessarily a mild service for POL. For example, industry failure data show that cooling water, which is known to be a dirty/scaling service, has one of the highest POFOD rates and therefore may be classified as severe. Conversely, PRDs in cooling water service have not demonstrated a significant amount of POL failures and therefore may be classified as mild service for the POL. Steam service is another example where industry data indicate that steam should be classified as mild for a POFOD failure. Steam is classified as severe for a POL failure since steam is known to cause PRD leaks due to erosion of high-temperature steam.

b) Default POFOD vs Time in Service.

1) General.

[Table 6.5](#) provides the default Weibull parameters for failure to open for conventional spring-loaded PRVs, balanced bellows PRVs, pilot-operated PRVs, and rupture disks. Weibull parameters provided in [Table 6.5](#) were determined using industry failure rate data with the majority of the available data from successful performance during the PRD service interval. Successful service test points are referred to as suspensions and were included with the failure data in determination of the Weibull parameters.

Weibull parameters are provided for the three categories of PRD service severity (mild, moderate, or severe), as discussed in [Section 6.3.4 a\)](#). The Weibull parameters provide the default POFOD curves for each of the PRD types listed in [Table 6.5](#) when used in the Weibull cumulative failure density function, $F(t)$, in [Equation \(5.90\)](#). For example, [Figure 6.2](#) provides the default Weibull cumulative failure distribution curves used for spring-loaded conventional PRVs using the Weibull function to describe the three categories of service severity.

NOTE The units for the POFOD data presented in [Figure 6.2](#) are failures/demand since the data were established from actual PRD bench test results rather than continuous service data. POFOD should not be confused with POF (failures/yr) that includes the demands on the PRD (see [Section 6.2](#)) and the probability that the protected component will fail in an overpressure event (see [Section 6.3.5](#)).

The cumulative failure distribution curves shown in [Figure 6.2](#) and the Weibull parameters presented in [Figure 6.6](#) are the default values based on the category of service severity of the PRD being evaluated. These base values are defaults and should be replaced with owner–operator site-specific data, if available [[Section 6.3.4 c\) 3](#)].

2) Presence of an Upstream Rupture Disk.

Rupture disks are often installed in combination with PRVs to isolate the PRV from process corrosive or fouling conditions and reducing the potential for POFOD. API 520, Parts 1 and 2 provide additional information related to the use and installation of rupture disks upstream of PRVs.

A mild service for POFOD is recommended for a PRD with upstream rupture disks, regardless of the process fluid severity. Assigning a mild POFOD service assumes that the space between the rupture

disk and the PRV is vented and monitored for leakage, as required by code and recommended by API 520. If the space is not vented and monitored for leakage, no credit for an upstream rupture disk is given.

3) Use of Plant-specific Failure Data.

Data collected from specific plant testing programs may be used for POFOD and POL analysis. MTTF or failure per million operating hours may be calculated in the required format using simple conversion routines.

c) Default Data for Balanced Bellows PRVs.

Balanced spring-loaded PRVs contain a bellows to isolate the back side of the disk from the effects of superimposed and built-up back pressure. The bellows isolates the PRD internals from a corrosive process fluid in the discharge system. Industry failure rate data indicates that balanced bellows PRVs have the same POFOD rates as conventional PRDs since process fluid is isolated from the PRV internals. As shown in [Table 6.6](#), the η characteristic life for bellows PRVs is the same as for conventional PRVs.

d) Default Weibull Parameters for Pilot-operated PRVs.

To date, there is little failure rate data in the industry available for pilot-operated PRVs. One source [\[10\]](#) indicates that pilot-operated PRVs are 20 times more likely to fail than their spring-loaded counterparts. The Weibull parameters for the POFOD curves for conventional PRVs in [Table 6.5](#) are used as the basis for pilot-operated PRVs with adjustment factors applied to the η characteristic life. For mild service, the η characteristic life for pilot-operated PRVs is reduced by a factor of 1.5; for moderate service, the reduction factor is 3.0; and for severe service, the reduction factor is 5.0.

e) Default Weibull Parameters for Rupture Disks.

To date, there is little failure rate data in the industry available for rupture disks. Rupture disks are simple to use and reliable. Rupture disks open at or near burst pressure unless the inlets or outlets are plugged or the disk is installed improperly. Failure of rupture disks are typically due to premature bursts. The Weibull parameters for POFOD for rupture disks are based on the mild severity curve for conventional PRVs and assuming that a rupture disk is at least as reliable as a conventional PRV. Default parameters assume that the rupture disk material is resistant to the process fluid corrosion. If the rupture disk material is resistant to the process fluid corrosion, the disk Weibull parameters should be adjusted accordingly.

f) Adjustment for Conventional PRVs Discharging to Closed System.

An adjustment factor is used to modify the base Weibull parameters for conventional PRVs discharging to a closed system or to flare. A conventional PRV characteristic life, η , is reduced by 25 % since no bellows is present to protect the bonnet housing from discharge system corrosion.

$$F_c = 0.75 \quad \text{for conventional valves discharging to closed system or flare}$$

$$F_c = 1.0 \quad \text{for all other cases}$$

g) Adjustment for Environmental Factors.

Environmental and installation factors that affect the reliability of PRDs include installed piping vibration, a history of chatter, or pulsing flow or cyclical service (downstream of reciprocating rotating equipment).

Other environmental factors that can significantly affect POL are operating temperature and operating ratio. The PRD operating ratio is the ratio of maximum system operating pressure to the set pressure. When the operating ratio is greater than 90 % for spring-loaded PRVs, the system pressure is close to overcoming the closing force provided by the spring on the seating surface and the PRV will be more

likely to leak (simmer). The increased potential for leakage is considered by applying an environmental factor to the default leakage curve. Similarly, an environmental factor is applied when the operating margin is greater than 95 % for pilot-operated PRVs.

NOTE Some pilot-operated PRVs can function at operating ratios up to 98 % (see API 520 for guidance on operation margin).

Analysis of the industry failure rate data shows that PRDs in vibration or cyclical service generally experience higher leakage rates, but POFOD rates are not significantly affected.

PRVs in service with a history of chattering should be redesigned or modified to eliminate the chatter, as soon as possible. An adjustment factor of 0.5 is applied to the Weibull η parameters for the POFOD and POL curves of a PRD experiencing chattering in service since the effects of chatter are detrimental to the protection provided by the PRD.

Table 6.6 provides the environmental adjustment factors applied to the default POFOD and POL Weibull curves. The environmental factor, F_{env} , increases the POFOD or POL (shifting the probability curves to the left) by reducing the curve's η characteristic life, as shown in Figure 6.5.

h) Updating POFOD Based on PRD-specific Inspection and Test Data.

1) Tracking Historical Inspection and Test Data.

An inspection program should track each PRD's testing and inspection history from its initial installation. Adjustments to the PRD POFOD, P_{fod} , and POL, P_l , curves are made to provide credit for information during a PRD inspection and test.

Data obtained from a PRD inspection and test will increase or decrease the POFOD and POL by modifying the Weibull parameters based on the pass/fail and no-leak/leak test results for the service duration, $t_{dur,i}$, since the last inspection. An increase or decrease in the POFOD and POL through inspection will increase or decrease the recommended inspection and test interval.

Modifying the POFOD based on test results alone (i.e. bench test) will be nonconservative if the inlet or outlet piping was plugged during operation, affecting the operating of the PRD. The visually inspected condition of the piping should be documented for each inspection and specifically noted if the piping is plugged. Plugged PRD piping should be considered to have failed the inspection and test, regardless of the bench test results or inspection method used. More than 25 % of the pipe is considered plugged and the PRD should fail the inspection and test.

2) Effectiveness of Inspection Programs in Confirming Failure Rates.

Inspection effectiveness is based on its ability to adequately predict the pass/fail condition of the PRD and detect/quantify damage. Definitions for PRD inspection and test effectiveness are provided in Part 2, Annex 2.C, Table 2.C.3.1.

PRD inspection and test should document the effectiveness of the inspection and test performed. The inspection effectiveness concept as described in Part 2, Section 3.4.3 for fixed equipment is similar for PRDs. In addition, PRD inspection effectiveness measures the confidence in the pass/fail/leak result of the inspection and test.

Table 6.7 provides default conditional probabilities based on expert opinion. The conditional probabilities indicate the ability of the inspection and test to reflect an accurate representation of the PRD performance in an overpressure event. For example, a 90 % effectiveness associated with passing a highly effective inspection and test indicates that there is a 90 % chance that the PRD would perform as intended in service. Conversely, there is a 10 % chance that the PRD would fail to perform as intended in service.

The conditional probabilities in [Table 6.7](#) assign the highest confidence to a PRD passing a bench tested without any prior cleaning (i.e. as-received condition). Bench testing of PRDs that were cleaned prior to testing or testing in situ, as well as visual inspections, provide information for expected PRD performance in service but are not considered as reliable as the as-received bench test.

PRDs that fail an inspection and test are treated differently than passed test results. For PRDs that fail a highly effective bench test, the 95 % confidence indicates a 95 % chance that the PRD would have failed to perform as intended in service. A usually effective bench test or test in situ after the PRD was steamed is assigned a 95 % confidence the PRD will fail to perform as intended in service.

An ineffective test does not provide additional information about the ability of the PRD to perform as intended in service and receives no inspection and test credit. Credit is provided for an overhauled PRD and is returned to service in like-new condition. In this case the service duration, $t_{dur,i}$, is calculated based on the date of the ineffective inspection and test.

3) Inspection Updating.

The initial default Weibull parameters for the listed provided process fluid services are modified as inspection and test data are provided.

The Bayesian updating approach used assumes that the Weibull β shape parameter remains constant based on historical data and modifies the η since no inspection data being available. This is analogous to evaluating a one-parameter Weibull to update the PRD performance. Bayes' theorem works best when the error rates for a test are very small; however, test effectiveness in [Table 6.8](#) varies from 50 % to 90 %. As a result, using Bayes' theorem high levels of uncertainty generates an unrealistically high adjusted POF, particularly for a pass bench test result. A modified inspection updating method was developed to provide a more realistic modification approach to characteristic life.

A default POFOD is defined for the PRD based on service duration, $t_{dur,i}$, at the time of inspection to provide a POFOD vs time. The methodology calculates a prior PRD POFOD (prior to inspection) using [Equation \(5.94\)](#).

$$P_{f,prior}^{prd} = 1 - \exp \left[- \left(\frac{t}{\eta_{mod}} \right)^{\beta} \right] \quad (5.94)$$

The prior probability that the PRD will operate on demand (pass) is calculated using [Equation \(5.95\)](#).

$$P_{p,prior}^{prd} = 1 - P_{f,prior}^{prd} \quad (5.95)$$

A PRD POFOD posterior probability is calculated based on the conditional probability, or confidence factor, CF , from [Table 6.7](#) after an inspection of a specific effectiveness is performed. The updated POFOD is the conditional POFOD and is calculated using [Equation \(5.96\)](#) or [Equation \(5.97\)](#) depending on the inspection and test result.

The conditional PRD POFOD, $P_{p,cond}^{prd}$, for a passed inspection is calculated using [Equation \(5.96\)](#).

$$P_{p,cond}^{prd} = (1 - CF_{pass}) \cdot P_{p,prior}^{prd} \quad (5.96)$$

The conditional PRD POFOD, $P_{f,cond}^{prd}$, for a failed inspection is calculated using Equation (5.97).

$$P_{f,cond}^{prd} = CF_{fail} \cdot P_{f,prior}^{prd} + (1 - CF_{pass}) \cdot P_{p,prior}^{prd} \quad (5.97)$$

Weighted equations were developed to increase credit for inspection and test conducted later in the characteristic life. The posterior POFOD, $P_{f,wgt}^{prd}$, is calculated using the weighted prior and conditional probability equations provided in Table 6.9.

The updated η characteristic life is calculated using Equation (5.101) based on the service duration, $t_{dur,i}$, of the PRD, the known β shape parameter, and $P_{f,wgt}^{prd}$.

The weighted equations produce a gradual shift from default POFOD data to PRD-specific POFOD data with a gradual increasing η characteristic life. A significantly shorter η characteristic life results if the PRD inspection and test has resulted in repeated failures early in the service.

Additional inspection and test updating guidance are as follows.

- i) Tests conducted less than 1 year apart should not be credited.
 - ii) The η characteristic life cannot decrease after a pass inspection and test result—if the methodology decreases the η characteristic life, the prior probability should be used for the η characteristic life.
 - iii) The η characteristic life cannot increase after a fail inspection and test result—if the methodology increases the η characteristic life, the prior probability should be used for the η characteristic life.
- 4) Updating Failure Rates After Modification to the Design of the PRD.

Design changes that improve the PRD performance may result in a failure rate change, such as upgrading to a corrosion-resistant material or installation of an upstream rupture disk. Past inspection data no longer applies after PRD design changes. A new default curve should be selected based on Figure 6.2 or PRD-specific Weibull parameters should be defined based on owner–operator experience (generating a unique PRD curve) should be used after PRD design changes.

- i) Adjustment for Overpressures Higher Than Set Pressure.

As discussed in Section 6.1.2, the POFOD curves are based on bench test data where a failure is defined as any test requiring a pressure greater than 1.3 times the set pressure. Industry failure data supports that as ratio of overpressure increases, the POFOD decreases, as shown in Figure 6.4.

A conservative assumption decreases the operating failure rate, $F_{op,j}$, by a factor of 5 at an overpressure of 4.0 times the set pressure and linearly interpolate between 1.3 and 4.0 at an overpressure times the set pressure, shown in Equation (5.98).

$$\begin{aligned}
 F_{op,j} &= 1.0 && \text{for } \frac{P_{o,j}}{P_{set}} < 1.3 \\
 F_{op,j} &= 0.2 && \text{for } \frac{P_{o,j}}{P_{set}} > 4.0 \\
 F_{op,j} &= 1 - \frac{1}{3.375} \cdot \left(\frac{P_{o,j}}{P_{set}} - 1.3 \right) && \text{for all other cases}
 \end{aligned} \quad (5.98)$$

The $F_{op,j}$ adjustment factor ranges from 0.2 and 1.0.

The overpressure factor, $F_{op,j}$, is an adjustment for overpressure scenarios higher than 1.3 times the set pressure where j is the overpressure demand case scenario.

6.3.5 Protected Equipment Failure Frequency as a Result of Overpressure

A damage adjusted POF for components evaluated with RBI is included in the PRD POF calculation (Section 6.1). The component DF increases as a function of time and is calculated based on the applicable damage mechanisms for the equipment, the inspection history, and condition of the equipment. As the PRD inspection interval is extended, the component damage continues and risk increases as well as the risk of the PRD over time.

a) DF Calculation Procedure for PRD with Fixed Equipment.

The damage adjusted POF that is calculated at the normal operating pressure of the component is adjusted when evaluating PRDs. When a PRD fails to open on demand, the protected component pressure exceeds the normal operating pressure and may significantly exceed the MAWP. Equation (5.99) is used to calculate the protected component damage POF based on the expected pressure for each overpressure demand case. The damage adjusted component POF, $P_{f,j}$, is the probability of a loss of containment of the protected component resulting from the overpressure event.

$$P_{f,j} = \min \left(\left(a \cdot D_f \cdot F_{MS} \right) \cdot e^{\left(b \cdot \frac{P_{o,j}}{MAWP} \right)}, 1.0 \right) \quad (5.99)$$

where a and b are the constants from Table 6.11 for $P_{f,j}$ are based on the design margin, DM, from Table 6.10 for the protected component material of construction determined in Step 1.2.

During PRD overpressure events, the probability of loss of containment in the protected component increases. An undamaged component ($D_f = 1$) has an upper limit probability of loss of containment of 1.0 when the overpressure is equal to the burst pressure (the expected failure pressure of the component). The burst pressure of the component is estimated using the design margin times the MAWP (with design margins for components constructed in accordance with various codes shown in Table 6.10). Alternatively, the burst pressure can be more accurately calculated using a more advanced analysis such as Svensson's method [11]. For damaged components ($D_f \gg 1$), the probability of loss of containment of 1.0 may occur at pressures much lower than the damaged component burst pressure (see Figure 6.6).

b) Selection of DF Class when PRD RBI Is Performed Without Fixed Equipment.

The D_f for the protected component may be specified using a DF class defined in Table 6.12 if a fixed equipment RBI study is not available. This D_f assignment is more qualitative than when an RBI analysis conducted to determine component D_f .

6.3.6 Calculation Procedure

The following calculation procedure may be used to determine the probability of a PRD failing to open.

- a) Step 2.1—Grade the PRD inspection and test histories for each inspection using [Part 2, Annex 2.C, Table 2.C.3.1](#) for guidance. Grade each inspection as pass/fail and no-leak/leak, assign the confidence factors, CF_i , and calculate the time duration, $t_{dur,i}$.
 - 1) Step 2.1.1—Grade each inspection and test using [Part 2, Annex 2.C, Table 2.C.3.1](#).
 - 2) Step 2.1.2—Record the inspection and test result as pass/fail and assign the appropriate CF_i .
 - 3) Step 2.1.3—Calculate the service duration, $t_{dur,i}$, for each inspection.
 - 4) Step 2.1.4—Determine if the PRD was overhauled. If the PRD was overhauled, the date of the most recent overhaul is the date to be used in Step 2.7 ([Figure 6.7](#)). The owner–operator may consider using the return to service date instead of the overhaul date to calculate the next inspection date. The owner–operator should define the timeframe (delay between overhaul and in-service date) for when the return to service date should be used. Refer to [Section 5.1.4](#) and [Section 5.1.5](#) for more information on acceptable time delays before a retest should be considered.
- b) Step 2.2—Select the most recent inspection and test history and service duration, $t_{dur,i}$.
- c) Step 2.3—Determine the default values for the Weibull parameters, β and η_{def} , based on category of service severity [[Section 6.3.4 a](#)], selection of the default POFOD curve [[Section 6.3.4 c](#)], type of PRD [[Sections 6.3.4 c](#)] through [6.3.4 e](#)], and using [Table 6.5](#) and [Table 6.6](#).
- d) Step 2.4—Determine the adjustment factor, F_c , for conventional PRDs discharging to a closed system or flare [[Section 6.3.4 f](#)].
- e) Step 2.5—Determine the environmental adjustment factor for conventional PRDs, F_{env} , using [Table 6.6](#).
- f) Step 2.6—Calculate the modified characteristic life, η_{mod} , using [Equation \(5.100\)](#), η_{def} from Step 2.3, and F_c Step 2.4.

$$\eta_{mod} = F_c \cdot F_{env} \cdot \eta_{def} \quad (5.100)$$

- g) Step 2.7—Calculate the updated characteristic life, η_{upd} , using η_{mod} from Step 2.6 and PRD inspection and test history from Step 2.1.
 - 1) Step 2.7.1—Calculate the prior POF, $P_{f,prior}^{prd}$, using [Equation \(5.94\)](#) and the time period, $t_{dur,i}$, from Step 2.6.

NOTE For the first inspection record, η_{mod} from Step 2.1 is used with subsequent inspection records using η_{upd} from Step 2.7.6.
 - 2) Step 2.7.2—Calculate the prior probability of passing, $P_{p,prior}^{prd}$, using [Equation \(5.95\)](#).
 - 3) Step 2.7.3—Determine the conditional probability of pass test result, $P_{p,cond}^{prd}$, using [Equation \(5.96\)](#).
 - 4) Step 2.7.4—Determine the conditional probability of failed test result, $P_{f,cond}^{prd}$, using [Equation \(5.97\)](#).
 - 5) Step 2.7.5—Calculate the weighted POF, $P_{f,wt}^{prd}$, using the equations in [Table 5.9](#).

- 6) Step 2.7.6—Calculate the η_{upd} using Equation (5.101) using Weibull parameters β from Step 2.3 and the weighted POF, $P_{\text{f,wgt}}^{\text{prd}}$, established in Step 2.7.5.

$$\eta_{\text{upd}} = \left(\frac{t_{\text{insp}}}{\left(-\ln(1 - P_{\text{f,wgt}}^{\text{prd}}) \right)^{\frac{1}{\beta}}} \right) \quad (5.101)$$

- 7) Step 2.7.7—Repeat these steps for each of the inspection records available for the PRD to calculate the final η_{upd} .
- 8) Step 2.7.8—Calculate the POFOD as a service duration, $t_{\text{dur},i}$, for the PRD using Equation (5.102) and η_{upd} from Step 2.7.7.

$$P_{\text{fod}} = 1 - \exp \left[- \left(\frac{t_{\text{dur},i}}{\eta_{\text{upd}}} \right)^{\beta} \right] \quad (5.102)$$

- h) Step 2.8—For each overpressure scenario, determine the overpressure adjustment factor, $F_{\text{op},j}$, using Equation (5.98).
- i) Step 2.9—Calculate the adjusted POFOD using Equation (5.103) and $F_{\text{op},j}$ from Step 2.8.

$$P_{\text{fod},j} = P_{\text{fod}} \cdot F_{\text{op},j} \quad (5.103)$$

- j) Step 2.10—For each overpressure demand case, determine the initiating event frequency, EF_j , using Table 6.3 or based on owner–operator experience for the overpressure demand case.
- k) Step 2.11—Determine the demand rate reduction factor, $DRRF_j$, accounting for layers of protection that may reduce the probability of an overpressure of the protected component; see Section 6.3.3 b) and Table 6.3 for guidance.
- l) Step 2.12—For each overpressure demand case, determine the demand rate, DR_j , placed on the PRD, using Equation (5.92).
- m) Step 2.13—Determine the MAWP of the protected equipment.
- n) Step 2.14—Calculate the protected component damage adjusted DF, D_{f} . The DF should be determined at the PRD service duration, $t_{\text{dur},i}$, from Step 2.2 for a DF as a function of time. If a fixed equipment RBI analysis has not been completed, the DF may be estimated using Table 6.12.
- o) Step 2.15—Calculate the protected component POF at the overpressure, $P_{\text{f},j}$, using Equation (5.99) and the overpressure is determined in Step 1.3 of Section 6.2.2.
- p) Step 2.16—Calculate the PRD POF, $P_{\text{f},j}^{\text{prd}}$, using Equation (5.91) using $P_{\text{fod},j}$ from Step 2.9, DR_j from Step 2.12, and $P_{\text{f},j}$ from Step 2.15.
- q) Step 2.17—Repeat Step 2.1 through Step 2.16 for each component protected by the PRD.

6.4 POL

6.4.1 Overview

The POL case is a function of failure during continuous operation. Industry data associated with POL, P_1 , is presented in failures/yr with not impacted by demand rate.

a) Categories of Service Severity.

Guidance on selecting the proper service severity for the POL case is provided in [Table 6.13](#). The owner–operator’s experience with a PRD in a particular service provides guidance for selecting the severity.

b) Default POL Rates vs Time in Service.

A set of Weibull curves provided for the POL case are from data of PRDs in continuous service (i.e. a continuous demand). The data were collected in units of failures/yr and were not modified by demand rate. [Table 6.14](#) provides the default PRD POL vs time information using a Weibull function to describe three types of service (mild, moderate, and severe). These data were based on a limited amount of industry data and should be supplemented by owner–operator data, where available.

The default cumulative POL distribution curves for spring-loaded conventional PRVs using the Weibull function to describe the three categories of service severity are provided in [Figure 6.3](#) as an example.

c) Default Weibull Parameters for Balanced Bellows PRVs.

The Weibull parameters for the POL curve for balanced bellows PRVs provided in [Table 6.14](#) match the industry failure rate data. These data reflect a minor increase in the POL compared to conventional PRVs.

d) Default Weibull Parameters for Pilot-operated PRVs.

The design of pilot-operated PRVs provide a better seal as the operating pressure approaches the set pressure. Owner–operator Weibull parameters for conventional or pilot-operated PRVs should be used, if available, until improved failure rate data are developed for η characteristic life for leakage provided in [Table 6.14](#).

e) Default Weibull Parameters for Rupture Disks.

Since no industry data were available for rupture disk leakage, Weibull parameters are based on the mild severity curve for conventional PRVs [see [Section 6.3.4 e\)](#) for additional information].

f) Adjusted Default POL Curve for PRVs Containing Soft Seats.

Soft seats (O-rings) are often added to spring-loaded PRVs to reduce the potential for leakage across the seat. When a conventional or balanced bellows PRV contains a soft seat design, the η parameter for the default POL Weibull curve is increased by a factor of 1.25 in accordance with the following factors:

$$F_s = 1.25 \quad \text{for soft-seated designs}$$

$$F_s = 1.0 \quad \text{for all other cases}$$

g) Environmental Modifiers to the Default POFOD and POL Data.

[Table 6.6](#) provides environmental adjustment factors, F_{env} , for the POL Weibull curves [[Section 6.3.4 g\)](#)]

h) Set Pressure Adjustment.

The POL decreases as the ratio of operating pressure to set pressure, $\frac{P_s}{P_{set}}$, decreases, as shown in [Table 6.8](#).

i) Presence of an Upstream Rupture Disk.

The POL is negligible (i.e. $P_1^{prd} = 0.0$) and the COF = 0 with a rupture disk installed upstream of the PRV.

j) Modification of Leakage Rates Based on PRD-specific Inspection and Test Data.

The characteristic life updating based on inspection and test history is the same as the approach described in [Section 6.3.4 h\)](#) for the POFOD case.

6.4.2 POL Calculation Procedure

The PRD POL is calculated using the following steps.

- a) Step 3.1—Determine default Weibull parameters, β and η_{def} , based on category of service severity and PRD type [[Section 6.3.4 a\)](#) through [Section 6.3.4 i\)](#)].
- b) Step 3.2—Apply an adjustment factor, F_s , for the presence of soft seats [[Section 6.3.4 j\)](#)].
- c) Step 3.3—Apply an adjustment factor, F_{env} , for environmental factors [[Section 6.3.4 j\)](#)].
- d) Step 3.4—Calculate the modified characteristic life, η_{mod} , using [Equation \(6.104\)](#).

$$\eta_{mod} = F_s \cdot F_{env} \cdot \eta_{def} \quad (5.104)$$

- e) Step 3.5—Calculate the updated characteristic life, η_{upd} , using η_{mod} from Step 3.4 and PRD inspection and test history from Step 2.6.

- 1) Step 3.5.1—Calculate the prior probability of leak, $P_{f,prior}^{prd}$, using [Equation \(5.94\)](#) and the time period, $t_{dur,i}$, from Step 2.6.

NOTE For the first inspection record, η_{mod} from Step 2.1 is used with subsequent inspection records using η_{upd} from [Step 3.5.6](#).

- 2) Step 3.5.2—Calculate the prior probability of no leak, $P_{p,prior}^{prd}$, using [Equation \(5.95\)](#).
- 3) Step 3.5.3—Determine the conditional probability of no-leak test result, $P_{p,cond}^{prd}$, using [Equation \(5.96\)](#).
- 4) Step 3.5.4—Determine the conditional probability of leak test result, $P_{f,cond}^{prd}$, using [Equation \(5.97\)](#).
- 5) Step 3.5.5—Calculate the weighted POF, $P_{f,wgt}^{prd}$, using the equations in [Table 6.9](#).
- 6) Step 3.5.6—Calculate η_{upd} using [Equation \(5.101\)](#) using Weibull parameters β from Step 2.3 and the weighted POF, $P_{f,wgt}^{prd}$, established in Step 3.5.5.

- 7) Step 3.5.7—Repeat these steps for each of the inspection records available for the PRD to calculate the final η_{upd} .
- f) Step 3.6—Calculate the set pressure factor, F_{set} , based on the PRD type, operating pressure, P_s , and set pressure, P_{set} (see [Table 6.8](#)).
- g) Step 3.7—Calculate the updated characteristic life, η_{upd} , from Step 3.5.7 using [Equation \(5.105\)](#).

$$P_i^{\text{prd}} = 1 - \exp \left[- \left(\frac{t_{\text{dur},i}}{\eta_{\text{upd}}} \right)^\beta \right] \cdot F_{\text{set}} \quad (5.105)$$

6.5 PRD Consequence of Failure to Open on Demand (COFOD)

6.5.1 General

The COFOD calculations for event outcomes such as fires, explosions, and toxic exposure are described in [Part 3](#). A PRD failure to open on demand will result in the protected component being exposed to significantly higher pressures than during normal operation. The PRD COFOD calculates the impact of each demand case scenario failure at the overpressure.

[Table 6.15](#) shows the expected potential consequences of a pressure vessel as a percentage of an overpressure above the MAWP. [Table 6.15](#) is provided as a qualitative discussion of the potential risks to pressure vessels due to an overpressure event and is not intended to indicate any specific event outcome. The methodology accounts for the effects of overpressure on protected equipment by increasing the probability of loss of containment. At an overpressure equal to the burst pressure (estimated to be the design margin times the MAWP), the probability of loss of containment is conservatively assumed to be equal to 1.0 [[Section 6.3.4 i](#)].

The COFOD, $C_{f,j}^{\text{prd}}$, is calculated for each overpressure demand case scenario as follows.

- a) Step 4.1—For each overpressure demand case, calculate the financial COFOD, $C_{f,j}^{\text{prd}}$, for the protected component using the overpressure from Step 1.6 and methodology in [Part 3](#).

6.6 Consequence of Leakage (COL)

6.6.1 General

The PRD consequence of leak is typically less significant than a component loss of containment resulting from a PRD COFOD. While the frequency of leakage is less significant, a leak may result in a high risk ranking of the PRD.

The COL, C_l^{prd} , from PRDs is calculated by summing the following costs and using [Equation \(5.106\)](#):

$$C_l^{\text{prd}} = \text{Cost}_{\text{inv}} + \text{Cost}_{\text{env}} + \text{Cost}_{\text{sd}} + \text{Cost}_{\text{prod}} \quad (5.106)$$

- Lost inventory cost based on the product of the cost of fluid, the leakage rate ([Section 5.4](#)), and the estimated number of days to discover the leak ([Table 6.15](#)).
- Regulatory and environmental costs associated with leakage.
- Downtime cost to repair or replace the PRD if a leaking or stuck open PRD cannot be tolerated.
- Production cost while conducting the repair or replacement of the leaking PRD.

For a multiple PRD installation, the POL for any one specific PRD does not increase. However, since the number of PRDs increases, the POL and the associated consequences increase in proportion to the number of PRDs protecting the system.

6.6.2 Estimation of PRD Leakage Rate

Analysis of industry bench test data indicates approximately 8.4 % of PRVs tested leaked during a bench test between 70 % and 90 % of the set pressure, 6.6 % of PRVs leaked at pressures below 70 % of the set pressure, and an additional 2.4 % of PRVs leaked significantly below 70 % of their set pressure. A summary of the leakage rates used for the consequence calculation is provided in [Table 6.17](#).

A leakage rate of 1 % of the PRD rated capacity, W_c^{prd} (calculated at normal operating conditions), was used for minor or moderate leaks and calculated using [Equation \(5.107\)](#). A minor or moderate leakage, C_l^{mild} , represents 90 % of the potential leakage cases, as shown in [Table 6.17](#).

$$lrate_{\text{mild}} = 0.01 \cdot W_c^{\text{prd}} \quad (5.107)$$

The leakage rate for a stuck open or spurious leaks is assumed to be 25 % of the PRD rated capacity, W_c^{prd} , and calculated using [Equation \(5.108\)](#). A leak from a stuck open PRD, C_l^{so} , represents 10 % of all potential leakage cases.

$$lrate_{\text{so}} = 0.25 \cdot W_c^{\text{prd}} \quad (5.108)$$

The rated capacity of the PRD, W_c^{prd} , can usually be found on the PRD datasheet. It can also be calculated using the methods presented in API 520, Part 1 [\[8\]](#).

6.6.3 Estimated Leakage Duration

The leakage duration, D_{mild} , is calculated mild or moderate leakage, as shown in [Table 6.14](#), assuming that mild leakage from larger PRDs will be discovered sooner than leakage from smaller PRDs. The leakage duration for the stuck open case is calculated using [Equation \(5.109\)](#), assuming that an immediate PRD repair is required with an isolation time of 30 minutes.

$$D_{\text{so}} = \frac{30 \text{ min}}{60 \text{ min/hr} \cdot 24 \text{ hr/day}} = 0.021 \text{ days} \quad (5.109)$$

6.6.4 Credit for Recovery of Leaking Fluid

The cost of lost inventory is not considered to be as severe when the unit has a flare recovery system installed or the discharge from the PRD is to a closed system. A recovery factor, F_r , is based on the discharge location of the PRD as follows:

$$F_r = 0.5 \quad \text{if the PRD discharges to flare and a flare recovery system is installed}$$

$$F_r = 0.0 \quad \text{if the PRD discharges to a closed system}$$

$$F_r = 1.0 \quad \text{for all other cases}$$

6.6.5 Lost Inventory Cost

The cost of lost fluid inventory, $Cost_{inv}$, is calculated using Equation (5.110) or Equation (5.111) from mild or stuck open leaks. When calculating the COL, the fluid cost, $Cost_{flu}$, is based on the process fluid at the PRD physical location.

$$Cost_{inv}^{mild} = 24 \cdot F_r \cdot Cost_{flu} \cdot D_{mild} \cdot lrate_{mild} \quad (5.110)$$

$$Cost_{inv}^{so} = 24 \cdot F_r \cdot Cost_{flu} \cdot D_{so} \cdot lrate_{so} \quad (5.111)$$

6.6.6 Environmental Cost

The environmental cost, $Cost_{env}$, is calculated when PRD leakage is released to the atmosphere or a flare system and may require cleanup costs or results in regulatory fines.

6.6.7 Shutdown for Repair PRD Cost

The cost associated with repair and maintenance, $Cost_{sd}$, is calculated if a leaking PRD cannot be tolerated, by using the following costs:

$$Cost_{sd} = \$1000 \quad \text{for PRDs} < \text{NPS 6 inlet size}$$

$$Cost_{sd} = \$2000 \quad \text{for PRDs} \geq \text{NPS 6 inlet size}$$

It is recommended that actual owner–operator work order costs be used that are associated with maintenance, inspection and test, and repair of the PRD.

6.6.8 Lost Production Cost

The cost of lost production, $Cost_{prod}$, to repair a leaking PRD is calculated using Equation (5.112) or Equation (5.113). Production losses are not considered when spare PRDs are installed in parallel or in cases where isolation valves underneath the PRD offer flexibility to repair without shutting down. For the stuck open case, it is assumed that prolonged operation cannot be tolerated and the production cost is calculated using Equation (5.114).

$$Cost_{prod}^{mild} = 0.0 \quad \text{if a leaking PRD can be tolerated or if the PRD can be isolated and repaired without requiring a shutdown} \quad (5.112)$$

$$Cost_{prod}^{mild} = Unit_{prod} \cdot D_{sd} \quad \text{if a leaking PRD cannot be tolerated} \quad (5.113)$$

$$Cost_{prod}^{so} = Unit_{prod} \cdot D_{sd} \quad \text{for a stuck open PRD} \quad (5.114)$$

6.6.9 Calculation of Final Leakage Consequence

The final leakage consequence is calculated for the two leaks cases discussed above.

a) Minor or Moderate Leakage.

The final consequence of the minor or moderate leakage, $Cost_l^{mild}$, is calculated using Equation (5.115).

$$Cost_l^{mild} = Cost_{inv}^{mild} + Cost_{env} + Cost_{sd} + Cost_{prod}^{mild} \quad (5.115)$$

b) Stuck Open Leakage.

The final consequence of the stuck open leak case, $Cost_I^{so}$, is calculated using Equation (5.116).

$$Cost_I^{so} = Cost_{inv}^{so} + Cost_{env} + Cost_{sd} + Cost_{prod}^{so} \quad (5.116)$$

c) Final Leakage Consequence.

The final total leakage weighted consequence is calculated using Equation (5.117).

$$C_I^{prd} = 0.9 \cdot Cost_I^{mild} + 0.1 \cdot Cost_I^{so} \quad (5.117)$$

6.6.10 COL Calculation Procedure

The following procedure may be used to determine the PRD COL.

- a) Step 5.1—Determine the flow capacity of the PRD, W_c^{prd} , from the PRD datasheet or calculated using the methods presented in API 520, Part 1 [8].
- b) Step 5.2—Calculate the minor or moderate leakage rate, $Irate_{mild}$, using Equation (5.107) and the rated capacity of the PRD obtained in Step 6.1.
- c) Step 5.3—Calculate the stuck open leakage rate, $Irate_{so}$, using Equation (5.108) and the rated capacity of the PRD obtained in Step 6.1.
- d) Step 5.4—Determine the leakage duration, D_{mild} , using Table 6.16.
- e) Step 5.5—Determine the stuck open duration, D_{so} , using Equation (5.109).
- f) Step 5.6—Calculate the cost of lost inventory for leakage, $Cost_{inv}^{mild}$, using Equation (5.110), recovery factor, F_r , from Section 5.6.4, and based on the PRD discharge location and discharge location.
- g) Step 5.7—Calculate the cost of lost inventory for stuck open, $Cost_{inv}^{so}$, using Equation (5.111), recovery factor, F_r , from Section 5.6.4, and based on the PRD discharge location.
- h) Step 5.8—Determine the environmental consequence associated with PRD leakage, $Cost_{env}$.
- i) Step 5.9—Determine the consequence associated with repair and maintenance of the PRD, $Cost_{sd}$. Default values based on PRD size are given in Section 6.6.7 or actual owner–operator costs may be used.
- j) Step 5.10—Calculate the cost of lost production for mild leaks, $Cost_{prod}^{mild}$, using Equation (5.112) or Equation (5.113) based on whether or not PRD leakage can be tolerated and the ability to isolate and repair a leaking PRD without a unit shutdown.
- k) Step 5.11—Calculate the costs of lost production for the stuck open case, $Cost_{prod}^{so}$, using Equation (5.114).
- l) Step 5.12—Calculate the final consequence associated with mild leakage, $Cost_I^{mild}$, using Equation (5.115).

- m) Step 5.13—Calculate the final consequence associated with a stuck open PRDs, $Cost_I^{so}$, using Equation (5.116).
- n) Step 5.14—Calculate the total final leakage consequence, $Cost_I^{prd}$, using Equation (5.117).

6.7 Risk Analysis

6.7.1 Failure to Open on Demand Risk

The calculation of risk for a PRD failing to open at a specified service duration, $t_{dur,i}$, is calculated for each applicable overpressure demand case scenario using Equation (5.118).

$$Risk_{f,j}^{prd} = P_{f,j}^{prd} \cdot C_{f,j}^{prd} \quad (5.118)$$

The overall risk for the fail to open case is calculated by the sum of the risks for each overpressure demand case scenario using Equation (5.119).

$$Risk_f^{prd} = \sum_{j=1}^{ndc} P_{f,j}^{prd} \cdot C_{f,j}^{prd} \quad (5.119)$$

where j represents each of the number of overpressure demand case scenarios, ndc .

If the PRD protects multiple components, the risk calculations are repeated for each protected component. The final risk is the maximum risk calculated for each protected component.

6.7.2 Leakage Risk

Risk associated with PRD leakage is calculated using Equation (5.120):

$$Risk_I^{prd} = P_I^{prd} \cdot C_I^{prd} \quad (5.120)$$

6.7.3 Total Risk

The total PRD risk is calculated using Equation (5.121).

$$Risk^{prd} = Risk_f^{prd} + Risk_I^{prd} \quad (5.121)$$

6.7.4 Risk Calculation Procedure

The following summarizes the calculation procedure for the failure to open case.

- Step 6.1—Calculate the failure to open on demand risk associated with each applicable overpressure demand case scenario, $Risk_{f,j}^{prd}$, using Equation (5.118).
- Step 6.2—Calculate the total risk for the failure to open case, $Risk_f^{prd}$, with the sum risk associated with each applicable overpressure demand case scenarios using Equation (5.119).
- Step 6.3—Calculate the risk for the PRD leakage case, $Risk_I^{prd}$ using Equation (5.120).
- Step 6.4—Calculate the total risk using Equation (5.121).

6.8 Inspection Planning Based on Risk Analysis

6.8.1 RBI Intervals

Risk increases as a function of time as both PRD POF and the probability of PRD leakage increases with time. The recommended PRD interval is calculated based on the date at which the PRD risk reaches the risk target ([Part 1](#), [Section 4.4.2](#)).

6.8.2 Effect of PRD Inspection, Testing, and Overhaul on Risk Curve

[Figure 6.7](#) shows the effect of inspection/test and repair of the PRDs and illustrates the effect of setting a risk target. The example presented in [Figure 6.7](#) uses a risk target of \$25,000/yr and resulted in inspection intervals of 5 years. Alternatively, if the risk target were \$10,000/yr, the resulting inspection interval would have been every 3 years.

Since PRDs are normally overhauled or replaced at the time of testing, the risk of failure goes to zero after inspection and test since the PRD is returned to an as-new condition after overhaul.

6.8.3 Effect of PRD Testing Without Overhaul on Risk Curve

A PRD is typically overhauled after inspection and test to return the PRD to the as-new condition. Occasionally a PRD is not overhauled after inspection and test. For example, a pop test performed in the shop in the as-received condition may be returned to service without overhaul. Or, for example, an in-situ pop test may be performed without a shop inspection and test. In the case where an overhaul has not been performed, confidence is increased that the PRD was in working condition is gained, but the PRD was not restored to an as-new condition. The POF and leakage curves are adjusted (characteristic life, η). If the test passed, the test interval will be increased, but the risk does not go to zero as if the PRD was overhauled.

6.9 Nomenclature

A^{prd}	is the orifice area of the PRD, in. ² (mm ²)
$A_{\text{total}}^{\text{prd}}$	is the total installed orifice area of a multiple PRD installation, in. ² (mm ²)
$C_{f,j}^{\text{prd}}$	is the PRD COF to open associated with the j^{th} overpressure demand case, \$
C_l^{mild}	is the consequence of a mild or moderate leak through a PRD, \$
C_l^{prd}	is the PRD COL, \$
C_l^{so}	is the consequence of a stuck open PRD, \$
C_{sd}	is the consequence associated with the repair and maintenance of the PRD, \$
CF	is the confidence factor placed on the inspection effectiveness
CF_{fail}	is the confidence factor that a failed test represents the true condition of the PRD at the time of the test
CF_i	is the confidence factor placed on the inspection effectiveness associated with the i^{th} historical inspection record

CF_{pass}	is the confidence factor that a passed test represents the true condition of the PRD at the time of the test
$Cost_{\text{env}}$	is the environmental costs due to a PRD leak, \$
$Cost_{\text{flu}}$	is the cost of the lost fluid, \$/lb (\$/kg)
$Cost_{\text{inv}}$	is the lost inventory or fluid costs due to a PRD leak, \$
$Cost_{\text{inv}}^{\text{mild}}$	is the cost of lost inventory due to a minor or moderate PRD leak, \$
$Cost_{\text{inv}}^{\text{so}}$	is the cost of lost inventory due to a stuck open PRD, \$
$Cost_{\text{prod}}$	is the production losses as a result of shutting down to repair a PRD, \$
$Cost_{\text{prod}}^{\text{mild}}$	is the production losses as a result of shutting down to repair a mild or moderate leaking PRD, \$
$Cost_{\text{prod}}^{\text{so}}$	is the production losses as a result of shutting down to repair a stuck open PRD, \$
$Cost_{\text{sd}}$	is the maintenance and repair costs associated with a PRD, \$
D_{f}	is the DF as a function of time for equipment components protected by the PRD
D_{mild}	is the duration that a minor or moderate PRD leak will go undiscovered, days
D_{sd}	is the number of days required to shut a unit down to repair a leaking or stuck open PRD, days
D_{so}	is the duration of a stuck open PRD, days
DR_j	is the demand rate associated with the j^{th} overpressure demand case, demands/yr
DR_{total}	is the total demand rate on a PRD, demands/yr
$DRRF_j$	is the demand rate reduction factor associated with the j^{th} overpressure demand case
EF_j	is the initiating event frequency associated with the j^{th} overpressure demand case, demands/yr
F_{a}	is the multiple PRD installation adjustment factor
F_{c}	is the adjustment factor for conventional PRVs
F_{env}	is the adjustment factor for environmental factors
F_{MS}	is the management systems factor

F_{op}	is the adjustment factor for overpressure
$F_{op,j}$	is the adjustment factor for the overpressure for the j^{th} overpressure demand case
F_r	is the recovery factor applied to lost inventory
F_s	is the adjustment factor for the presence of soft seats
F_{set}	is the adjustment factor for the ratio of operating pressure to set pressure
$F(t)$	is the cumulative failure density function or unreliability
gff_n	is the GFF for the protected equipment associated with the n^{th} hole size, failures/yr
gff_{total}	is the total GFF for the protected equipment, years
$lrate_{mild}$	is the leakage rate of a mild or moderate leaking PRD, lb/hr (kg/hr)
$lrate_{so}$	is the leakage rate for a stuck open PRD, lb/hr (kg/hr)
$MAWP$	is the maximum allowable working pressure of the protected equipment, psig (kPa)
$MTTF$	is the mean time to failure
ndc	is the number of demand cases
$P_{f,j}$	is the POF (loss of containment) of the protected equipment associated with the j^{th} overpressure demand case, failures/yr
$P_f(t)$	is the POF (loss of containment) of the protected equipment, failures/yr
$p_{f,cond}^{prd}$	is the conditional POFOD, failures/demand
$p_{p,cond}^{prd}$	
$P_{f,j}^n$	is the POF (loss of containment) of the protected equipment for the n^{th} hole size associated with the j^{th} overpressure demand case, failures/yr
$p_{f,j}^{prd}$	is the POF of a PRD associated with the j^{th} overpressure demand case, failures/yr
$p_{f,prior}^{prd}$	is the prior POFOD, failures/demand
$p_{f,wgt}^{prd}$	is the weighted POFOD, failures/demand
P_{fod}	is the PRD POFOD, failures/demand
$P_{fod,j}$	is the PRD POFOD associated with the j^{th} overpressure demand case, failures/demand
P_l^{prd}	is the PRD POF, failures/yr

P_o	is the overpressure likely to occur as a result of a PRD failing to open upon demand, psig (kPa)
$P_{o,j}$	is the overpressure likely to occur as a result of a PRD failing to open upon demand, associated with the j^{th} overpressure demand case, psig (kPa)
$P_{p,\text{cond}}^{\text{prd}}$	is the conditional probability of a no-leak or passing test result, failures/year
$P_{p,\text{prior}}^{\text{prd}}$	is the prior probability of passing on demand, failures/demand
P_s	is the storage or operating pressure of the protected equipment, psig (kPa)
P_{set}	is the set pressure of the PRD, psig (kPa)
$Risk_f^{\text{prd}}$	is the total risk for a PRD, \$/yr
$Risk_f^{\text{prd}}$	is the risk of a PRD failure to open, \$/yr
$Risk_{f,j}^{\text{prd}}$	is the risk of a PRD failure to open associated with the j^{th} overpressure demand case, \$/yr
$Risk_l^{\text{prd}}$	is the risk of PRD leakage, \$/yr
$R(t)$	is the risk as a function of time, ft ² /yr (m ² /yr) or \$/yr
t	is time, years
$t_{\text{dur},i}$	is the actual duration between inspections associated with the i^{th} historical inspection record, years
t_{insp}	is the service duration, years
$Unit_{\text{prod}}$	is the daily production margin on the unit, \$/day
W_c^{prd}	is the rated capacity of a PRD, lb/hr (kg/hr)
β	is the Weibull shape parameter
η	is the Weibull characteristic life parameter, years
η_{def}	is the Weibull characteristic life parameter based on the default service severity chosen for a specific PRD, years
η_{mod}	is the Weibull characteristic life parameter modified to account for installation factors, design features, overpressure, and environmental factors, years
η_{upd}	is the Weibull characteristic life parameter updated to account for inspection history, years

6.10 Tables

Table 6.1—Basic Data Needed for the PRD Module

Data	Description	Data Source
PRD type	Type of PRD — Conventional spring-loaded PRV (default) — Balanced bellows PRV — Pilot-operated PRV — PRV with rupture disk — Rupture disk only	User specified
Fluid composition	Process fluid mixture components, either mass or mole fraction. Limit of 10 components in mixture definition.	Fixed equipment
Service severity	Severity of process fluid. Choices are Mild, Moderate, and Severe. The service severity provides the basis for the selection of the default POFOD and POL curves. Fail to Open — Mild — Moderate (default) — Severe Leakage — Mild — Moderate (default) — Severe	User specified
Overpressure scenarios	Provide a listing of the applicable overpressure scenarios for each PRD. For each overpressure scenario, default values for the initiating event frequency and the PRD demand rate reduction factor (DRRF) are provided in Table 5.2 . These two parameters when multiplied together provide an estimate of the demand rate on the PRD installation.	User specified
PRD discharge location	— Atmosphere — Flare (default) — Closed process	User specified
PRD inspection history	— Date of testing — Install date — Type of test (effectiveness) — Results of test/inspection — Overhauled? Yes/No (see Section 5.1.6) — Inlet and outlet piping condition [see Section 5.2.4 i) 1]	User specified
Protected equipment details	Operating conditions, design conditions, dimensions, damage mechanisms, GFF, and DFs	Fixed equipment
Fluid inventory	Fluid inventory associated with the protected equipment (lbm). May be less than the RBI calculated inventory due to shut-in conditions, e.g. reactor discharge valve fails closed.	Fixed equipment
Injury costs	Cost of serious injury, \$	Fixed equipment
Environmental costs	Environmental fines and costs associated with PRD leakage or loss of equipment containment, \$/event.	Fixed equipment
Production costs	Cost of lost production, \$	Fixed equipment
Unit costs	Cost to replace unit, \$/ft ²	Fixed equipment

Table 6.2—Overpressure Scenario Logic

Initiating Event Frequency	Equipment Type	PRD DRRF	Qualifier	Overpressure Potential	Background and Comments
Overpressure Scenario—Fire					
1 per 250 years See Lees [12] , Table A7.4, states major fire at plant 1 every 10 years	All equipment types	0.1 Industry experience justifies this value	N/A	Calculated burst pressure or estimated as design margin $\times$ MAWP	— Modified by industry data that indicate demand rates on the order of 1 per 400 years — The DRRF factor of 0.1 recognizes the industry experience that relatively few vessels exposed to a fire will experience a PRD opening — Assumption is made that in those rare cases where a PRD would open during a fire, rupture will occur if the PRD failed to open upon demand
Overpressure Scenario—Loss of Cooling					
1 per 10 years	Process tower with fired heater heat source	1.0 Consider LOPA or risk reduction analysis associated with loss of flow controls on the fired heater	Heat source to tower is a fired heater	Calculated burst pressure or estimated as design margin $\times$ MAWP	Assumption is made that rupture occurs
	All other equipment with internal or external heat sources	1.0		Bubble point pressure of the feed stream at heat source temperature	
Overpressure Scenario—Electrical Power Failure					
0.08 per year (1 per 12.5 years) power supply failure per Table 9.7 on page 316 of Lees [12]	Process tower with fired heater heat source	1.0 Consider LOPA or risk reduction analysis associated with loss of flow controls on the fired heater	Heat source to tower is a fired heater	Calculated burst pressure or estimated as design margin $\times$ MAWP	Assumption is made that rupture occurs
	Process tower and other equipment with internal or external (non-fired) heat sources	1.0		Bubble point pressure of the feed stream at heat source temperature	

Initiating Event Frequency	Equipment Type	PRD DRRF	Qualifier	Overpressure Potential	Background and Comments
Overpressure Scenario—Blocked Discharge (Manual Valve)					
1 per 100 years (admin controls) 1 per 10 years (w/o admin controls) Multiply event frequency times the # of applicable block valves located in process flow path Lees ^[13] suggests an estimated rate of 0.5 to 0.1 events per year for shutting manual valve in error	Exchangers, fin fans, reactors, piping, drums, or rotating equipment	1.0	Downstream of rotating equipment other than positive displacement type	Deadhead pressure or 1.3 times the normal discharge pressure or bubble point pressure of the feed stream at heat source temperature (for cases where the equipment has internal or external heat sources), whichever is greatest	Most centrifugal rotating equipment will deadhead at 30 % above the normal operating point. Initiating event frequency should be adjusted if the protected equipment is removed from service for maintenance or operational needs (filter replacement or cyclic process operation) at a frequency greater than the unit turnaround frequency. Equipment with internal or external heat sources may have a significant potential for overpressure as a result of vaporization of the contained fluid stream.
		1.0	Downstream of positive displacement type rotating equipment	Calculated burst pressure or estimated as design margin × MAWP	Discharge pressure from positive displacement pumps will continue to increase pressure. Assumption is made that rupture will occur.
		1.0	Downstream of steam turbines	Steam supply pressure or bubble point pressure of the feed stream at steam supply temperature (for cases where the equipment has internal or external heat sources), whichever is greatest	
		1.0	Downstream of process units or vessels	1.1 × MAWP of upstream vessel source pressure	
	Process tower with fired heater heat source	1.0 Consider LOPA or risk reduction analysis associated with loss of flow controls on the fired heater	Heat source to tower is a fired heater	Calculated burst pressure or estimated as design margin × MAWP	Assumption is made that rupture occurs. This applies to the blocked vapor outlet line only; see liquid overfilling case for blocked liquid/bottoms outlet.
	Process tower, all other heat sources	1.0	No upstream fired heater	Bubble point pressure of the feed stream at heat source temperature	This applies to the blocked vapor outlet line only; see liquid overfilling case for blocked liquid/bottoms outlet
	Heaters	1.0		Calculated burst pressure or estimated as design margin × MAWP	Added increase in potential overpressure with fired/radiant heat transfer. Assumption is made that rupture occurs.

Initiating Event Frequency	Equipment Type	PRD DRRF	Qualifier	Overpressure Potential	Background and Comments
Overpressure Scenario—Control Valve Fail Close at Outlet					
1 per 10 years ^[14] for fail-closed control valves 1 per 50 years for fail-open control valves Multiply event frequency times the # of applicable control valves located in process flow path	Exchangers, fin fans, reactors, piping or drums, or rotating equipment	1.0	Downstream of rotating equipment other than positive displacement type	Deadhead pressure or 1.3 times the normal discharge pressure or bubble point pressure of the feed stream at heat source temperature (for cases where the equipment has internal or external heat sources), whichever is greatest	Most centrifugal rotating equipment will deadhead at 30 % above the normal operating point. Initiating event frequency should be adjusted if the protected equipment is removed from service for maintenance or operational needs (filter replacement or cyclic process operation) at a frequency greater than the unit turnaround frequency. Equipment with internal or external heat sources may have a significant potential for overpressure as a result of vaporization of the contained fluid stream.
		1.0	Downstream of positive displacement type rotating equipment	Calculated burst pressure or estimated as design margin × MAWP	Discharge pressure from positive displacement pumps will continue to increase pressure. Assumption is made that rupture will occur.
		1.0	Downstream of steam turbines	Steam supply pressure or bubble point pressure of the feed stream at steam supply temperature (for cases where the equipment has internal or external heat sources), whichever is greatest	
	Process tower with fired heater heat source	1.0	Downstream of process units or vessels	1.1 × MAWP of upstream vessel source pressure	
		1.0	Heat source to tower is a fired heater	Calculated burst pressure or estimated as design margin × MAWP	Assumption is made that rupture occurs. This applies to the blocked vapor outlet line only; see liquid overfilling case for blocked liquid/bottoms outlet.
	Process tower, all other heat sources	1.0		Bubble point pressure of the feed stream at heat source temperature	This applies to the blocked vapor outlet line only; see liquid overfilling case for blocked liquid/bottoms outlet
	Heaters	1.0		Calculated burst pressure or estimated as design margin × MAWP	Added increase in potential overpressure with fired/radiant heat transfer. Assumption is made that rupture occurs.

Initiating Event Frequency	Equipment Type	PRD DRRF	Qualifier	Overpressure Potential	Background and Comments
Overpressure Scenario—Control Valve Fail Open at Inlet, Including the HP/LP Gas Breakthrough Case					
1 per 10 years ^[14] for fail-closed control valves 1 per 50 years for fail-open control valves Multiply event frequency times the # of applicable control valves located in process flow path	All equipment types	1.0	N/A	Use the upstream source pressure	Overpressure potential is a function of the pressure ratio across the control valve
Overpressure Scenario—Runaway Chemical Reaction					
1 per year	All equipment	1.0		Calculated burst pressure or estimated as design margin × MAWP	This overpressure scenario should be based on a thorough review of the wide variety of potential initiating events and mitigation measures associated with the reactor system installation. The DRRF and the potential overpressure associated with failure of PRD to open upon demand should be chosen based on a risk assessment. Per shell study, 50 % of all vessel ruptures are attributed to reactive overpressure case.
Overpressure Scenario—Tube Rupture					
1 per 1000 years (9×10^{-4} per exchanger per ^[15])	Exchangers—HP gas in tubes, LP liquid in shell	1.0		Normal maximum operating pressure of the high-pressure side of the exchanger	Likelihood of shell rupture is increased when high-pressure tubeside gas enters low-pressure shellside liquid

Initiating Event Frequency	Equipment Type	PRD DRRF	Qualifier	Overpressure Potential	Background and Comments
Overpressure Scenario—Tower P/A or Reflux Pump Failure					
1 per 5 years	Process tower with fired heater heat source	1.0 Consider LOPA or risk reduction analysis associated with loss of flow controls on the fired heater	Heat source to tower is a fired heater	4.0 × MAWP (rupture)	Assumption is made that rupture occurs
	All other process towers	1.0		Bubble point pressure of the feed stream at heat source temperature	
Overpressure Scenario—Thermal/Hydraulic Expansion Relief					
1 per 100 years (manual valve w/admin controls) 1 per 10 years (manual valve w/o admin controls or control valve) Multiply initiating event frequency times the number of applicable block valves located in process flow path	Piping or other liquid filled equipment	1.0	N/A	Operating pressure or bubble point pressure of contained fluid at 140 °F, whichever is larger	Assumption is made that the probability of a leak is 1.0 (flange leaks), modeled as a 1/4 in. hole. The probability of rupture is assumed to be 0.0. For fluids that will not boil, since the pressure is relieved immediately upon leakage, the pressure for the consequence calculation will be the normal operating pressure of the piping. Not likely to result in rupture, likely to cause flange leaks/small leaks, heated only. If the fluid can boil due to solar energy, the consequence pressure could be maintained at the bubble point pressure of the contained fluid. Leak and rupture probabilities will be calculated as a function of the bubble point pressure.
	Cold side of heat exchangers	1.0	N/A	Operating pressure or bubble point pressure of contained fluid at the hot side fluid inlet temperature, whichever is larger	Added increase in potential overpressure with additional heat transfer from hot side. For liquids that do not boil, the assumption is made that the POF is 1.0 (flange leaks), modeled as a 1/4 in. hole, and the probability of rupture is 0.0. If the cold side fluid can boil, the consequence pressure could reach the bubble point pressure of the stored fluid at the hot side fluid inlet temperature. Leak and rupture probabilities will be calculated as a function of the bubble point pressure.

Initiating Event Frequency	Equipment Type	PRD DRRF	Qualifier	Overpressure Potential	Background and Comments
Overpressure Scenario—Liquid Overfilling					
1 per 100 years (admin controls) 1 per 10 years (w/o admin controls) Multiply event frequency times the number of applicable block valves located in process flow path	All equipment including process tower (blocked outlet of liquid bottoms)	1.0	Downstream of rotating equipment other than positive displacement type	Deadhead pressure or 1.3 times the normal discharge pressure or bubble point pressure of the feed stream at heat source temperature (for cases where the equipment has internal or external heat sources), whichever is greatest	Most centrifugal rotating equipment will deadhead at 30 % above the normal operating point. Initiating event frequency should be adjusted if the protected equipment is removed from service for maintenance or operational needs (filter replacement or cyclic process operation) at a frequency greater than the unit turnaround frequency. Equipment with internal or external heat sources may have a significant potential for overpressure as a result of vaporization of the contained fluid stream.
		1.0	Downstream of positive displacement type rotating equipment	Calculated burst pressure or estimated as design margin $\times$ MAWP	Discharge pressure from positive displacement pumps will continue to increase pressure. Assumption is made that rupture will occur.
		1.0	Downstream of steam turbines	Steam supply pressure or bubble point pressure of the feed stream at steam supply temperature (for cases where the equipment has internal or external heat sources), whichever is greatest	
		1.0	Downstream of process units or vessels	$1.1 \times$ MAWP of upstream pressure source vessel	

Table 6.3—Default Initiating Event Frequencies

Overpressure Demand Case	Event Frequency	EF_j (events/yr)	$DRRF_j$ (see Notes 2 and 3)	Reference
1. Fire	1 per 250 years	0.0040	0.10	[12]
2. Loss of cooling water utility	1 per 10 years	0.10	1.0	[12]
3. Electrical power supply failure	1 per 12.5 years	0.080	1.0	[12]
4a. Blocked discharge with administrative controls in place (see Note 1)	1 per 100 years	0.010	1.0	
4b. Blocked discharge without administrative controls (see Note 1)	1 per 10 years	0.10	1.0	
5. Control valve failure, initiating event is same direction as control valve normal fail position (i.e. fail safe)	1 per 10 years	0.10	1.0	[14]
6. Control valve failure, initiating event is opposite direction as control valve normal fail position (i.e. fail opposite)	1 per 50 years	0.020	1.0	[14]
7. Runaway chemical reaction	1 per year	1.0	1.0	
8. Heat exchanger tube rupture	1 per 1000 years	0.0010	1.0	[15]
9. Tower P/A or reflux pump failures	1 per 5 years	0.2	1.0	
10a. Thermal relief with administrative controls in place (see Note 1)	1 per 100 years	0.010	1.0	Assumed same as blocked discharge
10b. Thermal relief without administrative controls (see Note 1)	1 per 10 years	0.10	1.0	Assumed same as blocked discharge
11a. Liquid overfilling with administrative controls in place (see Note 1)	1 per 100 years	0.010	1.0	[12]
11b. Liquid overfilling without administrative controls (see Note 1)	1 per 10 years	0.10	1.0	[12]

NOTE 1 Administrative controls for isolation valves are procedures intended to ensure that personnel actions do not compromise the overpressure protection of the equipment.

NOTE 2 The DRRF recognizes the fact that demand rate on the PRD is often less than the initiating event frequency. As an example, PRDs rarely lift during a fire since the time to overpressure may be quite long and firefighting efforts are usually taken to minimize overpressure.

NOTE 3 The DRRF can also be used to take credit for other layers of overpressure protection such as control and trip systems that reduce the likelihood of reaching PRD set pressure.

NOTE 4 Where the Item Number has a subpart (such as “a” or “b”), this clarifies that the overpressure demand case will be on same subpart of Table 5.3.

Table 6.4—Categories of PRD Service Severity (Fail Case Only)

PRD Service Severity	Characteristic MTTF	Characteristic of Failure	Expected Stream Characterization	Typical Temperature	Examples of Service
Mild	Failure is characterized by a long (25 years) MTTF	Failure is strongly characterized as a “wear out” type of failure, in which the failure occurs due to an accumulation of damage over a long period of time	— Clean hydrocarbon products at moderate temperature — No aqueous phase present — Low in sulfur and chlorides	Low temperature, always << 500 °F	Examples include: product hydrocarbon streams (including lubricating oils), liquefied petroleum gas (LPG), BFW, low-pressure steam, and clean gases such as nitrogen and air
Moderate	Failure occurs at an average (15 years) MTTF	Failure is weakly characterized as a “wear out” type of failure, in which the failure occurs due to an accumulation of damage over a long period of time	— Hydrocarbons that may contain some particulate matter — A separate aqueous phase may be present but is a minor component — Clean, filtered, and treated water may be included in this category — Some sulfur or chlorides may be present	Up to 500 °F (may exist)	Examples include: intermediate hydrocarbon streams, in-service lube and seal oils, process water (NOT cooling water or BWF), and medium- to high-pressure steam
Severe	Failure is characterized as a relatively short (7 years) MTTF	Failure is characterized as a “random” type of failure, in which the failure can occur due to a variety of mechanisms (such as corrosion or plugging)	— High-temperature hydrocarbon streams with significant tendency to foul — Sulfur and chloride concentrations may be high — Monomers processed at any temperature that can polymerize are in this group as well — Sometimes included are aqueous solutions of process water, including cooling water	> 500 °F	Examples include: heavy hydrocarbon streams such as crude, amine services, cooling water, corrosive liquids and vapors, and streams containing H ₂ S

NOTE 1 MTTF does not reflect replacement history, where the history indicates a renewal of the asset without a failure noted.

NOTE 2 Refer to [Table 5.13](#) for the categories for the LEAK case.

Table 6.5—Default Weibull Parameters for POFOD

Fluid Severity	Conventional and Balanced Bellows PRVs ¹		Pilot-operated PRVs ²		Rupture Disks ³	
	β	η_{def}	β	η_{def}	β	η_{def}
Mild	1.8	50.5	1.8	33.7	1.8	50.5
Moderate	1.8	23.9	1.8	8.0	1.8	50.5
Severe	1.8	17.6	1.8	3.5	1.8	50.5

NOTE 1 The η_{def} parameter values for conventional PRVs are reduced by 25 % if the discharge is to a closed system or to flare; see [Section 5.2.4 g](#).

NOTE 2 The η_{def} parameter values for pilot-operated PRVs are currently based on the conventional PRV data; however, reduced by a factor of 1.5, 3, and 5 for Mild, Moderate, and Severe services, respectively; see [Section 5.2.4 e](#).

NOTE 3 Without any failure rate data for rupture disks, the conventional PRV values for Mild services were used. This assumes that the rupture disk material has been selected appropriately for the fluid service; see [Section 5.2.4 f](#).

Table 6.6—Environmental Adjustment Factors to Weibull η Parameter

Environment Modifier	Adjustment to POFOD η Parameter	Adjustment to POL η Parameter
Operating temperature 200 °F < T < 500 °F	1.0	0.8
Operating temperature > 500 °F	1.0	0.6
Operating ratio > 90 % for spring-loaded PRVs or > 95 % for pilot-operated PRVs	1.0	0.5 ¹
Installed piping vibration	1.0	0.8
Pulsating or cyclical service, such as downstream of positive displacement rotating equipment	1.0	0.8
History of excessive actuation in service (greater than 5 times per year)	0.5	0.5 ²
History of chatter	0.5	0.5

NOTE 1 Some pilot-operated PRVs operate extremely well with operating ratios approaching 98 %. In these cases, the environmental factor should not be applied (reference API 520, Part 1).

NOTE 2 This factor should not be applied if the environmental factor for operating ratio is already applied.

Table 6.7—Level of Inspection Confidence Factors

Inspection Result	Confidence Factor That Inspection Result Determines the True Damage State, CF			
	Ineffective	Fairly Effective	Usually Effective	Highly Effective
Pass, CF_{pass}	0.4	0.5	0.70	0.9
Fail, CF_{fail}	0.4	0.70	0.95	0.95
No Leak, CF_{noleak}	0.4	0.5	0.70	0.9
Leak, CF_{leak}	0.4	0.70	0.95	0.95

Table 6.8—Set Pressure Factor

PRV Type	Set Pressure Factor
Pilot-operated PRVs	$F_{\text{set}} = 1 - \frac{\left[0.95 - \min \left[0.95, \frac{P_s}{P_{\text{set}}} \right] \right]}{0.95}$
Rupture disks	$F_{\text{set}} = 1$
Conventional PRVs and balanced bellows PRVs	$F_{\text{set}} = 1 - \frac{\left[0.90 - \min \left[0.90, \frac{P_s}{P_{\text{set}}} \right] \right]}{0.90}$
NOTE P_s denotes the operating pressure, and P_{set} denotes the set pressure.	

Table 6.9—Inspection Updating Equations

Inspection Effectiveness and Result	Equation for Weighted POFOD
Highly Effective Pass	$P_{f,\text{wgt}}^{\text{prd}} = P_{f,\text{prior}}^{\text{prd}} - 0.2 \cdot P_{f,\text{prior}}^{\text{prd}} \left(\frac{t}{\eta} \right) + 0.2 \cdot P_{f,\text{cond}}^{\text{prd}} \left(\frac{t}{\eta} \right)$
Usually Effective Pass	
Fairly Effective Pass	
Highly Effective Fail	$P_{f,\text{wgt}}^{\text{prd}} = P_{f,\text{cond}}^{\text{prd}}$
Usually Effective Fail	$P_{f,\text{wgt}}^{\text{prd}} = 0.5 \cdot P_{f,\text{prior}}^{\text{prd}} + 0.5 \cdot P_{f,\text{cond}}^{\text{prd}}$
Fairly Effective Fail	
Ineffective/No Inspection	$P_{l,\text{cond}}^{\text{prd}} = CF_l \cdot P_{l,\text{prior}}^{\text{prd}} + (1 - CF_{nl}) \cdot P_{nl,\text{prior}}^{\text{prd}}$

Table 6.10—Design Margins for Various Codes of Construction

Construction Code	Design Margin
ASME Section VIII, Division 1, pre-1950	5.0
ASME Section VIII, Division 1, 1950–1998	4.0
ASME Section VIII, Division 1, 1999 and later	3.5
ASME Section VIII, Division 2, pre-2007	3.0
ASME Section VIII, Division 2, 2007 and later	2.4
ASME B31.3	3.0
AS 1210	3.5
NOTE For any construction code not listed in this table or when design by analysis was utilized to design the equipment, it is the responsibility of the owner–operator to determine the design margin.	

Table 6.11—Constants for Design Margin

Design Margin	Constant <i>a</i>	Constant <i>b</i>
5	2.28E-06	2.598628
4	9.57E-07	3.464837
3.5	4.79E-07	4.157804
3	1.69E-07	5.197255
2.4	1.82E-08	7.42465
NOTE 1 Constants <i>a</i> and <i>b</i> are used in Equation (5.99) .		
NOTE 2 A <i>g_{ff}</i> of 3.06E-05 is used to calculate constant <i>a</i> .		

Table 6.12—DF Classes for Protected Equipment

DF Class	DF	Description
None	1	New vessel or inspection shows little if any damage.
Minimal	20	Equipment has been in service for a reasonable amount of time and inspection shows evidence of minor damage. Damage mechanisms have been identified and inspection data are available.
Minor	200	One or more damage mechanisms have been identified, limited inspection data available, and fairly minor evidence of damage. Single damage mechanism identified, recent inspection indicates minor evidence of damage.
Moderate	750	Moderate damage found during recent inspection. Low susceptibility to one or more damage mechanisms, and limited inspection exists.
Severe	2000	One or more active damage mechanisms present without any recent inspection history. Limited inspection indicating high damage susceptibility.

Table 6.13—Categories of PRD Service Severity (LEAK Case Only)

PRD Service Severity	Typical Temperature	Expected Stream Characterization	Examples of Service
Mild	Low temperature, always << 500 °F	Many heavy liquid streams such as crude oil tend not to leak through a PRD and are considered mild service severity	— Cooling water and amine services are examples of corrosive/fouling fluids that do not leak — Clean fluids such as LPG, air, and nitrogen are Mild leakage services
Moderate	Up to 500 °F (may exist)	Most of the intermediate and product hydrocarbon streams and most hydrocarbon vapors	— Lube, seal and cycle oils, and process water (NOT cooling water, condensate, or BFW)
Severe	> 500 °F	High-temperature services	BFW/condensate, steam, and corrosive liquids such as caustic and acids

NOTE Refer to [Table 5.4](#) for the categories for the FAIL case.

Table 6.14—Default Weibull Parameters for POL

Fluid Severity	Conventional PRVs ¹		Balanced Bellows PRVs ¹		Pilot-operated PRVs ²		Rupture Disks ³	
	β	η_{def}	β	η_{def}	β	η_{def}	β	η_{def}
Mild	1.6	17.5	1.6	16.0	1.6	17.5	1.6	17.5
Moderate	1.6	15.5	1.6	14.0	1.6	15.5	1.6	17.5
Severe	1.6	13.1	1.6	11.5	1.6	13.1	1.6	17.5

NOTE 1 The η_{def} parameter values are increased by 25 % for conventional and balanced PRVs that have soft seats.

NOTE 2 The η_{def} parameter values for pilot-operated PRVs are currently based on the conventional PRV data, since there are currently no failure rate data to support otherwise.

NOTE 3 Without any failure rate data for rupture disks, the conventional PRV values for Mild service were used.

Table 6.15—Potential Consequences of Pressure Vessel Overpressure

Accumulation (% over MAWP)	Significance [11]	Potential Consequence
10 %	ASME Code allowable accumulation for process upset cases (non-fire) protected by a single PRD	No expected consequence at this accumulation level
16 %	ASME Code allowable accumulation for process upset cases protected by multiple PRDs	No expected consequence at this accumulation level
21 %	ASME Code allowable accumulation for external fire relief cases regardless of the number of PRDs	No expected consequence at this accumulation level
50 %	ASME standard hydrostatic test pressure (may be 30 % on new designs)	Possible leaks in associated instrumentation, etc. Medium consequence.
90 %	Minimum yield strength (dependent on materials of construction)	Catastrophic vessel rupture, remote possibility. Significant leaks probable. Failure of damaged vessel areas (corrosion, cracks, blisters, etc.) likely. High consequence.
300 %	Ultimate tensile strength (dependent on materials of construction)	Catastrophic vessel rupture predicted. Highest consequence.

Table 6.16—Estimated Leakage Duration from PRDs

PRD Inlet Size (in.)	Leak Duration Discharge to Flare or Closed System, D_{mild} (days)	Leak Duration Discharge to Atmosphere, D_{mild} (days)
$\leq 3/4$ in.	60	8
$3/4 < \text{inlet size} \leq 1 1/2$	30	4
$1 1/2 < \text{inlet size} \leq 3$	15	2
$3 < \text{inlet size} \leq 6$	7	1
Greater than 6	2	0.33

Table 6.17—Estimated Leakage Rate from PRVs

Bench Test Leak Description	Leak Categorization	Percent of PRVs Leaking on Bench	Percent of All Leaks	Assumed Leakage (Percent of Capacity)
Leaked between 70 % and 90 % of set pressure, PRV opened at set pressure	Minor	8.4	50	1
Leakage below 70 % of set pressure, PRV opened at set pressure	Moderate	6.6	40	10
Immediate leakage or PRV leaked too much to open	Severe	2.4	10	25

6.11 Figures

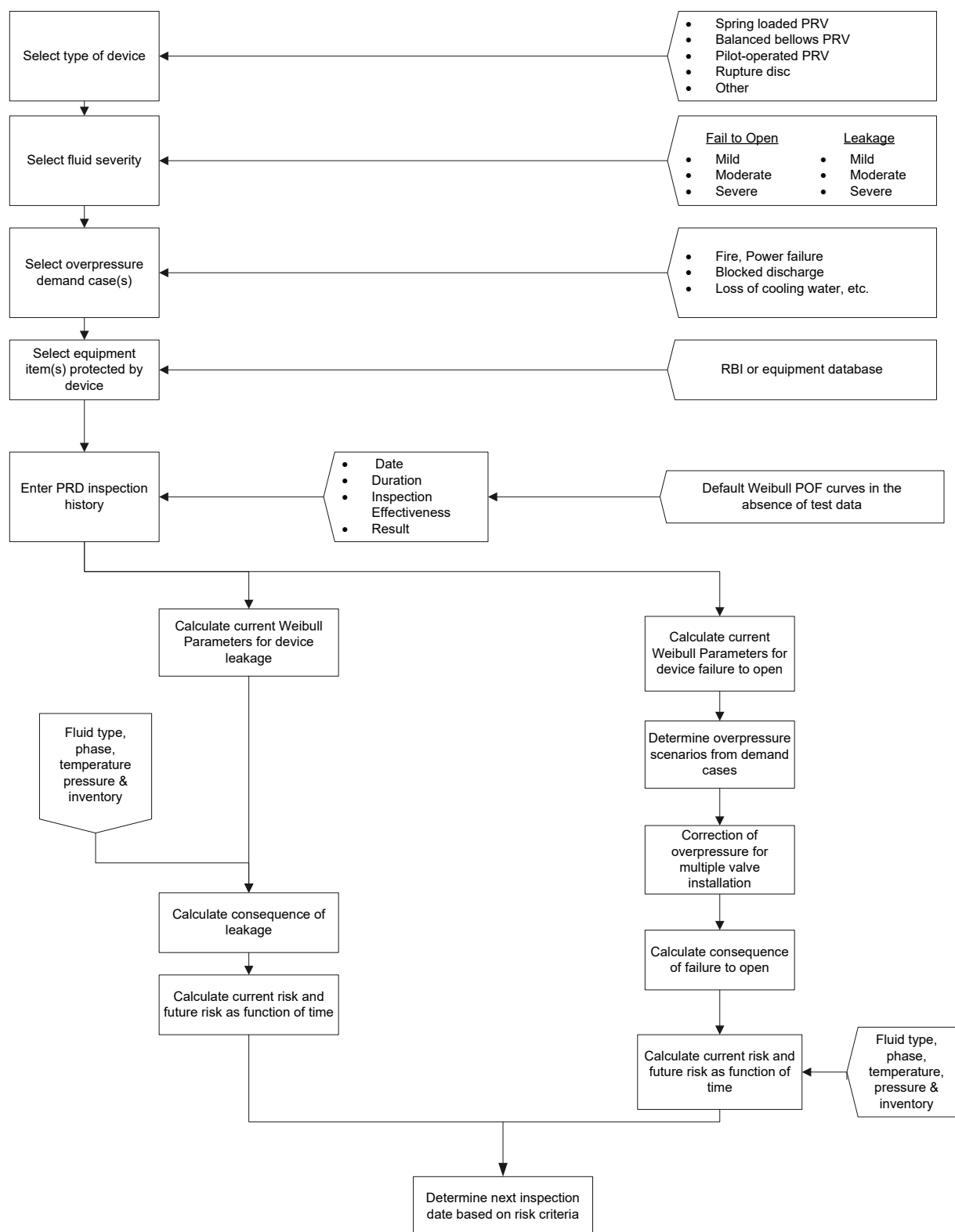


Figure 6.1—PRD RBI Methodology

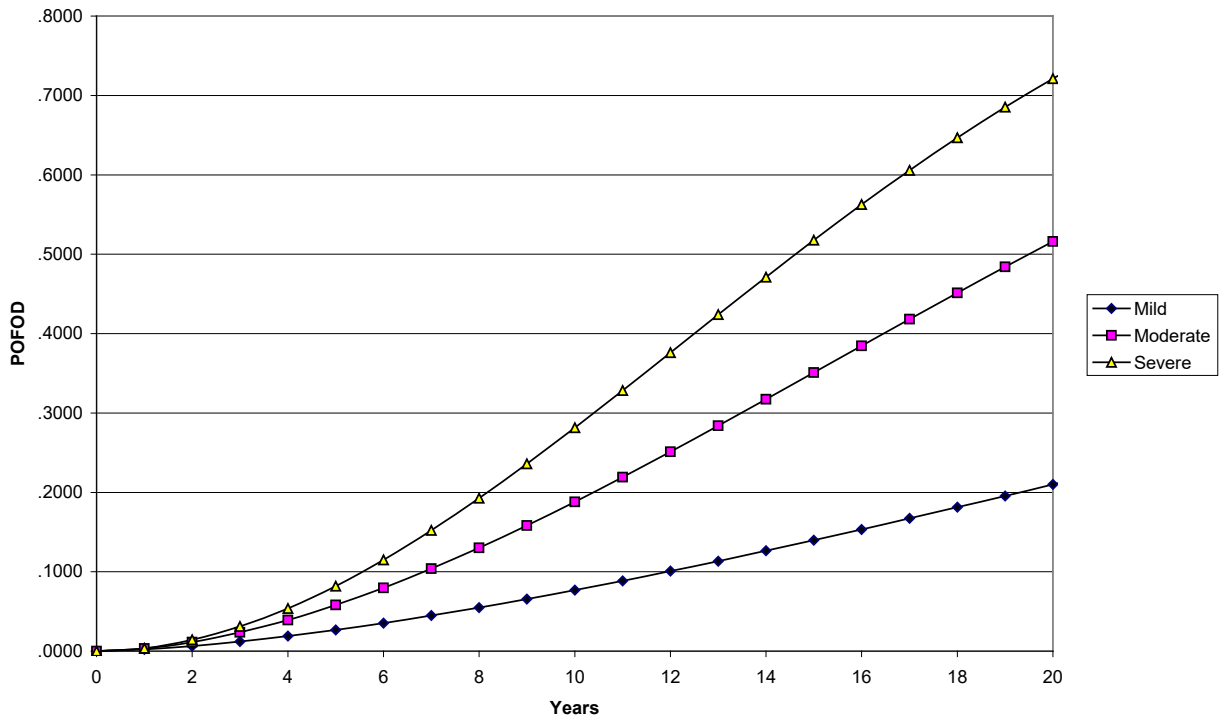


Figure 6.2—Default Conventional PRV Fail to Open on Demand Weibull Curves

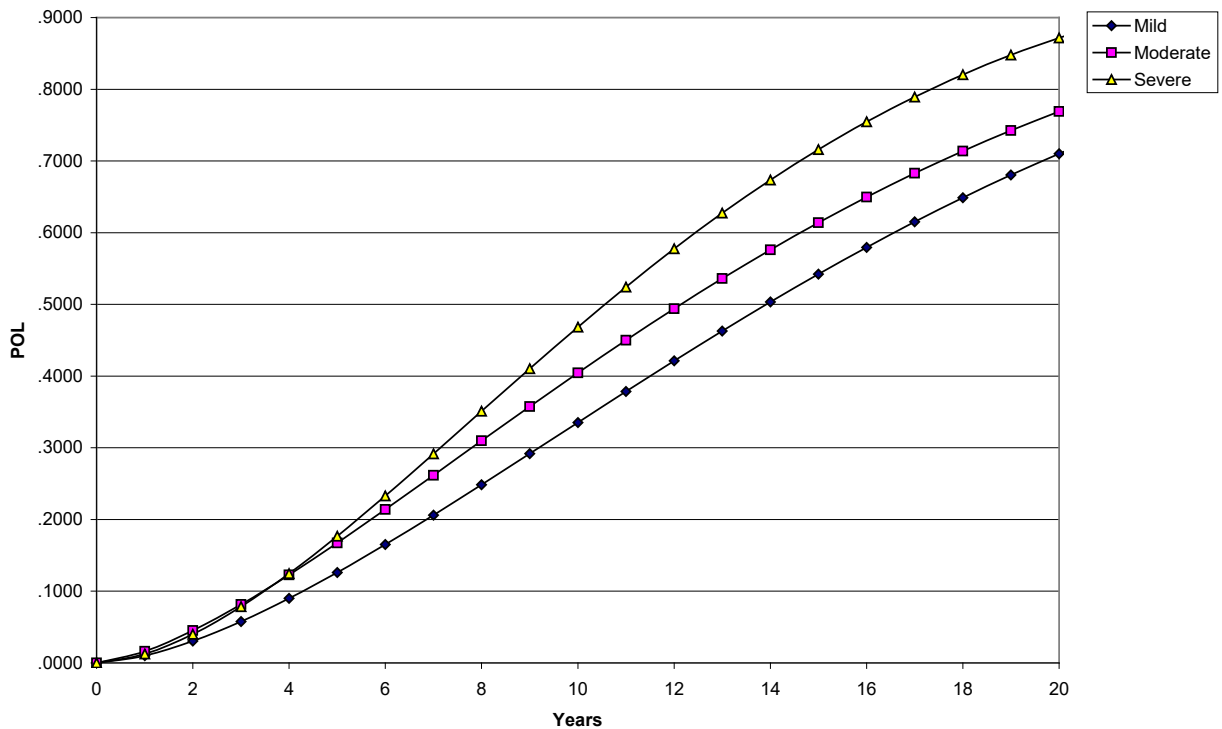


Figure 6.3—Default Leakage Failure Rate for Conventional PRVs

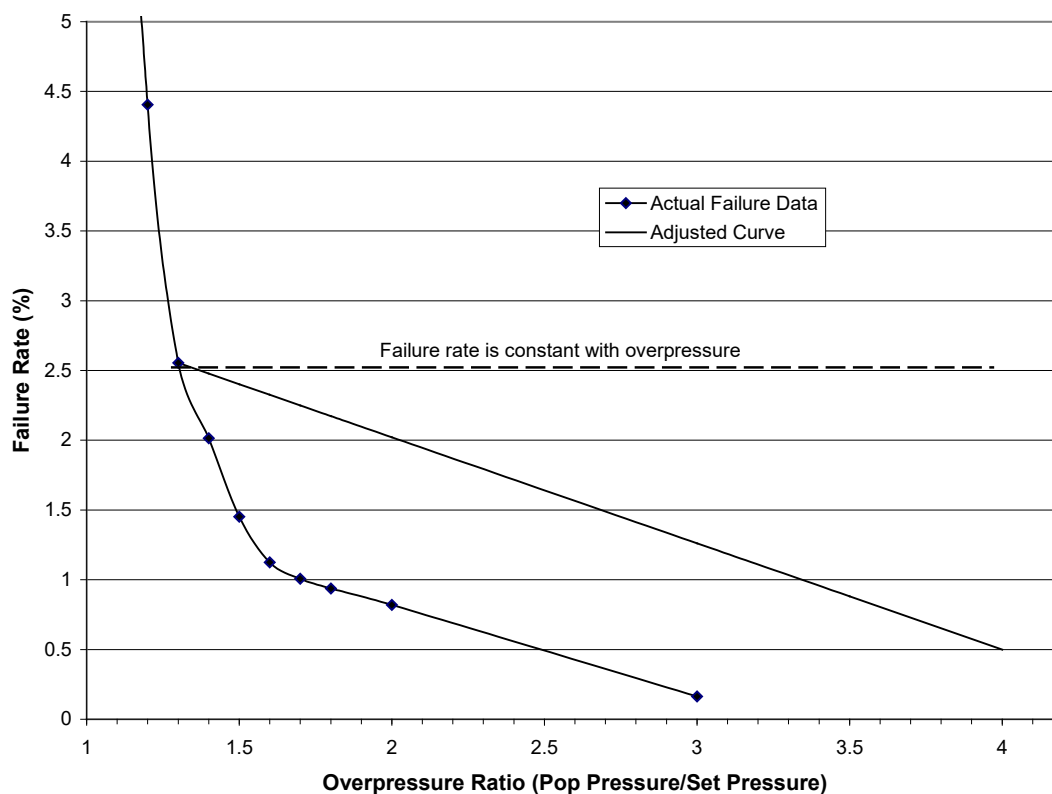


Figure 6.4—PRD Failure Rate as a Function of Overpressure

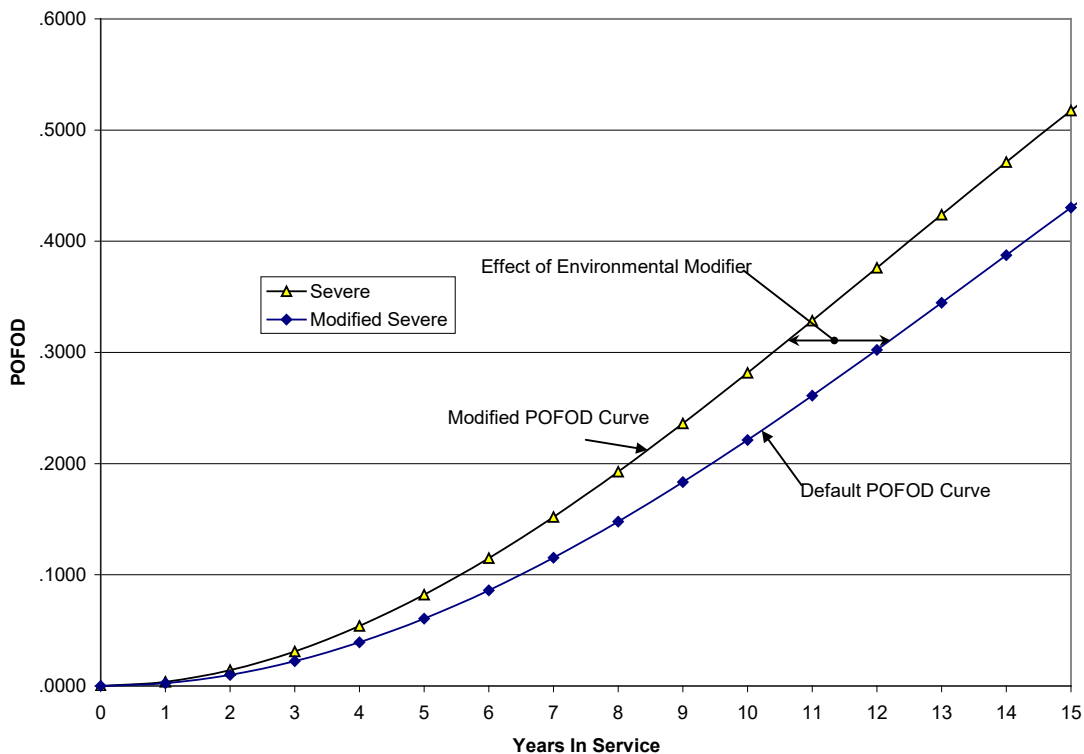
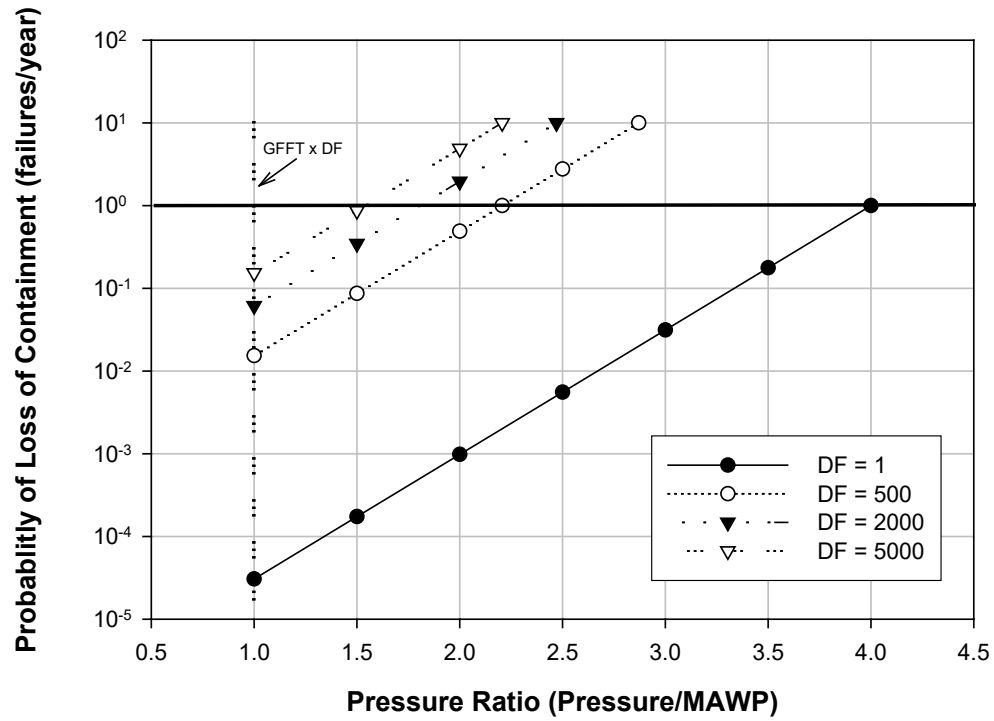


Figure 6.5—Effect of Environmental Factors on PRD Weibull Curves



For an example pressure vessel with:

$$gff_{\text{total}} = 3.06 \times 10^{-5}$$

Design margin = 4

Estimated burst pressure of $4 \times \text{MAWP}$

Figure 6.6—Probability of Loss of Containment as a Function of Overpressure

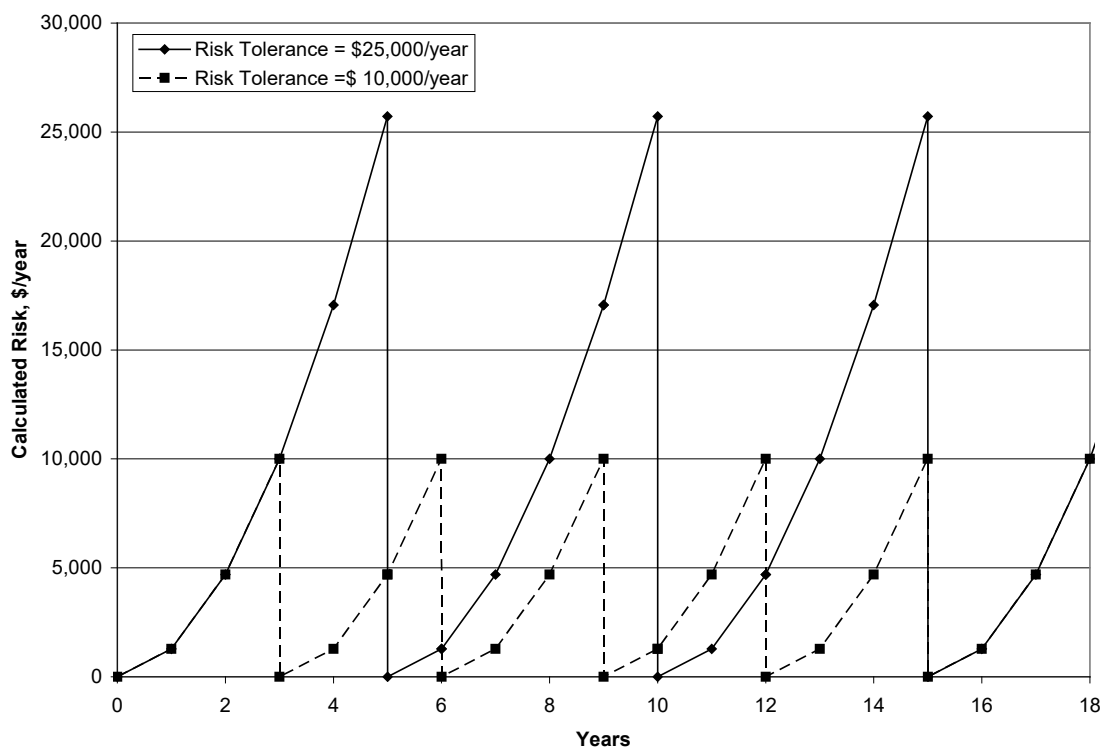


Figure 6.7—Inspection Test Updating of PRDs

7 Steam System

7.1 Overview

7.1.1 General Background

Steam systems account for approximately 30 % of the total energy used in a typical petroleum refinery [17] based on U.S. Department of Energy figures. Steam systems are utilized throughout the plant for motive, heating, and process purposes, such as in the steam turbine driver for the recycle gas compressor, the reboiler for the depentanizer column, and for stripping steam for crude distillation.

Steam system specialists work with plants to identify opportunities to reduce the amount of energy consumed by steam systems to stay competitive. Steam system maintenance costs should also be optimized and to protect health and safety issues as well as avoid unplanned downtime. The integrity and efficiency of steam-using equipment is critical to the operation and productivity of petrochemical industry as well as steam distribution systems and steam tracing systems that provide the heat necessary to maintain flow rates in product distribution piping, vessels, and reactors [18].

Routine inspection and testing of steam systems consisting of steam traps, associated piping, and steam equipment is required to avoid failures of the traps, associated piping, or equipment, leading to failure of the system. Such failures have resulted in a significant loss of steam and have led to personal injury.

A risk-based approach to evaluate the criticality of equipment in steam systems is covered here to set inspection and testing interval or possible mitigation actions. The scope of this section includes steam traps, associated steam distribution piping, and equipment using steam. The methodology involves the use of reliability data for steam trap types in the form of Weibull parameters.

It is assumed that devices have been designed in accordance with specific design standards and sized, selected, and installed appropriately. It is also assumed that the devices are included in inspection plans. The

fundamental approach is to determine the POF from plant-specific data if available or to be determined from industry default data. These inputs are used to generate a POF as a function of time via a Weibull statistical approach. The consequence of device failure is calculated using methods outlined in [Part 3](#), modified to include different failure scenarios. The combination of consequence and time-based POF provides a risk value that increases with time between inspections/tests. This allows inspection and test intervals to be determined based on risk targets. [Figure 7.1](#) illustrates the basic methodology required for the determination of POF and is the basis for setting up inspection and test intervals or any mitigation actions.

7.1.2 Steam Application Types

Steam is essential for heating, mechanical drives, and several other applications in process plants, and steam traps are commonly used to ensure that steam is not wasted. A steam trap is a type of automatic valve that filters out condensate (e.g. condensed steam) and non-condensable gases such as air without letting steam escape. As described in ANSI/FCI 69-1 (1989), a steam trap is a self-contained valve which automatically drains the condensate from a steam-containing enclosure while remaining tight to live steam, or if necessary, allows steam to flow at a controlled or adjusted rate [\[19\]](#). Most steam traps will also pass non-condensable gases while remaining tight to live steam. Various types of steam trap mechanisms (operating principles) have been developed to automatically discharge condensate and non-condensable gases. The most widely used mechanisms are those reliant on differences in temperature, specific gravities, and pressure. Each of these types of steam traps has its own advantages and applications.

Steam traps are usually required to drain condensate from steam piping, steam-using process and comfort heating equipment, tracer piping, and drive-power equipment such as turbines. Each of these applications may require the steam trap to perform a slightly different role.

In general, there are five major steam application groups that use steam traps: steam distribution piping; steam-heated equipment; steam-driven equipment; steam tracing; and direct steam applications. These systems can be indispensable in delivering the energy needed for operating an industrial plant, including process heating (e.g. heat exchangers) and steam tracing systems, as well as mechanical drives (e.g. steam turbines) [\[20\]](#).

Examples of equipment used in steam systems, illustrating the importance of their application to the refining process, are listed in [Table 7.1](#) [\[20\]](#).

7.2 The Definition of Steam System

7.2.1 Overview

The role of the steam system is to reliably supply steam of the highest quality to the steam-using equipment. In order for this to be achieved, condensate is quickly and efficiently removed through steam traps to the correct condensate discharge location (CDL). Therefore, steam systems are an integral part of the process plant. A steam system is defined as one piece of steam-using equipment and its associated piping and traps. [Figure 7.2](#) shows multiple steam systems with the following components:

- a) steam traps,
- b) associated steam piping (distributing and condensate),
- c) equipment (steam-using equipment).

Depending on the system design, mechanical pumps or control valves may be installed in place of steam traps (as shown in [Figure 7.2](#)).

COF is a key driver for an RBI approach in steam-using/distribution systems, for assessment of steam traps, associated steam piping, and steam-using equipment (as described in [Section 7.4](#)).

7.2.2 Steam Trap

Steam traps are a type of automatic valve that filters out condensate (i.e. condensed steam) and non-condensable gases, such as air, without letting steam escape. In industry, steam is used regularly for heating or as a driving force for mechanical power. Steam traps are used in such applications to ensure steam is not wasted. Based on the operating principles of steam traps, they can be classified as mechanical, thermostatic, or thermodynamic. [Table 7.2](#) describes different types of steam traps for each of the above categories.

7.2.3 Steam Piping

Steam piping supply steam to the steam-using equipment. As described, condensate is removed through steam traps installed at CDLs. The steam flow rates are typically higher in steam distribution piping than in other equipment, reaching velocities of > 100 ft/s (30 m/s). At these speeds, when the cross-sectional area of a pipe section is liquid full, slugs of condensate can be carried through the piping at high velocities, causing water hammer. Potentially, this may cause failures of piping, valves, and equipment as well as personal injuries. The higher velocities in steam piping should be considered during design when the location of trap installations is being decided.

7.2.4 Steam-using Equipment

As described in [Section 7.1.2](#), there are many applications for steam, and depending on the application, various types of steam-using equipment are used. [Table 7.1](#) provides examples of five steam application groups.

7.2.5 Steam System Damage Mechanism Equipment and Failure Modes

7.2.5.1 Background

The role of steam distribution piping is to reliably supply high-quality steam to steam-using equipment. Condensate is quickly and efficiently removed through steam traps installed in proper CDL installations. CDLs are susceptible to failures due to blockage (cold) or leakage (described in [Section 7.2.5.3.1](#) and [Section 7.2.5.3.2](#)). This methodology currently does not cover freeze protection of CDLs.

The failures described in this section will also result in equipment failure consequences such as industrial steam turbine erosion failures, flooding of heat exchangers, and failures in steam tracing systems, flare systems (loss of steam will prevent atomizing of gases prior to burning), distillation towers, and strippers.

7.2.5.2 Damage Mechanism

7.2.5.2.1 Water Hammer

A sudden release of steam or scalding water can occur due to the consequences of water hammer, a common damage mechanism affecting steam systems. Water hammer has been cited by Paffel [\[20\]](#) as the primary problem in steam systems and is sometimes referred to as condensate induced water hammer. Water hammer occurs when steam is introduced into cold pipework that has not been drained sufficiently. As the steam cools, it turns into condensate, taking up a smaller volume in the pipework than steam. This produces a vacuum or pocket into which the water flows rapidly, creating an impact against the pipework.

Water hammer generated in steam and condensate recovery systems is ordinarily classified via two main causes:

- a) high-speed condensate slamming into, for example, piping;
- b) sudden condensation of steam, which produces walls of condensate that crash into each other.

When water hammer occurs, a momentary abrupt pressure change of over 1450 psi (10 MPa) may occur inside the piping. The change in pressure may result in an impact and can cause pipe rupture, severely jarring piping, equipment, or machinery housings, possibly resulting in damage to gaskets and valve flanges or the valves themselves. Water hammer in steam distribution piping interrupts service and can cause failures leading to personal injury and property damage. According to historical failures, 82 % of steam systems experience some type of water hammer. In a typical steam-using system, water hammer causes 67 % of premature steam system component failures [17].

Water hammer events are commonly caused by the following systemic failures.

- a) Failure to ensure water (condensate) has been removed using steam traps and drains prior to admitting steam into the piping system.
- b) Failure to correctly maintain steam traps, drain, and blowdown valves (in order to preserve operable condition).
- c) Failure to ensure an adequate number of steam traps and drains have been installed at locations conducive to condensate removal.
- d) Failure to operate system valves correctly as well as failure to use bypass valves to safely warm system piping downstream of isolation valves.

7.2.5.3 Failure Modes

7.2.5.3.1 Steam Trap Blockage Leading to Water Hammer

Condensate cannot be discharged when the steam trap is blocked, often resulting in water hammer contributing to potential equipment damage.

7.2.5.3.2 Steam Trap Leakage

Leakage is another mode of steam trap failure resulting in energy waste and poor environmental compliance. The failure COL is described in [Section 7.4.2](#).

7.3 POF Methodology

7.3.1 Use of Weibull Curves

The POF for steam systems is calculated using a two-parameter Weibull distribution as expressed in [Equation \(5.122\)](#) and as shown in [Part 1, Section 4.1.3](#). Use of Weibull curves for establishing POF is further described in [Part 1, Section 4.1.3](#).

$$P_f = 1 - \exp \left(- \left(\frac{t}{\eta} \right)^\beta \right) \quad (5.122)$$

where β is the Weibull shape parameter, η is the Weibull characteristic life parameter, in years, and t is the independent variable time in years.

The POF of the specific trap is related to identifiable process and installation conditions. Such conditions may be related to design, operational, and maintenance/inspection history conditions. Also associated with failure are conditions such as poor manufacturing and installation and excessive piping vibration. Improper installations or poor operational and maintenance condition may also increase the POF.

7.3.2 Required Data

The basic data required for the evaluation of POF for steam systems are listed in [Table 7.3](#).

7.3.3 Overview

This section presents a procedure to calculate the POF for a steam system. [Figure 7.2](#) provides an overview of the POF calculation framework for steam systems. POF is a function of time for a range of steam trap types and properties, using Weibull fitting of steam trap failure data. The POF of the associated piping is then derived and combined with the steam-using equipment GFFs to calculate a system POF. Final POF values are obtained by tailoring the POF for steam traps and equipment to local conditions by customized probability factors.

As described in [Section 7.2](#), a steam system is defined as one piece of steam-using equipment and its associated piping and traps. The POF of each system will be considered as the combined effect of individual equipment with its associated traps for both leakage and blockage, i.e.:

$$P(t)_{f,final,leak(steam\ system)} = P(t)_{f(equ)} \cdot P(t)_{f,final,leak(ST,MP\ or\ CV)} \quad (5.123)$$

$$P(t)_{f,final,cold(steam\ system)} = P(t)_{f(equ)} \cdot P(t)_{f,final,cold(ST,MP\ or\ CV)} \quad (5.124)$$

The procedure for calculation of $P(t)_{f,final,leak(ST,MP\ or\ CV)}$ and $P(t)_{f,final,cold(ST,MP\ or\ CV)}$ is provided in [Section 7.3.4](#) and [Section 7.3.5](#). $P(t)_{f(equ)}$ is the POF calculated for the steam-using equipment as explained in [Section 7.3.6](#).

7.3.4 POF (Steam Piping)

7.3.4.1 POF for Steam Traps, Mechanical Pumps, and Control Valves

Analysis has been carried out on the historical time to failure data (for various failure types), and a Weibull distribution has been fitted. As described in [Section 7.3.1](#), Weibull functions are suitable for such analysis with the added advantage of having the ability to evaluate large populations of data to seek trends. In the absence of large sets of failure data, the functions are still useful as a starting point.

[Equation \(5.122\)](#) is the cumulative failure density function of a two-parameter Weibull distribution, also referred to as the probability of failure (POF) for a steam trap. In this equation, t is the in-service life of the steam trap (in years), η is the characteristic life (also in years), and β is the shape parameter.

Once the characteristic life parameter $\eta_{def,ST}$ (for leak and blockage) and shape β_{ST} parameters are obtained from [Table 7.4](#) (from historical data analysis), the POF of the steam trap is calculated using [Equation \(5.125\)](#) for leakage and [\(5.126\)](#) for blockage.

$$P(t)_{f,def,leak} = 1 - \exp \left[- \left(\frac{t}{\eta_{def,leak,ST}} \right)^{\beta_{ST}} \right] \quad (5.125)$$

$$P(t)_{f,def,cold} = 1 - \exp \left[- \left(\frac{t}{\eta_{def,cold,ST}} \right)^{\beta_{ST}} \right] \quad (5.126)$$

The data presented in [Table 7.4](#) are based on the best available sources and experience to date from owner–operators. [Table 7.4](#) introduces default Weibull parameters for the different steam trap types in both failure modes. However, it is recommended that both Weibull parameters be used by the owner–operator where more accurate data for default shape/characteristic life parameters are available. The default parameters in [Table 7.4](#) are suggested for use when data is unavailable.

7.3.4.2 Adjusted POF for Steam Traps, Mechanical Pumps, and Control Valves

Adjustments are made to the η parameter to increase or decrease POF as a result of condition of design/installation, operation, or maintenance history factors. POF is adjusted based on the adjustment multiplier for each design/installation, F_D , operational, F_O , or maintenance history, F_M , conditions. The default POF [$P(t)_{f,def,leak}$ and $P(t)_{f,def,cold}$] needs to be adjusted by the adjustment multipliers given in [Table 7.5](#) to [Table 7.13](#).

$$\eta_{adj,leak_{ST,MP \text{ or } CV}} = \eta_{def,leak,ST} \cdot F_{D_{(ST,MP \text{ or } CV)}} \cdot F_{O_{(ST,MP \text{ or } CV)}} \cdot F_{M_{(ST,MP \text{ or } CV)}} \quad (5.127)$$

$$\eta_{adj,cold_{ST,MP \text{ or } CV}} = \eta_{def,cold,ST} \cdot F_{D_{(ST,MP \text{ or } CV)}} \cdot F_{O_{(ST,MP \text{ or } CV)}} \cdot F_{M_{(ST,MP \text{ or } CV)}} \quad (5.128)$$

$$P(t)_{f,final,leak_{(ST,MP \text{ or } CV)}} = 1 - \exp \left[- \left(\frac{t}{\eta_{adj,leak_{(ST,MP \text{ or } CV)}}} \right)^{\beta_{ST}} \right] \quad (5.129)$$

$$P(t)_{f,final,cold_{(ST,MP \text{ or } CV)}} = 1 - \exp \left[- \left(\frac{t}{\eta_{adj,cold_{(ST,MP \text{ or } CV)}}} \right)^{\beta_{ST}} \right] \quad (5.130)$$

The adjusted η parameter [$\eta_{adj,leak_{(ST,MP \text{ or } CV)}}$ and $\eta_{adj,cold_{(ST,MP \text{ or } CV)}}$] is used to calculate the final (tailored) POF using [Equation \(5.129\)](#) for leakage and [Equation \(5.130\)](#) for blockage for each steam trap, mechanical pump, or control valve operating within a steam system. The shape factor β_{ST} used in [Equation \(5.129\)](#) and [\(5.130\)](#) is the same shape factor generated from [Table 7.4](#). [Equation \(5.129\)](#) and [Equation \(5.130\)](#) provide the final POF for each steam trap, mechanical pump, or control valve in a steam system.

Suggested adjustment multiplier categories that need to be considered for steam traps, mechanical pumps, and control valves are given in [Table 7.5](#) to [Table 7.13](#). It should be noted that the value of each adjustment multiplier depends on engineering judgement.

7.3.5 Multiple Steam Trap or Mechanical Pumps or Control Valves Installations

For any steam-using equipment, there are several associated piping with steam traps (or mechanical pumps or control valves) installed. The piping usually have steam traps installed in parallel or series. When there are multiple steam traps (or mechanical pumps or control valves) installed, the calculated POF for any one specific steam trap in the multiple installation will remain the same. However, the overall combined POF for leakage and blockage of multiple traps (in parallel or series) should be considered for each piping using [Equations \(5.131\)](#) and [\(5.132\)](#) for traps in series and [Equations \(5.133\)](#) and [\(5.134\)](#) for traps in parallel.

$$P(t)_{f,final \text{ series},leak_{(ST,MP \text{ or } CV)}} = 1 - \left(1 - P(t)_{f1,leak} \right) \cdot \left(1 - P(t)_{f2,leak} \right) \cdot \dots \cdot \left(1 - P(t)_{fn,leak} \right) \quad (5.131)$$

$$P(t)_{f,final \text{ series},cold_{(ST,MP \text{ or } CV)}} = 1 - \left(1 - P(t)_{f1,cold} \right) \cdot \left(1 - P(t)_{f2,cold} \right) \cdot \dots \cdot \left(1 - P(t)_{fn,cold} \right) \quad (5.132)$$

$$P(t)_{f, \text{final parallel, leak}_{(ST, MP \text{ or } CV)}} = P(t)_{f1, \text{leak}} \cdot P(t)_{f2, \text{leak}} \cdot \dots \cdot P(t)_{fn, \text{leak}} \quad (5.133)$$

$$P(t)_{f, \text{final parallel, cold}_{(ST, MP \text{ or } CV)}} = P(t)_{f1, \text{cold}} \cdot P(t)_{f2, \text{cold}} \cdot \dots \cdot P(t)_{fn, \text{cold}} \quad (5.134)$$

For example, [Figure 7.3](#) is the sample arrangement of the traps showing their different capacity. Calculation of the POF for each piping is given by [Equation \(5.133\)](#) and [Equation \(5.134\)](#), which allow calculation of the total POF for the piping in parallel configuration [[Figure 7.3 a](#)]. In addition, if the capacity of Trap 1 and Trap 2 are not sufficient for the equipment requirement individually, these two traps (or mechanical pumps or control valves) are treated as series configurations [[Figure 7.3 b](#)] using [Equation \(5.131\)](#) and [Equation \(5.132\)](#).

7.3.6 POF for Equipment

As discussed in [Section 7.1.2](#), there are different types of equipment used in steam systems. Examples of some of these types were given in [Table 7.1](#). In this section, the POF calculation due to steam related failure will be covered. Equipment consists of the following:

- a) heat exchanger,
- b) distillation tower/column,
- c) stripper,
- d) flare,
- e) steam turbine
- f) piping (steam main or condensate piping),
- g) tracing (instrumentation/relief valve).

The calculation of the POF of equipment takes into account the effect of both equipment and its associated piping. It is also important to note that the calculation assumes that each individual item of equipment is independent.

For example, [Figure 7.4 a](#)) shows an arrangement of a steam turbine with traps. Block diagrams for combining the POF calculation for the same system Steam Trap 1 and Steam Trap 2 in parallel and series are provided in [Figure 7.4 b](#)) and [Figure 7.4 c](#)), respectively.

The equations below are used in estimating the POF for the equipment listed above, and each equipment is considered independent and assessed separately.

$$\eta_{\text{adj, equ}} = \eta_{\text{def, equ}} \cdot (F_{D_{\text{equ}}} \cdot F_{O_{\text{equ}}} \cdot F_{M_{\text{equ}}}) \quad (5.135)$$

$$P(t)_{f, \text{final(equ)}} = 1 - \exp \left[- \left(\frac{t}{\eta_{\text{adj, equ}}} \right)^{\beta_{\text{equ}}} \right] \quad (5.136)$$

The default characteristic life parameter, $\eta_{\text{def, equ}}$, and shape parameter, β_{equ} , are obtained from historical data analysis. [Table 7.14](#) shows default Weibull parameters for the different types of steam-using equipment. The data presented in [Table 7.14](#) are based on the best available sources and experience to date from owner–operators. However, it is recommended that other Weibull parameters be used by the owner–operator where plant-specific data for default shape/characteristic life parameters are available. The default

parameters in [Table 7.14](#) are suggested when plant-specific data is unavailable and are based on failure of steam systems.

Similar to the approach for steam traps discussed in [Section 7.3.4.2](#), $\eta_{\text{adj, equ}}$ is used to calculate the final (tailored) POF [[Equation \(5.136\)](#)] for steam-using equipment. The shape factor β_{equ} used in [Equation \(5.136\)](#) is the shape factor from [Table 7.14](#). $P(t)_{\text{f, final(equ)}}$ is the final POF of the steam-using equipment. The adjustment multiplier categories for each design/installation, $F_{\text{D equ}}$, operational, $F_{\text{O equ}}$, or maintenance history, $F_{\text{M equ}}$, factors are given in [Table 7.15](#) to [Table 7.17](#) and are used to modify the default characteristic life parameter, $\eta_{\text{def, equ}}$. It should be noted that the value of each adjustment multiplier depends on engineering judgement.

7.3.7 POF for Steam Systems

The total POF for one piece of steam system is calculated using [Equation \(5.123\)](#) and [Equation \(5.124\)](#) where $P(t)_{\text{f, final, leak(ST, MP or CV)}}$ and $P(t)_{\text{f, final, cold(ST, MP or CV)}}$ is calculated from [Equation \(5.129\)](#) and [Equation \(5.130\)](#) for individual steam traps, and for multiple steam traps the procedure in [Section 7.3.5](#) is used.

7.3.8 POF After Inspection

7.3.8.1 General

Weibull parameters for the failure on demand curves are determined based on the analysis of a sample set of data ([Section 7.3.1](#)). However, as inspection data is collected, these parameters may be adjusted for each device based on the actual inspection results. This approach assumes that the Weibull shape parameter, β , remains constant based on the historical data and adjusts the characteristic life, η , as inspection data are collected.

The effectiveness of inspection and testing is provided in [Annex 2.F](#), [Section 2.F.11.2](#), [Table 2.F.11.1](#). The probability of succeeding the inspection prior to inspection is given by [Equation \(5.137\)](#) and [Equation \(5.138\)](#).

$$P(t)_{\text{f, prior, leak}} = 1 - P(t)_{\text{f, final, leak(ST, MP or CV)}} \quad (5.137)$$

$$P(t)_{\text{f, prior, cold}} = 1 - P(t)_{\text{f, final, cold(ST, MP or CV)}} \quad (5.138)$$

After inspection, the POF is updated based on the results. Use [Equations \(5.139\)](#) and [\(5.140\)](#) if the inspection results do not show the expected failure.

$$P(t)_{\text{f, after, leak}} = (1 - CF_{\text{pass}}) P(t)_{\text{f, prior, leak}} \quad (5.139)$$

$$P(t)_{\text{f, after, cold}} = (1 - CF_{\text{pass}}) P(t)_{\text{f, prior, cold}} \quad (5.140)$$

Use [Equations \(5.141\)](#) and [\(5.142\)](#) if the inspection confirms the expected failure.

$$P(t)_{\text{f, after, leak}} = (1 - CF_{\text{pass}}) \cdot P(t)_{\text{f, prior, leak}} + \left(P(t)_{\text{f, final, leak(ST, MP or CV)}} \cdot CF_{\text{fail}} \right) \quad (5.141)$$

$$P(t)_{f,after,cold} = (1 - CF_{pass}) \cdot P(t)_{f,prior,cold} + \left(P(t)_{f,final,cold(ST,MP \text{ or } CV)} \cdot CF_{fail} \right) \quad (5.142)$$

Based on the outcome of the inspection and its effectiveness, the updated POF after inspection is calculated using equations in [Table 7.19](#). The characteristic life $\left[\eta_{adj,leak(ST,MP \text{ or } CV)} \text{ and } \eta_{adj,cold(ST,MP \text{ or } CV)} \right]$ is updated based on the outcome of the inspection using [Equation \(5.143\)](#) and [Equation \(5.144\)](#).

$$\eta_{upd,leak} = \frac{t}{\left(-\ln(1 - P(t)_{f,wgt,leak}) \right)^{\frac{1}{\beta_{ST}}}} \quad (5.143)$$

$$\eta_{upd,cold} = \frac{t}{\left(-\ln(1 - P(t)_{f,wgt,cold}) \right)^{\frac{1}{\beta_{ST}}}} \quad (5.144)$$

where β_{ST} is shape factor established earlier and t is the inspection interval. The updated characteristic life is then used in the calculation of the POF using [Equation \(5.145\)](#) and [\(5.146\)](#).

$$P(t)_{f,upd,leak} = 1 - \exp \left[- \left(\frac{t}{\eta_{upd,leak}} \right)^{\beta_{ST}} \right] \quad (5.145)$$

$$P(t)_{f,upd,cold} = 1 - \exp \left[- \left(\frac{t}{\eta_{upd,cold}} \right)^{\beta_{ST}} \right] \quad (5.146)$$

7.3.8.2 POF After Cleaning

The steam trap POF will be reduced after each cleaning. For example, if the periodic cleaning is done every 0.5 years, the POF at 0.6 years will be reduced to the same POF value as at 0.1 year, and at 1.1 years the POF will also be equal to the POF at 0.1 years.

7.3.9 POF Calculation Procedure

The following calculation procedure is used to determine the POF due to leak and blockage for steam traps and steam-using equipment. The POF of each steam system is calculated as the combined effect of individual equipment with its associated traps for both leak and blockage.

- a) Step 1—Identify the steam traps, mechanical pumps, control valves, and associated steam-using equipment item in the steam system. Provide required data defined in [Table 7.3](#).
- b) Step 2—Calculate the POF for each steam trap, mechanical pump, and control valve for both failure modes.
 - 1) Step 2.1—Determine the default values of the Weibull parameters for both failure modes from [Table 7.4](#).
 - 2) Step 2.2—Using [Table 7.5](#) to [Table 7.13](#), determine the design, operating, and maintenance condition adjustment for each item (steam trap, mechanical pump, and control valve).

- 3) Step 2.3—Using Equation (5.127) and Equation (5.128), adjust the Weibull parameters $\eta_{\text{def,leak,ST}}$ and $\eta_{\text{def,cold,ST}}$ based on the values in Step 2.2 for both failure modes.
 - 4) Step 2.4—Calculate $P(t)_{\text{f,final,leak(ST,MP or CV)}}$ and $P(t)_{\text{f,final,cold(ST,MP or CV)}}$ using Equation (5.129) and Equation (5.130) based on the adjusted Weibull parameters $\eta_{\text{adj,leak(ST,MP or CV)}}$ and $\eta_{\text{adj,cold(ST,MP or CV)}}$ using Equation (5.127) and Equation (5.128). Repeat for each steam trap, mechanical pump, and control valve.
 - 5) Step 2.5—For steam traps, mechanical pumps, and control valves installed in parallel or series, use Equations (5.131) to (5.134) for both failure modes to calculate POF.
- c) Step 3—Inspection POF updating for each steam trap, mechanical pump, and control valve for both failure modes. Repeat the following steps in case of multiple steam traps, mechanical pumps, and control valves.
- 1) Step 3.1—Identify the effectiveness of the inspection and testing method using Annex 2.F, Section 2.F.11.2, Table 2.F.11.1.
 - 2) Step 3.2—Using Equations (5.137) and (5.138), calculate the probability of not failing the inspection prior to inspection for both failure modes.
 - 3) Step 3.3—Identify the confidence factor associated with the inspection effectiveness and inspection result using Table 7.18.
 - 4) Step 3.4—Calculate $P(t)_{\text{f,after}}$ for blockage and leakage failures using Equations (5.139) and (5.140) if the inspection results do not show the expected failure and Equations (5.141) and (5.142) if the inspection confirms the expected failure.
 - 5) Step 3.5—Calculate $P(t)_{\text{f,wtg}}$ using the appropriate equation for inspection using Table 7.19 and based on the inspection effectiveness and inspection results.
 - 6) Step 3.6—Calculate the updated characteristic life, using Equations (5.143) and (5.144).
 - 7) Step 3.7—Calculate the POF at year in service using Equations (5.145) and (5.146).
 - 8) Step 3.8—Calculate the POF for both failure modes, at $t_{\text{service(ST)}}$ based on the steam trap arrangement using Equations (5.131) and (5.132) for series or Equations (5.133) and (5.134) for parallel configuration.
- d) Step 4—Calculate the POF for one piece of steam-using equipment in the steam system. Repeat the following steps for each piece of steam-using equipment in the steam system.
- 1) Step 4.1—Use the default Weibull parameters for the steam-using equipment from Table 7.14.
 - 2) Step 4.2—Using Table 7.15, determine the design condition adjustment, $F_{\text{D}_{\text{equ}}}$, for the steam-using equipment.
 - 3) Step 4.3—Using Table 7.16, determine the operation condition adjustment, $F_{\text{O}_{\text{equ}}}$, for the steam-using equipment.
 - 4) Step 4.4—Using Table 7.17, determine the maintenance history/inspection condition adjustment, $F_{\text{M}_{\text{equ}}}$, for the steam-using equipment.

- 5) Step 4.5—Using Equation (5.135), adjust the Weibull parameter, $\eta_{\text{def,equ}}$, based on the values in Steps 4.2, 4.3, and 4.4.
 - 6) Step 4.6—Using Equation (5.136), calculate the, $P(t)_{\text{f,final(equ)}}$, for the steam-using equipment based on the adjusted Weibull parameter, $\eta_{\text{adj,equ}}$.
- e) Step 5—Calculate the final POF for the steam system using Equations (5.123) and (5.124) for both failure modes.

Steps 1 to 5 are repeated for multiple steam systems—a steam system is one piece of steam-using equipment and its associated piping and traps.

7.4 COF Methodology

7.4.1 Background

This section presents a procedure to calculate COF for a steam system. Equipment can be connected to either an open system or a closed system and have COF due to leakage and blockage. An open system will allow the steam/condensate to escape into the environment, while a closed system circulates the steam/condensate to be reused.

7.4.2 Models for Assessing COF

7.4.2.1 Overview

The calculation of the COF is performed by evaluating costs involved in different failure consequences, such as the cost of the loss of inventory, regulatory cost, cost of downtime, and cost of repairs. Failure will result in a consequence, i.e. potential impact on people, as well as product loss and component damage in some cases.

COF varies with different equipment and failure modes. The following sections provide the potential costs due to failures and outlines the COF calculation steps.

7.4.2.2 Cost of Steam Loss Due to Leakage

$$FC_{\text{loss}} = \left(\frac{\text{Irate} \cdot 8760 \cdot FC_{\text{steam}}}{1000} \right) \quad (5.147)$$

The leakage rate (*Irate*) is based on historical inspection data.

7.4.2.3 Cost of Condensate Loss Due to Downstream Equipment Rupture

$$FC_{\text{loss,D/S}} = \text{mass}_{\text{condensate}} \cdot FC_{\text{condensate}} \quad (5.148)$$

The condensate mass, $\text{mass}_{\text{condensate}}$, is calculated following the procedure recommended in Part 3, Section 4.7.2, Equation (3.14). The cost of condensate, $FC_{\text{condensate}}$, is user specified.

7.4.2.4 Cost of Component Damage Due to Rupture Caused by Water Hammer

The temporary default component damage cost uses the recommended values from Part 3, Section 4.12.2 for heat exchangers and steam tracing process pipes and the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) for steam turbines. The default values are able to be customized by the user.

7.4.2.5 Cost of Production Loss Due to Shutdown or Reduced Service Efficiency

The production loss value can be manually assigned or calculated using Equation (5.149).

$$FC_{\text{prod}} = \text{Unit}_{\text{prod}} \cdot \left(\frac{\text{Rate}_{\text{red}}}{100} \right) \cdot D_{\text{sd}} \quad (5.149)$$

where $\text{Unit}_{\text{prod}}$ is the daily profit margin on the unit (\$/day). This will be input by the user. Rate_{red} is the production rate reduction on a unit as a result of the equipment being out of service (%), which will also be user input. D_{sd} is the number of days required to shut down a unit in order to repair the equipment during an unplanned shutdown.

7.4.2.6 Cost of Safety Impact to Personnel Due to Rupture and Leakage

The steam released through leakage or rupture may result in a safety impact on personnel. The total personnel injury cost, FC_{inj} , within a certain area is calculated using Equation (5.150).

$$FC_{\text{inj}} = CA_{\text{f},\text{inj}} \cdot \text{popdens} \cdot \text{injcost} \quad (5.150)$$

where $CA_{\text{f},\text{inj}}$ is calculated by using the procedure in Part 3, Section 4.10.2.

The hole size used to calculate the $CA_{\text{f},\text{inj}}$ due to rupture from blockage is the inlet/connection size using Part 3, Equation (3.70). A medium hole size of 1 in. (25 mm) is used to calculate $CA_{\text{f},\text{inj}}$ due to leakage using Part 3, Equation (3.69). The popdens and injcost used in Equation (5.150) is defined in Part 3, Section 4.12.5. The required input parameters are listed in Table 7.20.

The cost of safety impact to personnel due to rupture and leakage of downstream equipment ($FC_{\text{inj},\text{D/S}}$) is calculated by using water as model fluid.

Financial consequence as a result of serious injury to personnel due to process ($FC_{\text{inj},\text{process}}$) is calculated using Equation (5.151) based on the hole size in Part 3, using the product in the process pipe.

$$FC_{\text{inj},\text{process}} = \max(FC_{\text{inj},\text{nfnt}} + FC_{\text{inj},\text{flam}} + FC_{\text{inj},\text{toxic}}) \quad (5.151)$$

For multiple traps, use Equations (5.152) and Equation (5.153) to calculate COF.

Blockage:

$$FC_{\text{inj},\text{cold}} = \max(FC_{\text{inj},\text{cold}_1}, FC_{\text{inj},\text{cold}_2}, \dots, FC_{\text{inj},\text{cold}_n}) \quad (5.152)$$

Leak:

$$FC_{\text{inj},\text{leak}} = (FC_{\text{inj},\text{leak}_1} + FC_{\text{inj},\text{leak}_2} + \dots + FC_{\text{inj},\text{leak}_n}) \quad (5.153)$$

7.4.3 Cost Models for Steam System with Different Equipment

7.4.3.1 Overview

The financial COF varies for steam systems with different equipment and failure modes. A list of potential costs due to failure and calculation methods was introduced in [Section 7.4.2](#). The financial COF is calculated differently for steam system depending on the type of equipment connected. Currently, “type of connected equipment” is one of the data requirements for steam distribution COF calculation. [Section 7.4.3.2](#) through [Section 7.4.3.10](#) outline the calculation methodology for estimating financial COF for different types of steam systems, which includes steam traps and steam-using equipment. Only one of these sections will apply for a steam system.

7.4.3.2 COF Model for Steam System with Heat Exchanger or Steam Turbine

The failure modes for heat exchanger and steam turbines can be either blockage or leakage and are calculated separately. The presence of an opening bypass for the steam system should be determined in the case of a blockage. If no opening bypass exists, a blockage could cause the steam system to shut down and may result in water hammer inside the equipment, causing a production loss and/or rupture. A rupture may cause a financial loss due to component damage and safety impact (personnel injury). The financial COF due to blockage without an opened bypass for heat exchanger and turbine is calculated using [Equation \(5.154\)](#).

$$FC_{\text{cold}}^{\text{HEX,Turbine}} = FC_{\text{prod}} + FC_{\text{comp}} + FC_{\text{inj}} \quad (5.154)$$

The blockage consequence is calculated the same as a leakage consequence [[Equation \(5.155\)](#)] in an open system if the bypass is opened.

The total steam loss is calculated for both leakage and blockage with an open bypass. If the bypass is open, the safety impact is considered in addition to the loss of steam.

If the outlet is closed while the traps are leaking, there will be a subsequent consequence of water hammer occurring to the downstream equipment/pipe in addition to steam loss from leaking traps. In the worst case, the downstream pipe will be ruptured. This will result in production loss due to downstream equipment shutdown, downstream pipe component damage, loss of condensate, and associated safety impacts. The financial COF due to both leakage and blockage with an open bypass for a heat exchanger and turbine is calculated using [Equation \(5.155\)](#) and [Equation \(5.156\)](#). If the bypass is closed or if there is no bypass, then $FC_{\text{inj}} = 0$ in [Equation \(5.155\)](#).

$$FC_{\text{leak,open}}^{\text{HEX,Turbine}} = FC_{\text{loss}} + FC_{\text{inj}} \quad (5.155)$$

$$FC_{\text{leak,closed}}^{\text{HEX,Turbine}} = FC_{\text{loss}} + FC_{\text{loss,D/S}} + (FC_{\text{prod,D/S}} + FC_{\text{comp,D/S}} + FC_{\text{inj,D/S}}) \quad (5.156)$$

7.4.3.3 COF Model for Steam System with General Steam Tracing

The failure modes for general steam tracing equipment (tracing with steam temperatures above 356 °F [180 °C]) can be either blockage or leakage, which are calculated separately. Unlike a heat exchanger or turbine (as described in [Section 7.4.3.2](#)), the COF for tracing is considered for the process pipe and tracing piping. When “blockage” happens, it shall be established whether there is an opened bypass for the system or the trap is disconnected. If the bypass is closed or the trap is not disconnected, the blockage will cause the steam system to shut down or the content to cool down and possibly water hammer inside the tracing piping. In one case, the steam system shut down and content sub-cooling will result in production loss in addition to the cost of process pipe cut-off (component damage). In another case, the water hammer inside the tracing piping will cause the tracing piping to rupture (worst case scenario), which will result in costs of the tracing piping component damage in addition to associated safety impacts.

The COF due to blockage in an open and closed system without opened bypass or trap disconnection for general steam tracing is calculated using Equation (5.157).

$$FC_{\text{cold}}^{\text{Tracing,HT}} = FC_{\text{prod}} + FC_{\text{comp,process}} + FC_{\text{comp,line}} + FC_{\text{inj}} + FC_{\text{inj,process}} \quad (5.157)$$

For leakage, in an open system the COF is calculated using Equation (5.155). For a closed system, the leakage COF is calculated using Equation (5.156).

7.4.3.4 COF Model for Steam System with Low-temperature Steam Tracing

Low-temperature steam tracing is used in applications that require low flow or needs to be kept warm due to low ambient conditions. The temperature of steam used in low-temperature steam tracing is between 302 °F and 356 °F (150 °C and 180 °C). The failure modes can be either blockage or leakage, which will be calculated separately. The COF for tracing is considered for process pipe and tracing piping separately.

Similar to the general steam tracing (Section 7.4.3.3), when blockage occurs, the COF is calculated using Equation (5.157) for both open and closed system without bypass.

For both leakage and blockage with open bypass or trap disconnection, the common failure consequence for both an open and closed system is as follows.

- a) The steam leaking will result in costs from steam loss; if multiple traps are leaking, the sum of steam loss costs should be reported.
- b) Leakage causes equipment shutdown or overheating, which gives rise to costs from production loss.

Water hammer may occur inside the process piping due to leakage may results in a rupture of the process piping and costs from process piping component damage and safety impact. The fluid within the process piping is assigned as flammable or toxic or flammable and toxic. The semiquantitative model to estimate safety COF is developed based on Part 3. If the fluid is both flammable and toxic, the worst case will be used.

In addition to costs listed above, for an open system (i.e. the outlet is opened), there are further safety impacts caused by leaking steam. If it is a closed system, there is a subsequent consequence of water hammer occurring to the downstream equipment/pipe; use Equation (5.158) with $FC_{\text{inj}} = 0$.

The COF due to both leakage and blockage with open bypass or trap disconnection for low-temperature steam tracing is calculated using Equation (5.158) for open system and Equation (5.159) for closed system.

$$FC_{\text{leak,open}}^{\text{Tracing,LT}} = FC_{\text{inj}} + (FC_{\text{loss}} + FC_{\text{comp,process}} + FC_{\text{prod,process}} + FC_{\text{inj,process}}) \quad (5.158)$$

$$FC_{\text{leak,closed}}^{\text{Tracing,LT}} = (FC_{\text{loss}} + FC_{\text{loss,D/S}} + FC_{\text{comp,process}} + FC_{\text{prod,process}} + FC_{\text{inj,process}}) + (FC_{\text{prod,D/S}} + FC_{\text{comp,D/S}} + FC_{\text{inj,D/S}}) \quad (5.159)$$

where $FC_{\text{inj,process}}$ is calculated using Equation (5.151).

7.4.3.5 COF Model for Steam System with Steam Tracing with Relief Valve

The relief valve is a type of valve used to control or limit the pressure in the steam tracing system. Pressure can build up as a result of a process, instrument, or equipment failure. However, if the relief valve fails, there is the possibility the high pressure of the fluid within the pipe is raised further and causes leakage through the joints. In this case, the failure consequence is the sum of the cost of fluid loss and injury costs due to the

leakage where the relief valve is installed (see [Section 6.1.7](#)). The financial COF calculation follows the COF equations for low-temperature steam tracing.

7.4.3.6 COF Model for Steam System with Steam Tracing with Flow Meter

A flow meter is an instrument used to measure linear, nonlinear, volumetric or the mass flow rate of fluids, which can be found on both general tracing and low-temperature applications. If the flow meter fails, the fluid is transported without measurement. This will not cause any safety consequence or financial loss in terms of product loss or component damage. However, without measurement, there may be a certain amount of business loss, which will be assessed by the user. In summary, the total financial COF is the same as for general tracing on a low-temperature tracing system, with modified business loss that will be assessed by the user directly.

7.4.3.7 COF Model for Steam System with Distillation Columns with Stripping Steam

The steam trap failure modes considered for distillation columns are leakage and blockage. For the failure mode of leakage in an open system when the bypass is open, financial COF is the sum of steam loss and cost of the safety impact due to condensate/steam discharge into the open air [[Equation \(5.155\)](#)]. If the outlet is closed, steam loss is the leakage financial COF [[Equation \(5.156\)](#)]. In terms of failure due to blockage when the bypass is not open, there is the possibility of condensate carryover and/or water hammer, and the financial COF is calculated as the sum of component damage, production loss, and the cost of safety impact using [Equation \(5.154\)](#). If the bypass is open, the financial COF of due to blockage is the same as the COF of leakage.

7.4.3.8 COF Model for Steam System with Flare

The steam trap failure modes considered for flare are leakage and blockage. Similar to distillation columns ([Section 7.4.3.7](#)), if the steam trap of the flare leaks and its outlet is open, financial COF is the sum of steam loss and the cost of the safety impact due to condensate/steam discharge to the open air [[Equation \(5.155\)](#)]. Otherwise, if the outlet is closed, steam loss is the only leakage financial COF [[Equation \(5.156\)](#)]. In terms of failure due to blockage when the bypass is not open, there is the possibility of condensate carryover and/or water hammer, and the financial COF is calculated using [Equation \(5.160\)](#) as the sum of component damage, production loss, the cost of safety impact due to pipe rupture, and environmental costs due to reduced burning efficiency. If the bypass is open, the financial COF of due to blockage is the same as the COF of leakage.

$$FC_{\text{cold}}^{\text{Flare}} = FC_{\text{loss}} + FC_{\text{comp}} + FC_{\text{inj}} + FC_{\text{comp,process}} + FC_{\text{prod,process}} + FC_{\text{inj,process}} + FC_{\text{env}} \quad (5.160)$$

where $FC_{\text{inj,process}}$ is calculated from [Equation \(5.151\)](#).

7.4.3.9 COF Model for Steam System with Steam Distribution Piping

The failure modes considered for steam distribution piping are leakage and blockage. Similar to distillation columns ([Section 7.4.3.7](#)), if the steam trap of the main steam distribution piping leaks and its outlet is open, financial COF is the sum of steam loss and cost of the safety impact due to condensate/steam discharge to open air using [Equation \(5.155\)](#). If the outlet is closed, the leakage financial COF due to steam loss is calculated by using [Equation \(5.155\)](#) with $FC_{\text{inj}} = 0$. In terms of failure due to blockage when the bypass is not open, there will be the possibility of water hammer; the financial COF is calculated as the sum of component damage (steam distribution piping), production loss, and the cost of any safety impact [[Equation \(5.154\)](#)]. If the bypass is open, the financial COF due to blockage is the same as the financial COF of leakage.

7.4.3.10 COF Model for Steam System with Condensate Recovery Piping

The failure mode considered for the steam recovery piping is leakage only. This is because blocked steam traps are not discharging into the condensate recovery piping, so they do not have any effect. When the recovery piping fails due to a steam trap leakage, the condensate pipe may rupture due to water hammer. The

financial COF is calculated as the sum of any component damage (pipe), cost of safety impact, condensate loss, and downstream equipment production loss using Equation (5.161).

$$FC_{\text{leak}}^{\text{Recovery}} = FC_{\text{loss,D/S}} + FC_{\text{prod,D/S}} + FC_{\text{comp,D/S}} + FC_{\text{inj,D/S}} \quad (5.161)$$

7.4.4 COF Calculation Procedure

The following calculation procedure may be used to determine the financial COF for a steam system. The financial COF needs to be calculated for both failure modes.

- a) Step 1—Calculate the cost of steam loss due to leakage using Equation (5.147).
- b) Step 2—Calculate the cost of condensate loss due to downstream equipment rupture using Equation (5.148). Go to Step 3 if no downstream equipment is connected or if the system is open, i.e. the condensate is discharged to open.
- c) Step 3—Calculate the cost of production loss due to shutdown or reduced service efficiency using Equation (5.149).
- d) Step 4—Calculate the cost of safety impact to personnel due to steam and process release using Equation (5.150) and Equation (5.151), respectively. If there are multiple steam traps, use Equation (5.152) and Equation (5.153).
- e) Step 5—Determine if the steam system is open or closed and calculate the financial COF (FC_{leak} and FC_{cold}) for steam system based on the type of steam-using equipment, using Table 7.21 and Table 7.22.

7.5 Risk-based Analysis

The risks due to leakage and blockage are calculated using Equations (5.162) and (5.163), where the POF of steam system is calculated from Equations (5.123) and (5.124) for both leakage and blockage. The FC_{leak} and FC_{cold} are calculated in Step 5 in Section 7.4.4.

$$R(t)_{\text{leak}} = P(t)_{\text{f,final,leak(steam system)}} + FC_{\text{leak}} \quad (5.162)$$

$$R(t)_{\text{cold}} = P(t)_{\text{f,final,cold(steam system)}} + FC_{\text{cold}} \quad (5.163)$$

The total risk $R(t)$ is the sum of the risk due to blockage and leakage and is calculated from Equation (5.164).

$$R(t) = R(t)_{\text{leak}} + R(t)_{\text{cold}} \quad (5.164)$$

For the output, the risk is calculated as a function of time on a risk matrix. All of the post-assessment analysis are conducted based on this; this will be discussed in the following sections.

7.6 Inspection and Risk Mitigation Planning

7.6.1 Risk Mitigation Plan

7.6.1.1 Overview

The mitigation plan comprises risk mitigation suggestions/actions to assist asset owner–operator managing their steam system through the identification of the influence of each mitigation action on the system. The method for illustration of the risk target is the “iso-risk target.” the iso-risk target is defined as a line of constant risk and a method of graphically showing POF and COF values in a log-log, two-dimensional plot where risk increases toward the upper right-hand corner. The value of the target risk will be determined by the user.

The possible mitigation actions listed in [Section 7.6.2.1](#) to [Section 7.6.2.3](#) are suggestions only and may not be applicable in all situations.

7.6.1.2 Configuration of Steam System

The risk can be modified by changing the configurations of the steam system, either by adding spare equipment or extra steam traps to the piping or changing the type of the existing steam traps. The influence will depend on the number and location of the extra steam traps. Specifically, if extra steam traps are added, the arrangement of the steam system will be changed. The value of POF will be amended accordingly. Meanwhile, different steam traps will have a different $P(t)_{\text{adjusted}}$, which will affect the POF of the steam system [[Equations \(5.123\)](#) and [\(5.124\)](#)].

7.6.1.3 Inspection

If an inspection is performed, or a condition monitoring device installed, the risk categories will also be shifted as the tailored characteristic life η_{adjusted} will be updated accordingly. The procedure proposed in [Section 7.3.9](#) will be followed. For sensors, the confidence factor, CF , value will be defaulted to “usually effective.”

Cleaning of the steam trap has a significant impact on the POF; the more frequent the cleaning, the lower the POF over time.

7.6.1.4 Spare Equipment

If any spare equipment is included in one steam system, this may help to reduce the consequential cost of production loss. The POF can also be mitigated by intentionally releasing steam, e.g. via “bypass open.” However, this action is not recommended due to environmental and safety viewpoints. In addition, it not only causes an increment of COF due to loss of steam but could also lead to local corrosion damage, i.e. FC_{loss} and FC_{comp} .

7.7 Nomenclature

$CA_{f,\text{inj}}$	is the final personnel injury consequence area, ft ² (m ²)
CF_{fail}	is the confidence factor for the inspection results in failure
CF_{pass}	is the confidence factor for the inspection not to result in failure
D_{sd}	is the time required to shut down a unit to perform a repair, days
F_{DCV}	is the design adjustment multiplier for control valve
F_{Dequ}	is the design adjustment multiplier for steam-using equipment
F_{DMP}	is the design adjustment multiplier for mechanical pump
F_{DST}	is the design adjustment multiplier for steam traps
F_{MCV}	is the maintenance/inspection history adjustment multiplier for control valve
F_{Mequ}	is the maintenance/inspection history adjustment multiplier for steam-using equipment

F_{MMP}	is the maintenance/inspection history adjustment multiplier for mechanical pump
F_{MST}	is the maintenance/inspection history adjustment multiplier for steam traps
F_{OCV}	is the operational adjustment multiplier for control valve
$F_{O_{equ}}$	is the operational adjustment multiplier for steam-using equipment
F_{OMP}	is the operational adjustment multiplier for mechanical pump
F_{OST}	is the operational adjustment multiplier for steam traps
FC_{cold}	is the financial COF of steam system due to blockage, \$
FC_{cold}^{Flare}	is the financial COF of flare due to blockage, \$
$FC_{cold}^{HEX, Turbine}$	is the financial COF of heat exchanger and turbine due to blockage, \$
FC_{comp}	is the cost of component damage, \$
$FC_{comp,D/S}$	is the cost of component damage (downstream), \$
$FC_{comp,line}$	is the cost of component damage (tracing piping), \$
$FC_{comp,main}$	is the cost of component damage (main pipe), \$
$FC_{comp,process}$	is the cost of component damage (process piping), \$
$FC_{condensate}$	is the cost of condensate, \$/lb (\$/kg)
FC_{env}	is the cost of environmental damage, \$
FC_{inj}	is the financial consequence as a result of serious injury to personnel, \$
$FC_{inj,cold}$	is the financial consequence due to blockage as a result of serious injury to personnel, \$
$FC_{inj,D/S}$	is the financial consequence as a result of serious injury to personnel (downstream), \$
$FC_{inj,flam}$	is the financial consequence of as a result of serious injury to personnel due to flammable release, \$
$FC_{inj,leak}$	is the financial consequence due to leakage as a result of serious injury to personnel, \$
$FC_{inj,nfnt}$	is the financial consequence as a result of serious injury to personnel due to nonflammable, nontoxic, \$
$FC_{inj,process}$	is the financial consequence as a result of serious injury to personnel (process piping), \$
$FC_{inj,toxic}$	is the financial consequence of as a result of serious injury to personnel due to toxic release, \$

FC_{leak}	is the financial COF of steam system due to leakage, \$
$FC_{\text{leak}}^{\text{Recover}}$	is the financial COF of condensate recover piping due to leakage, \$
$FC_{\text{leak,closed}}^{\text{HEX,Turbine}}$	is the financial COF of heat exchanger and turbine due to leakage (closed system), \$
$FC_{\text{cold}}^{\text{Tracing,HT}}$	is the financial COF of general steam tracing due to blockage, \$
$FC_{\text{leak,closed}}^{\text{Tracing,LT}}$	is the financial COF of low-temperature tracing due to leakage (closed system), \$
$FC_{\text{leak,open}}^{\text{HEX,Turbine}}$	is the financial COF of heat exchanger and turbine due to leakage (open system), \$
$FC_{\text{leak,open}}^{\text{Tracing,LT}}$	is the financial COF of low-temperature tracing due to leakage (open system), \$
FC_{loss}	is the cost of steam loss, \$
$FC_{\text{loss,D/S}}$	is the cost of condensate loss (downstream), \$
FC_{prod}	is the cost of production loss, \$
$FC_{\text{prod,D/S}}$	is the cost of production loss (downstream), \$
$FC_{\text{prod,process}}$	is the cost of production loss (process piping), \$
FC_{steam}	is the cost of steam production, \$/lb (\$/kg)
$F_{\text{D (ST, MP, or CV)}}$	is the design adjustment multiplier for steam traps, mechanical pump, or control valves
$F_{\text{O (ST, MP, or CV)}}$	is the operational adjustment multiplier for steam traps, mechanical pump, or control valves
$F_{\text{M (ST, MP, or CV)}}$	is the maintenance/inspection history adjustment multiplier for steam traps, mechanical pump, or control valves
injcst	is cost of personnel injury per individual, \$
irate	leakage rate is based on historical inspection data, lb/hr (kg/hr)
$\text{mass}_{\text{condensate}}$	is the condensate mass used in the consequence calculation associated with the n^{th} release hole size, lb (kg)
$P(t)_{\text{adjusted}}$	is the tailored probability of failure calculation based on the condition of design/installation, operation, or maintenance history factors for steam trap, failure/year
$P(t)_{\text{f,after,cold}}$	is the POF due to blockage after inspection depending on the results, failure/year
$P(t)_{\text{f,after,leak}}$	is the POF due to leakage after inspection depending on the results, failures/year

$P(t)_{f,def,cold}$	is the POF due to leakage of steam traps, mechanical pumps, and control valves based on default values for Weibull parameters, failures/year
$P(t)_{f,def,leak}$	is the POF due to leakage of steam traps, mechanical pumps, and control valves based on default values for Weibull parameters, failures/year
$P(t)_{f(equ)}$	is the POF calculated for the steam-using equipment, failures/year
$P(t)_{f,final,cold(ST,MP \text{ or } CV)}$	is the tailored POF due to blockage calculated for the associated piping (combined POF), consisting of multiple steam traps, mechanical pumps, and control valves, failures/year
$P(t)_{f,final,cold(steam \text{ system})}$	is the POF for steam system due to blockage, failures/year
$P(t)_{f,final(equ)}$	is the tailored POF calculated for the steam-using equipment, failures/year
$P(t)_{f,final,leak(ST,MP \text{ or } CV)}$	is the tailored POF due to leakage calculated for the associated piping (combined POF), consisting of multiple steam traps, mechanical pumps, and control valves, failures/year
$P(t)_{f,final,leak(steam \text{ system})}$	is the POF for steam system due to leakage, failures/year
$P(t)_{f,final \text{ parallel},cold(ST,MP \text{ or } CV)}$	is the POF due to blockage for multiple steam traps, mechanical pumps, and control valves in parallel, failures/year
$P(t)_{f,final \text{ parallel},leak(ST,MP \text{ or } CV)}$	is the POF due to leakage for multiple steam traps, mechanical pumps, and control valves in parallel, failures/year
$P(t)_{f,final \text{ series},cold(ST,MP \text{ or } CV)}$	is the POF due to blockage for multiple steam traps, mechanical pumps, and control valves in series, failures/year
$P(t)_{f,final \text{ series},leak(ST,MP \text{ or } CV)}$	is the POF due to leakage for multiple steam traps, mechanical pumps, and control valves in series, failures/year
$P(t)_{f,prior,cold}$	is the probability of not failing due to blockage the inspection prior to inspection, failures/year
$P(t)_{f,prior,leak}$	is the probability of not failing due to leakage the inspection prior to inspection, failures/year
$P(t)_{f,upd,cold}$	is the probability of failure due to blockage used for inspection updating, failures/year
$P(t)_{f,upd,leak}$	is the probability of failure due to leakage used for inspection updating, failures/year

$P(t)_{f,wgt,cold}$	is the updated POF due to blockage after inspection, failures/year
$P(t)_{f,wgt,leak}$	is the updated POF due to leakage after inspection, failures/year
$P(t)_{fn,cold}$	is the POF due to blockage of steam traps, mechanical pumps, and control valves, n in series or parallel configurations, failures/year
$P(t)_{fn,leak}$	is the POF due to leakage of steam traps, mechanical pumps, and control valves, n in series or parallel configurations, failures/year
$popdens$	is the population density of personnel or employees in the unit, personnel/ft ² (personnel/m ²)
$Rate_{red}$	is the production rate reduction on a unit as a result of the equipment being out of service (%)
$R(t)$	is the risk as a function of time, \$/year
$R(t)_{cold}$	is the risk due to blockage as a function of time, \$/year
$R(t)_{leak}$	is the risk due to leakage as a function of time, \$/year
t	is the time at which the risk is to be calculated, years
$Unit_{prod}$	is the unit production margin (\$/day)
B	is the Weibull shape parameter estimated using AFT model
β_{equ}	is the shape factor for equipment from Table 7.14
β_{ST}	is the shape factor for steam traps, mechanical pumps, and control valves from Table 7.4
η	is the Weibull characteristic life parameter, years
$\eta_{adjusted}$	is the tailored characteristic life for the probability of failure calculation based on the condition of design/installation, operation, or maintenance history factor for steam trap, years
$\eta_{adj,cold(ST,MP \text{ or } CV)}$	is the tailored characteristic life for blockage based on condition of design/installation, operation, or maintenance history factors for equipment, years
$\eta_{adj,equ}$	is the tailored characteristic life based on condition of design/installation, operation, or maintenance history factors for equipment, years
$\eta_{adj,leak(ST,MP \text{ or } CV)}$	is the tailored characteristic life for leakage based on condition of design/installation, operation, or maintenance history factors for equipment, years
$\eta_{def,cold,ST}$	is the characteristic life parameter for blockage estimated using Weibull AFT model from Table 7.4 , years

$\eta_{\text{def, equ}}$	is the characteristic life parameter for equipment estimated using Weibull AFT model from Table 7.14 , years
$\eta_{\text{def, leak, ST}}$	is the scaled parameter for leakage estimated using Weibull AFT model from Table 7.4 , years
$\eta_{\text{upd, cold}}$	is the updated characteristic life for blockage after inspection results, years
$\eta_{\text{upd, leak}}$	is the updated characteristic life for leakage after inspection results, years

7.8 Tables

Table 7.1—Steam-using Application Groups and Equipment Examples

Application Group	Equipment Example	Process Application Examples
Steam-heated equipment	Process heat exchanger	Alkylation, distillation, gas recovery, isomerization, visbreaking, coking, storage tank heating
Direct steam application	Distillation tower	Distillation, fractionation
	Stripper	Crude and vacuum distillation, catalytic cracking, catalytic reforming, asphalt processing, lube oil processing, hydrogen treatment
	Flare	Air-assisted flares, pressure-assisted flares, enclosed ground flares
Steam-driven equipment	Steam turbine	Power generation, compressor mechanical drive, hydrocracking, naphtha reforming, pump mechanical drive
Steam distribution piping	Piping	Piping to distribute steam and condensate recovery
Steam tracing	Tracing	Utility stations, steam and condensate piping

Table 7.2—Steam Trap Types for Each of Three Categories of Steam Trap

Steam Trap Category	Common Applications	Steam Trap Type
Mechanical steam traps	The mainstream of traps used today on equipment that requires large discharge capacities. Temperature/pressure-controlled applications with fluctuating loads.	Free float
		Lever float
		Inverted bucket
Thermostatic steam traps	Where condensate backup can be tolerated or is required in order to remove excess enthalpy, e.g. noncritical tracing	Bimetal
		Balanced pressure trap
Thermodynamic steam traps	Tracing, drip, and certain light process steam applications	Thermodynamic disc
		Thermodynamic piston

Table 7.3—Basic Data Needed for POF Calculation of Steam System

Data	Description	Data Source
Steam trap type	Type of steam trap: — mechanical steam traps — free float — lever float — inverted bucket — thermostatic steam traps — bimetal — balanced pressure trap — thermodynamic steam traps — thermodynamic disc — thermodynamic piston	User specified
Steam trap/mechanical pump or control valve design, operational and maintenance/inspection history conditions	Data required on whether the following conditions apply: — design conditions exceed maximum allowable pressure or maximum allowable temperature (PMA/TMA) — steam trap configuration and capacity of individual steam traps — possibility of steam locking — any pipe bundling (i.e. inlet tracing pipe is heated by other bundled pipes) — no protection from weather — poor installation environment (i.e. higher than average failure rate at this location or area) — no strainer exists — trap is made of stainless steel (any grade) — internal and/or external strainer upstream of steam trap is installed — operation conditions do not exceed maximum operating pressure or PMO/TMO — operational stability is high, i.e. pressure/temperature/flow rate does not vary during normal operation — water hammer near the trap is recorded — disassembly preventive maintenance exists — built-in integral/self-cleaning exists	User specified
Steam system inspection history	— Date of testing — Type of test (effectiveness) — Results of test/inspection — Overhauled?	User specified
Steam-using Equipment	Steam-using equipment: — steam turbine — heat exchanger — tracing—general — tracing—low temperature [lower than 176 °F (80 °C)] — tracing—instrumentation — tracing—relief valve — steam main piping — condensate piping (recovery) — flare — distillation column	Fixed equipment
Equipment details	— Operating conditions — Design conditions — Dimensions	User specified

Table 7.4—Default Weibull Parameters for Different Steam Traps, Control Valve, and Mechanical Pump

Steam Trap Category	Steam Trap Type	Default β_{ST}	Default Value for Leakage Failure Mode $\eta_{def,leak,ST}$	Default Value for Blockage Failure Mode $\eta_{def,cold,ST}$
Mechanical steam traps	Free float	1.8	16.1	13.8
	Inverted bucket	1.6	16.1	13.8
	Lever float	1.7	11.7	8.5
Thermostatic steam traps	Bimetal	1.8	8	7.5
	Balanced pressure	2	5.3	5.2
Thermodynamic steam traps	Disc	2	9.4	5
	Impulse	2	9.4	5
Control valve		1.8	61.5	61.5
Mechanical pump		1.2	3.1	3.1

Table 7.5—Design Condition Adjustment for Steam Trap

Design Condition	Description	Adjustment Multiplier for Design Conditions, F_{DST}
Poor	If all of the below criteria are true: a. design conditions exceed PMA/TMA b. possibility of steam locking c. if any pipe bundling d. no protection from weather e. poor installation environment f. no strainer exists	0.5
Average	If any of the following criteria are true: a. design conditions exceed PMA/TMA b. possibility of steam locking c. if any pipe bundling d. no protection from weather e. poor installation environment f. no strainer exists	0.85
Good	If none of the following criteria are true AND the trap is not made of stainless steel (any grade) AND internal or external strainer is installed: a. design conditions exceed PMA/TMA b. possibility of steam locking c. if any pipe bundling d. no protection from weather e. poor installation environment f. no strainer exists	1.0
Very Good	If none of the following criteria are true AND the trap is made of stainless steel (any grade) AND both internal and external strainer is installed: a. design conditions exceed PMA/TMA b. possibility of steam locking c. if any pipe bundling d. no protection from weather e. poor installation environment f. no strainer exists	1.15
NOTE 1 Steam locking: equipment configuration causing steam-condensate mixture entering the trap or piping configuration causing steam to move ahead of condensate into the trap. NOTE 2 Pipe bundling: inlet tracing pipe is heated by other bundled pipes. NOTE 3 Poor installation environment: higher than average failure rate at this location or area.		

Table 7.6—Operation Condition Adjustment for Steam Trap

Operation Condition	Description	Adjustment Multiplier for Design Conditions, F_{OST}
Poor	If operation conditions exceed PMO/TMO AND operational stability is low (i.e. > 50 % operation load variations expected)	0.77
Average	If operation conditions do not exceed PMO/TMO AND operational stability is medium (i.e. $\leq$ 50 % operation load variations expected)	0.85
Good	If operation conditions do not exceed PMO/TMO AND operational stability is high (i.e. no operation load variations expected)	1

Table 7.7—Maintenance History/Inspection Condition Adjustment for Steam Trap

Maintenance Condition	Description	Adjustment Multiplier for Design Conditions, F_{MST}
Poor	If water hammer near the trap (i.e. within 10 m) is recorded in the past AND no disassembly preventive maintenance exists	0.65
Average	If water hammer near the trap (i.e. within 10 m) is recorded in the past AND disassembly preventive maintenance exists	0.72
Good	If water hammer near the trap (i.e. within 10 m) is not recorded AND disassembly preventive maintenance does not exist AND built-in manual cleaning exists	1.0
Very Good	If water hammer near the trap (i.e. within 10 m) is not recorded AND disassembly preventive maintenance exists AND built-in integral/self-cleaning exists	1.1

Table 7.8—Design Condition Adjustment for Mechanical Pump

Design Condition	Description	Adjustment Multiplier for Design Conditions, F_{DMP}
Poor	If all of the below criteria are true: a. design conditions exceed PMA/TMA b. possibility of steam locking c. poor installation environment d. system installation is nonideal	0.5
Average	If any of the following criteria are true: a. design conditions exceed PMA/TMA b. possibility of steam locking c. poor installation environment d. system installation is nonideal	0.8
Good	If none of the following criteria are true AND the trap is not made of stainless steel (any grade) AND system installation is average: a. design conditions exceed PMA/TMA b. possibility of steam locking c. poor installation environment	1.0
Very Good	If none of the following criteria are true AND the trap is made of stainless steel (any grade) AND system installation is ideal AND strainer installed: a. design conditions exceed PMA/TMA b. possibility of steam locking c. poor installation environment	1.25
NOTE System installation is nonideal: functionality is affected by sizing or configuration.		

Table 7.9—Operation Condition Adjustment for Mechanical Pump

Operation Condition	Description	Adjustment Multiplier for Design Conditions, F_{OMP}
Poor	If operation conditions exceed PMO/TMO AND operational stability is low (i.e. > 50 % operation load variations expected) AND pump load is high (i.e. > 75 % of pump capacity)	0.76
Average	If operation conditions do not exceed PMO/TMO AND operational stability is medium (i.e. ≤ 50 % operation load variations expected) OR pump load is medium (i.e. 50 % to 75 % of pump capacity)	1.2
Good	If operation conditions do not exceed PMO/TMO AND operational stability is high (i.e. no operation load variations expected) AND pump load is low (i.e. < 50 % of pump capacity)	1.6

Table 7.10—Maintenance History/Inspection Condition Adjustment for Mechanical Pump

Maintenance Condition	Description	Adjustment Multiplier for Design Conditions, F_{MMP}
Poor	If water hammer near the pump (i.e. within 10 m) is recorded in the past	0.65
Average	If water hammer near the pump (i.e. within 10 m) is not recorded AND disassembly preventive maintenance does not exist	1
Good	If water hammer near the pump (i.e. within 10 m) is not recorded AND disassembly preventive maintenance exists	2

Table 7.11—Design Condition Adjustment for Control Valve

Design Condition	Description	Adjustment Multiplier for Design Conditions, F_{DCV}
Poor	If all of the below criteria are true: a. design conditions exceed PMA/TMA b. possibility of steam locking c. poor installation environment (i.e. higher than average failure rate at this location or area)	0.6
Average	If any of the following criteria are true: a. design conditions exceed PMA/TMA b. possibility of steam locking c. poor installation environment (i.e. higher than average failure rate at this location or area)	0.75
Good	If none of the following criteria are true: d. design conditions exceed PMA/TMA e. possibility of steam locking f. poor installation environment (i.e. higher than average failure rate at this location or area)	1.0
Very Good	If none of the following criteria are true AND the trap is made of stainless steel (any grade) AND strainer installed: g. design conditions exceed PMA/TMA h. possibility of steam locking i. poor installation environment (i.e. higher than average failure rate at this location or area)	1.3

Table 7.12—Operation Condition Adjustment for Control Valve

Operation Condition	Description	Adjustment Multiplier for Design Conditions, $F_{O_{CV}}$
Poor	If operation conditions exceed PMO/TMO AND operational stability is low (i.e. > 50 % operation load variations expected) AND load is high (i.e. > 75 % of valve capacity)	0.77
Average	If operation conditions do not exceed PMO/TMO AND operational stability (i.e. ≤ 50 % operation load variations expected) is medium OR load is medium (i.e. 50 % to 75 % of valve capacity)	0.9
Good	If operation conditions do not exceed PMO/TMO AND operational stability is high (i.e. no operation load variations expected) AND load is low (i.e. < 50 % of valve capacity)	1.0

Table 7.13—Maintenance History/Inspection Condition Adjustment for Control Valve

Maintenance Condition	Description	Adjustment Multiplier for Design Conditions, $F_{M_{CV}}$
Poor	If water hammer near the trap (i.e. within 10 m) is recorded in the past	0.65
Average	If water hammer near the trap (i.e. within 10 m) is not recorded AND disassembly preventive maintenance does not exist	1
Good	If water hammer near the trap (i.e. within 10 m) is not recorded AND disassembly preventive maintenance exists	1.1

Table 7.14—Default Weibull Parameters for Steam-using Equipment

Equipment	Default $\eta_{\text{def,equ}}$	Default β_{equ}
Steam turbine	34.48	3
Heat exchanger	22.73	3
Tracing—instrumentation	52.63	3
Tracing—relief valve	55.56	3
Steam header	25.1	3
Condensate recovery piping	21.5	3
Distillation column	37	3
Flare	13.3	3

Table 7.15—Design Condition Adjustment for Steam-using Equipment

Design Condition	Description	Adjustment Multiplier for Design Conditions, $F_{D_{equ}}$
Poor	If all of the below criteria are true: a. no inlet steam separator b. no appropriate steam trap (type and capacity) is installed c. major reduction in number of steam traps (as per design) d. no automatic/manual start function e. one or more locations on steam supply that require condensate drainage cannot discharge continuously	0.5
Average	If any of the following criteria are true: a. no inlet steam separator b. no appropriate steam trap (type and capacity) is installed c. major reduction in number of steam traps (as per design) d. no automatic/manual start function e. one or more locations on steam supply that require condensate drainage cannot discharge continuously	0.7
Good	If none of the below criteria are true AND steam traps are not equipped with bypass: a. no inlet steam separator b. no appropriate steam trap (type and capacity) is installed c. major reduction in number of steam traps (as per design) d. no automatic/manual start function e. one or more locations on steam supply that require condensate drainage cannot discharge continuously	1.0
Very Good	If none of the below criteria are true AND all steam traps equipped with bypass a. no inlet steam separator b. no appropriate steam trap (type and capacity) is installed c. major reduction in number of steam traps (as per design) d. no automatic/manual start function e. one or more locations on steam supply that require condensate drainage cannot discharge continuously	1.1

Table 7.16—Operation Condition Adjustment for Steam-using Equipment

Operation Condition	Description	Adjustment Multiplier for Design Conditions, $F_{O_{equ}}$
Poor	If all of the below criteria are true: a. superheat rate < 18 °F (10 °C) b. cyclic operation c. exceed PMO/TMO/steam mass d. in the case of turbine: superheat rate < 27 °F (15 °C) AND (for condensing turbine only) operating vacuum > 25 % weaker than design e. in the case of heat exchanger: superheat rate is ≥ 18 °F (10 °C) AND steam passing through outlet control valve (if existing) AND > 50 % operation load variations expected AND stall condition exists (i.e. insufficient different pressure)	0.45
Average	If minimum of four criteria from the below are true: a. superheat rate < 10 °C (18 °F) b. cyclic operation c. exceed PMO/TMO/steam mass d. in the case of turbine: superheat rate < 27 °F (15 °C) AND (for condensing turbine only) operating vacuum > 25 % weaker than design e. in the case of heat exchanger: superheat rate is ≥ 18 °F (10 °C) AND steam passing through outlet control valve (if existing) AND > 50 % operation load variations expected AND stall condition exists (i.e. insufficient different pressure)	0.7
Good	If minimum of two criteria from the below are true: a. superheat rate < 18 °F (10 °C) b. cyclic operation c. exceed PMO/TMO/steam mass d. in the case of turbine: superheat rate < 27 °F (15 °C) AND (for condensing turbine only) operating vacuum > 25 % weaker than design e. in the case of heat exchanger: superheat rate is ≥ 18 °F (10 °C) AND steam passing through outlet control valve (if existing) AND > 50 % operation load variations expected AND stall condition exists (i.e. insufficient different pressure)	0.85
Very Good	If none of the below criteria is true: a. superheat rate < 18 °F (10 °C) b. cyclic operation c. exceed PMO/TMO/steam mass d. in the case of turbine: superheat rate < 27 °F (15 °C) AND (for condensing turbine only) operating vacuum > 25 % weaker than design e. in the case of heat exchanger: superheat rate is ≥ 18 °F (10 °C) AND steam passing through outlet control valve (if existing) AND > 50 % operation load variations expected AND stall condition exists (i.e. insufficient different pressure)	1.0

Table 7.17—Maintenance History/Inspection Condition Adjustment for Steam-using Equipment

Maintenance Condition	Description	Adjustment Multiplier for Design Conditions, $F_{M_{equ}}$
Poor	Ongoing likelihood of water hammer AND damage/repair AND trips reported previously AND no maintenance conducted as recommended	0.4
Average	Low likelihood of water hammer AND damage/repair AND trips reported previously AND no maintenance conducted as recommended	0.6
Good	No likelihood of water hammer AND damage/repair AND trips not reported previously in previous AND maintenance recommendations are all conducted	1.0

Table 7.18—Level of Inspection Confidence Factor for Steam Traps, Mechanical Pumps, and Control Valves

Inspection Results	Confidence Factor that Inspection Result Determines the True Damage State, CF				
	Ineffective	Poorly Effective	Fairly Effective	Usually Effective	Highly Effective
Leak detected, CF_{fail}	No credit	0.3	0.6	0.85	0.95
Leak not detected, CF_{pass}	No credit	0.3	0.6	0.75	0.9
Blocked, CF_{fail}	No credit	0.3	0.6	0.85	0.95
Not blocked, CF_{pass}	No credit	0.3	0.6	0.85	0.95

Table 7.19—Equations for Updating POF After Inspection

Inspection Effectiveness	Inspection Results	Equation for Updating the POF After Inspection
Highly Effective	No leakage or blockage detected	$P(t)_{f,wgt,leak} = P(t)_{f,final,leak(ST,MP \text{ or } CV)}^{-0.2}$ $\cdot P(t)_{f,final,leak(ST,MP \text{ or } CV)} \left(\frac{t}{\eta_{adj,leak(ST,MP \text{ or } CV)}} \right) + 0.2$ $\cdot P(t)_{f,final,leak(ST,MP \text{ or } CV)} \left(\frac{t}{\eta_{adj,leak(ST,MP \text{ or } CV)}} \right)$ $P(t)_{f,wgt,cold} = P(t)_{f,final,cold(ST,MP \text{ or } CV)}^{-0.2}$ $\cdot P(t)_{f,final,cold(ST,MP \text{ or } CV)} \left(\frac{t}{\eta_{adj,cold(ST,MP \text{ or } CV)}} \right) + 0.2$ $\cdot P(t)_{f,final,cold(ST,MP \text{ or } CV)} \left(\frac{t}{\eta_{adj,cold(ST,MP \text{ or } CV)}} \right)$
Usually Effective		
Fairly Effective		
Poorly Effective		
Highly Effective	Leakage or blockage detected	$P(t)_{f,wgt,leak} = P(t)_{f,after,leak}$ $P(t)_{f,wgt,cold} = P(t)_{f,after,cold}$
Usually Effective		
Fairly Effective		$P(t)_{f,wgt,leak} = \left(0.5 \cdot P(t)_{f,final,leak(ST,MP \text{ or } CV)} \right)$ $+ \left(0.5 \cdot P(t)_{f,after,leak} \right)$ $P(t)_{f,wgt,cold} = \left(0.5 \cdot P(t)_{f,final,cold(ST,MP \text{ or } CV)} \right)$ $+ \left(0.5 \cdot P(t)_{f,after,cold} \right)$
Poorly Effective		

Table 7.20—Required Data for COF Assessment

Cost Description	Data Source
Cost of steam, \$/lb (FC_{steam})	User specified
Cost of condensate, \$/lb ($FC_{\text{condensate}}$)	User specified
Leakage rate is based on historical inspection data, lb/hr (kg/hr) ($lrate$)	User specified
Cost of personnel injury per individual as per Part 3, Section 4.12.5 , \$ ($injcost$)	User specified
Population density of personnel or employees in the unit as per Part 3, Section 4.12.5 , personnel/ft ² ($popdens$)	User specified
Inspection interval, 8760 hours IF not defined by user	User specified
Daily production margin, $Unit_{\text{prod}}$, on the unit (\$/day)	User specified
Production rate reduction, $Rate_{\text{red}}$, on a unit as a result of the equipment being out of service (%)	User specified
The number of days, D_{sd} , required to shut a unit down to repair the equipment during an unplanned shutdown, days	User specified
The cost of production loss from downstream equipment, \$ ($FC_{\text{prod,D/S}}$)	User specified
The cost of production loss in process piping, \$ ($FC_{\text{prod,process}}$)	User specified
Component damage costs, applies to the cost of all downstream equipment as in Table 7.14 , \$ (FC_{comp} , $FC_{\text{comp,line}}$, $FC_{\text{comp,main}}$, $FC_{\text{comp,process}}$, $FC_{\text{comp,D/S}}$)	User specified

Table 7.21—COF Equations for Blockage (FC_{cold}) in Steam System

Equipment	Open/Closed System	Bypass (Open)	Bypass (Close)
Steam turbine	Open	5.155	5.154
	Closed	5.156	
Heat exchanger	Open	5.155	
	Closed	5.156	
Tracing—general	Open	5.155	5.157
	Closed	5.156	
Tracing—low temperature	Open	5.158	
	Closed	5.159	
Tracing—instrumentation	Open (general)	5.155	
	Open (low-temp)	5.158	
	Closed (general)	5.156	
	Closed (low-temp)	5.159	
Tracing—relief valve	Open (general)	5.155	
	Open (low-temp)	5.158	
	Closed (general)	5.156	
	Closed (low-temp)	5.159	
Steam header	Open	5.155	5.154
	Closed	5.156	
Condensate recovery	Open	N/A	
	Closed		
Distillation column	Open	5.155	5.154
	Closed	5.156	
Flare	Open	5.155	5.16
	Closed	5.156	

Table 7.22—COF Equations for Leakage (FC_{leak}) in Steam System

Equipment	Open/Closed System	Bypass (Open)	Bypass (Close)
Steam turbine	Open	5.155	5.155 (see Note)
	Closed	5.156	
Heat exchanger	Open	5.155	
	Closed	5.156	
Tracing—general	Open	5.155	
	Closed	5.156	
Tracing—low temperature	Open	5.158	5.158 (see Note)
	Closed	5.159	
Tracing—instrumentation	Open (general)	5.155	5.155 (see Note)
	Open (low-temp)	5.158	5.158 (see Note)
	Closed (general)	5.155	5.155 (see Note)
	Closed (low-temp)	5.159	5.158 (see Note)
Tracing—relief valve	Open (general)	5.155	5.155 (see Note)
	Open (low-temp)	5.158	5.158 (see Note)
	Closed (general)	5.155	5.155 (see Note)
	Closed (low-temp)	5.159	5.158 (see Note)
Steam header	Open	5.155	5.155 (see Note)
	Closed	5.156	
Condensate recovery	Open	N/A	
	Closed	5.161	N/A
Distillation column	Open	5.155	5.155 (see Note)
	Closed	5.156	
Flare	Open	5.155	
	Closed	5.156	
NOTE For leakage with a closed bypass in an open or closed system, use $FC_{inj} = 0$ in appropriate equations.			

7.9 Figures

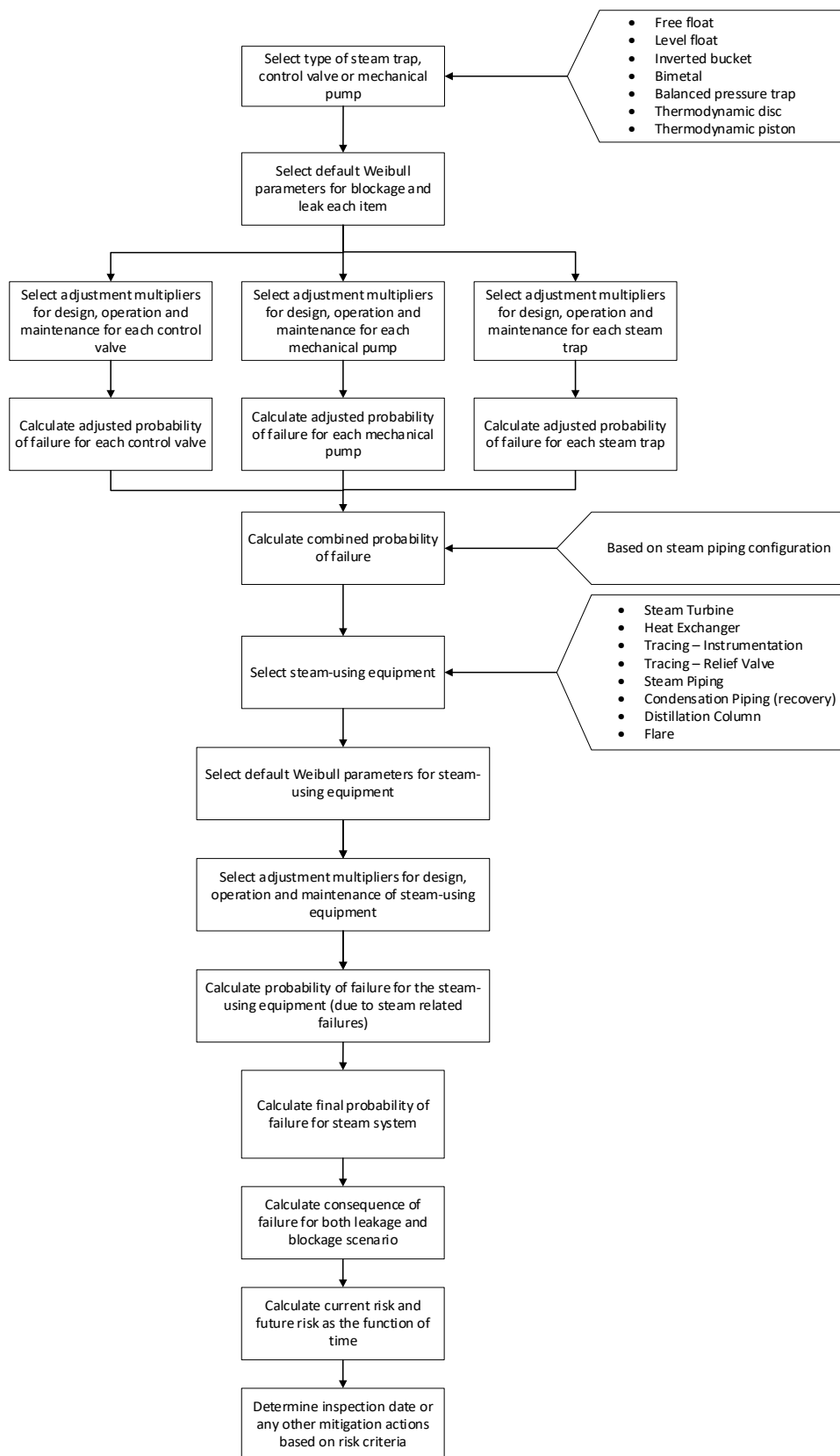


Figure 7.1—Overview of POF Calculation Framework for Steam Systems

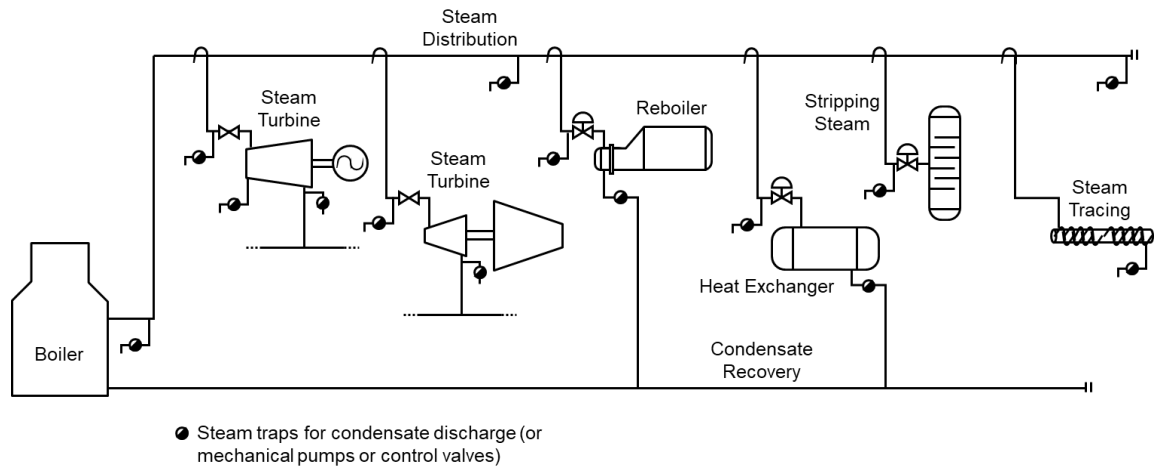


Figure 7.2—A Typical Layout of Multiple Steam Systems Containing Steam Traps (or Mechanical Pumps or Control Valves), Steam Piping, and Associated Equipment

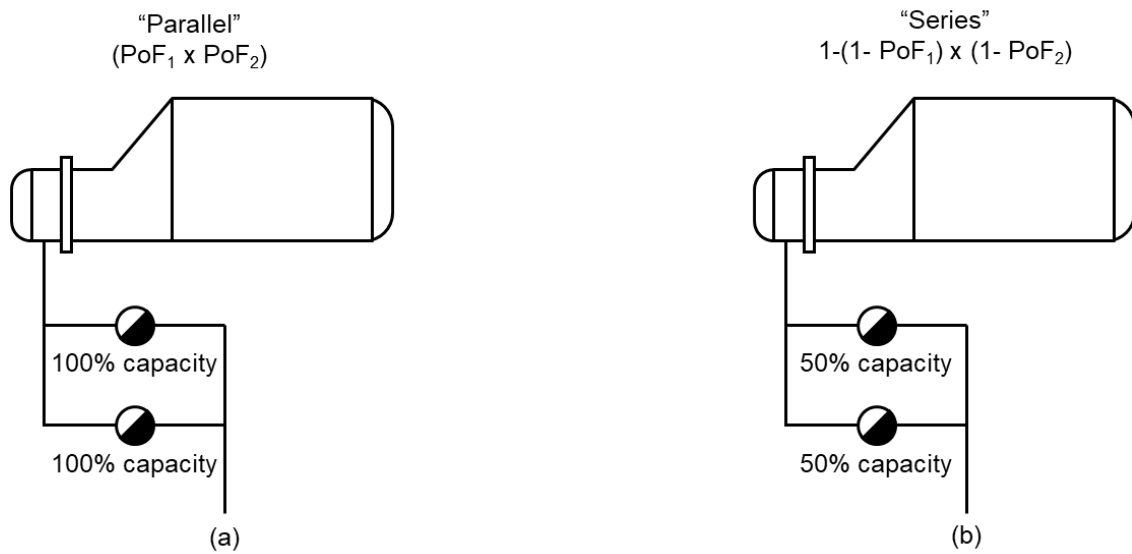
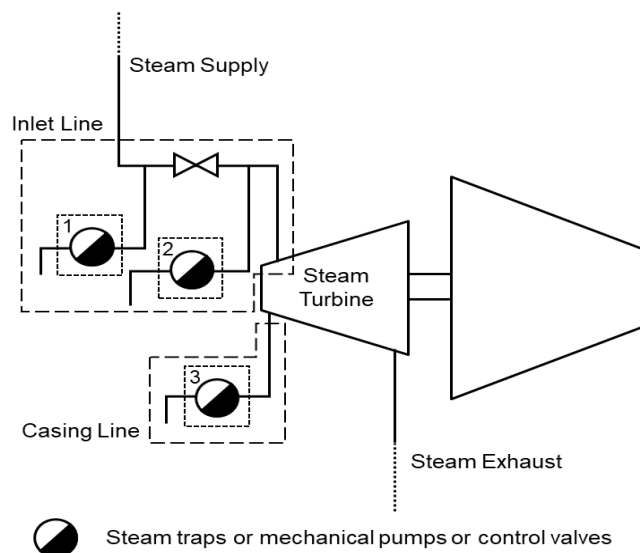
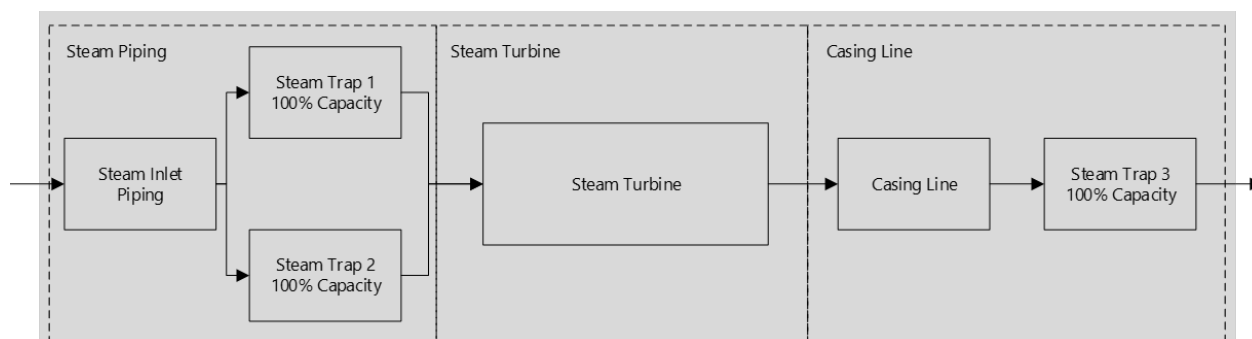


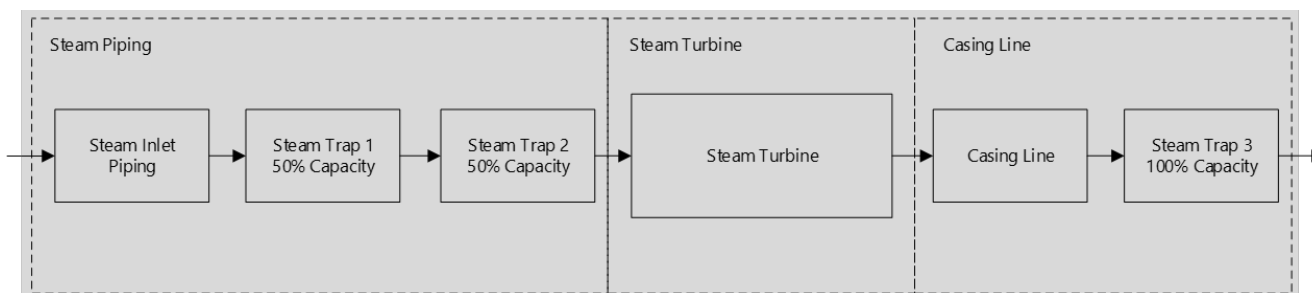
Figure 7.3—Sample Configuration of Multiple Steam Traps (or Mechanical Pumps or Control Valves)



a) Configuration of a Steam Turbine with Steam Traps or Mechanical Pumps or Control Valves



b) Reliability Block Diagram when Steam Trap 1 and 2 Are in Parallel and Operating at 100 % Capacity for the Calculation of POF



c) Reliability Block Diagram when Steam Trap 1 and 2 Are in Series and Operating at 50 % Capacity for the Calculation of POF

Figure 7.4—Sample Configuration of a Steam Turbine with Steam Traps or Mechanical Pumps or Control Valves

Part 5, Annex 5.A—Bundle Weibull Approach

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Risk-based Inspection Methodology

Part 5—Special Equipment

Annex 5.A—Bundle Weibull Approach

5.A.1 General

One method of an exchanger bundle Weibull analysis is performed using an exchanger reliability library to calculate β and η parameters. This annex provides an example and additional information for conducting a Weibull analysis using the reliability library described in [Part 5](#).

5.A.2 References

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 1—Introduction to Risk-Based Inspection Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 2—Probability of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 3—Consequence of Failure Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 4—Inspection Planning Methodology*

API Recommended Practice 581, *Risk-Based Inspection Methodology, Part 5—Special Equipment*

5.A.3 Determining Weibull Parameters

Weibull parameters (η , and β) are required to determine the POF of a heat exchanger bundle unless an MTTF is specified. [Part 5](#) references the process of statistically determining Weibull parameters of a set of previous bundles of a given heat exchanger or a set of similar bundles from an exchanger bundle reliability library. The Weibull parameters are used to calculate POF as a function of time for a bundle. This annex provides an example of calculating the Weibull parameters from a bundle failure library.

The advantage of using Weibull analysis to calculate POF is engineering decisions can be made with fewer failure data points than needed with other statistical distributions ^[11]. Weibull analysis is performed with less data, which is an advantage when little or no specific bundle failure data is available to provide a POF determination.

Two Weibull analyses to consider are provided in [Part 5](#), as follows.

- 1) An exchanger has experienced multiple tube bundle failures. A Weibull analysis is performed using the failure data from that specific exchanger. For example, if there is an exchanger with a sixth bundle in service, a Weibull analysis is performed using the five previous bundles failure data for that exchanger. This is a two-parameter (η and β) Weibull analysis.
- 2) An exchanger has no prior tube bundle failure data. In this case a slightly different Weibull analysis (Weibayes) is used. The Weibayes approach combines the methods of Weibull with the principles of Bayes theorem to develop statistical inferences using a combination of prior knowledge and current observations. The principle assumption of the Weibayes approach is that the shape parameter, β , which represents the slope of the Weibull plot for the group of similar bundles, will be identical to the bundle under evaluation. This assumption is valid for similarly designed bundles in similar service with the same failure mechanisms. The Weibayes approach provides a statistical failure analysis without large amounts of failure data for the specific bundle under evaluation.

Both Weibull analyses use a median rank regression analysis procedure to determine the Weibull parameters.

5.A.4 Required and Recommended Data to Perform a Weibull Analysis

The minimum required data to perform an RBI analysis of an exchanger bundle is given in [Part 5, Table 5.1](#). Additional information is recommended to determine η and β from a Weibull statistical analysis using a reliability library. This information is used to match criteria from the reliability library and filter the library to a subset of bundles with similar physical design and service. More data provided from the recommended data improves the subset of bundles that will represent the bundle under evaluation. The list of recommended additional data to perform a Weibull analysis is listed in [Table 5.A.1](#).

5.A.5 General Steps to Determine Weibull Parameters from an Exchanger Bundle Reliability Library

The following steps outline the procedure to determine Weibull parameters from a matching cut-set chosen from an exchanger bundle reliability library. If there are sufficient bundle failures of the specific exchanger, a Weibull analysis using only those bundles should be performed.

- a) Step 1—Provide the required and recommended bundle failure data or use a reliability library.

A reliability library is required for evaluation of risk associated with bundle failure. Specific exchanger data are required for each bundle in the reliability library. Minimum basic data required are indicated in [Part 5, Table 5.1](#). Recommended additional data needed for matching/filtering capability using a bundle reliability library are shown in [Table 5.A.1](#).

- b) Step 2—Determine the specific bundle failures or matching criteria cut-set ¹.

A group of bundles with similar characteristics is selected to create the data set for the Weibull analysis using the bundle reliability library and filtered using the data defined in [Section 5.A.4](#); [Part 5, Table 5.1](#); and [Table 5.A.1](#). The bundle reliability library is filtered to isolate one specific damage mechanism and to create an acceptable Weibull plot. It is important to note that exchanger bundles experience several damage mechanisms including corrosion, pitting, cracking, erosion/corrosion, vibration damage, mechanical failure, and tube end thinning. Failure data as well as “no-failure” data (suspensions) are used in the plotting of the Weibull curve.

- c) Step 3—Perform the Goodness of Fit Test.

The bundle data will not plot properly if the Weibull plot is created from a broad cut-set of the bundle reliability failure library. This is often caused by including multiple failure mechanisms in the plot and requires further filtering of the matching criteria to isolate the failures for one mechanism. A goodness of fit test is required to determine whether the subset of data accurately represents the bundle.

The two approaches for goodness of fit test for the data are *pve%* and *r²* methods, outlined in the *New Weibull Handbook* [21]. In general, a *pve%* of > 20 % is adequate for small failure sample sizes (< 20), and *pve%* fit improves as it approaches 100.

- d) Step 4—Determine Weibull Parameters from the Matching Cut-set.

The Weibull parameters β and η are obtained after the goodness of fit test has been applied in accordance with the *Weibull Handbook* methodology [21]. The standard method and best practice for estimating the Weibull parameters β and η for small- to moderate-sized data sets is a median rank

¹ Cut-sets are the unique combinations of component failures that can cause system failure. Cut-sets are user-defined partial data sub-sets of a heat exchanger bundle reliability library that share common attributes such as tube material, exchanger type, process unit, and shellside or tubeside fluids.

regression curve fitting using the time-to-failure as the dependent variable (X onto Y). Commercial software is available for performing a Weibull statistical analysis.

NOTE Most statisticians use confidence bounds on data to account for statistical distribution of the data. A 90 % lower bound confidence (LBC) interval is recommended using Fisher matrix bounds [19]. A 90 % LBC interval provides a 90 % confidence that the data point will fall to the right of the line on a Weibull plot.

5.A.6 Example Determination of Weibull Parameters Using Weibayes Analysis with a Reliability Library

Exchanger bundle 191-X-25A was evaluated using a bundle reliability failure library to match the following criteria.

- a) Tubeside fluid category—Crude.
- b) Controlling damage mechanism—General corrosion.
- c) Tubeside operating temperature range between 350 °F and 500 °F.
- d) TEMA type AES.
- e) Exchanger type—liquid/liquid process exchanger.
- f) Sulfur content greater than 1 %.

Of the nine bundles matching the criteria in the library in Table 5.A.2, five were failures and four were suspensions (bundles in service without failure reported). Three records were inspection records for the specific bundle under evaluation (191-X-25A). The remaining data was obtained for similar service bundles in the reliability library.

The data from Table 5.A.2 was plotted as a Weibull distribution in Figure 5.A.1 and calculated Weibull parameters for this matching bundle set were:

$$\begin{array}{ll} \beta = 2.568 & \text{slope parameter} \\ \eta = 20.45 & \text{characteristic life in years} \end{array}$$

The goodness of fit test parameter, $pve\%$, is shown in Figure 5.A.1 to be 99.9, which implies that the data properly fits a Weibull distribution.

POF as a function of time is determined for the cut-set data using Part 5, Equation (5.55).

$$\begin{aligned} P_{f,adj}^{\text{tube}} &= 1 - \exp \left[- \left(\frac{t}{\eta_{\text{mod}}} \right)^{\beta} \right] \\ P_{f,adj}^{\text{tube}} &= 1 - \exp \left[- \left(\frac{t}{20.45} \right)^{2.568} \right] \end{aligned} \tag{5.A.1}$$

NOTE The difference in η is only used in the Weibull analysis for the previous bundles.

Table 5.A.2 shows 191-X-25A bundle failures experienced after 18 and 22 years. The third bundle (T3) was in service for 16 years without failure (suspension). The modified characteristic life may be recalculated using Part 5, Equation (5.63) as demonstrated below:

$$\eta_{\text{mod}} = \left(\frac{1}{r} \sum_{i=1}^N t_{i,\text{dur}}^\beta \right)^{\frac{1}{\beta}} \quad (5.A.2)$$

$$\eta_{\text{mod}} = \left[\frac{(22)^{2.568} + (18)^{2.568} + (16)^{2.568}}{2} \right]^{\frac{1}{2.568}} = 22.16 \text{ years}$$

The characteristic life for the specific bundle experience is higher than the 20.45-year characteristic life calculated using the matching bundles from the reliability library (Figure 5.A.1).

It should be noted that this method assumes that the operating conditions for the bundle have not changed for the time period being evaluated and has not been redesigned. Changes in metallurgy, process conditions, or bundle design should be considered to determine if the entire past bundle history is representative of the current bundle under evaluation.

5.A.7 Nomenclature

The following lists the nomenclature used in Section 5.A.1.

P_f^{tube}	is the probability of the bundle failure, failures/yr
$pve\%$	is a goodness of fit test method for the data
r^2	is a goodness of fit test method for the data
t	is time, years
β	is the Weibull shape parameter that represents the slope of the line on a POF vs time plot
η	is the Weibull characteristic life parameter that represents the time at which 62.3 % of the bundles are expected to fail, years

5.A.8 Tables

Table 5.A.1—Minimum Required Data to Determine Weibull Parameters

Bundle Attribute General Data	Comments/Example Input
Exchanger type	Exchanger type or function, e.g. steam generator, steam reboiler, vaporizer
Tube type	Type of tube (e.g. plain, finned tube, or twisted tube)
Tube specification	Tube material specification and grade from TEMA datasheet and/or ASME manufacturer's form (e.g. SA-179, SA-213-TP304)
Tube material	Tube material type (e.g. carbon steel, 2.25 % Cr, 304L/321/347 SS, 2205 duplex SS, 904L, Alloy 800, Nickel 200, titanium Grade 2, aluminum alloy)
Process unit	Process unit type (e.g. amine treating, crude distillation unit, delayed coker, hydrogen reforming, sour water stripper, tail gas treater, ethylene, polypropylene, styrene)
Fluid name	Fluid name or description [e.g. crude, effluent, heavy gas oil (HGO)]
Fluid category	Fluid category (e.g. heavy crude feed, medium distillate, rich amine, H ₂ S, HF, well water, CO ₂)

Table 5.A.2—Example—Matching Bundles from Reliability Library

Bundle Tag #	In-service Duration (years)	Failure Reported
191-X-25A-T1	18	Yes
191-X-25A-T2	22	Yes
191-X-25A-T3	16	No
E101-A-T1	10	Yes
E322-A-T1	12	No
E322-A-T2	13	No
HE-115-T1	14	Yes
HE-115-T2	25	No
PR6419-T1	8	Yes

5.A.9 Figures

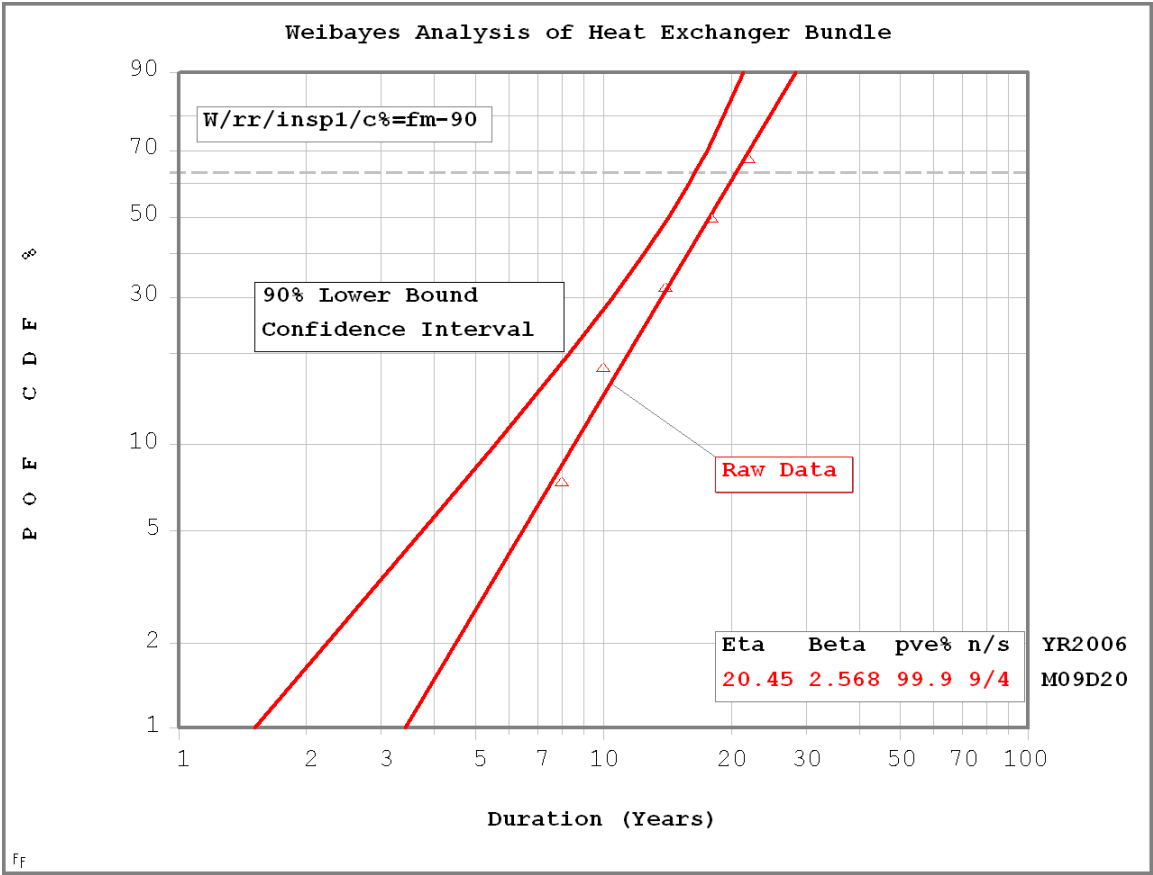


Figure 5.A.1—Weibull Plot of Similar Bundle Data

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Risk-based Inspection Methodology

Part 5—Special Equipment

Annex 5.B—Bibliography

5.B.1 General

The references for [Part 5](#) of this document are provided in [Section 5.B.2](#) of this annex.

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