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Addendum 1

Below is a summary of the changes made in this addendum.

Part 1

- Editorial changes and corrections
- Modified definition in Section 3.1.48
- Added/modified acronyms
- Combined generic failure frequency discussion from 4.1.2.1 into Part 2 discussion
- Updated example in Section 4.3.2.2 a) and b)
- Changed use of CA as variable name for consequence area throughout document
- Modified NOTE 1 in Tables 4.1/4.1M and 4.2/4.2M
- General clarifications and corrections in Section 7
    a. Modified Equation (1.31) (now 1.30)
    b. Added burst pressure discussion to Section 7.2.5 a)
    c. Added burst pressure consideration to Table 7.3
    d. Added Table 7.4 for design margins
    e. Added basis for example in Figure 7.6
- General clarifications and corrections in Section 8
    a. Correction Equation (1.79) (now (1.77)) and removed Equations (1.80) and (1.81) and text
    b. Removed software related terminology and references in Table 8.1
    c. Added notes to Table 8.5
    d. Added/modified notes in Table 8.6

Part 2

- Editorial changes and corrections
- Revised generic failure frequency discussion in Section 3.3 with text moved from Part 1, Section 4.1.2.1
- Equations (2.2) and (2.3): Changed definition for combining internal and external thinning damage based on general and local behavior
- Corrected total generic failure frequency for Tank650/TankBottom in Table 3.1
- Corrected question count for Safe Work Practices and total in Table 3.3
- Added consideration for cladding/weld overlay thickness in Section 4.5.7, Step 1
- Modified Equation (2.11) for cladding/weld overlay age
- Modified/simplified Step 6 determining the A_{rt} factor calculation with and without cladding/weld overlay (combining 2-4 and Equations (2.13) through (2.15) into one calculation step and equation

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- Added definition for base material thickness, t_{bm}, and cladding/weld overlay thickness, t_{cm}, to nomenclature in Section 4.6
- Section 15, *External Corrosion Damage Factor—Ferritic Component*
    a. Modified climate driver definitions and names in Sections 15.2 and 15.6.2, and driver description in Tables 15.1 and 15.2/15.2M
    b. Added consideration for measured wall loss, L_e, in Section 15.6.4, Step 4
    c. Modified age_{tke} definition in 15.7, *Nomenclature*
    d. Added measured wall loss, L_e, from external corrosion definition to 15.7 Nomenclature
- Section 16, *Corrosion Under Insulation Damage Factor—Ferritic Component*
    a. Modified climate driver definitions and names in Section 16.2 and driver description in Tables 16.1 and 16.2/16.2M
    b. Added consideration for measured wall loss, L_e, in Section 16.6.3, Step 4
    c. Modified age_{tke} definition in 16.7, *Nomenclature*
    d. Added measured wall loss, L_e, from external corrosion definition to 16.7 Nomenclature
- Section 17, *External Chloride Stress Corrosion Cracking Damage Factor—Austenitic Component*
    a. Added inspection explanation in Section 17.6.3, Step 3
    b. Modified driver definition in Tables 17.1 and 17.2
- Section 18, *External Chloride Stress Corrosion Cracking Under Insulation Damage Factor—Austenitic Component*
    a. Added inspection explanation in Section 18.6.3, Step 3
    b. Modified driver definition in Tables 18.1 and 18.2

Annex 2.A

- Corrected Possible Score points addition for Table 2.A.6, *Safe Work Practices*

Annex 2.B

- Corrected equation for NH_4HS concentration in Table 2.B.7.1, *Alkaline Sour Water Corrosion—Basic Data Required for Analysis*, for wt% NH_4HS based on wt% NH_3
- Corrected C_3 and C_4 factors in Table 2.B.11.3, *pH Calculation Parameters*

Annex 2.C

- Added/modified description of inspection for PRDs in Table 2.C.3.1, *Inspection and Testing Effectiveness for Pressure-relief Devices*

Part 3

- Editorial changes and corrections
- Modified Type 1 Fluid description in Section 4.1.5 b), Section 4.8.8 l), Step 8.12, and Section 4.8.8 n), Step 8.14
- Redefined diameter, d_n, for each hole size to a maximum of the component diameter in Sections 4.2.2 a) and 4.3.4 b)
- Modified definition of continuous release for blending based on release type in Sections 4.8.5 a) and 4.8.5 b)

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- Modified/simplified Equations (3.63) and (3.64) in Section 4.9.6 (does not change result)
- Added clarification for toxic consequences in the case of an instantaneous release using 3-minute continuous release factors in Section 4.9.15, Step 9.4.3
- Added calculation basis in Section 4.10.2 (1st paragraph)
- Clarified acid and caustic leaks are modeled as liquid and gas in Section 4.10.3 (1st paragraph)
- Clarifies liquid releases for acid and caustic releases in Section 4.10.6.2
- Corrected Equation (4.12.6) for financial impact based on personnel injury
- Corrected Equation (3.92)
- Added energy efficiency correction factor, $eneff_n$, definition to Section 4.13, *Nomenclature*
- Added representative fluids to Tables 4.1, 4.2/4.2M, 4.8/4.8M, and 4.9/4.9M to allow modeling of 100% toxic fluids without a flammable process carrier
- Redefined diameter, d_n, for each hole size to a maximum of the component diameter in Table 4.4/4.4M
- Corrected Equation (3.209) in Section 6.3.2, *Atmospheric Storage Tank Shell Course*
- Added definitions for the following variables in Section 6.13, *Nomenclature*:
    - $mass_{total}$
    - n^{th}
    - μ_w

Annex 3.A

- Editorial changes and corrections
- Added instantaneous release description for toxic consequences in Section 3.A.3.6.9.3

Annex 3.B

- No changes or corrections

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Risk-Based Inspection Methodology

API RECOMMENDED PRACTICE 581
THIRD EDITION, APRIL 2016

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AMERICAN PETROLEUM INSTITUTE

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PART 1

INSPECTION PLANNING METHODOLOGY

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PART 1 CONTENTS

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Risk-Based Inspection Methodology
Part 1—Inspection Planning Methodology

1 Scope

1.1 Purpose

This recommended practice, API 581, *Risk-Based Inspection Methodology*, provides quantitative 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, *Risk-Based Inspection* 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 quantitative calculation methods to determine 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 nondestructive examination (NDE). It is a consensus document containing methodology that owner–users 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.

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1.4 Organization and Use

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

a) Part 1—Inspection Planning Methodology,

b) Part 2—Probability of Failure Methodology,

c) Part 3—Consequence of Failure Methodology.

Part 1 provides methods used to develop an inspection plan for fixed equipment, including pressure vessels, piping, atmospheric storage tanks (ASTs), PRDs, and heat exchanger tube bundles. The pressure boundaries of rotating equipment may also be evaluated using the methods in Part 1. The methods for calculating the POF for fixed equipment are covered in Part 1 and Part 2. 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. 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.

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

1.5 Tables

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

Equipment Type	POF Calculation	COF Calculation		Risk Calculation	Inspection Planning
		Area	Financial		
Pressure vessels	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Part 1, Section 4.3	Part 1, Section 4.4
Heat exchangers [2]	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Part 1, Section 4.3	Part 1, Section 4.4
Air fin heat exchanger header boxes	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Part 1, Section 4.3	Part 1, Section 4.4
Pipes & tubes	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Part 1, Section 4.3	Part 1, Section 4.4
AST—shell courses	Part 2	Part 3, Section 4 or 5	Part 3,Section 6	Part 1, Section 4.3	Part 1, Section 4.4
AST—bottom plates	Part 2	NA	Part 3, Section 6	Part 1, Section 4.3	Part 1, Section 4.4
Compressors [3]	Part 2	Part 3, Section 4 or 5	Part 3, Section 4 or 5	Part 1, Section 4.3	Part 1, Section 4.4
Pumps [3]	Part 2	Part 3, Section 4 or 6	Part 3, Section 4 or 5	Part 1, Section 4.3	Part 1, Section 4.4
PRDs [4]	Part 1, Sections 7.2 and 7.3	NA	Part 1, Sections 7.4 and 7.5	Part 1, Section 7.6	Part 1, Section 7.7
Heat exchanger tube bundles	Part 1, Section 8.3	NA	Part 1, Section 8.4	Part 1, Section 8.5	Part 1, Section 8.6

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.

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2 References

2.1 Normative

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*, Risk-Based Inspection*, American Petroleum Institute, Washington, DC.

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*

2.2 Informative

[1] API 579-1/ASME FFS-1 2007, *Fitness-For-Service*, American Petroleum Institute, Washington, DC, 2007.

[2] CCPS, *Guidelines for Consequence Analysis of Chemical Releases*, ISBN 978-0-8169.0786-1, published by the Center for Chemical Process Safety of the American Institute of Chemical Engineers, 1995.

[3] TNO, *Methods for Calculation of Physical Effects* (TNO Yellow Book, Third Edition), Chapter 6: Heat Flux from Fires, CPR 14E, ISSN 0921-9633/2.10.014/9110, Servicecentrum, The Hague, 1997.

[4] CCPS, *Guidelines for Evaluating the Characteristics of Vapor Cloud Explosions, Flash Fires, and BLEVEs*, ISBN 0-8169-0474-X, published by the Center for Chemical Process Safety of the American Institute of Chemical Engineers, 1994.

[5] CCPS, *Guidelines for Vapor Cloud Explosions, Pressure Vessel Burst, BLEVE and Flash Fires Hazards*, ISBN 978-0-470-25147-8, published by the Center for Chemical Process Safety of the American Institute of Chemical Engineers, 2010.

[6] Lees, F.P., *Loss Prevention in the Process Industries: Hazard Identification, Assessment and Control*, Butterworth-Heinemann, Second Edition, Reprinted 2001.

[7] Baker, W.E., P.A. Cox, P.S. Westine, J.J. Kulesz, and R.A. Strelow, *Explosion Hazards and Evaluation*, Elsevier, New York, 1983.

[8] OFCM, Directory of Atmospheric Transport and Diffusion Consequence Assessment Models (FC-I3-1999), published by the Office of the Federal Coordinator for Meteorological Services and Supporting Research (OFCM) with the assistance of SCAPA members.

[9] Cox, A.W., F.P. Lees, and M.L. Ang, *Classification of Hazardous Locations*, Institution of Chemical Engineers, Rugby, UK, 1990.

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[11] API Standard 521, *Pressure-relieving and Depressuring Systems*, American Petroleum Institute, Washington, DC.

[12] API Standard 520, *Part 1—Sizing, Selection, and Installation of Pressure–relieving Devices,* American Petroleum Institute, Washington, DC.

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[15] CCPS, *Guidelines for Pressure Relief and Effluent Handling Systems*, ISBN 978-0-8169-0476-1, Center for Chemical Process Safety of the American Institute of Chemical Engineers, New York, 1998.

[16] Lees, F.P., *The Assessment of Human Reliability in Process Control*, Institution of Chemical Engineers Conference on Human Reliability in the Process Control Centre, London, 1983.

[17] IEC 61511, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector*, International Electrotechnical Commission, Geneva, Switzerland.

[18] Trident, Report to the Institute of Petroleum on the "Development of Design Guidelines for Protection Against Over-pressures in High Pressure Heat Exchangers: Phase One," Trident Consultants Ltd and Foster Wheeler Energy, Report J2572, known as "The Trident Report," 1993.

[19] Nelson, W., *Applied Life Data Analysis*, John Wiley, 1982.

[20] Mateshuki, R., "The Role of Information Technology in Plant Reliability," P/PM Technology, June 1999.

[21] Schulz, C.J., "Applications of Statistics to HF Alky Exchanger Replacement Decision Making," presented at the NPRA 2001 Annual Refinery & Petrochemical Maintenance Conference and Exhibition, 2001.

[22] Svensson, N.L., *The Bursting Pressure of Cylindrical and Spherical Shells, Pressure Vessel and Piping Design, Collected Papers 1927–1959*, pp. 326–333, ASME, New York, 1960.

[23] OSHA 29 *CFR* 1910.119, *Process Safety Management of Highly Hazardous Chemicals*.

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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.

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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).

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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

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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
HAZOP
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.

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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 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 (PM) 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 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.

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

3.1.53
physical explosion
The catastrophic rupture of a pressurized gas-filled vessel.

3.1.54
plan date
Date set by the owner–user that defines the end of plan period.

3.1.55
plan period
Time period set by the owner–user 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.

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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–user 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.

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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
Level of acceptable risk defined for inspection planning purposes.

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).

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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

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
CA	corrosion allowance
CCPS	Center for Chemical Process Safety
CFR	*Code of Federal Regulations*
CLSCC	chloride stress corrosion cracking
CML	condition monitoring location

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COD	chemical oxygen demand
COF	consequence of failure
CP	cathodic protection
CUI	corrosion under insulation
CUI CLSCC	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
external CLSCC	external chloride stress corrosion cracking
FC	financial consequence
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
GOR	gas–oil ratio
GFF	generic failure frequency
HAZ	heat-affected zone
HCL	hydrochloric acid
HF	hydrofluoric acid

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HGO	heavy gas oil
HIC	hydrogen-induced cracking
HP	high pressure
HSAS	heat stable amine salts
HSC	hydrogen stress cracking
HTHA	high temperature hydrogen attack
ID	inside diameter
IDLH	immediately dangerous to life or health
KO	knock-out
LBC	lower bound confidence
LFL	lower flammability limit
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
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

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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
PHA	process hazard analysis
PHAST	process hazard analysis software tools
P&ID	piping and instrumentation diagram
PM	preventative maintenance
POF	probability of failure
POFOD	probability of failure on demand
POL	probability of leak
PP	polypropelene
PRD	pressure-relief device
PRV	pressure-relief valve
PSM	process safety management
PT	penetrant testing
PTA	polythionic acid
P/V	pressure/vacuum vent
PVC	polyvinyl chloride
PWHT	postweld heat treatment
RBI	risk-based inspection
REM	rare earth mineral
RH	relative humidity
RMP	risk management plan
RPB	release prevention barrier
RSI	Ryznar Stability Index

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RT	radiographic testing
SCC	stress corrosion cracking
SCE	step cooling embrittlement
SFPE	Society of Fire Protection Engineers
SOHIC	stress-oriented hydrogen induced cracking
SOP	standard operating procedure
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 limits
TEMA	Tubular Exchanger Manufacturers Association
TKS	total key species
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).

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

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 accounts for the probability that accumulating damage that may result in a loss of containment will be discovered prior to the occurrence. The factor is also indicative of the quality of a facility's mechanical integrity and PSM programs. 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.

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 [2]. 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:

a) thinning (both general and local);

b) component lining damage;

c) external damage (thinning and cracking);

d) stress corrosion cracking (SCC);

e) high temperature hydrogen attack (HTHA);

f) mechanical fatigue (piping only);

g) 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.

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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):

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

Where the Weibull Shape Parameter, β, is unit-less, the Weibull characteristic life parameter, η, in years, and 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 β = 1, the mean time to failure (MTTF) and η are equal. This is true for all Weibull distributions regardless of the shape factor. 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 [3], [4], [5], [6], [7] 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 4.1.

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.

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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.

$$CA_f = a \cdot X^b \tag{1.3}$$

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 4,536 kg (10,000 lb) 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).

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

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

$$gff_{total} = \sum_{n=1}^{4} gff_n \tag{1.5}$$

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).

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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.

a) 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 fluids toxic consequence is not represented adequately by any of the reference fluids.

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 methodology.

d) The effects of boiling liquid expanding vapor explosion (BLEVE) are to be included in the methodology.

e) 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.

f) 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) [8], account for these important factors and will produce the desired data for the Level 2 analysis.

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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, Lees, and Ang [9], 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.

$$R(t) = P_f(t) \cdot C_f \tag{1.6}$$

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 procedure and/or integrity operating windows 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- and financial-based risk, as shown in Equations (1.7) and (1.8).

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

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

In these equations:

CA_f^{flam} is the consequence impact area expressed in units of area; and

CA_f^{fin} is the financial consequence expressed in economic terms.

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Note that in Equation (1.7) and Equation (1.8), the risk varies with time due to the fact that the POF is a function of time. Figure 4.1 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–user 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 towards the upper right-hand corner.

Two risk matrix examples are shown in Figure 4.2 and Figure 4.3. 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 or financial terms. Example numerical values associated with POF and COF (as area or financial) categories are shown in Table 4.1 and Table 4.2.

a) Unbalanced Risk Matrix (Figure 4.2)—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 4.1 values, a POF of 5.00E-04 is assigned a Category 3 and a COF of 800 ft^2 corresponds to a Category B. The 3B box is Low risk category when plotted on Figure 4.2.

b) Balanced Risk Matrix (Figure 4.3)—Similar to Figure 4.2, 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 4.1 are used, a POF of 5.00E-04 failures/year is assigned a Category 3 and a COF of 800 ft^2 corresponds to a Category B. However, the 3B box in the Figure 4.3 example corresponds to a Medium risk category.

Note that all ranges and risk category shading provided in Table 4.1 and Table 4.2 as well as Figure 4.2 and Figure 4.3 are examples of dividing the plot into risk categories and are not recommended risk targets and/or thresholds. It is the owner–users' 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 area and financial COF are shown in Figure 4.4 and Figure 4.5, 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 or financial 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 4.4. For example, a POF of 5.00E-04 and a COF of $125,000 are assigned a Medium risk category.

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4.3.3 General Comments Concerning Risk Plotting

Note the following when using the examples in Figure 4.2 through Figure 4.5:

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 towards 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 4.2 though Figure 4.5 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 towards inspection-based methods;

b) if COF drives the risk (the data drift toward the COF axis), the risk mitigation strategy may be weighted more towards 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–user to:

a) determine the type of plot to be used for reporting and prioritization,

b) determine the risk acceptance criteria (POF and COF category ranges),

c) document the risk plotting process,

d) 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) and 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, 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.

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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) and Equation (1.8), 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) and Equation (1.8), the equations can be rewritten as Equation (1.9) and Equation (1.10):

$$R(t,I_E) = P_f(t,I_E) \cdot CA_f^{flam} \text{ for area-based risk} \tag{1.9}$$

$$R(t,I_E) = P_f(t,I_E) \cdot CA_f^{fin} \text{ for financial-based risk} \tag{1.10}$$

4.4.2 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 (ft^2/year) or financial ($/year) terms, based on the owner–user preference.

b) POF Target—A frequency of failure or leak (#/year) 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 consequence area (CA_f) or financial consequence (FC) based on owner–user 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–user'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–user and that specific target criteria is not provided within this document. The above targets should be developed based on owner–user internal guidelines and overall risk tolerance. Owner–users often have corporate risk criteria defining acceptable and prudent levels of safety, environmental, and financial risks. These owner–user criteria should be used when making RBI decisions since acceptable risk levels and risk management decision-making will vary among companies.

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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 [10] 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 (1.9) or Equation (1.10).

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–user to create, adopt, and document their own specific levels of inspection effectiveness tables.

4.4.4 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 4.6, 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 4.7, the risk at the start time of the RBI analysis, or RBI date, exceeds the risk target. An inspection is recommended to reduce the risk below the risk target by the plan date.

c) Case 3—Risk at the Plan Date Does Not Exceed the Risk Target**—**As shown in Figure 4.8, 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 4.6. 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 that in Figure 4.6, a *C Level* inspection at the target date would not have been sufficient to satisfy the risk target criteria.

4.5 Nomenclature

A_n	is the cross-sectional hole area associated with the n^{th} release hole size, mm^2 (in.^{2})
A_{rt}	is the metal loss parameter

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a	is a variable provided for reference fluids for Level 1 COF analysis
b	is a variable provided for reference fluids for Level 1 COF analysis
C_f	is the COF, m^2 (ft^2) or $
CA_f	is the consequence impact area, m^2 (ft^2)
CA_f^{fin}	is the financial consequence, $
CA_f^{flam}	is the flammable consequence impact area, m^2 (ft^2)
$CA_{f,n}^{flam}$	is the flammable consequence impact area for each hole, m^2 (ft^2)
$D_f(t)$	is the DF as a function of time, equal to $D_{f\text{-}total}$ evaluated at a specific time
D_f^{thin}	is the DF for thinning
$D_{f\text{-}total}$	is total DF for POF calculation
F_{MS}	is the management systems factor
FC	is the financial consequence, $
gff	is the GFF, failures/year
gff_n	is the GFF for each of the n release hole sizes selected for the type of equipment being evaluated, failures/year
gff_{total}	is the sum of the individual release hole size generic frequencies, failures/year
k	is the release fluid ideal gas specific heat capacity ratio, dimensionless
$P_f(t)$	is the POF as a function of time, failures/year
$P_f(t,I_E)$	is the POF as a function of time and inspection effectiveness, failures/year
P_s	is the storage or normal operating pressure, kPa (psi)
R	is the universal gas constant = 8314 J/(kg-mol)K [1545 ft-lbf/lb-mol°R]
$R(t)$	is the risk as a function of time, m^2/year (ft^2/year) or $/year
$R(t,I_E)$	is the risk as a function of time and inspection effectiveness, m^2/year (ft^2/year) or $/year
t_{min}	is the minimum required thickness, mm (in.)
X	is the release rate or release mass for a Level 1 COF analysis, kg/s [lb/s] or kg [lb]
β	is the Weibull shape parameter
η	is the Weibull characteristic life parameter, years

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4.6 Tables

Table 4.1—Numerical Values Associated with POF and Area-based COF Categories

	Probability Category [1,2,3]		**Consequence Category** [4]	
Category	**Probability Range**	**DF Range**	**Category**	**Range** (ft^2)
1	$P_f(t,I_E) \le$ 3.06E-05	$D_{f\text{-}total} \le 1$	A	$CA_f^{flam} \le 100$
2	3.06E-05 < $P_f(t,I_E) \le$ 3.06E-04	$1 < D_{f\text{-}total} \le 10$	B	$100 < CA_f^{flam} \le 1{,}000$
3	3.06E-04 < $P_f(t,I_E) \le$ 3.06E-03	$10 < D_{f\text{-}total} \le 100$	C	$1{,}000 < CA_f^{flam} \le 10{,}000$
4	3.06E-03 < $P_f(t,I_E) \le$ 3.06E-02	$100 < D_{f\text{-}total} \le 1{,}000$	D	$10{,}000 < CA_f^{flam} \le 100{,}000$
5	$P_f(t,I_E) >$ 3.06E-02	$D_{f\text{-}total} > 1{,}000$	E	$CA_f^{flam} > 100{,}000$

NOTE 1 POF values are based on a *gff* of 3.06E-05 and an F_{MS} of 1.0. If the suggested *gff* 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 Part 1, 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 4.11.4.

Table 4.1M—Numerical Values Associated with POF and Area-based COF Categories

	Probability Category [1,2,3]		**Consequence Category** [4]	
Category	**Probability Range**	**DF Range**	**Category**	**Range** (m^2)
1	$P_f(t,I_E) \le$ 3.06E-05	$D_{f\text{-}total} \le 1$	A	$CA_f^{flam} \le 9.29$
2	3.06E-05 < $P_f(t,I_E) \le$ 3.06E-04	$1 < D_{f\text{-}total} \le 10$	B	$9.29 < CA_f^{flam} \le 92.9$
3	3.06E-04 < $P_f(t,I_E) \le$ 3.06E-03	$10 < D_{f\text{-}total} \le 100$	C	$92.9 < CA_f^{flam} \le 929$
4	3.06E-03 < $P_f(t,I_E) \le$ 3.06E-02	$100 < D_{f\text{-}total} \le 1000$	D	$929 < CA_f^{flam} \le 9290$
5	$P_f(t,I_E) >$ 3.06E-02	$D_{f\text{-}total} > 1000$	E	$CA_f^{flam} > 9290$

NOTE 1 POF values are based on a *gff* of 3.06E-05 and an F_{MS} of 1.0. If the suggested *gff* 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 Part 1, 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 4.11.4.

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Table 4.2—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	$P_f(t,I_E) \le$ 3.06E-05	$D_{f\text{-}total} \le 1$	A	$CA_f^{fin} \le 10{,}000$
2	3.06E-05 < $P_f(t,I_E) \le$ 3.06E-04	$1 < D_{f\text{-}total} \le 10$	B	$10{,}000 < CA_f^{fin} \le 100{,}000$
3	3.06E-04 < $P_f(t,I_E) \le$ 3.06E-03	$10 < D_{f\text{-}total} \le 100$	C	$100{,}000 < CA_f^{fin} \le 1{,}000{,}000$
4	3.06E-03 < $P_f(t,I_E) \le$ 3.06E-02	$100 < D_{f\text{-}total} \le 1000$	D	$1{,}000{,}000 < CA_f^{fin} \le 10{,}000{,}000$
5	$P_f(t,I_E) >$ 3.06E-02	$D_{f\text{-}total} > 1000$	E	$CA_f^{fin} > 10{,}000{,}000$

NOTE 1 POF values are based on a *gff* of 3.06E-05 and an F_{MS} of 1.0. If the suggested *gff* 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 Part 1, 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 4.12.1.

4.7 Figures

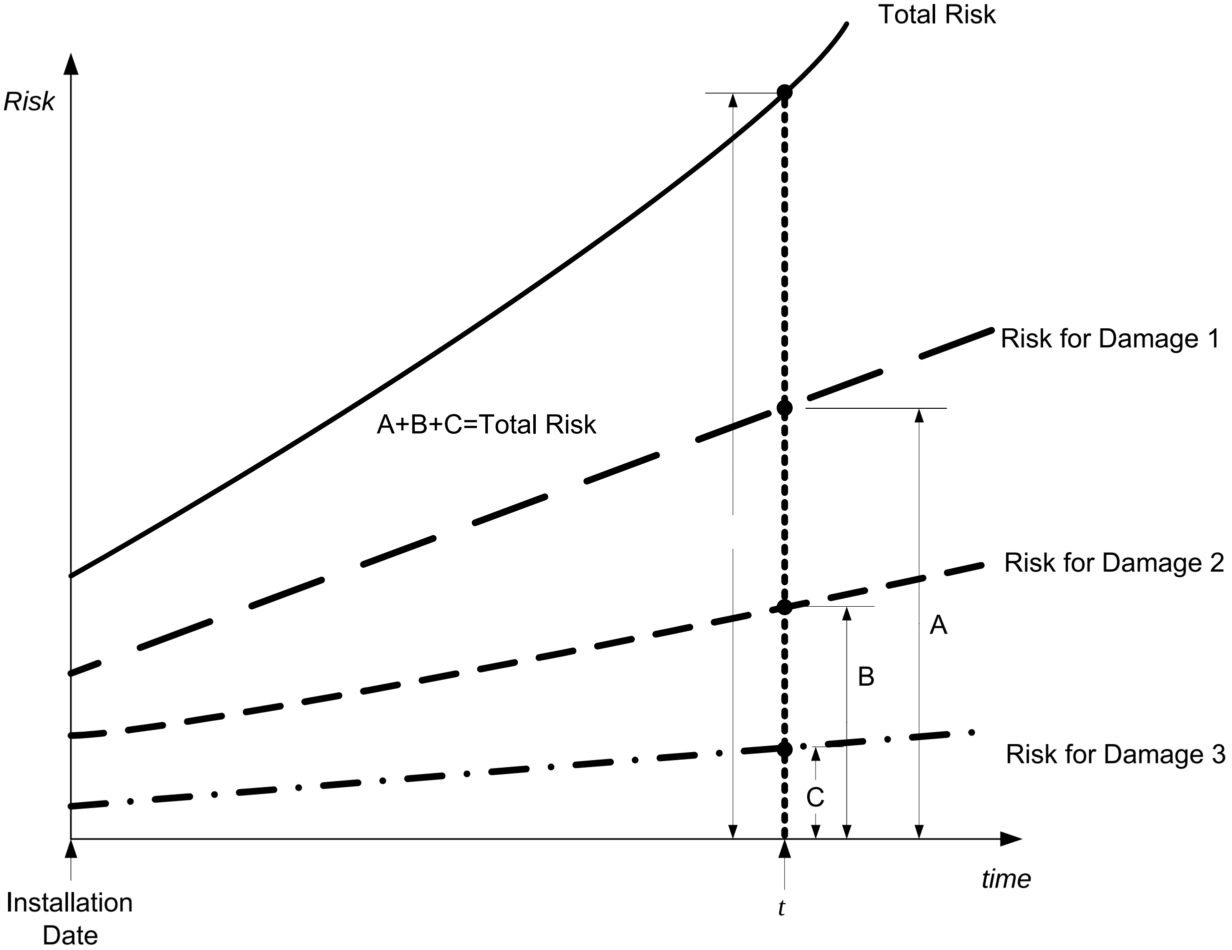

Figure 4.1—Superposition Principle for the Calculation of Risk

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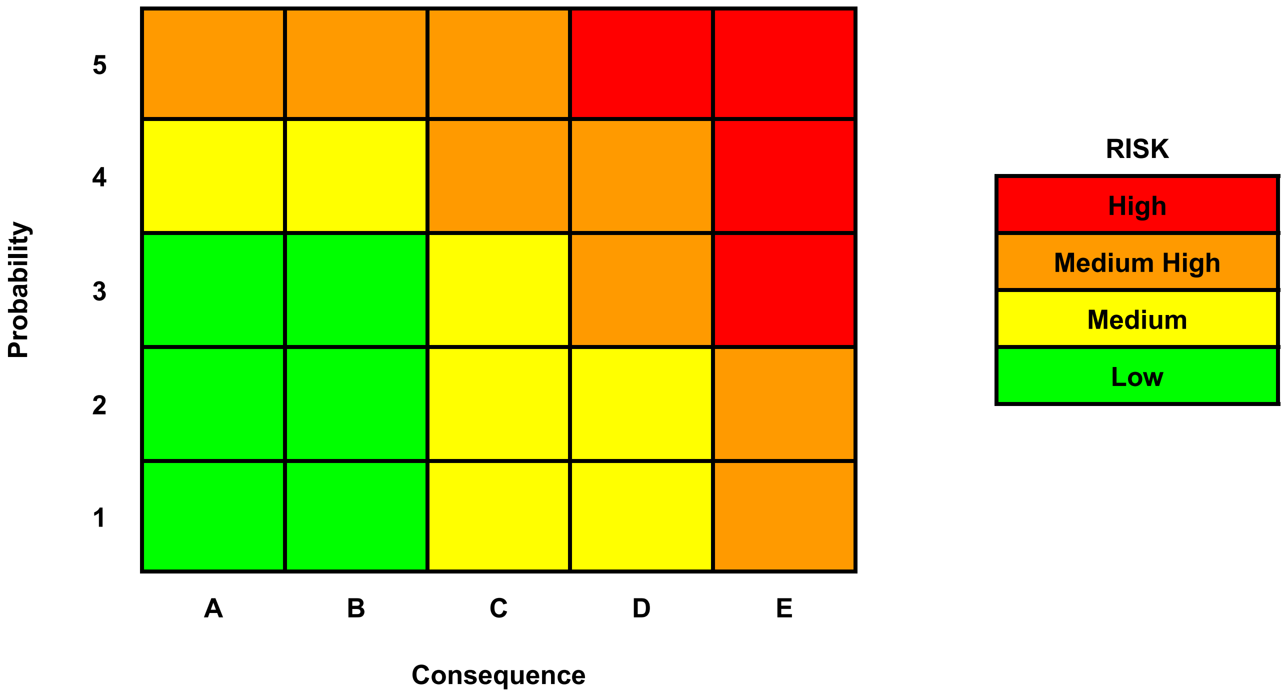
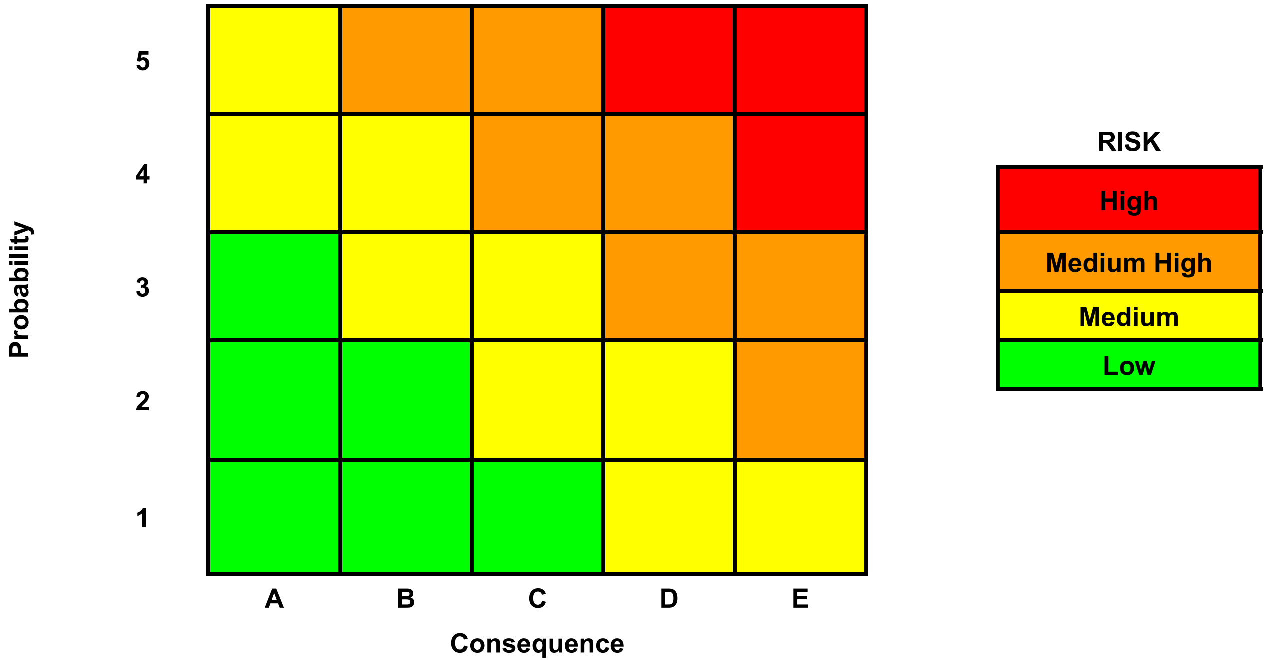


Probability	A	B	C	D	E
5	🟧	🟧	🟧	🟥	🟥
4	🟨	🟨	🟧	🟧	🟥
3	🟩	🟩	🟨	🟧	🟥
2	🟩	🟩	🟨	🟨	🟧
1	🟩	🟩	🟨	🟨	🟧

RISK
🟥 High
🟧 Medium High
🟨 Medium
🟩 Low

NOTE See Table 4.1 and Table 4.2 for ranges in probability and consequence categories.

Figure 4.2—Unbalanced Risk Matrix Example



Probability	A	B	C	D	E
5	🟨	🟧	🟧	🟥	🟥
4	🟨	🟨	🟧	🟧	🟥
3	🟩	🟨	🟨	🟧	🟧
2	🟩	🟩	🟨	🟨	🟧
1	🟩	🟩	🟩	🟨	🟨

RISK
🟥 High
🟧 Medium High
🟨 Medium
🟩 Low

NOTE See Table 4.1 and Table 4.2 for ranges in probability and consequence categories.

Figure 4.3—Balanced Risk Matrix Example

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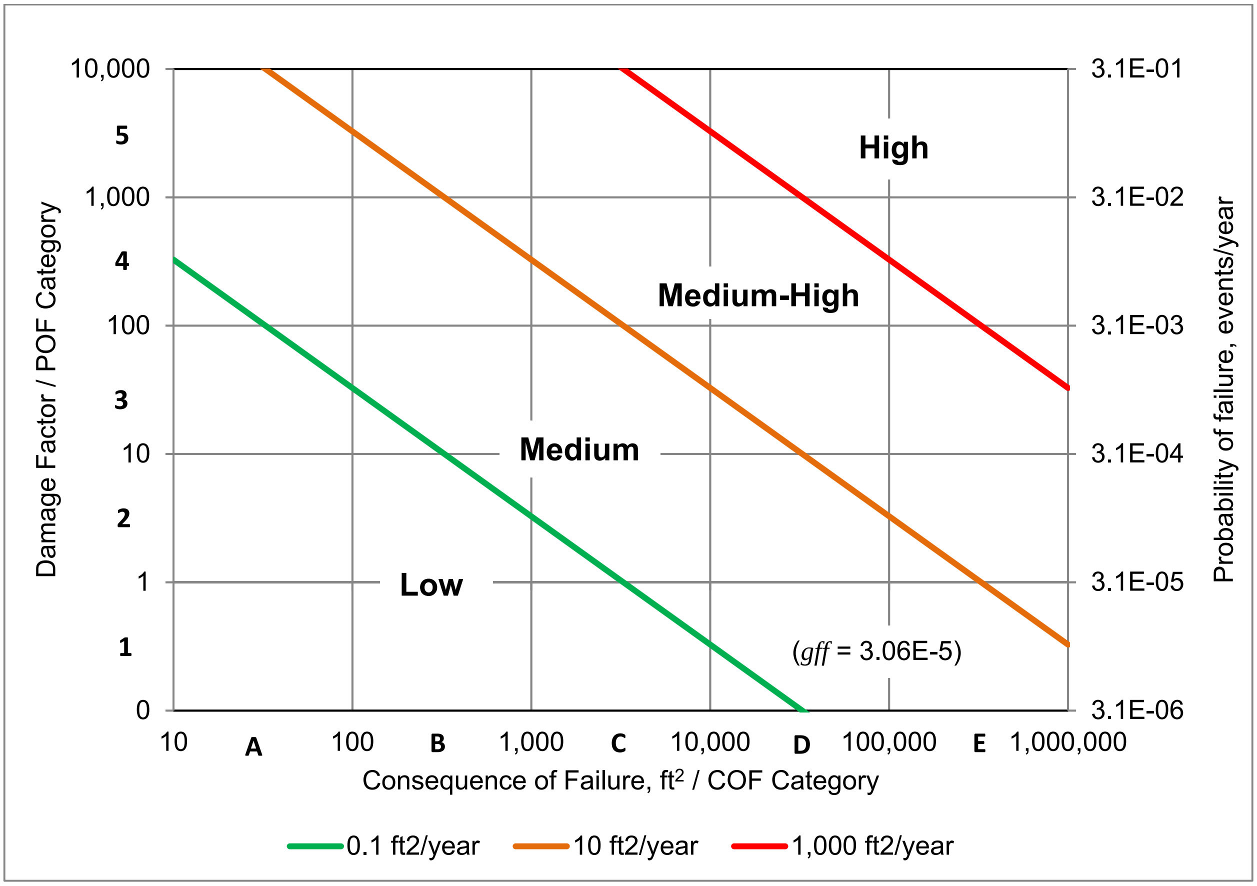

Figure 4.4—Example Iso-risk Plot for Consequence Area

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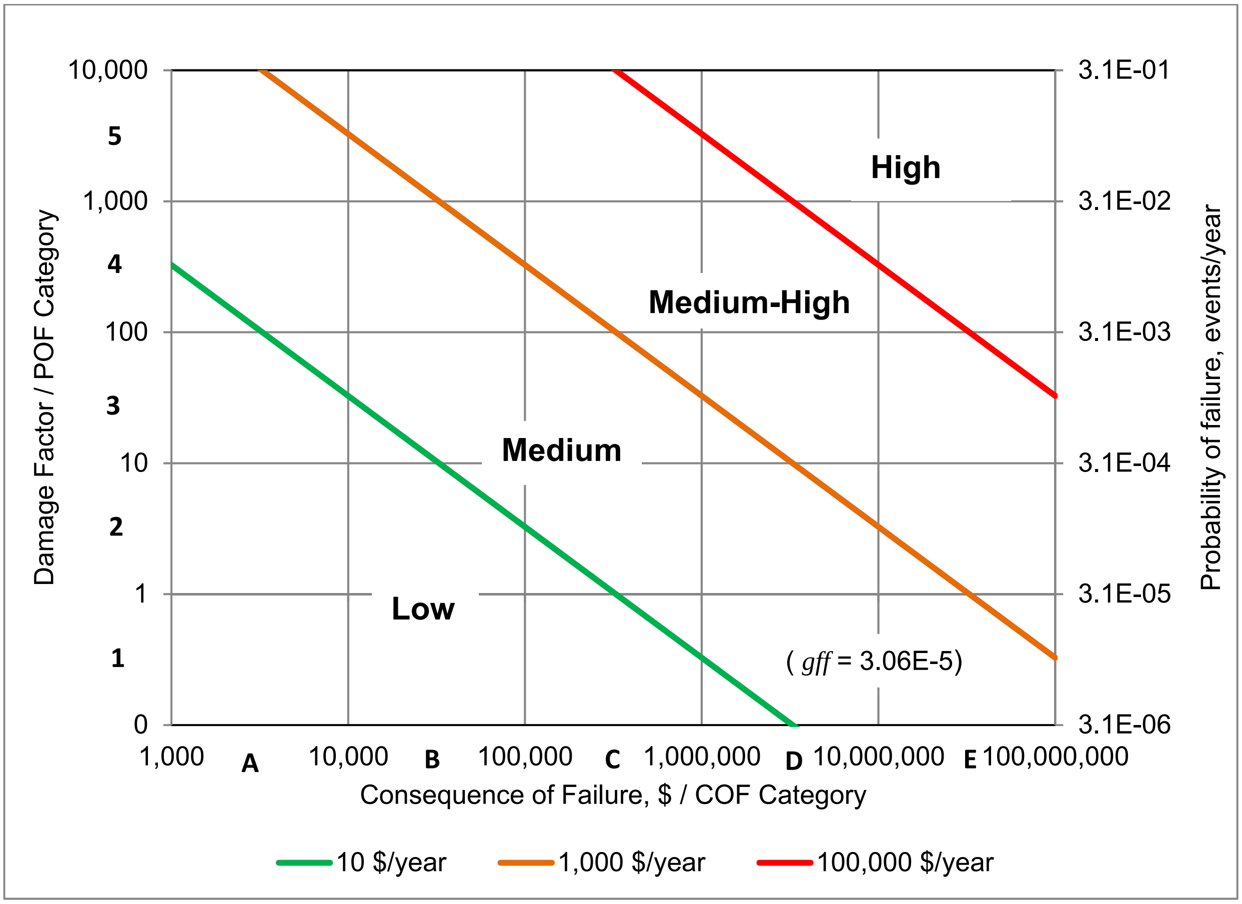

Figure 4.5—Example Iso-risk Plot for Financial Consequence

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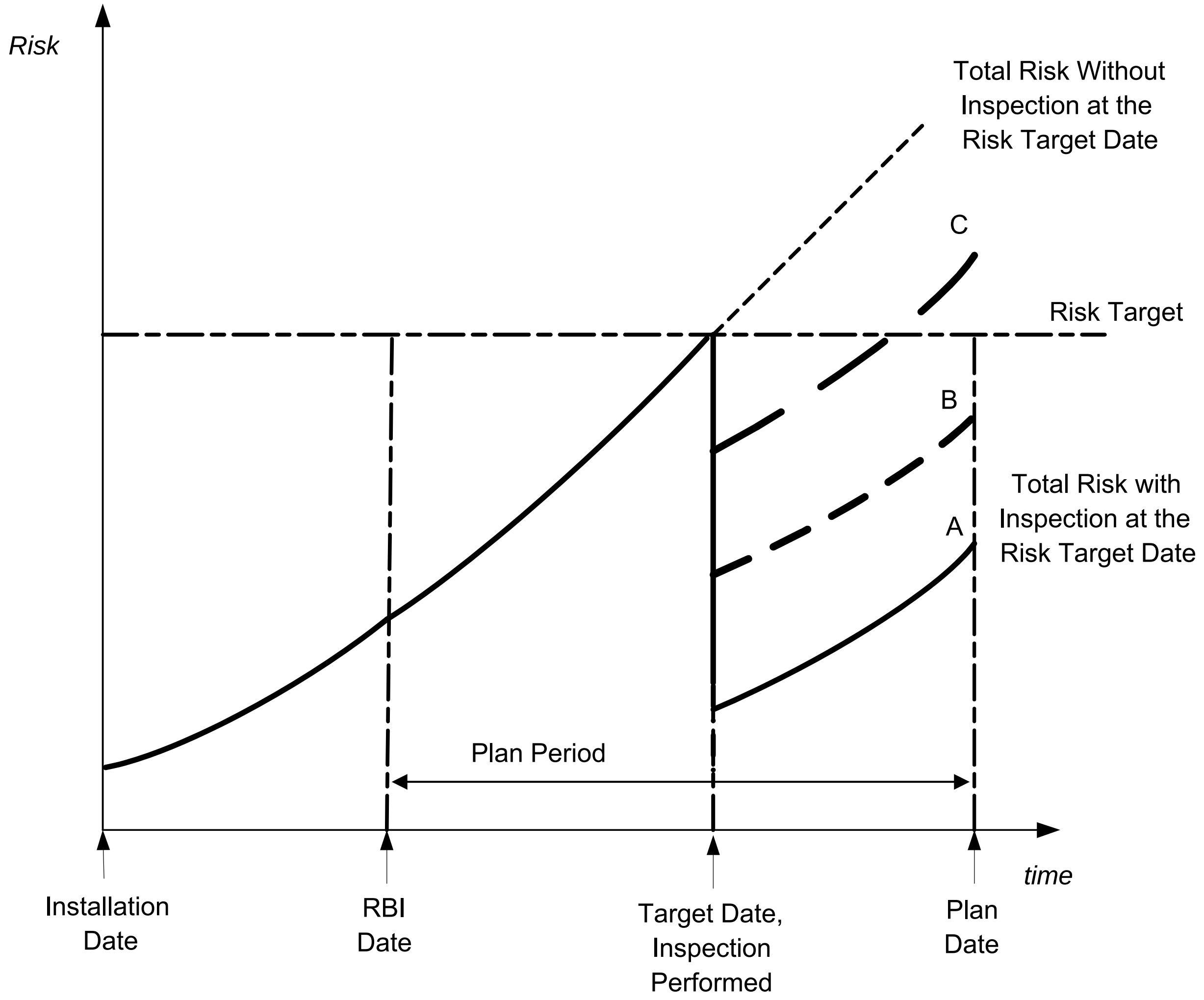

Figure 4.6—Case 1: Inspection Planning when the Risk Target Is Exceeded During the Plan Period

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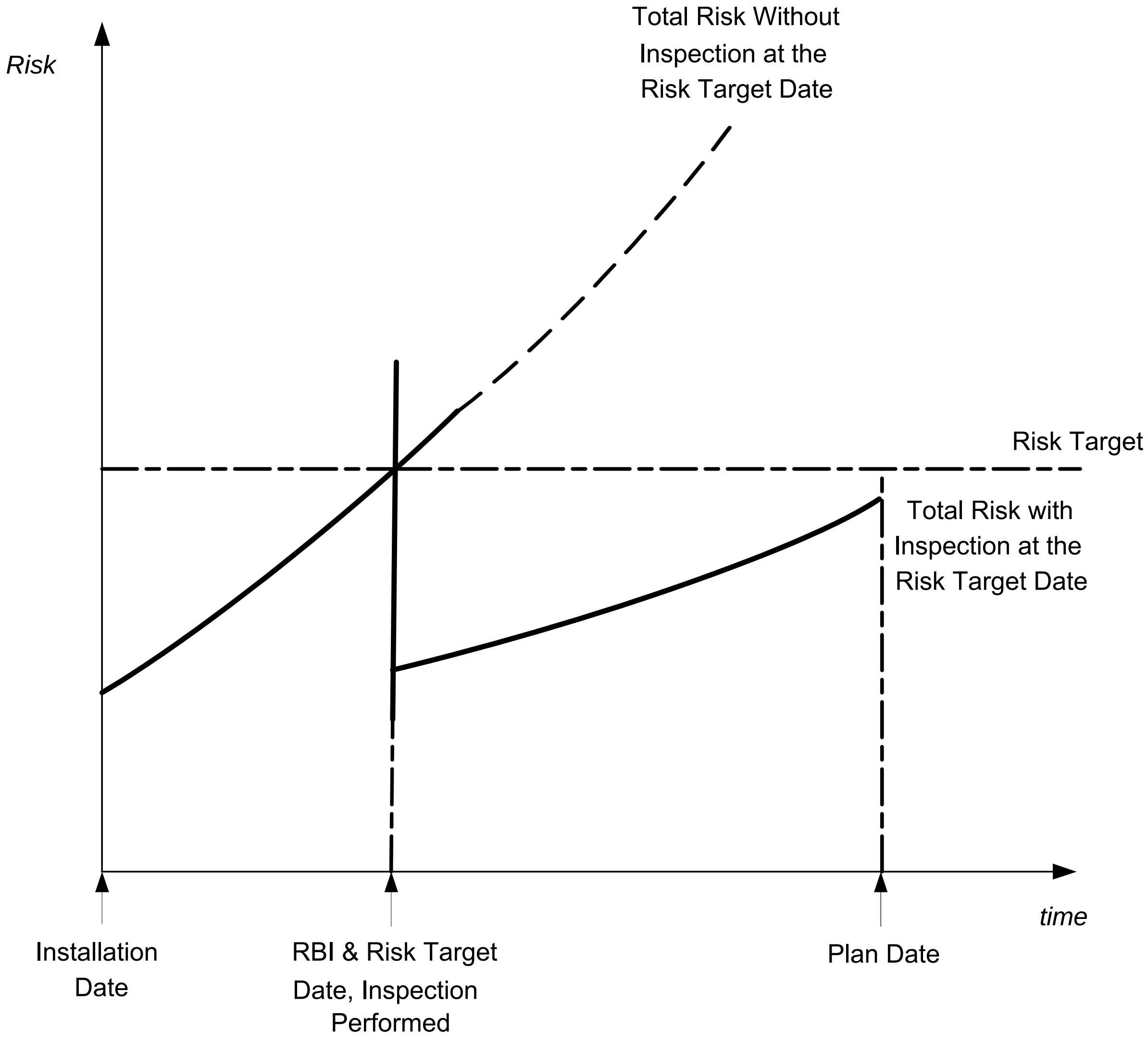

Figure 4.7—Case 2: Inspection Planning when the Risk Target Has Been Exceeded at or Prior to the RBI Date

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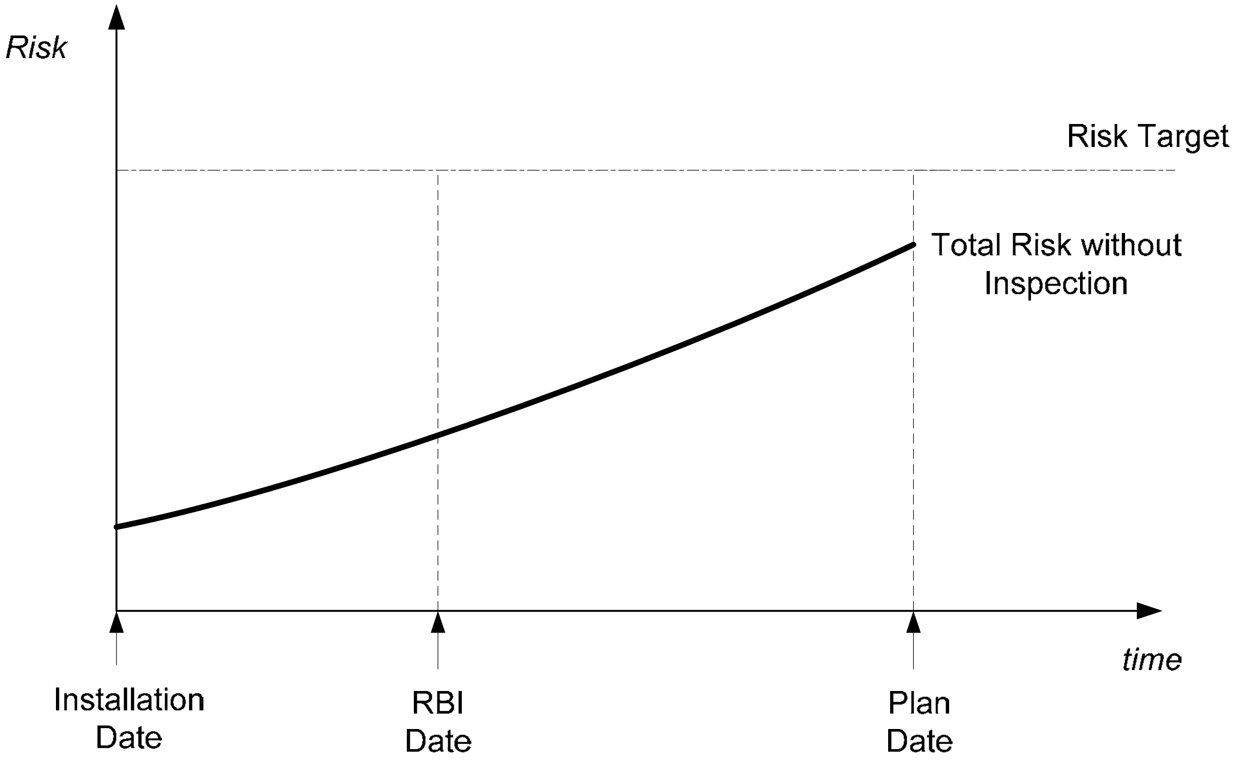

Figure 4.8—Case 3: Inspection Planning when Risk Target Is Not Exceeded During the Plan Period

5 Pressure Vessels and Piping

5.1 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.

5.2 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.

5.3 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.

5.4 Inspection Planning Based on Risk Analysis

The procedure to determine an inspection plan is provided in Section 4.4. 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.

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6 Atmospheric Storage Tanks (ASTs)

6.1 POF

POF calculation procedures for AST shell courses and bottom plates 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. Typically, the DFs for thinning in Part 2, Section 4 are used for AST components. However, DFs for other active damage mechanisms may also be calculated using Part 2, Sections 4 through Section 24.

6.2 COF

COF calculation procedures for two levels of consequence analysis are provided in Part 3, Section 6. In both methods, the COF may be determined in terms of consequence 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.

6.3 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.

6.4 Inspection Planning Based on Risk Analysis

The procedure to determine an inspection plan is provided in Section 4.4. 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.

7 Pressure-relief Devices (PRDs)

7.1 General

7.1.1 Overview

The major concern with PRDs and the main reason that routine PRD inspection and testing is required is that the device may fail to relieve overpressure events that can cause failure of the equipment protected by the device, leading to a loss of containment. There are also consequences associated with leakage of PRDs.

A risk-based approach to evaluating PRD criticality to set inspection/testing frequency is covered in this section. Included in the scope are all spring-loaded and pilot-operated relief valves and rupture disks. Additional PRD types, such as AST pressure/vacuum vents (P/Vs) and explosion hatches, may be analyzed provided reliability data in the form of Weibull parameters exist for the PRD type being considered.

It is not the intention of the methodology for the user to perform or check PRD design or capacity calculations. It is assumed that the owner–user has completed due diligence and the devices have been designed in accordance with API 521 [11] and sized, selected, and installed in accordance with API 520 [12]. It is also assumed that minimum inspection practices in accordance with API 576 [13] are in place.

The fundamental approach is to use a demand rate for the device combined with a probability of failure on demand (POFOD) determined from plant-specific data if available, or starting with 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 determined based on methods outlined in Part 3, but modified to include overpressure demand cases, the amount of expected overpressure upon PRD failure, and the additional consequences associated with

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device leakage. The combination of consequence with a time-based POF results in a risk value that increases with time between tests. This allows test intervals to be determined based on risk targets.

The flow chart shown in Figure 7.1 illustrates the basic methodology required for the determination of a RBI inspection and test schedule. The basic data required for the evaluation are listed in Table 7.1.

7.1.2 PRD Interdependence with Fixed Equipment

The risk of a PRD is directly related to the equipment that is protected by the PRD. The consequence analysis is performed as described in Part 3 for the protected equipment at an elevated pressure representing the estimated overpressure upon PRD failure to open upon demand.

7.1.3 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).

The FAIL modes are the primary concern, since their failure results in the potential of overpressuring protected equipment and loss of containment. Included in this case is the instance when a device only opens partially (DPO), where consequences are not as severe, but equipment may be overpressured nonetheless. API 581 conservatively considers any data indicating a partially open device as a failure to open as discussed in Section 7.2.2. Data that indicates a device OASP is included in the FAIL failure mode, since 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 test point that opens above set pressure 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 of this document.

A secondary concern is a failure of the 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 are failures that will not result in overpressure or loss of containment from the protected equipment, but will result in potential 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.

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7.1.4 Use of Weibull Curves

It is necessary to express the POF to open and the probability of leakage 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 [14], the cumulative failure density function, $F(t)$, sometimes referred to as Unreliability, is expressed in Equation (1.2) as shown in Section 4.1.3.

The Weibull η parameter or characteristic life is equivalent to the MTTF when the Weibull β parameter is equal to 1.0. Throughout this document, discussions are made related to the adjustment of the Weibull η parameter. Adjustments are made to the η parameter to increase or decrease the POFOD and leakage either as a result of environmental factors, PRD types, or as a result of actual inspection data for a particular PRD. These adjustments may be viewed as an adjustment to the MTTF for the PRD.

The assumption used to determine the default Weibull parameters is that PRDs in similar services will have a similar POFOD, P_{fod}, and similar probability of leakage, P_l. Therefore, industry failure rate data may be used as a basis for establishing the initial (or default) probabilities of failure for a specific device. The POFOD of the specific device is related to identifiable process and installation conditions. Such conditions may include process temperature, process corrosivity, and the tendency of the process to foul, polymerize, or otherwise block the PRD inlet or prevent the PRD from reseating during operation. Also associated with failure are conditions such as rough handling during transportation and installation and excessive piping vibration. Increased demand rates and improper installations that result in chatter may also increase the POFOD and leakage.

7.1.5 PRD Testing, Inspection, and Repair

Inspection, testing, reconditioning, or replacement of PRDs are recognized safe practices and serve to reduce the POFOD and leakage. One of the key assumptions of the PRD methodology is that a bench test of a PRD performed in the as-received condition from a process unit will result in a true determination of the performance of the PRD on the unit.

A good inspection program for PRDs will track the history of inspection and testing of each PRD. Based on this historical data, the PRD methodology will adjust the POF data for each PRD and allow for the varying degrees of inspection effectiveness. Where a shop bench pre-pop test is performed, the resulting pass/fail data are given the highest degree of confidence and the highest inspection effectiveness. Similarly, if a PRD is inspected and overhauled without a pre-test, a lower confidence level or lower inspection effectiveness is associated with the inspection.

7.1.6 PRD Overhaul or Replacement Start Date

When a PRD is overhauled in the shop, the basic assumption is made that the PRD is placed back into service in an as-new condition. The original install date for the PRD remains the same, but the last inspection date is changed to reflect the date that the PRD was overhauled. In this way, the calculated inspection interval and subsequent new due date for the PRD is based on the last inspection date on which the PRD was overhauled.

When a PRD is replaced in lieu of overhaul, the install date and last inspection date are identical. The calculated inspection interval and subsequent new due date for the PRD are based on the new install date.

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Often PRDs are pop-tested either in the field or in the shop without overhauling the PRD. In these instances, the PRD has not been returned to service in an as-new condition. Without an overhaul, the assumption is made that the PRD remains in the condition that it was in prior to testing. In these cases, the POFOD for the device may be adjusted based on the results of the field test (i.e. credit for inspection to reduce uncertainty); however, the last overhaul date remains unchanged and therefore 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 and not the last inspection date.

7.1.7 Risk Ranking of PRDs

The PRD methodology allows a risk ranking to be made between individual PRDs and also allows a risk ranking to be made between PRDs and other fixed equipment being evaluated.

There are two key drivers for the effective risk ranking of PRDs with other PRDs. The first driver is in establishing the specific reliability for each PRD. This may be accomplished by selecting the severity of service of each PRD, establishing a default POF, and modifying the POFOD using the actual testing and inspection history of each PRD. The second key driver is in the relative importance or criticality of each PRD. This is accomplished through the relief system design basis and knowledge of the overpressure demand cases applicable for each PRD. The more demand placed on a PRD and the more critical the PRD application, the higher the risk ranking should be.

7.1.8 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 must be tied directly to the equipment that the PRD protects. This is accomplished using direct links to the fixed equipment RBI analysis as covered in Part 2 and Part 3 of this document. The risk of loss of containment from fixed equipment increases proportionately with the amount of overpressure that occurs as a result of the PRD failing 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, this is tempered by the fact that the use of realistic PRD demand rates and accurate PRD failure rate data results in a low frequency of occurrence.

7.2 PRD POF (FAIL)

7.2.1 Definition

For a PRD, it is important that the definition of failure be understood, since it is different than failure of other equipment types. A PRD failure is defined as failure to open during emergency situations causing an overpressure situation in the protected equipment, resulting in loss of containment (failures/year). Leakage through a PRD is also a failure. This type of failure is discussed in Section 7.3.

7.2.2 Calculation of POF to Open

The fundamental calculation applied to PRDs for the fail to open case is the product of an estimated overpressure demand case frequency (or demand rate), the probability of the PRD failing to open on demand, and the probability that the protected equipment at higher overpressures will lose containment.

A PRD protects equipment components from multiple overpressure scenarios. Guidance on overpressure demand cases and pressure relieving system design is provided in API 521 [11]. Each of these scenarios (fire, blocked discharge, etc.) can result in a different overpressure, $P_{o,j}$, if the PRD were to fail to open upon demand. Additionally, each overpressure scenario has its own demand rate, DR_j. Demand cases are discussed in more detail in Section 7.4.3, Table 7.2, and Table 7.3. The expression for POF for a PRD for a particular overpressure demand case is as shown in Equation (1.11).

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$$P_{f,j}^{prd} = P_{fod,j} \cdot DR_j \cdot P_{f,j} \tag{1.11}$$

The subscript j in the above equation indicates that the POF for the PRD, $P_{f,j}^{prd}$, needs to be calculated for each of the applicable overpressure demand cases associated with the PRD.

The POF (loss of containment) of the equipment component that is protected by the PRD, $P_{f,j}$, is a function of time and the potential overpressure. API 581 recognizes that there is an increase in probability of loss of containment from the protected equipment due to the elevated overpressure if the PRD fails to open during an emergency event.

Each of the terms that make up the POF for the PRD shown in Equation (1.11) is discussed in greater detail in the following sections.

a) Section 7.2.3—PRD Demand Rate, DR_j.

b) Section 7.2.4—PRD POFOD, $P_{fod,j}$.

c) Section 7.2.5—POF of Protected Equipment as a Result of Overpressure, $P_{f,j}$.

7.2.3 PRD Demand Rate

The first step in evaluating the probability of a PRD failure is to determine the demand rate (demands or events/year) placed on the device.

a) Default Initiating Event Frequencies

   API 581 provides estimates for the PRD initiating event frequencies, EF_j, based on the various relief overpressure demand cases that the device is providing protection. Examples of the initiating event frequencies are provided in Table 7.2. Additional background on the default initiating event frequencies is provided in Table 7.3.

b) Credit for Other Layers of Protection

   It is recognized that the actual demand rate on a PRD is not necessarily equal to the initiating event frequency. The concept of a demand rate reduction factor, $DRRF_j$, is introduced here to account for the difference in the overpressure demand case event frequency and the demand rate on the PRD.

   Many pressure vessel installations include control systems, high integrity protective instrumentation, shutdown systems, and other layers of protection to reduce the demand rate of a PRD. Credit can be taken for operator intervention to reduce the probability of overpressure.

   The $DRRF_j$ is used to account for these additional layers of protection. The $DRRF_j$ may be determined rigorously for the installation as a result of a layer of protection analysis (LOPA) or use the estimated value provided in Table 7.2.

   Another example of where credit may be taken using the $DRRF_j$ is for the fire overpressure demand case. A good estimate for the initiating event frequency of a fire on a specific pressure vessel is 1 every 250 years (0.004 events/year). However, due to many other factors, fire impingement from a pool directly on a pressure vessel rarely causes the pressure in the vessel to rise significantly enough to cause the PRD to open. Factors reducing the actual demand rate on the PRD include fire proofing, availability of other escape paths for the process fluid, and fire-fighting efforts at the facility (to reduce the likelihood of overpressure).

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c) Calculation of Demand Rate

The demand rate (DR) on the PRD is calculated as the product of the initiating event frequency and the $DRRF_j$ in accordance with Equation (1.12):

$$DR_j = EF_j \cdot DRRF_j \tag{1.12}$$

The subscript j in Equation (1.12) signifies that the demand rate on a PRD is calculated for each applicable overpressure demand case.

Typically, a PRD protects equipment for several overpressure demand cases and each overpressure case has a unique demand rate. Default initiating event frequencies for each of the overpressure cases are provided in Table 7.2. Additional guidance on overpressure demand cases and pressure relieving system design is provided in API 521 [11]. An overall demand rate on the PRD can be calculated in Equation (1.13):

$$DR_{total} = \sum_{j=1}^{ndc} DR_j \tag{1.13}$$

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 can usually be estimated from past operating experience for the PRD.

d) Owner–User Experience

The initiating event frequencies for any or all of the overpressure demand cases as shown in Table 7.2 are default values that may not be applicable in all situations. Owner–users may have operating experience with a particular process system that may warrant using other event frequencies. Additionally, a PRD that protects multiple pieces of equipment may legitimately see 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 event frequency for the fire case may be appropriate. In general, where a PRD protects multiple pieces of equipment, the initiating event frequencies should be evaluated to determine if an increase is justified.

7.2.4 PRD POF on Demand

The next step is to obtain the probability that the PRD will fail to open upon demand in service.

a) General

API 581 provides default failure on demand failure rates developed from industry data. These default values are expressed as default Weibull curves that are modified by several factors based on the following procedure.

1) STEP 1.1—Determine default Weibull parameters, β and η_{def}, based on category of service severity [Section 7.2.4 b)], selection of the default POFOD curve [Section 7.2.4 c)], and type of PRD [Sections 7.2.4 d) through 7.2.4 f)].

2) STEP 1.2—Apply an adjustment factor, F_c, for conventional valves discharging to closed system or to flare [Section 7.2.4 g)].

3) STEP 1.3—Apply an adjustment factor, F_{env}, for environmental factors [Section 7.2.4 h)].

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4) STEP 1.4—The result of the procedure outlined above will be a modified characteristic life, η_{mod}, as defined in Equation (1.14).

$$\eta_{mod} = F_c \cdot F_{env} \cdot \eta_{def} \tag{1.14}$$

5) STEP 1.5—At this point, the modified characteristic life, η_{mod}, needs to be updated to the updated characteristic life, η_{upd}, based on the PRD's specific inspection and testing history [Section 7.2.4 i)].

6) STEP 1.6—This updated characteristic life, η_{upd}, is then used to calculate the POFOD as a function of time, t, for the specific PRD in accordance with Equation (1.15).

$$P_{fod} = 1 - exp\left[-\left(\frac{t}{\eta_{upd}}\right)^{\beta}\right] \tag{1.15}$$

7) STEP 1.7—The POFOD should be adjusted based on the overpressure scenario with Equation (1.16). The overpressure factor, $F_{OP,j}$, is an adjustment for overpressure scenarios higher than 1.3 times the set pressure [Section 7.2.4 j)]. The subscript j identifies the specific overpressure and accounts for the fact that each has a different potential overpressure.

$$P_{fod,j} = P_{fod} \cdot F_{OP,j} \tag{1.16}$$

b) Categories of Service Severity

The failure rates of PRDs are directly related to the severity of service in which they are installed. Different categories of service are established in the PRD module as a function of the fluid tendency to induce PRD failure due to corrosion, fouling, plugging, or other effects. Temperature has also been found to be a factor in determining the severity of service. The categories of service severity (MILD, MODERATE, or SEVERE) are linked to specific failure tendencies (and default Weibull cumulative failure distribution curves) and are described in Table 7.5.

It is important to note that a fluid that is classified as being a MILD service group for the fail to open failure mode is not necessarily a MILD service for the leakage failure mode. As an example, industry failure data show that cooling water, which is known to be a dirty/scaling service, has one of the highest failure rates for the fail to open case and therefore may be classified as SEVERE for the FAIL case. Conversely, PRDs in cooling water service have not demonstrated a significant amount of leakage failures and therefore may be classified as MILD for the leak case. Another example is steam, where industry data indicate that steam should be classified as MILD for the fail to open case, but classified as SEVERE for the leak case. Steam is known to be a leaking service due to the erosive nature of the high-temperature steam.

c) Default POFOD vs Time in Service

1) General

Table 7.6 provides the default Weibull parameters for failure to open for conventional spring-loaded pressure-relief valves (PRVs), balanced bellows PRVs, pilot-operated PRVs, and rupture disks. These parameters were determined using industry failure rate data. The majority of the available data indicated successful performance during the interval that the PRD was in service. The successful test points are referred to as suspensions and were included with the failure data in determination of the Weibull parameters.

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Weibull parameters are provided for the three categories of PRD service severity—MILD, MODERATE, and SEVERE—as discussed in Section 7.2.4 b). These values, when substituted into the Weibull cumulative failure density function, $F(t)$, given by Equation (1.2), provide the default POFOD curves for each of the PRD types listed in the table.

For example, Figure 7.2 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 that the units for the POFOD data presented in Figure 7.2 are failures/demand as these data were established from bench tests of actual PRDs, not from continuous service data. POFOD should not be confused with POF (failures per year) that includes the demands on the PRD (see Section 7.2.3) and the probability that the protected equipment will fail (see Section 7.2.5).

The cumulative failure distribution curves shown in Figure 7.2 and the Weibull parameters presented in Figure 7.6 are the default values based on the category of service severity of the PRD being evaluated. These base values are defaults and should be overridden if the owner–user provides site-specific data as explained in Section 7.2.4 c) 3).

2) Presence of an Upstream Rupture Disk

Rupture disks are often installed in combination with PRVs to isolate the valve from process conditions and corrosive or fouling fluids that can reduce the probability that the valve will open upon demand. API 520, Parts 1 and 2 provide additional information related to the use and installation of rupture disks upstream of PRVs.

The presence of upstream rupture disks is accounted for by using the POFOD curve for MILD service regardless of what fluid severity is selected. This assumes that the space between the rupture disk and the PRV is vented and monitored for leakage as required by Code and as recommended by API 520. If this is not the case, the upstream rupture disk should not be considered in the analysis (i.e. assume the disk is not present).

3) Use of Plant-specific Failure Data

Data collected from specific plant testing programs can also be used to obtain POFOD and probability of leakage values. Different measures such as MTTF or failure per million operating hours may be converted into the desired form via simple conversion routines.

d) Default Data for Balanced Bellows PRVs

A balanced spring-loaded PRV uses a bellows to isolate the back side of the disk from the effects of superimposed and built-up back pressure. The bellows also isolates the internals of the PRD from the corrosive effects of the fluid in the discharge system.

An analysis of industry failure rate data shows that balanced bellows PRVs have the same POFOD rates as their conventional PRD counterparts, even though they typically discharge to dirty/corrosive closed systems. This is due to the isolation of the valve internals from the discharge fluid and the effects of corrosion and fouling. As shown in Table 7.6, the characteristic life (Weibull η parameter) is the same for bellows PRVs as it is for conventional PRVs.

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e) 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 [15] 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 as shown in Table 7.6 are used as the basis for pilot-operated PRVs with adjustment factors applied to the characteristic life (η parameter). For MILD service, the η parameter 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.

f) 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, reliable devices that are not likely to fail to open at pressures significantly over their burst pressure (unless inlet or outlet plugging is a problem, or unless they are installed improperly). Typically, if a rupture disk were to fail, it would burst early. Therefore, the Weibull parameters for the failure to open upon demand case for rupture disks are based on the MILD severity curve for conventional PRVs. This makes the assumption that a rupture disk is at least as reliable as a conventional PRV. It also assumes that the rupture disk material has been properly selected to withstand the corrosive potential of the operating fluid. Where it is known that the rupture disk material is not properly selected for the corrosive service, the disk Weibull parameters should be adjusted accordingly.

g) Adjustment for Conventional PRVs Discharging to Closed System

An adjustment is made to the base Weibull parameters for conventional valves that discharge to a closed system or to flare. Since a conventional valve does not have a bellows to protect the bonnet housing from the corrosive fluids in the discharge system, the characteristic life (represented by the η parameter) is reduced by 25 %, using an adjustment factor of 0.75.

$F_c = 0.75$ for conventional valves discharging to closed system or flare

$F_c = 1.0$ for all other cases

h) Adjustment for Environmental Factors

There are several environmental and installation factors that can affect the reliability of PRDs. These include the existence of vibration in the installed piping, a history of chatter, and whether or not the device is located in pulsing flow or cyclical service, such as when the device is installed downstream of reciprocating rotating equipment. Other environmental factors that can significantly affect leakage probability are operating temperature and operating ratio.

The operating ratio of a PRD 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). This increased potential for leakage is taken into account 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 that some pilot-operated PRVs can function at operating ratios up to 98 % (see API 520 for guidance on operation margin).

An analysis of the industry failure rate data shows that PRDs installed in vibratory or cyclical service tend to have higher leakage rates. The analysis showed, however, that the fail to open failure rates remain about the same when a PRD is installed in these services.

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If a PRV has a history of chattering, the installation should be modified or redesigned as soon as possible to eliminate the chatter, since the effects of chatter may be very detrimental to the protection provided by the PRD. An assumed adjustment factor of 0.5 is applied to the Weibull η parameters for the POFOD and probability of leakage (POL) curves of a PRD that has a history of chattering in service.

Table 7.7 provides the environmental adjustment factors applied to the default POFOD and POL Weibull curves.

The environmental factor, F_{env}, is used to increase the POFOD or leakage by reducing the curve's characteristic life (Weibull η parameter). As shown in Figure 7.5, the modifier effectively shifts the probability curves to the left.

i) Updating Failure on Demand Based on PRD-specific Testing Data

1) Tracking Historical Inspection and Testing Data

An inspection program should track each PRD's testing and inspection history from its initial installation. From this history, adjustments can be made to each device's P_{fod} and P_l curves to take advantage of the knowledge gained by the testing of a particular relief device in a specific service.

After actual testing, data are obtained for a PRD, the probability functions of that device are adjusted up or down (modifying the Weibull parameters) depending upon the results (pass/fail/leak) of the device's specific inspection tests and the length of service since the last inspection. In this way, an increase or reduction in the recommended interval is obtained based on historical test data.

In general, the adjustment of the POFOD is based on the results of the inspection of the PRD itself (e.g. bench test results). This could lead to nonconservative results if the inlet or outlet piping plugs during operation and could affect the reliability of the PRD system. For each inspection date entered, the inspected condition of the piping should be documented. If the piping is determined to be plugged, the methodology assumes the inspection/test to be a FAIL, regardless of the results of the bench test or inspection method used on the PRD. Good engineering practice would suggest that if the piping is plugged by more than 25 %, the piping should be defined as being plugged, since this would then drive down the inspection interval. This methodology adjusts the reliability of the PRD system to reflect excessive pipe plugging.

2) Effectiveness of Inspection Programs in Confirming Failure Rates

Inspection programs vary in their effectiveness for determining failure rates. The definitions for inspection and testing effectiveness for PRDs are provided in Part 2, Annex 2.C, Table 2.C.3.1. The inspection's effectiveness is based on its ability to adequately predict the failure (or pass) state of the PRD being inspected. Limitations in the ability of the program to improve confidence in the failure rate result from the inability of some test methods to detect and quantify damage.

For PRDs, an inspection and testing program should track the effectiveness of the inspection and the testing performed for each PRD. The concept of inspection effectiveness is similar to the concept that is described in Section 4.4.3 of this document for fixed equipment. For inspection effectiveness of PRDs, a measure of confidence in the pass/fail/leak result of the inspection effort is used.

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Table 7.9 provides default confidence values based on expert opinion. The confidence values are an indication that the inspection will result in an accurate representation of actual PRD performance during an overpressure demand case. For example, the 90 % effectiveness associated with passing a "highly effective" bench test means that there is a 90 % probability the device would have opened upon demand in its installed service. Therefore, it also carries a 10 % probability that the PRD would have failed upon demand during operation. The values shown in Table 7.9 are called *conditional* probabilities.

The conditional probabilities listed reflect the confidence that an inspection result will predict the device's performance upon demand. For passing PRDs, the highest confidence is assigned when the PRD is bench tested without any prior cleaning (i.e. as-received condition). Bench testing where the devices are cleaned prior to testing, in situ testing, and visual inspections provide some information about PRD performance, but are not considered as reliable as the as-received bench test.

The philosophy is different for PRDs that fail an inspection. In the case of a "highly effective" bench test failure, the 95 % confidence translates to a 95 % chance that the PRD would have failed upon demand in service. Unlike the passing test case, the "usually effective" in situ test, or bench test where the device has been steamed out prior to testing, is assumed to have the same 95 % confidence for failure upon demand in actual service.

An ineffective test does not provide any information to predict PRD performance upon demand and therefore the PRD does not receive any credit for the test/inspection date. The inspection still will get some credit if an overhaul was performed in that the device is assumed to be returned to service in like-new condition, and the in-service duration is calculated from the ineffective inspection date.

3) Inspection Updating

As previously discussed, Weibull parameters for the failure on demand curves have been determined based on the analysis of a sample set of data. Initially, these values are default (suggested) parameters for the listed fluid services. As inspection data are collected for each PRD, these parameters may be adjusted for each device based on the inspection results.

Applying a Bayesian updating approach to problems of this type is common to adjust probabilities as new information is collected. This approach assumes that the Weibull shape parameter (β parameter) remains constant based on the historical data, and adjusts the characteristic life (η parameter), as inspection data are collected. 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. This is not the case for PRDs. Test effectiveness, shown in Table 7.8, range from 50 % to 90 %. This uncertainty using Bayes' Theorem results in an unrealistically high adjusted POF, particularly for a passed bench test. Therefore, a modified inspection updating method was devised to provide reasonable adjustments of characteristic life.

Since the default Weibull parameters for a given PRD provide the probability of a failure on demand vs time, a default POFOD (modified as per Section 7.2.4) may be obtained for the device based on its in-service duration at the time of inspection. This inspection method begins with the prior POFOD and is calculated using Equation (1.17) as follows:

$$P_{f,prior}^{prd} = 1 - exp\left[-\left(\frac{t}{\eta_{mod}}\right)^{\beta}\right] \tag{1.17}$$

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The prior probability that the device will pass on demand is:

$$P_{p,prior}^{prd} = 1 - P_{f,prior}^{prd} \tag{1.18}$$

After the inspection, a second POFOD is calculated based upon the conditional probability factor, or confidence factor (CF) for the effectiveness of the inspection performed (see Table 7.9). This second, calculated probability is called the conditional POFOD and is calculated using Equation (1.19) or Equation (1.20) depending on the result of the inspection:

When the PRD passed the inspection, the conditional POFOD is calculated as follows:

$$P_{f,cond}^{prd} = \left(1 - CF_{pass}\right) \cdot P_{p,prior}^{prd} \tag{1.19}$$

With a failed inspection, the conditional POFOD is calculated as follows:

$$P_{f,cond}^{prd} = CF_{fail} \cdot P_{f,prior}^{prd} + \left(1 - CF_{pass}\right) \cdot P_{p,prior}^{prd} \tag{1.20}$$

A weighted POF, $P_{f,wgt}^{prd}$, is then calculated, where the weighting factors have been formulated to give more credit to tests conducted later in the characteristic life. Using the prior and conditional probabilities and the weighting factors, an updated or posterior POFOD is calculated using the equations provided in Table 7.10.

A revised characteristic life may be obtained using Equation (1.21) based on the in-service duration of the PRD, the known β parameter, and the posterior probability.

$$\eta_{upd} = \frac{t}{\left(-ln\left[1 - P_{f,wgt}^{prd}\right]\right)^{\frac{1}{\beta}}} \tag{1.21}$$

4) Example—Modified Bayesian Updating Calculation

Consider a conventional PRV that is in a severe fluid service. The default Weibull parameters in accordance with Table 7.6 are as follows:

$$\beta = 1.8 \tag{1.22}$$

$$\eta_{def} = \eta_{mod} = 17.6 \tag{1.23}$$

For this example, there are assumed to be no other adjustments, so that the modified characteristic life value is equal to the default value.

The $P_{f,prior}^{prd}$ may be determined using Equation (1.24) for any in-service duration. Assuming an inspection is conducted at an in-service duration of 6 years, the POF at 6 years, $P_{f,prior}^{prd}$, is:

$$P_{f,prior}^{prd} = 1 - exp\left[-\left(\frac{6}{17.6}\right)^{1.8}\right] = 0.1342 \tag{1.24}$$

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The probability that the device will pass a bench test may be determined using Equation (1.25):

$$P_{p,prior}^{prd} = 1 - P_{f,prior}^{prd} = 1 - 0.1342 = 0.8658 \tag{1.25}$$

These probabilities are defined as the *Prior Probabilities.*

At the 6-year in-service inspection, a highly effective bench test is performed and the device passes the test. Using Table 7.9, a 90 % confidence factor has been estimated for this type of inspection, meaning that 10 % of devices that pass this type of test would fail on demand in service. An adjusted or conditional POF is calculated using Equation (1.26):

$$P_{f,cond}^{prd} = \left(1 - CF_{pass}\right) \cdot P_{p,prior}^{prd} = 0.1 \cdot 0.8658 = 0.087 \tag{1.26}$$

For a highly effective pass, the weighted probability is calculated (see Table 7.10 for equations):

$$P_{f,wgt}^{prd} = P_{f,prior}^{prd} - 0.2 \cdot P_{f,prior}^{prd} \cdot \left(\frac{t}{\eta_{mod}}\right) + 0.2 \cdot P_{f,cond}^{prd} \left(\frac{t}{\eta_{mod}}\right) \tag{1.27}$$

or

$$P_{f,wgt}^{prd} = 0.1342 - 0.2 \cdot 0.1342 \cdot \left(\frac{6}{17.6}\right) + 0.2 \cdot (0.087) \cdot \left(\frac{6}{17.6}\right) = 0.1310 \tag{1.28}$$

Finally, using the prior β and the calculated weighted probability, $P_{f,wgt}^{prd}$, an updated value for the η parameter is calculated for the in-service duration using Equation (1.29).

$$\eta_{upd} = \frac{6}{\left(-ln\left[1 - 0.1310\right]\right)^{\frac{1}{1.8}}} = 17.9 \tag{1.29}$$

The weighting factors assure a gradual shift from default POFOD data to field POFOD data and do not allow the characteristic life to adjust upward too rapidly. They will, however, shorten characteristic life if the device has repeated failures early in its service.

Other points that are not accounted for in the calculation procedure regarding inspection updating are as follows.

i) Tests conducted at less than 1 year do not get credit.

ii) After a pass, the characteristic life cannot decrease. If the procedure yields a decrease in characteristic life, this value should not be used. The characteristic life should be kept equal to the previous value.

iii) After a fail, the characteristic life cannot increase. If the procedure yields an increase in characteristic life, this value should not be used. The characteristic life should be kept equal to the previous value.

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5) Updating Failure Rates After Modification to the Design of the PRD

Design changes are often made to PRDs that improve the reliability of the device and result in a change in the failure rate, for example upgrading to a corrosion-resistant material or installation of an upstream rupture disk. Past inspection data are no longer applicable to the newly designed installation. In these cases, either a new default curve should be selected per Figure 7.2 or device-specific Weibull parameters should be chosen based on owner–user experience, thus generating a unique curve for the device.

j) Adjustment for Overpressures Higher Than Set Pressure

As discussed in Section 7.1.3, 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. Intuitively, one would expect that at higher overpressures, the probability that the PRD would fail to open goes down dramatically. A review of the industry failure data supports this. Figure 7.4 shows that as the overpressure ratio increases, the PRD failure rate reduces significantly.

A conservative approach is to assume that the failure rate is cut by a factor of 5 at 4.0 times the set pressure and to assume linear interpolation between 1.3 and 4.0 times the set pressure. A factor for overpressure, $F_{op,j}$, is introduced in Equation (1.30).

$$
\begin{aligned}
F_{op,j} &= 1.0 && \text{for } \frac{P_{o,j}}{P_{set}} < 1.3 \\
F_{op,j} &= 0.2 && \text{for } \frac{P_{o,j}}{P_{set}} > 4.0 \\
F_{op,j} &= 1 - \frac{1}{3.375} \cdot \left(\frac{P_{o,j}}{P_{set}} - 1.3 \right) && \text{for all other cases}
\end{aligned}
\tag{1.30}
$$

The adjustment factor calculated above cannot be less than 0.2, nor greater than 1.0.

7.2.5 Protected Equipment Failure Frequency As a Result of Overpressure

Where risk analysis has been completed for equipment components being protected by PRDs, each piece of protected equipment has a damage adjusted POF calculated as the equipment's GFF multiplied by a DF, see Section 4.1 and Equation (1.1). The DF is determined based on the applicable damage mechanisms for the equipment, the inspection history, and condition of the equipment. The DFs for the protected equipment are calculated as a function of time. This is very important when evaluating the inspection interval for the PRD. As the PRD inspection interval is extended, the damage related to the vessel increases as does the risk associated with the PRD.

a) Damage Factor Calculation Procedure for PRD with Fixed Equipment

The damage adjusted POF are calculated at the normal operating pressure of the equipment and are adjusted when evaluating PRDs as follows. When a PRD fails to open upon demand, the pressure in the protected equipment rises above the operating pressure and in many cases, significantly above the $MAWP$. The protected equipment damage adjusted POF [$P_f(t)$ from Equation (1.1)] is adjusted based on the calculated overpressure for the overpressure demand case under consideration. The damage adjusted POF, which is equal to the probability of loss of containment from the protected equipment, at the overpressure is calculated as follows:

$$
P_{f,j} = \left(0.0312881 \cdot gff_{total} \cdot D_f \cdot F_{MS} \right) \cdot e^{\left(3.464837 \cdot \frac{P_{o,j}}{MAWP} \right)}
\tag{1.31}
$$

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The above equation is set up so that at normal operating pressure (≤ $MAWP$), the probability of loss of containment from the equipment, $P_{f,j}$, is equal to the damage adjust failure frequency, P_f, calculated in fixed equipment RBI for the protected equipment using Equation (1.1). At elevated overpressures when the PRD is being evaluated, the probability of loss of containment in the protected equipment increases. As an upper limit, for an undamaged piece of equipment (D_f = 1.0), the probability of loss of containment will equal 1.0 when the overpressure is equal to the burst pressure, or the failure pressure of the vessel. The burst pressure of the vessel can be estimated using the design margin times the $MAWP$ (the design margin of the equipment, also known as safety factors, constructed in accordance with various codes are shown in Table 7.5). Alternatively, the burst pressure can be more accurately calculated using a more advanced analysis such as Svensson's method [22]. For a damaged piece of equipment (D_f □ 1.0), the probability of loss of containment can reach 1.0 at pressures much lower than the damaged equipment burst pressure, see Figure 7.6 for further clarification.

The probability of occurrence of any of the four holes sizes (i.e. small leak to rupture) is increased at elevated overpressures due to the increased probability of loss of containment and may be calculated as follows:

$$P_{f,j}^{n} = P_{f,j}\left(\frac{gff_n}{gff_{total}}\right) \tag{1.32}$$

See Section 4.2.2 for initial discussion on the discrete hole sizes; Part 2, Table 3.1 for gff_n and gff_{total}; and Part 3, Table 4.4 for definitions of the hole and actual representative sizes.

b) Selection of DF Class when PRD RBI Is Performed Without Fixed Equipment

If fixed equipment risk analysis has not been performed, then the DFs for the protected equipment that normally would be calculated for fixed equipment will have to be specified. The DFs may be determined quantitatively using a DF class as shown in Table 7.11. This method should be considered to be less quantitative than when an RBI analysis is conducted to determine fixed equipment DFs.

7.2.6 Calculation Procedure

The following calculation procedure may be used to determine the probability of a PRD failure to open at a specified inspection interval.

a) STEP 2.1—Select an inspection interval, t_{insp}.

b) STEP 2.2—Determine the default values for the Weibull parameters, β and η_{def}, using Table 7.6 and Table 7.7.

c) STEP 2.3—Determine the adjustment factor for conventional valves, F_c, using Section 7.2.4 g).

d) STEP 2.4—Determine the environmental adjustment factor for conventional valves, F_{env}, using Table 7.7.

e) STEP 2.5—Calculate the modified characteristic life, η_{mod}, using Equation (1.14) and the factors obtained from STEP 2.3 and STEP 2.4.

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f) STEP 2.6—Assemble the PRD's inspection history. Grade each record using the inspection effectiveness table, Part 2, Annex 2.C, Table 2.C.3.1. Record the results of each inspection record; PASS/FAIL and NO LEAK/LEAK and determine the confidence factors, CF_i, as applicable, for each inspection history based on the results of the test. Determine the time duration, $t_{dur,i}$, of each inspection cycle.

   1) STEP 2.6.1—Each inspection record must be graded using the PRD inspection effectiveness table, Part 2, Annex 2.C, Table 2.C.3.1.

   2) STEP 2.6.2—Record the PASS/FAIL and NO LEAK/LEAK in order to determine the confidence factors, CF_i, as applicable, for each inspection history where a test was conducted.

   3) STEP 2.6.3—Determine the time duration, $t_{dur,i}$, between each inspection cycle.

   4) STEP 2.6.4—Determine if the PRD was overhauled.

      — If the PRD was overhauled, the date of the most recent overhaul becomes the earliest inspection record at which STEP 2.7 is started.

      — Refer to Section 7.7.2 and Section 7.7.3, as well as Figure 7.7, for more information.

g) STEP 2.7—Starting at the earliest inspection record, update the modified characteristic life, η_{mod}, determined in STEP 2.5 as follows.

   1) STEP 2.7.1—Calculate the prior POF, $P_{f,prior}^{prd}$, using Equation (1.17). The time period for use in Equation (1.17). is the time duration of the inspection cycle, $t_{dur,i}$, as determined in STEP 2.6. Note that for the first inspection record, the modified characteristic life, η_{mod}, is used. Subsequent inspection records will use the updated characteristic life, η_{upd}, from STEP 2.7.5.

   2) STEP 2.7.2—Calculate the prior probability, $P_{p,prior}^{prd}$, of passing using Equation (1.18).

   3) STEP 2.7.3—Determine the conditional POF, $P_{f,cond}^{prd}$, and the conditional POFOD with failed inspection, $P_{f,cond}^{prd}$, using Equation (1.19) and Equation (1.20), respectively.

   4) STEP 2.7.4—Calculate the weighted POF, $P_{f,wgt}^{prd}$, using the appropriate equation from Table 7.10.

   5) STEP 2.7.5—Determine the updated characteristic life, η_{upd}, using Equation (1.21) Weibull parameters β from STEP 2.2, and the weighted POF, $P_{f,wgt}^{prd}$, established in STEP 2.7.4.

   6) STEP 2.7.6—Repeat these steps for each of the inspection records available for the PRD until a final updated value for the characteristic life, η_{upd}, is determined.

h) STEP 2.8—For each overpressure scenario, determine the adjustment factor, $F_{op,j}$, using Equation (1.30). Note that to perform this step, an estimate of the overpressure given a failure of the PRD to open upon demand is required. This is covered in more detail in Section 7.4.6, STEP 5.2.

i) STEP 2.9—For each overpressure demand case, determine the initiating event frequency, EF_j, using **Table 7.** or based on owner–user experience for the particular overpressure demand case.

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j) STEP 2.10—Determine the demand rate reduction factor, $DRRF_j$, which accounts for any layers of protection in the process that may reduce the probability of overpressuring the protected piece of equipment, see Section 7.2.3 b) and Table 7.2 for guidance.

k) STEP 2.11—For each overpressure demand case, determine the demand rate placed on the PRD, DR_j, using Equation (1.12).

l) STEP 2.12—Determine the MAWP of the protected equipment.

m) STEP 2.13—If an RBI study has been completed for the protected equipment, calculate its damage adjusted POF, P_f, using Equation (1.1). Since the DF for the protected equipment is a function of time, the DF must be determined at the PRD inspection interval, t_{insp}, specified in STEP 2.1. If a risk analysis for fixed equipment has not been completed, a DF can be estimated using the values in Table 7.11.

n) STEP 2.14—Calculate the POF of the protected equipment at the elevated overpressure, $P_{f,j}$, using Equation (1.31). Use the overpressure determined in STEP 5.2 of Section 7.4.6, the MAWP of the protected equipment and the POF determined in STEP 2.13.

o) STEP 2.15—Calculate the POF, $P_{f,j}^{prd}$, using Equation (1.11) using $P_{fod,j}$ from Equation (1.16).

p) STEP 2.16—Repeat STEP 2.1 through STEP 2.15 for each piece of equipment protected by the PRD.

7.3 Probability of Leakage (POL)

7.3.1 Overview

The leakage case is different than the fail to open case since the POF is not a function of demand rate but rather is based on failure during continuous operation. The industry data associated with the probability of leakage, P_l, data are in per year units (i.e. failures/year). No multiplication by any demand rate is necessary.

7.3.2 Probability of Leakage Calculation Procedure

The probability of leakage for a PRD is determined using the following steps.

a) STEP 3.1—Determine default Weibull parameters, β and ηdef, based on category of Service Severity and type of PRD; see Section 7.3.2 f) through Section 7.3.2 j).

b) STEP 3.2—Apply an adjustment factor, F_s, to account for the presence of soft seats; see Section 7.3.2 k).

c) STEP 3.3—Apply an adjustment factor, F_{env}, for environmental factors; see Section 7.3.2 l).

The result of the procedure outlined above will be a modified characteristic life, η_{mod}, as defined in Equation (1.33).

$$\eta_{mod} = F_s \cdot F_{env} \cdot \eta_{def} \tag{1.33}$$

The modified characteristic life, η_{mod}, is updated based on the PRD's inspection history, identical to the method presented in Section 7.2.4 i) for the failure to open case. This updated characteristic life, η_{upd}, is then used to calculate the probability of leakage for the specific PRD in accordance with Equation (1.34).

d) STEP 3.4—The modified characteristic life, η_{mod}, is updated based on the PRD's inspection history, identical to the method presented in Section 7.2.4 i) for the failure to open case. This updated

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characteristic life, η_{upd}, is then used to calculate the probability of leakage for the specific PRD in accordance with Equation (1.34).

$$P_l^{prd} = 1 - exp\left[-\left(\frac{t}{\eta_{upd}} \right)^{\beta} \right] \tag{1.34}$$

e) STEP 3.5—The probability of leakage needs to be adjusted based on the closeness the system is operating near the set pressure with Equation (1.35). The set pressure factor, F_{set}, is dependent on the PRD type, operating pressure, P_s, and set pressure, P_{set} (see Table 7.7 for equations).

$$P_l^{prd} = P_l^{prd} \cdot F_{set} \tag{1.35}$$

f) Categories of Service Severity

Guidance on selecting the proper service severity for the leakage case is provided in Table 7.12. Ideally, the owner–user's experience with a PRD in a particular service will provide guidance as to the choice of service severity for the leakage case.

g) Default Probability of Leakage Rates vs Time in Service

An additional set of Weibull curves tracks the leakage failure case. In this case, the curves are not based on a per demand failure rate, but are taken from data of PRDs in continuous service (i.e. a continuous demand, unlike the failure to open case, which is on a per demand basis). The data are collected in units of failures/year and do not have to be multiplied by a demand rate. Table 7.13 provides the default PRD probability of leakage vs time information using a Weibull function to describe the three types of service: MILD, MODERATE, and SEVERE. These data are currently based on a limited amount of industry data and should be supplemented by owner–user data where available.

As an example, the default cumulative failure (leakage) distribution curves for spring-loaded conventional PRVs using the Weibull function to describe the three categories of service severity—MILD, MODERATE, and SEVERE—are provided in Figure 7.3.

h) Default Weibull Parameters for Balanced Bellows PRVs

The Weibull parameters for the probability of leakage curve for balanced bellows PRVs provided in Table 7.13 match the industry failure rate data. These data reflect a minor increase in the probability of leakage compared to conventional valves.

i) Default Weibull Parameters for Pilot-operated PRVs

For leakage, it is known that pilot-operated PRVs actually have a better seal as the operating pressure approaches the valve set pressure due to their inherent design. Until failure rate data are accumulated to support an increase in the η parameter for leakage, it is suggested that the owner–user use the Weibull values for conventional PRVs for pilot-operated PRVs. Table 7.13 shows the default Weibull parameters for the POL curve for pilot-operated PRVs.

j) Default Weibull Parameters for Rupture Disks

There are no industry data for leakage available for rupture disks. Therefore, the Weibull parameters for the leakage case for rupture disks were based on the MILD severity curve for conventional PRVs (see Section 7.2.4 f) for additional information).

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k) 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:

$F_s = 1.25$ for soft seated designs

$F_s = 1.0$ for all other cases

l) Environmental Modifiers to the Default Failure on Demand and Leakage Data

Table 7.7 provides all of the environmental adjustment factors, F_{env}, that applies to the default POL Weibull curves. See Section 7.2.4 h) for additional information on the effect that the applied environmental factors have on the default probability of leakage Weibull curves.

m) Set Pressure Adjustment

The probability of leakage decreases as the gap between operating pressure and set pressure increases. Table 7.8 provides the equations for obtaining the set pressure factor.

n) Presence of an Upstream Rupture Disk

When a rupture disk is installed upstream of the PRV, the methodology assumes that the probability of leakage is negligible (i.e. $P_l^{prd} = 0.0$) and does not calculate a consequence resulting from leakage.

o) Modification of Leakage Rates Based on PRD Specific Testing Data

The updating scheme for inspection history is identical to the scheme presented in Section 7.2.4 i) for the failure to open case.

7.3.3 Calculation Procedure—POL at Specified Inspection Interval

The following calculation procedure may be used to determine the PRD probability of leakage at a specified inspection interval.

a) STEP 4.1—Select an inspection interval, t_{insp}.

b) STEP 4.2—Determine the default values for the Weibull parameters, β and η_{def}, using Table 7.5 and Table 7.13.

c) STEP 4.3—Determine the adjustment factor, F_s, using Section 7.3.2 g).

d) STEP 4.4—Determine the environmental adjustment factor, F_{env}, using Table 7.7.

e) STEP 4.5—Calculate the modified characteristic life, η_{mod}, using Equation (1.33) and the factors obtained in STEP 4.3 and STEP 4.4.

f) STEP 4.6—Assemble the PRD's inspection history. Grade each record using the inspection effectiveness table, Part 2, Annex 2.C, Table 2.C.3.1. Record the results of each inspection record; NO LEAK/LEAK and determine the confidence factors, CF_i, as applicable, for each inspection history based on the results of the test. Determine the time duration, $t_{dur,i}$, of each inspection cycle.

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g) STEP 4.7—Starting at the earliest inspection record, update the modified characteristic life, η_{mod}, determined in STEP 4.5 as follows.

1) STEP 4.7.1—Calculate the prior probability of leakage using Equation (1.17). Note that for the first inspection record, the modified characteristic life, η_{mod}, is used. Subsequent inspection records will use the updated characteristic from STEP 4.7.5 below.

2) STEP 4.7.2—Calculate the prior probability of passing using Equation (1.18).

3) STEP 4.7.3—Determine the conditional probability of leakage and conditional probability of pass using Equation (1.19) and Equation (1.20), respectively.

4) STEP 4.7.4—Calculate the weighted probability of leakage, $P_{l,wgt}^{prd}$, using the appropriate equation from Table 7.10.

5) STEP 4.7.5—Determine the updated characteristic life, η_{upd}, using Equation (1.21) and the weighted probability of leakage, $P_{l,wgt}^{prd}$, established in STEP 4.7.4.

6) STEP 4.7.6—Repeat these steps for each of the inspection records available for the PRD until a final updated value for the characteristic life, η_{upd}, is determined.

h) STEP 4.8—Calculate the probability of leakage, $P_{l,wgt}^{prd}$, for the specific PRD in accordance with Equation (1.34). Adjust the probability of leakage for operating close to the set pressure using Equation (1.35).

7.4 Consequence of PRD Failure to Open

7.4.1 General

The consequence calculations for event outcomes such as fires, explosions, and toxic exposure are described in Part 3. For PRDs, failures to open upon demand will likely result in the protected equipment being exposed to significantly higher pressures than during normal operations. This methodology calculates the consequences for each PRD failing to open at sometimes significantly higher overpressure than the normal operating pressure of the equipment.

Table 7.12 shows the expected potential consequences of an overpressure event in a pressure vessel. Table 7.12 is only provided for a qualitative discussion of the potential risks to equipment due to overpressure 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; see Section 7.2.4 j).

7.4.2 Damage State of the Protected Equipment

A direct link to the current condition, or damage state, of the protected equipment is critical to the evaluation of the consequence of PRD failure. Damage for each protected vessel is measured by a DF, D_f, which is calculated considering each of the damage mechanisms (corrosion, cracking, creep, etc.) that are applicable to the protected equipment. The higher the overall DF of the protected equipment, the more likely the equipment is to experience undesirable consequences as a result of a PRD that is in a failed state (stuck) upon demand. Part 2 of this document provides details on calculation of the DF and the probability of loss of containment from fixed equipment.

Where damage assessment has not been completed in conjunction with a RBI analysis of the PRD, then assumptions of the damage state of the protected equipment must be made as described in Section 7.2.5 b).

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7.4.3 Overpressure Potential for Overpressure Demand Cases

For API 581 to provide a relative ranking of risk between PRDs, the analysis must include an assessment of the overpressure demand cases (overpressure scenarios) that are applicable to each PRD. In other words, what process upsets are the device protecting against and how critical would the effect on the protected equipment be if the device were to fail to open upon demand.

The PRD methodology makes a clear distinction between criticality of the overpressure demand cases that the device is protecting against, i.e. why the device is there. For example, a PRD that protects equipment and piping for the blocked discharge demand case downstream of a pump is considered to be less critical than a device that is protecting a reactor from a runaway chemical reaction since the amount of overpressure expected as a result of a PRD failure to open upon demand would be much less. Likewise, a device that is only protecting piping against thermal relief is much less critical than a device that is protecting low-pressure equipment from gas breakthrough from a high-pressure source due to control valve failure.

For most of the overpressure demand cases, the potential overpressure that results when a PRD fails to open upon demand from an overpressure event may be calculated. The logic for determining the potential overpressure for each of the overpressure demand cases is provided in Table 7.3. In many situations, the potential overpressure will approach the burst pressure (estimated to be design margin times the $MAWP$) of the protected equipment since the overpressure demand case is not self-limiting. In other overpressure scenarios, such as a blocked discharge downstream of a centrifugal pump, the potential overpressure will limit itself to the deadhead pressure of the pump, which is typically 1.3 times the normal discharge pressure of the pump.

This part of the analysis requires a thorough review of the unit pressure-relief study and piping and instrumentation diagrams (P&IDs) and should be performed by personnel qualified and experienced in the design and installation of pressure-relief systems.

In general, the determination of the potential overpressure, P_o, as a result of PRD failure to open upon demand is a function of the following.

a) Type of Upstream Overpressure Source—For example, centrifugal pumps, steam supply headers, upstream pressure vessels, etc.

b) Upstream Source Pressures—These include the 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—In cases of blocking-in equipment, the heat source supplying energy to the system has a significant impact on the potential overpressure. For example, solar heat/energy supplied in a thermal relief scenario will typically result in flange leaks and the overpressure ends up nominally being the normal operating pressure of the system. On the other hand, if the heat source is a fired heater, the overpressure can build until a rupture occurs (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—In many overpressure scenarios, the pressure buildup is limited to the bubble point pressure of the contained fluid at the temperature of the heat/energy source being supplied to the process.

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7.4.4 Multiple Relief Device Installations

When the relief requirements for the process are such that multiple PRDs are needed to handle the required relief capacity, there is a reduction of risk since the probability that all of the PRDs are in a failed state upon demand will be reduced. The protected equipment will have a higher probability that some of the PRD capacity is available on demand to minimize the amount of overpressure during an overpressure demand case.

When a piece of equipment is protected by multiple PRDs, the calculated POFOD for any one specific PRD in the multiple device installation will remain the same. However, an adjustment is made to the potential overpressure as a result of the PRD failing to open on demand. This multiple device installation adjustment, F_a, takes into consideration common cause failures and also considers the likelihood that other PRDs of the multiple device installation will be available to minimize the potential overpressure.

$$F_a = \sqrt{\frac{A^{prd}}{A^{prd}_{total}}} \tag{1.36}$$

This multiple device installation factor reduces the potential overpressure that is likely to occur by assuming that some of the installed PRD relief area will be available if the PRD under consideration fails to open upon demand. The multiple device installation adjustment factor has a minimum reduction value of 0.25. The presence of the square root takes into consideration that the PRDs in a multiple device installation may have common failure modes. The reduction in overpressure as a result of multiple PRDs is in accordance with Equation (1.37):

$$P_{o,j} = F_a \cdot P_{o,j} \tag{1.37}$$

The multiple installation adjustment factor, F_a, is a ratio of the area of a single PRD (being analyzed) to the overall areas of all PRDs in the multiple setup.

This reduced overpressure should be implemented when determining the protected equipment failure frequency. However, it should not be considered when determining the overpressure factor, F_{op}, which is used to determine the POFOD in Section 7.2.4 i).

7.4.5 Calculation of COF to Open

Consequence calculations are performed for each overpressure demand case that is applicable to the PRD. These consequence calculations are described in Part 3 of this document for each piece of equipment that is protected by the PRD being evaluated and are performed at higher potential overpressures as described in Section 7.4.1.

The overpressure for each demand case that may result from a failure of a PRD to open upon demand has two effects. The probability of loss of containment from the protected equipment can go up significantly as discussed in Section 7.2.5. Secondly, the COF as a result of the higher overpressures also increases. The magnitude of the release increases in proportion to the overpressure, thus increasing the consequence of events such as jet fires, pool fires, and VCEs. Additionally, the amount of explosive energy released as a result of a vessel rupture increases in proportion to the amount of overpressure. Part 3 provides detail for the consequences associated with loss of containment from equipment components.

The consequence calculations should be performed in accordance with Part 3 for each of the overpressure demand cases applicable to the PRD and for each piece of equipment that is protected by the PRD. The resultant consequence is $C^{prd}_{f,j}$ expressed in financial terms, ($/year).

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7.4.6 Calculation Procedure

The following procedure may be used to determine the consequence of a PRD failure to open.

a) STEP 5.1—Determine the list of overpressure scenarios applicable to the piece of equipment being protected by the PRD under evaluation. Table 7.2 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 [11].

b) STEP 5.2—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. Section 7.4.3 and Table 7.3 provide guidance in this area.

c) STEP 5.3—For installations that have multiple PRDs, determine the total amount of installed PRD orifice area, A_{total}^{prd}, including the area of the PRD being evaluated. Calculate the overpressure adjustment factor, F_a, in accordance with Equation (1.36).

d) STEP 5.4—Reduce the overpressures determined in STEP 5.3 by the overpressure adjustment factor in accordance with Equation (1.37).

e) STEP 5.5—For each overpressure demand case, calculate the financial consequence, $C_{f,j}^{prd}$, of loss of containment from the protected equipment using procedures developed in Part 3. Use the overpressures for the demand cases as determined in STEP 5.4 in lieu of the operating pressure, P_s.

f) STEP 5.6—Using the values as determined above, refer to Section 7.6 to calculate the risk.

7.5 Consequence of Leakage

7.5.1 General

Even though the consequences of PRD leakage are typically much less severe than that of a loss of containment from the protected equipment as a result of a PRD failure to open, the frequency of leakage may be high enough that the PRD may be ranked as a high priority on a leakage risk basis.

The calculation of leakage consequence from PRDs, C_l^{prd}, is estimated by summing the costs of several items. The cost of the lost inventory is based on the cost of fluid multiplied by the leakage rate (see Section 7.5.5) and the number of days to discover the leak (see Table 7.14). Regulatory and environmental costs associated with leakage should be considered as well. Next, the cost of downtime to repair or replace the device is estimated if it is determined that continuous operation of the unit with a leaking or stuck open PRD cannot be tolerated. If a shutdown is required to repair the leaking PRD, then the cost associated with lost production will also be added.

The consequence of leakage, C_l^{prd}, is calculated using the following equation:

$$C_l^{prd} = Cost_{inv} + Cost_{env} + Cost_{sd} + Cost_{prod} \tag{1.38}$$

For a multiple device installation, the probability of leakage for any one specific PRD does not increase. However, since the number of devices increases, the probability of a leak and its associated consequences does increase in proportion to the number of devices protecting the system.

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7.5.2 Estimation of PRD Leakage Rate

An analysis of industry bench test data shows that approximately 8.4 % of the PRVs tested had some leakage on the bench stand between 70 % and 90 % of their set pressure. An additional 6.6 % of the PRVs tested leaked at pressures below 70 % of their set pressure. An additional 2.4 % of the tested PRVs leaked significantly below 70 % of their set pressure. A summary of the estimated leakage rates used for the consequence calculation is provided in Table 7.16.

As shown in Table 7.16, a leakage rate of 1 % of the PRD capacity (calculated at normal operating conditions) is used for minor or moderate leaks. For a stuck open PRD, the leakage rate is assumed to be 25 % of the PRD capacity, as given in Equation (1.40).

Two leak cases are evaluated. The first case handles minor or moderate leakage, C_l^{mild}, and represents 90 % of all of the potential leakage cases, per Table 7.16. A stuck open case results in a leakage consequence, C_l^{so}, and makes up 10 % of all possible leakage cases.

For mild and moderate leaks, 1 % of the rated capacity of the PRD, W_c^{prd}, is the basis for the leakage rate; see Equation (1.39).

$$lrate_{mild} = 0.01 \cdot W_c^{prd} \tag{1.39}$$

For the stuck open or spurious open case, the leakage rate is estimated per Equation (1.40).

$$lrate_{so} = 0.25 \cdot W_c^{prd} \tag{1.40}$$

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 [12].

7.5.3 Estimation of Leakage Duration

The leakage duration, D_{mild}, is estimated for the mild or moderate leakage case as shown in Table 7.13. The durations shown make the assumption that mild leakage from larger PRDs will be discovered sooner than leakage from smaller PRDs. The stuck open category is handled differently. For the stuck open case, it is assumed that immediate repair to the PRD is required and that the time to isolate the PRD will be within 30 minutes. Therefore,

$$D_{so} = \frac{30\ \text{min}}{60\ \text{min/hr} \cdot 24\ \text{hr/day}} = 0.021\ \text{days} \tag{1.41}$$

7.5.4 Credit for Recovery of Leaking Fluid

API 581 recognizes that the cost of lost inventory is not as severe when the unit has a flare recovery system installed or the discharge from the relief devices is to a closed system. A recovery factor, F_r, is applied to the leakage consequence as defined by the following cases.

$F_r = 0.5$ if the PRD discharges to flare and a flare recovery system is installed

$F_r = 0.0$ if the PRD discharges to a closed system

$F_r = 1.0$ for all other cases

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7.5.5 Cost of Lost Inventory

The cost of lost fluid inventory, $Cost_{inv}$, can be calculated using Equation (1.42) or Equation (1.43). Note that when determining the consequence of leakage, the fluid costs, $Cost_{flu}$, in Equation (1.42) should be based on the fluid that exists in the protected equipment where the PRD is physically located.

$$Cost_{inv}^{mild} = 24 \cdot F_r \cdot Cost_{flu} \cdot D_{mild} \cdot lrate_{mild} \tag{1.42}$$

$$Cost_{inv}^{so} = 24 \cdot F_r \cdot Cost_{flu} \cdot D_{so} \cdot lrate_{so} \tag{1.43}$$

7.5.6 Environmental Costs

The environmental costs, $Cost_{env}$, are added when leakage through a PRD either to atmosphere or to a flare system could possibly result in cleanup costs or regulatory fines.

7.5.7 Costs of Shutdown to Repair PRD

The cost associated with repair and maintenance is added to calculate a PRD, $Cost_{sd}$, if a leaking device cannot be tolerated. The following values can be used to calculate repair and maintenance cost:

$Cost_{sd} = \$1000$ for PRDs < NPS 6 inlet size

$Cost_{sd} = \$2000$ for PRDs ≥ NPS 6 inlet size

However, API recommends using actual owner–user work order costs associated with the maintenance, testing, inspection, and repair of the PRD.

7.5.8 Cost of Lost Production

The cost of lost production to repair a leaking PRD, $Cost_{prod}$, can be calculated using Equation (1.44) or Equation (1.45). Where spare PRDs are installed in parallel or in cases where isolation valves underneath the PRD offer flexibility to repair without shutting down, production losses need not be considered. For the stuck open case, it is assumed that prolonged operation cannot be tolerated, in which case Equation (1.46) should be used.

$$Cost_{prod}^{mild} = 0.0 \quad \text{if a leaking PRD can be tolerated or if the PRD can be isolated and repaired without requiring a shutdown} \tag{1.44}$$

$$Cost_{prod}^{mild} = Unit_{prod} \cdot D_{sd} \quad \text{if a leaking PRD cannot be tolerated} \tag{1.45}$$

$$Cost_{prod}^{so} = Unit_{prod} \cdot D_{sd} \quad \text{for a stuck open PRD} \tag{1.46}$$

7.5.9 Calculation of Leakage Consequence

The consequence of leakage is calculated for two leaks cases.

a) Minor or Moderate Leakage

The first case handles minor or moderate leakage, C_l^{mild}, and is used to represent 90 % of all of the potential leakage cases, per Table 7.16. In this case, the leakage rate is 1 % of the PRD capacity and

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the duration (or time to discover the leak) is a function of PRD inlet size and discharge location as shown in Table 7.15.

$$C_l^{mild} = C_{inv}^{mild} + C_{env} + C_{sd} + C_{prod}^{mild} \tag{1.47}$$

b) Stuck Open Leakage

The second case handles the stuck open leak case, C_l^{so}, and is assumed to have a duration of 30 minutes. In this case, to determine the cost of lost fluid, 25 % of the full capacity of the PRD (calculated at normal operating conditions) is used for the leakage rate and it is assumed that the PRD will be repaired immediately (within 30 minutes).

$$C_l^{so} = C_{inv}^{so} + C_{env} + C_{sd} + C_{prod}^{so} \tag{1.48}$$

c) Final Leakage Consequence

The final leakage consequence is calculated using Equation (1.49) and is weighted based on the how likely each of the cases is to occur as follows:

$$C_l^{prd} = 0.9 \cdot C_l^{mild} + 0.1 \cdot C_l^{so} \tag{1.49}$$

7.5.10 Calculation Procedure

The following procedure may be used to determine the consequence of leakage from a PRD.

a) STEP 6.1—Determine the flow capacity of the PRD, W_c^{prd} . This can be taken from the PRD datasheet or calculated using the methods presented in API 520, Part 1 [12].

b) STEP 6.2—Calculate the leakage rate for the minor or moderate leak case, $lrate_{mild}$, using Equation (1.39) and the rated capacity of the PRD obtained in STEP 6.1.

c) STEP 6.3—Calculate the leakage rate for the stuck open case, $lrate_{so}$, using Equation (1.40) and the rated capacity of the PRD obtained in STEP 6.1.

d) STEP 6.4—Estimate the leakage duration, D_{mild}, using Table 7.15 and the stuck open duration, D_{so}, using Equation (1.41).

e) STEP 6.5—Calculate the cost of lost inventory, $Cost_{inv}^{mild}$ and $Cost_{inv}^{so}$, using Equation (1.42) or Equation (1.43) for the two leak cases. The recovery factor, F_r, can be obtained from Section 7.5.4, based on the PRD discharge location and the presence of a flare recovery unit.

f) STEP 6.6—Determine the environmental consequence associated with PRD leakage, C_{env}.

g) STEP 6.7—Determine the consequence associated with repair and maintenance of the PRD, $Cost_{sd}$. Default values based on PRD size are given in Section 7.5.7 or actual owner–user costs should be used.

h) STEP 6.8—Calculate the cost of lost production for mild leaks, C_{prod}^{mild} , using Equation (1.44) or Equation (1.45) based on whether or not PRD leakage can be tolerated and the ability to isolate and repair a leaking PRD without shutting the unit down. Calculate the costs of lost production for the stuck open case, C_{prod}^{so} , using Equation (1.46).

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i) STEP 6.9—Calculate the consequence associated with mild leakage, C_l^{mild}, and the consequence of stuck open PRDs, C_l^{so}, using Equation (1.47) and Equation (1.48), respectively.

j) STEP 6.10—Calculate the final leakage consequence, C_l^{prd}, using Equation (1.49).

7.6 Risk Analysis

7.6.1 Risk from Failure to Open

The calculation of risk for a PRD failing to open at a specified inspection interval, t_{insp}, is calculated for each applicable overpressure demand case using the POF of the PRD, $P_{f,j}^{prd}$, and the calculated overall COF for the demand case, $C_{f,j}^{prd}$, as follows:

$$Risk_{f,j}^{prd} = P_{f,j}^{prd} \cdot C_{f,j}^{prd} \tag{1.50}$$

The overall risk for the fail to open case is then determined by summing the individual risks associated with the applicable overpressure demand cases as follows:

$$Risk_{f}^{prd} = \sum_{j=1}^{ndc} P_{f,j}^{prd} \cdot C_{f,j}^{prd} \tag{1.51}$$

In Equation (1.51), j represents each of the number of applicable overpressure demand case, ndc.

Since a PRD may protect multiple pieces of equipment, the above calculations are repeated for each piece of equipment protected by the PRD. The resulting risk for the PRD is the maximum risk calculated for each of the pieces of equipment protected by the PRD.

7.6.2 Risk from Leakage

The calculation of the risk associated with PRD leakage is obtained by multiplying the probability of leakage, P_l^{prd}, and the consequence of leakage, C_l^{prd}, in accordance with Equation (1.52):

$$Risk_{l}^{prd} = P_{l}^{prd} \cdot C_{l}^{prd} \tag{1.52}$$

7.6.3 Total Risk

The total risk associated with PRD failure to open and leakage is obtained as follows:

$$Risk^{prd} = Risk_{f}^{prd} + Risk_{l}^{prd} \tag{1.53}$$

7.6.4 Calculation Procedure

The following summarizes the calculation procedure for the failure to open case.

a) STEP 7.1—For the PRD failure to open case, calculate the risk associated for each of the applicable overpressure demand cases, $Risk_{f,j}^{prd}$, using Equation (1.50).

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b) STEP 7.2—Sum up the individual risks associated with the applicable overpressure demand cases to get a total risk for the failure to open case, $Risk_f^{prd}$, using Equation (1.51).

c) STEP 7.3—Calculate the risk for the PRD leakage case, $Risk_l^{prd}$ using Equation (1.52).

d) STEP 7.4—Calculate the total risk using Equation (1.53).

7.7 Inspection Planning Based on Risk Analysis

7.7.1 RBI Intervals

The inspection intervals for PRDs are determined by the probability and consequence of the event outcomes that can result from PRD failure to open or leakage. The probability side of the equation relates to the probability that the PRD fails to perform its function, either failing to open upon demand or leaking. The consequence side relates to loss of containment from the piece of equipment protected by the PRD or to leakage through the PRD.

Risk increases as a function of time since the POF of the PRD increases and the probability of leakage through the PRD increases with time. Additionally, the consequence of PRD failure increase since the protected equipment damage increases over time, which increases the likelihood and consequence associated with loss of containment. The recommended interval is determined for a PRD by calculation of the risk as a function of time and determination of the time at which the risk is equal to the risk target. See Section 4.4.2 for a discussion of risk targets.

7.7.2 Effect of PRD Inspection, Testing, and Overhaul on Risk Curve

Figure 7.7 shows the effect of testing, inspection, and repair of the PRDs. The figure also illustrates the effect of the risk target. For the example presented in Figure 7.7 a risk target of $25,000/year resulted in inspection intervals of 5 years. Alternatively, if the risk target were $10,000/year, the resulting inspection interval would have been every 3 years.

Since devices are normally overhauled or replaced at the time of testing, the risk of failure goes to zero just after the test. This is a critical assumption—that the PRD is returned to an as-new condition upon overhaul.

7.7.3 Effect of PRD Testing Without Overhaul on Risk Curve

Typically, when a PRD is inspected and tested, the opportunity is taken to overhaul the PRD and return it to service in an as-new condition. Occasionally, however, a PRD is inspected and/or tested without overhaul. An example would be performing a pop test in the shop in the as-received condition and returning the PRD to service without overhaul. Another example would be performing an in situ pop test while the PRD remains on the unit.

In these situations, confidence that the PRD is in working condition is gained, but the PRD has not been restored to an as-new condition. Inspection is credited by adjusting the POF and leakage curves (adjustment of Weibull η parameter). If the test were successful, the test interval will be increased, marginally. However, the risk does not drop back down to zero as would be the case if the PRD were overhauled. Therefore, the full benefit of the increased test interval will not be realized.

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7.8 Nomenclature

A^{prd}	is the orifice area of the PRD, mm^2 (in.^{2})
A_{total}^{prd}	is the total installed orifice area of a multiple device installation, mm^2 (in.^{2})
C_{env}	is the environmental consequence from PRD leakage, $
$C_{f,j}^{prd}$	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 consequence of leakage, $
C_l^{so}	is the consequence of a stuck open PRD, $
C_{prod}^{mild}	is the consequence of lost production of mild or moderate leaks, $
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
$Cost_{env}$	is the environmental costs due to a PRD leak, $
$Cost_{flu}$	is the cost of the lost fluid, $/kg ($/lb)
$Cost_{inv}$	is the lost inventory or fluid costs due to a PRD leak, $
$Cost_{inv}^{mild}$	is the cost of lost inventory due to a minor or moderate PRD leak, $
$Cost_{inv}^{so}$	is the cost of lost inventory due to a stuck open PRD, $
$Cost_{prod}$	is the production losses as a result of shutting down to repair a PRD, $
$Cost_{prod}^{mild}$	is the production losses as a result of shutting down to repair a mild or moderate leaking PRD, $
$Cost_{prod}^{so}$	is the production losses as a result of shutting down to repair a stuck open PRD, $
$Cost_{sd}$	is the maintenance and repair costs associated with a PRD, $

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D_f	is the damage factor 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/year
DR_{total}	is the total demand rate on a PRD, demands/year
$DRRF_j$	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/year
F_{MS}	is the management systems factor
F_a	is the multiple device installation adjustment factor
F_c	is the adjustment factor for conventional valves
F_{env}	is the adjustment factor for environmental factors
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/year
gff_{total}	is the total GFF for the protected equipment, years
$lrate_{mild}$	is the leakage rate of a mild or moderate leaking PRD, kg/hr (lb/hr)
$lrate_{so}$	is the leakage rate for a stuck open PRD, kg/hr (lb/hr)
$MAWP$	is the maximum allowable working pressure of the protected equipment, kPa (psig)
$MTTF$	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/year

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$P_f(t)$	is the POF (loss of containment) of the protected equipment, failures/year
$P_{f,cond}^{prd}$	is the conditional POFOD, failures/demand
$P_{f,j}^{n}$	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/year
$P_{f,j}^{prd}$	is the POF of a PRD associated with the j^{th} overpressure demand case, failures/year
$P_{f,prior}^{prd}$	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 probability of leakage, failures/year
$P_{l,wgt}^{prd}$	is the weighted probability of leakage, failures/demand
P_o	is the overpressure likely to occur as a result of a PRD failing to open upon demand, kPa (psig)
$P_{o,j}$	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, kPa (psig)
$P_{p,prior}^{prd}$	is the prior probability of passing on demand, failures/demand
P_s	is the storage or operating pressure of the protected equipment, kPa (psig)
P_{set}	is the set pressure of the PRD, kPa (psig)
$Risk^{prd}$	is the total risk for a PRD, \$/year
$Risk_f^{prd}$	is the risk of a PRD failure to open, \$/year
$Risk_{f,j}^{prd}$	is the risk of a PRD failure to open associated with the j^{th} overpressure demand case, \$/year
$Risk_l^{prd}$	is the risk of PRD leakage, \$/year
$R(t)$	is the risk as a function of time, m^2/year (ft^2/year) or \$/year
t	is time, years
$t_{dur,i}$	is the actual duration between inspections associated with the i^{th} historical inspection record, years

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t_{insp}	is the inspection interval, years
$Unit_{prod}$	is the daily production margin on the unit, \$/day
W_c^{prd}	is the rated capacity of a PRD, kg/hr (lb/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

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7.9 Tables

Table 7.1—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 probability of leakage curves.	User specified
	FAIL TO OPEN — Mild — Moderate (default) — Severe	
	LEAKAGE — Mild — Moderate (default) — Severe	
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 7.2. 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 7.1.6) — Inlet and outlet piping condition [see Section 7.2.4 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

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Table 7.2—Default Initiating Event Frequencies

Overpressure Demand Case	Event Frequency	EF_j (events/year)	$DRRF_j$ (See Notes 2 and 3)	Reference
1. Fire	1 per 250 years	0.0040	0.10	[6]
2. Loss of cooling water utility	1 per 10 years	0.10	1.0	[6]
3. Electrical power supply failure	1 per 12.5 years	0.080	1.0	[6]
4a. Blocked discharge with administrative controls in place (see Note 1)	1 per 100 years	0.010	1.0	[16]
4b. Blocked discharge without administrative controls (see Note 1)	1 per 10 years	0.10	1.0	[16]
5. Control valve failure, initiating event is same direction as CV normal fail position (i.e. fail safe)	1 per 10 years	0.10	1.0	[17]
6. Control valve failure, initiating event is opposite direction as CV normal fail position (i.e. fail opposite)	1 per 50 years	0.020	1.0	[17]
7. Runaway chemical reaction	1 per year	1.0	1.0	
8. Heat exchanger tube rupture	1 per 1000 years	0.0010	1.0	[18]
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	0.10	[6]
11b. Liquid overfilling without administrative controls (see Note 1)	1 per 10 years	0. 10	0.10	[6]

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 7.3.

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Table 7.3—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 [16] page A7-7, 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 × 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 × 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 on page 9/30 of [16]	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
	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	

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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, 1983 [16] 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.

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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 [17] 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 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		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.

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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 [17] 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 [18])	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

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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 probability of leakage 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.

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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 × 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 pressure source vessel	

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Table 7.4—Design Margins for Various Codes of Construction

Construction Code	Design Margin
ASME Section VIII, Div. 1, pre-1950	5.0
ASME Section VIII, Div. 1, 1950–1998	4.0
ASME Section VIII, Div. 1, 1999 and later	3.5
ASME Section VIII, Div. 2, pre-2007	3.0
ASME Section VIII, Div. 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–user to determine the design margin.

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Table 7.5—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 gasses 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 boiler feed water), 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_2S

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 7.11 for the categories for the LEAK case.

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Table 7.6—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 7.2.4 g).

NOTE 2 The η_{def} parameter values for pilot-operated valves 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 7.2.4 e).

NOTE 3 Without any failure rate data for rupture disks, the conventional PRV values for Mild services were used. This assumes that the RD material has been selected appropriately for the fluid service; see Section 7.2.4 f).

Table 7.7—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.

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Table 7.8—Set Pressure Factor

PRV Type	Set Pressure Factor
Pilot-operated PRVs	$F_{set} = 1 - \left[\dfrac{0.95 - min\left[0.95, \dfrac{P_S}{P_{set}}\right]}{0.95}\right]$
Rupture disks	$F_{set} = 1$
Conventional PRVs and balanced bellows PRVs	$F_{set} = 1 - \left[\dfrac{0.90 - min\left[0.90, \dfrac{P_S}{P_{set}}\right]}{0.90}\right]$
NOTE 1 P_S denotes the operating pressure and P_{set} denotes the set pressure.	

Table 7.9—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}	No credit	0.5	0.70	0.9
Fail, CF_{fail}	No credit	0.70	0.95	0.95
No leak, CF_{noleak}	No credit	0.5	0.70	0.9
Leak, CF_{leak}	No credit	0.70	0.95	0.95

Table 7.10—Inspection Updating Equations

Inspection Effectiveness and Result	Equation for Weighted POFOD
Highly effective pass	$P^{prd}_{f,wgt} = P^{prd}_{f,prior} - 0.2 \cdot P^{prd}_{f,prior}\left(\dfrac{t}{\eta}\right) + 0.2 \cdot P^{prd}_{f,cond}\left(\dfrac{t}{\eta}\right)$
Usually effective pass	
Fairly effective pass	
Highly effective fail	$P^{prd}_{f,wgt} = P^{prd}_{f,cond}$
Usually effective fail	
Fairly effective fail	$P^{prd}_{f,wgt} = 0.5 \cdot P^{prd}_{f,prior} + 0.5 \cdot P^{prd}_{f,cond}$

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Table 7.11—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 7.12—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 7.4 for the categories for the FAIL case.			

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Table 7.13—Default Weibull Parameters for Probability of Leakage (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 valves 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 7.14—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 relief device	No expected consequence at this accumulation level
16 %	ASME code allowable accumulation for process upset cases protected by multiple relief devices	No expected consequence at this accumulation level
21 %	ASME code allowable accumulation for external fire relief cases regardless of the number of relief devices	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.

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Table 7.15—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)
≤ $^{3}/_{4}$ in.	60	8
$^{3}/_{4}$ < inlet size ≤ $1^{1}/_{2}$	30	4
$1^{1}/_{2}$ < inlet size ≤ 3	15	2
3 < inlet size ≤ 6	7	1
Greater than 6	2	0.33

Table 7.16—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

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7.10 Figures

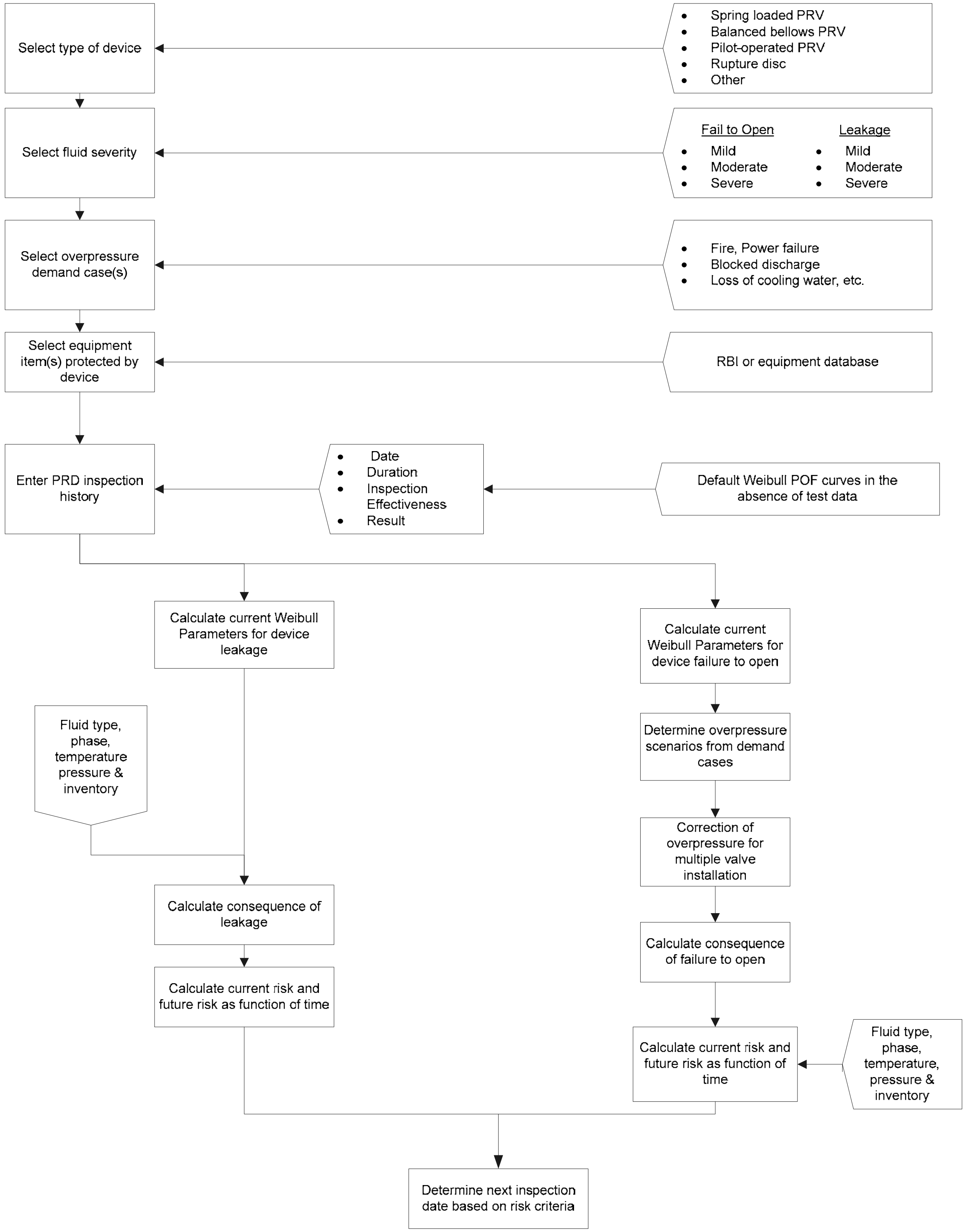

Figure 7.1—PRD RBI Methodology

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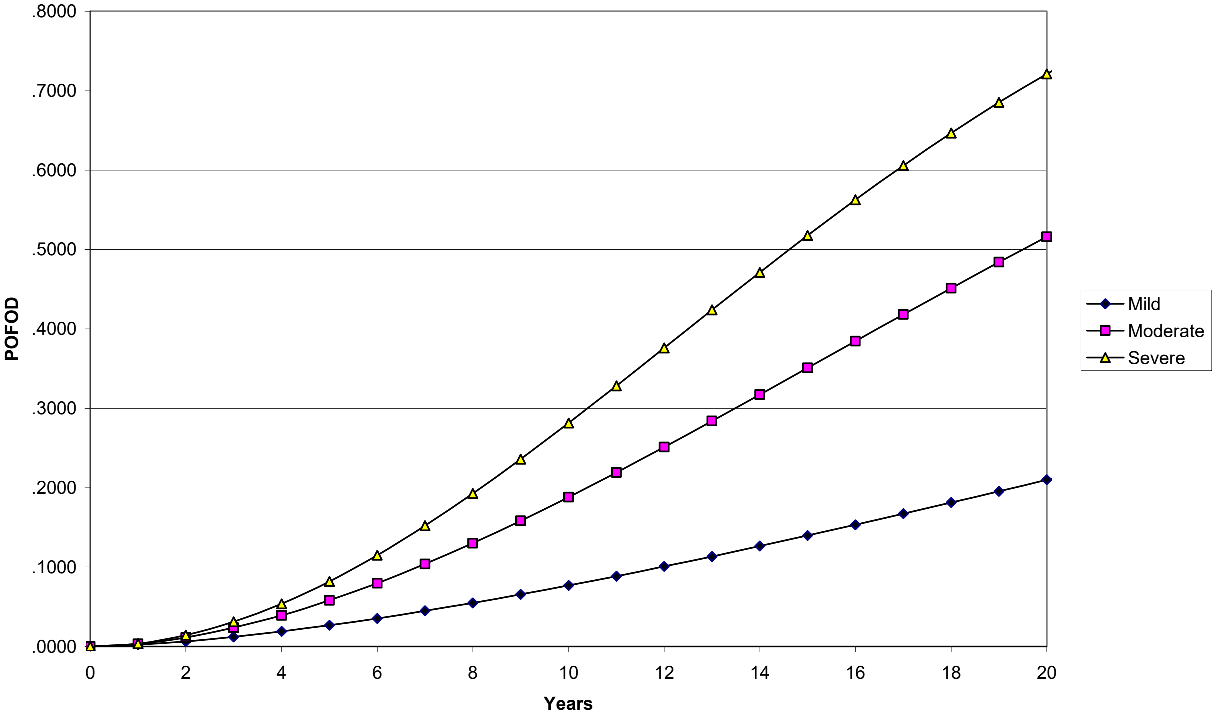

Figure 7.2—Default Conventional PRV Fail to Open on Demand Weibull Curves

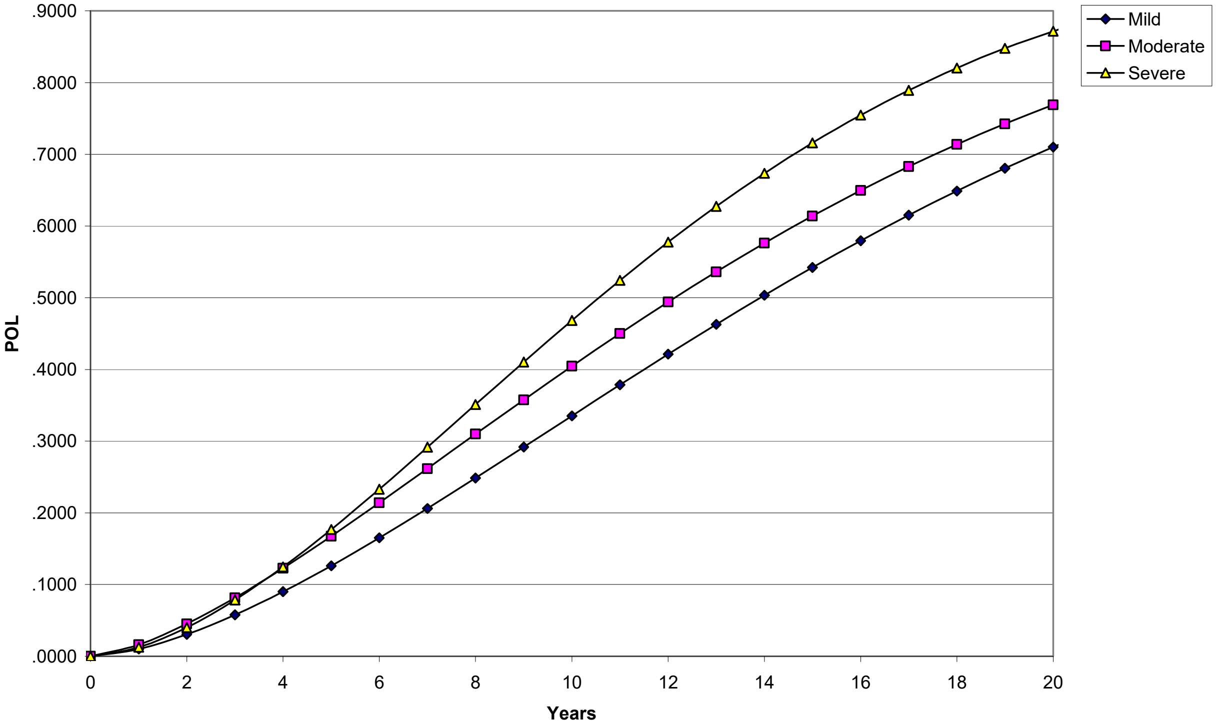

Figure 7.3—Default Leakage Failure Rate for Conventional PRVs

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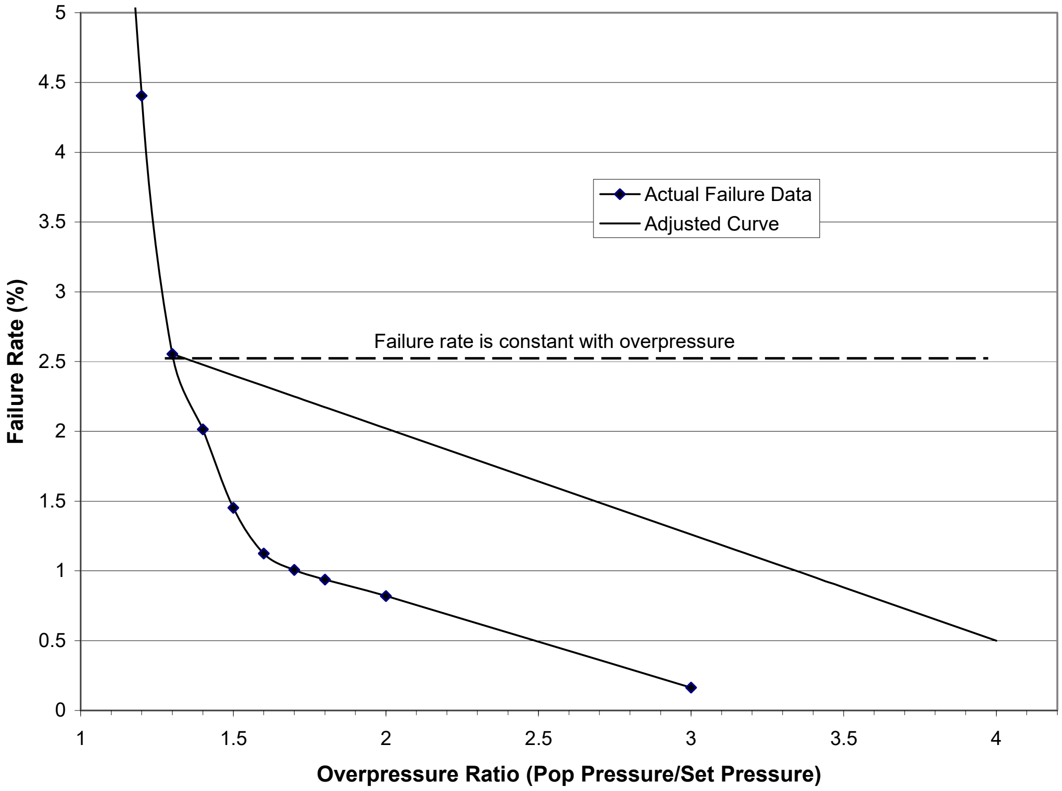

Figure 7.4—PRD Failure Rate As a Function of Overpressure

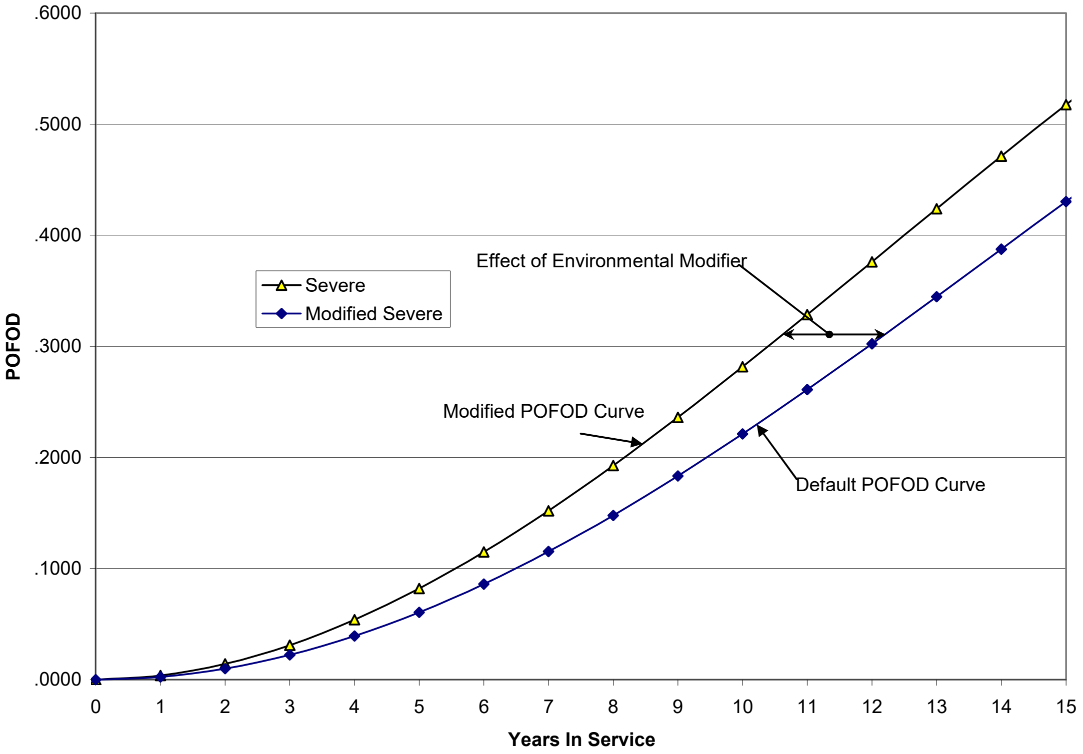

Figure 7.5—Effect of Environmental Factors on PRD Weibull Curves

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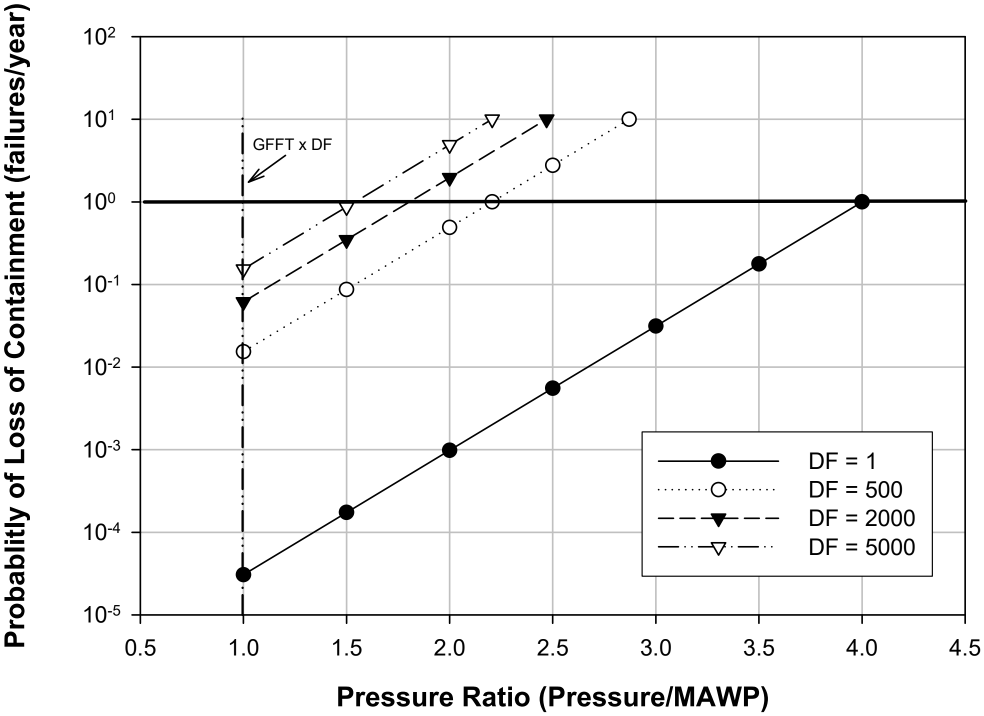

For an example pressure vessel with:

1. $gff_{total} = 3.06 \times 10^{-5}$
2. Design margin = 4
3. Estimated burst pressure of 4 × MAWP

Figure 7.6—Probability of Loss of Containment As a Function of Overpressure

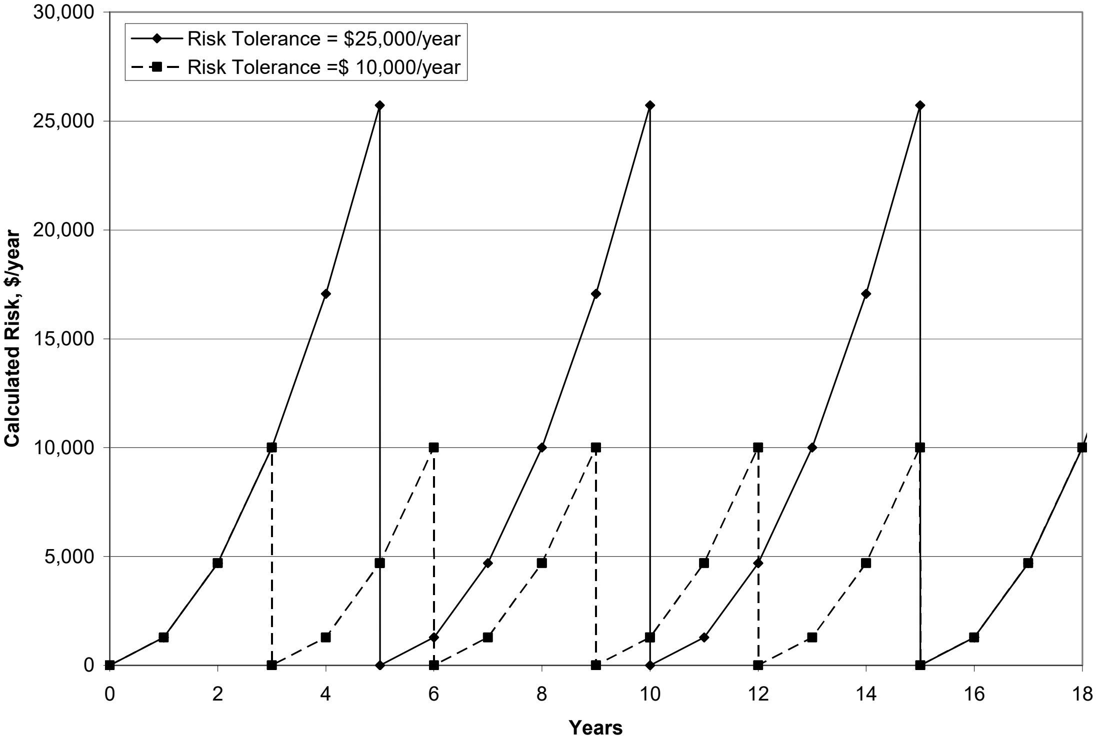

Figure 7.7—Inspection Test Updating of PRDs

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8 Heat Exchanger Tube Bundles

8.1 General

8.1.1 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 optimize heat exchanger bundle inspection and replacement cycles and to minimize the annual operating and maintenance costs of heat exchanger bundles. These costs include bundle 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 bundle failure.

8.1.2 Background

Many companies currently predict bundle life by analyzing the history of each heat exchanger bundle from the service start date. These condition-based inspection programs do not, in general, consider the financial consequences associated with bundle failure. The problem with a condition-based approach for heat exchanger bundles is that many exchangers may experience few, if any, bundle failures and some failures may not apply to current operating conditions or practices. In addition, these approaches are not based on a statistically significant data set to make an accurate prediction of future performance or POF for the heat exchanger bundle. This philosophy also does not allow any predictions for newly installed bundles or for bundles where inspection information is not available.

8.1.3 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.

To facilitate a more accurate prediction of future performance, the combined experience of other heat exchanger bundles of similar design and in similar service may be combined and statistically analyzed. With this method, it is critical that the owner–user maintains a heat exchanger bundle reliability library of failure data for exchanger bundles. The exchanger bundle being evaluated is matched to a subset of similar bundles from the reliability library and a Weibayes analysis is performed to estimate the future POF of the bundle. The results from the analysis may be used to determine if the exchanger bundle will survive until the next scheduled maintenance shutdown.

The advantage of using Weibayes analysis is that sound engineering decisions may be made with significantly fewer failure data points as would be needed with other statistical distributions [11]. The Weibayes approach is used as this method incorporates past experience of other similar bundles (Weibull library or seed database) with the specific data available for the bundle being evaluated.

8.1.4 Required and Optional Data

The data listed in Table 8.1 show the minimum data requirements for each heat exchanger bundle. In addition, optional information can be supplied for the bundle being evaluated. The minimum and optional data are used as matching criteria for the reliability library to filter the database down to a subset of bundles with similar physical design and service. The more data that are used, the better the ability the user has to filter down to a subset of bundles that is representative of the bundle being evaluated.

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8.2 Methodology Overview

Calculations for the risk and inspection benefit of the heat exchanger bundles are performed following the flow chart shown in Figure 8.1.

There are several steps involved in estimating the POF and the overall risks. The following steps describe the methodology.

a) STEP 1.1—Gather and input the bundle basic input data.

b) STEP 1.2—Gather and input inspection historical data.

c) STEP 1.3—Determine consequences of bundle failure, C_f^{tube}.

d) STEP 1.4—Determine the maximum acceptable POF based on the calculated C_f^{tube} and the owner–user's risk target, $Risk_{tgt}$.

e) STEP 1.5—Provide MTTF or Weibull parameters for the bundle failure rate curve, if known. If supplied, go to STEP 1.12; otherwise proceed to STEP 1.6.

f) STEP 1.6—Select a set of matching criteria and establish a cut-set of similar bundles from the reliability library.

g) STEP 1.7—Generate a Weibull plot of the cut-set data.

h) STEP 1.8—Assess the goodness of fit. Repeat cut-set selection (STEP 1.6 and STEP 1.7), if not acceptable.

i) STEP 1.9—Determine Weibull parameters for the library cut-set data (raw data).

j) STEP 1.10—Apply an uncertainty based on effectiveness of inspection to obtain the adjusted Weibull curve.

k) STEP 1.11—If the inspection history provides thickness measurements or some other estimate of the current condition and/or the remaining life for the bundle, adjust the Weibull curve to account for the known condition of the bundle.

l) STEP 1.12—Calculate the POF at the current date using the adjusted Weibull curve.

m) STEP 1.13—Calculate the risk at the plan date with and without inspection.

n) STEP 1.14—Generate an inspection plan.

8.3 Probability of Failure

8.3.1 Definition of Bundle Failure

To be able to determine the bundle life (failure life) of bundles that are in the failure database and to predict the point in time at which an existing bundle will reach its end of life, a definition of bundle failure must be established. A failure is defined as a tube leak for the purposes of RBI.

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When the controlling damage mechanism for the bundle is general corrosion, the current condition or remaining life of a bundle can usually be quantified or expressed as a percent of the original wall thickness. Where inspection records document average remaining wall thickness, these data may be used to determine when failure occurred or to predict the point in the future where a failure is probable.

Other damage mechanisms, such as local corrosion, erosion, or vibration damage, may not be easily predicted based on measurements taken during an inspection. In these cases, prediction of the bundle failure may need to be based on an estimation of remaining life of the bundle.

Typically, bundles are replaced or repaired prior to failure due to a deteriorated condition. In these situations, one approach for estimating bundle failure is to assume that the bundle was replaced at 75 % of the bundle life. A 75 % bundle life assumption is recommended and may be modified, if desired. The degraded condition assumption allows consideration for remaining life of the bundle when replaced prior to actual tube failure. A degraded condition is a bundle that would not be expected to make another operating cycle without expected tube failures.

8.3.2 Probability of Failure Using Weibull Distribution

The POF for a heat exchanger bundle may be expressed using a two-parameter Weibull distribution using Equation (1.54) [12].

$$P_f^{tube} = 1 - R(t) = 1 - exp\left[-\left(\frac{t}{\eta}\right)^{\beta}\right] \tag{1.54}$$

In Equation (1.54), P_f^{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 and η is the Weibull characteristic life in years, and t is the independent variable time in years.

The time to reach a desired POF can be determined by rearranging Equation (1.54) as shown in Equation (1.55).

$$t = \eta \cdot \left(-ln\left[1 - P_f^{tube}\right]\right)^{\frac{1}{\beta}} \tag{1.55}$$

The calculation of POF as a function of in-service duration may be performed using one of the methods shown below:

1) Method 1—Using Matching Criteria to Filter on the Reliability Library (see Section 8.3.2)—If a value of the MTTF has not been specified, then the Weibull distribution is assumed and a Weibayes analysis is performed on the matching bundles in the reliability library.

2) Method 2—Owner–User-specified Weibull Parameters (see Section 8.3.4)—This involves specification of the Weibull β and η parameters for the exchanger bundle being evaluated.

3) Method 3—Owner–User-specified MTTF (see Section 8.3.4.2)—This involves the owner–user providing the MTTF for the bundle being evaluated. The method will convert the MTTF to a Weibull curve using a β value of 3.0. As an option, the Weibull β parameter in addition to the MTTF is specified.

4) Method 4—Specific Bundle Inspection History (see Section 8.3.4.3)—Once enough inspection history is accumulated, the statistics could be determined for the bundle.

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8.3.3 Exchanger Bundle Reliability Library or Seed Database

A reliability database or Weibull library is extremely important to the evaluation of the risks associated with bundle failure. Certain exchanger details are required to be gathered for each bundle entry in the reliability database. Minimum basic data required for the database are indicated in Table 8.1. Optional data are also shown in Table 8.1 that could be collected to provide additional matching/filtering capability for the reliability library.

a) Weibayes Analysis

If the assumption is made that similarly designed bundles in similar service will have the same failure mechanism, a Weibayes approach can be used. This approach assumes that the shape, or slope, of the Weibull curve for the cut-set of similar bundles will be identical to the bundle that is being evaluated. The Weibayes approach also allows an accurate statistical failure analysis to be performed without having a large amount of failure data for the specific bundle being evaluated.

b) Developing Matching Criteria or Cut-set

It is important to note that there are several different failure mechanisms that a heat exchanger bundle can experience such as:

1) corrosion,
2) pitting,
3) cracking,
4) erosion/corrosion,
5) vibration damage,
6) mechanical failure,
7) tube end thinning.

The bundle reliability database is filtered using the parameters listed in Table 8.1. The goal is to filter the database sufficiently enough to isolate the failure mechanism within the cut-set to one specific damage mechanism and to get the data to plot acceptably on a Weibull plot.

c) Goodness of Fit Test

If a Weibull plot is created from too broad of a cut-set on the failure reliability database, the data will not properly plot on the Weibull plot. When this occurs, a likely reason is that multiple failure mechanisms are being plotted and a more specific list of matching criteria is required to isolate the failures to one mechanism.

A goodness of fit test should be used to determine whether or not the subset of data is correct. Once this is accomplished, there is added confidence that the Weibull distribution of the cut-set is applicable to the specific heat exchanger being evaluated.

Two approaches to the goodness of fit test for the data are the $pve\%$ and r^2 methods. The methodology for determining these values are given in *The New Weibull Handbook* [14]. The closer the $pve\%$ is to 100, the better the fit of the Weibull curve. In general, a $pve\%$ of greater than 20 is considered adequate for small failure sample sizes (<20).

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d) Determination of Weibull Curve Parameters from Matching Data

After similar bundles have been matched from the database, the data have been plotted on a Weibull plot, and a goodness of fit test has been applied, the Weibull parameters, β and η, are obtained. In accordance with the Weibull Handbook [14], the standard method and best practice for estimating the Weibull parameters, β and η, for small and moderate sized data sets is median rank regression curve fitting using the time-to-failure as the dependent variable (X onto Y).

Note that failure data as well as "no-failure" data (suspensions) are used in the plotting of the Weibull curve.

e) Confidence Bounds

Most statisticians will use confidence bounds on data of this nature to account for the statistical distribution in the data. A 90 % lower bound confidence (LBC) interval is recommended using Fisher Matrix Bounds [19]. The 90 % LBC provides a 90 % confidence that the data point will fall to the right of the line.

f) Example Calculation of POF Using Weibayes with Failure Database

As an example of calculating a POF as a function of time in service for a hypothetical heat exchanger bundle, a reliability database was searched to find bundles matching the following criteria.

1) Tubeside fluid category—crude.
2) Controlling damage mechanism—general corrosion.
3) Tubeside operating temperature range between 350 °F and 500 °F.
4) Tubular Exchanger Manufacturers Association (TEMA) type AES.
5) Exchanger type—liquid/liquid process exchanger.
6) Sulfur content greater than 1 %.

Nine bundles in the database were retrieved. Five failures and four suspensions (bundles in-service without failure reported) were found. The data are represented in Table 8.2.

The first three records shown in Table 8.2, noted by the exchanger tag number 191-X-25A, are data accumulated from the inspection records for the specific bundle that is being evaluated. The remaining data were obtained from similar bundles found in the reliability database.

The data supplied in Table 8.2 for the matching bundles have been plotted as a Weibull distribution on Figure 8.2. The calculated Weibull parameters for this matching bundle set are:

$$\beta = 2.568 \qquad \text{slope parameter} \tag{1.56}$$

$$\eta = 20.45 \qquad \text{characteristic life in years} \tag{1.57}$$

The goodness of fit parameter, $pve\%$, is shown on Figure 8.2 to be 99.9, which implies that the data properly fit a Weibull distribution.

With the Weibull parameters defined, the POF as a function of time is determined for the example problem using Equation (1.58).

$$P_f^{tube} = 1 - exp\left[-\left(\frac{t}{20.45}\right)^{2.568}\right] \tag{1.58}$$

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8.3.4 POF Calculation Options

8.3.4.1 POF Using the Owner–User Supplied Weibull Parameters

As an option, the owner–user can provide the β and η parameters for the exchanger bundle and use Equation (1.58) to determine the POF for the bundle as a function of time.

8.3.4.2 POF Using the User Supplied MTTF

When sufficient inspection information exists for a bundle such that a MTTF may be determined, the analyst can specify the bundle MTTF. A Weibull distribution can still be used. If the β parameter (slope) is known (default is 3.0), the η parameter (characteristic life) can be calculated using the gamma function as shown in Equation (1.59).

$$MTTF = \eta \cdot \Gamma\left[1 + \frac{1}{\beta}\right] \tag{1.59}$$

8.3.4.3 POF Calculated Using Specific Bundle History

Once the bundle has accumulated at least two life cycles with inspection data, a Weibayes analysis can be performed keeping the β parameter the same as determined from the matching bundle criteria. The η parameter (characteristic life) can be recalculated using Equation (1.60).

$$\eta = \left(\sum_{i=1}^{N} \frac{t_{dur,i}^{\beta}}{r}\right)^{\frac{1}{\beta}} \tag{1.60}$$

In Equation (1.60), N is the number of past bundles, $t_{dur,i}$ is the time in service for each bundle in years, r is the number of failed bundles, and β is the Weibull slope parameter.

For the 191-X-25A exchanger in our example (see Table 8.2), there were failures recorded after 18 and 22 years. The current bundle (T3) has been in-service for 16 years without failure (suspension). The modified characteristic life may be recalculated using Equation (1.61) as demonstrated below:

$$\eta = \left[\frac{(22)^{2.568} + (18)^{2.568} + (16)^{2.568}}{2}\right]^{\frac{1}{2.568}} = 22.16 \text{ years} \tag{1.61}$$

Note that this is slightly higher than the 20.45 year characteristic life calculated using the matching bundles from the reliability database; see Equation (1.63).

The user should be cautioned that this method assumes that the bundle has not been redesigned over its life time. Changes in metallurgy, process conditions, or bundle design need to be considered before assuming that all of the past failure history is representative of the current bundle being evaluated.

8.4 COF

8.4.1 Calculation Method

Bundle failure is defined as a tube leak. Financial consequences are 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 (1.62).

$$C_f^{tube} = Cost_{prod} + Cost_{env} + Cost_{bundle} + Cost_{maint} \tag{1.62}$$

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The unit production or lost opportunity cost, $Cost_{prod}$, is determined using Equation (1.63).

$$Cost_{prod} = Unit_{prod} \cdot \left(\frac{Rate_{red}}{100}\right) \cdot D_{sd} \tag{1.63}$$

Consider the impact of a full unit/plant shutdown or rate cut when determining the lost opportunity cost, $Cost_{prod}$ (\$/day), for bundles that cannot be bypassed online. The default used for the environmental cost, $Cost_{env}$, in cooling water service is \$100,000. The days to repair the bundle during an unplanned failure, D_{sd}, should include the time it takes to purchase and install a new bundle at a future date.

Equation (1.64) may be used to estimate the bundle replacement costs, $Cost_{bundle}$. This equation assumes a typically sized carbon steel bundle, 800 mm (31.5 in.) diameter × 6 m (20 ft) long with a volume of 3.016 m^3 (106.5 ft^3), costs \$22,000 to replace. Bundle costs are prorated as a function of size (volume) and tube material of construction. Tube material cost factors, M_f, are provided in Table 8.3.

$$Cost_{bundle} = \frac{22{,}000 \cdot \left(\frac{\pi D_{shell}^2}{4}\right) \cdot L_{tube} \cdot M_f}{C_1} \tag{1.64}$$

8.4.2 Example

To illustrate the calculation for COF, the following data are supplied as an example.

a) Unit production costs: \$100,000/day.

b) Production impact: bypass with rate reduction of 25 % if bundle failure occurs.

c) Planned shutdown days to repair: 1 days.

d) Unplanned shutdown days to repair: 4 days.

e) Bundle replacement costs: \$25,000.

f) Maintenance cost associated with bundle replacement: \$25,000.

g) Environmental impact: \$0.00.

h) Corporate financial risk target: \$75,000.

The consequence of an unplanned failure is calculated using Equation (1.65) as follows:

$$C_f^{tube} = 100{,}000 \cdot \left(\frac{25}{100}\right) \cdot 4 + 0 + 25{,}000 + 25{,}000 = \$150{,}000 \tag{1.65}$$

8.5 Risk Analysis

8.5.1 General

Risk as a function of time is the product of the POF and the COF in financial terms.

$$Risk_f^{tube} = P_f^{tube} \cdot C_f^{tube} \tag{1.66}$$

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8.5.2 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 Table 8.7, and enables each bundle to be plotted on the risk matrix as shown in 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 8.6.4.

8.6 Inspection Planning Based on Risk Analysis

8.6.1 Use of Risk Target in Inspection Planning

The risk target is a function of the owner–user'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.

Rearranging Equation (1.66), the maximum acceptable POF for any bundle as a function of the consequence of tube failure and the risk target specified by the user is as follows:

$$P_{f,max}^{tube} = \frac{Risk_{tgt}}{C_f^{tube}} \tag{1.67}$$

From this and the equation for POF in time (see Equations (1.54), a target inspection date can be determined. This target date is the date at which the risk for the bundle meets the risk target specified by the user.

8.6.2 Example

Using the example risk target and C_f^{tube} calculated in Section 8.4.2, Equation (1.68) yields a maximum or target POF that may be used in inspection planning as follows:

$$P_{f,max}^{tube} = \frac{75{,}000}{150{,}000} = 0.5 \tag{1.68}$$

8.6.3 Inspection Planning Without Inspection History (First Inspection Date)

To plan inspections, the risk at any point in time must be calculated. Figure 8.2 provides the POF curve for the example problem or Section 8.4.2 using the matching heat exchanger bundles from the reliability database. Using the value of $P_{f,\max}^{tube}$ that was calculated in Equation (1.68) and using the risk target, the risk as a function of time can be determined.

a) Introduction of Uncertainty and its Effect on Risk

Without a large sampling of inspection data for the bundle, there is a degree of uncertainty associated with whether or not the matching set of exchanger bundles from the failure database accurately represents the bundle being evaluated. To account for inaccuracies and biases that are inherent in the failure database, additional uncertainty (AU) is introduced into the statistics. A default value for AU of

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50 % is used. Figure 8.3 shows the curve from the example problem shifted to the left as a result of the addition of the 50 % uncertainty.

If the bundle has no inspection record and no knowledge exists as to the condition of the bundle, the 50 % uncertainty curve is used to predict the POF as a function of time for the bundle. The calculated risk for a bundle without any inspection knowledge will be higher than for a bundle that has inspection records. Although the action of inspection does not in itself reduce risk, this agrees with governing RBI principles stating that the more knowledge obtained for a piece of equipment, the less uncertainty exists, resulting in a reduction of the calculated risk.

Without any inspection, the recommended length of service for the bundle in the example problem as a function of time may be determined using the 50 % AU curve on Figure 8.3 or may be obtained from Table 8.4.

In the example problem, the maximum acceptable POF, $P_{f,max}^{tube}$, as calculated per Equation (1.68), was determined to be 0.5 (or 50 %). Based on this, the recommended first inspection would be 7.1 years after installation. This compares to a predicted value of 14.7 years if the raw data (90 % LBC) representing the matching set of bundles in the reliability database were used. This shows the direct effect that inspection uncertainty has on the calculated risk and the subsequent inspection plan.

8.6.4 Inspection Planning with Inspection History

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.

a) Effect of Inspection on POF

An inspection provides two things:

1) Reduction in 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 % AU curve (no inspection history) to a curve 20 % AU curve (usually effective inspection). See Section 8.6.4 b) for a discussion of inspection effectiveness. Table 8.5 provides examples of inspection effectiveness applied to bundles.

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; see Section 8.6.4 c).

b) Reduction in Uncertainty due to Inspection Effectiveness

If the tube bundle has been inspected, the uncertainty is reduced (the POF curve moves to the right) and the POF at any time decreases. In this way, inspection knowledge reduces the POF and the calculated risk.

At this point, the concept of inspection effectiveness is introduced, similar to the methodology used in other modules. 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 Part 2, Table 2.C.4.1.

The discussion of inspection effectiveness is continued in Part 2, Annex 2.C.

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c) Shift of POF Curve due to Knowledge of True Bundle Condition

1) General

Not only does an inspection reduce the uncertainty in the data, it also provides knowledge of the current condition of the bundle. It may be determined that the bundle is in excellent condition and that the curve being used for the POF is too conservative. Conversely, it may also be determined that the bundle is in worse condition than what has been predicted using data from bundles in similar service.

Where general corrosion is the controlling damage mechanism in the bundle, the average measured tube thickness data may be used to predict the future bundle failure date. For other damage mechanisms (vibration, tube end thinning, etc.) or where measured thickness data do not exist, a qualitative estimate of the remaining life can be used to predict the future bundle failure date.

Whichever method is used to calculate a future failure date based on an inspection record, the predicted future failure data can be used to modify the base POF curve.

2) Predicted Future Failure Date Based on Measured Thickness Data

The thinning rate of the tube bundle may be determined using the average furnished wall thickness and the average wall thickness as measured at the last inspection as follows:

$$t_{rate} = \frac{\bar{t}_{orig} - \bar{t}_{insp}}{t_{dur}} \tag{1.69}$$

With the failure point defined as a fraction of remaining wall thickness, RWT_f, the predicted bundle life adjusted for inspection, PBL_{adj}, can be calculated using Equation (1.70).

$$PBL_{adj} = \frac{RWT_f \cdot \bar{t}_{orig}}{t_{rate}} \tag{1.70}$$

As an example, let’s assume that the example bundle from Section 8.4.2 had the following inspection details.

i) Installation Date—January 1992 with original wall thickness, $\bar{t}_{orig}$, of 0.12 in.

ii) June 2000—Bundle had minor general corrosion throughout on outside diameter (OD), 10 % of the tubes were sampled using Elliot gages/calipers and found to have an average wall thickness of 0.11 in. (8.5 % wall loss). Bundle was hydrotested without leaks. Inspection effectiveness graded as “C.”

iii) September 2003—Bundle showed minor wall loss to 0.104 in. average thickness (13 % wall loss). Bundle was hydrotested without leaks. Inspection effectiveness graded as “C.”

iv) A failure definition of 50 % remaining wall thickness is used, i.e. $RWT_f = 0.5$.

For the example problem, the bundle was inspected in September 2003 after 11^{3}/4 years in service. Over this time period, the average measured wall thickness went from 0.12 in. down to 0.104 in.

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The thinning rate is calculated using Equation (1.71) as follows:

$$t_{rate} = \frac{0.12 - 0.104}{11.75} = 0.001362 \text{ in./year} \tag{1.71}$$

The predicted bundle life adjusted for inspection, PBL_{adj}, is then calculated using Equation (1.72).

$$PBL_{adj} = \frac{0.5 \cdot 0.12}{0.001362} = 44.1 \text{ years} \tag{1.72}$$

At this rate, the average wall thickness would reach 50 % of the original wall thickness or the remaining wall thickness (RWT_f) in 44.1 years, or in January of 2036. This bundle is in better condition than predicted by bundles in similar service.

d) Predicted Future Failure Date Based on Estimated Remaining Life

As an alternative, when tube wall thickness data are unavailable for calculation of a bundle tube thinning rate, or when the damage mechanism is something other than general corrosion, the estimated remaining life (ERL) of the bundle can be used to calculate predicted bundle life. The ERL may be obtained using inspection data combined with accepted FFS calculations based on the damage mechanism known or anticipated.

$$PBL_{adj} = t_{dur} + ERL \tag{1.73}$$

e) Adjustment to Failure Rate Curve Based on Actual Condition of Bundle

Once the predicted bundle life based on the last inspection has been determined using either Equation (1.70) or Equation (1.72), a modified characteristic life (Weibull η parameter) for the bundle may be determined using Equation (1.74). It is modified by adding the adjusted predicted life of the bundle as an additional failure point as follows:

$$\eta_{mod} = \left(\frac{1}{r} \sum_{i=1}^{N} t_i^{\beta} \right)^{\frac{1}{\beta}} \tag{1.74}$$

For the example bundle with matching data of Table 8.2, a modified η parameter, η_{mod}, is calculated by adding the 44.1 year predicted failure life to the original data set as follows:

$$\eta_{mod} = \left[\frac{1}{6} \begin{pmatrix} (18)^{2.568} + (22)^{2.568} + (16)^{2.568} + (10)^{2.568} + (12)^{2.568} + \\ (13)^{2.568} + (14)^{2.568} + (25)^{2.568} + (8)^{2.568} + (44.1)^{2.568} \end{pmatrix} \right]^{\frac{1}{2.568}} = 27.2 \text{ years} \tag{1.75}$$

Plotting this as the failure point on the Weibull diagram results in a shift to the right as shown in Figure 8.4. Note that the β parameter (Weibull slope parameter) was kept the same as the original curves from data obtained from similar bundles. This is the basis of Weibayes analysis that assumes that similar failure mechanisms will produce similar slope values.

The new POF curve in Figure 8.3 (second from left) shows the impact of the September 2003 inspection. In the example problem, two adjustments to the right were made. The uncertainty was reduced from 50 % (no inspection) to 30 % ("C" inspection) as a result of the Elliot gauging/calipers measurements taken to estimate the remaining wall thickness. Additionally, the base curve containing the raw data was shifted to the right of the original raw data curve because the bundle was not in as poor condition as was expected using the initial curve.

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As a result, the recommended inspection interval at the maximum acceptable POF of 50 % for the bundle was increased from 7.1 years to 17.1 years or to February 2009. This calculation can be made using Equation (1.76) as follows:

$$t_{insp} = \eta_{mod} \cdot \left(-ln\left[1 - P_{f,max}^{tube}\right]\right)^{\frac{1}{\beta}} = 27.2 \cdot \left(-ln\left[1-0.5\right]\right)^{\frac{1}{2.568}} = 17.1\,\text{years} \tag{1.76}$$

8.6.5 Effects of Bundle Life Extension Efforts

In general, during an inspection, only minor repairs and cleaning operations are performed on exchanger bundles. Bundles are not returned to an “as-new” condition and therefore the bundle POF is typically calculated at a service duration (i.e. time in service) based on the bundle’s original installation date.

However, there are several life extension methods that may be made to a bundle during shutdowns that serve to return the bundle back into service in an improved (not as-new) condition. In these situations, it would be too conservative to calculate the future bundle POF based on the original service duration, so an adjustment is made to the start date for calculation purposes. Table 8.6 provides a list of life extension methods and the credit given as represented by the life extension factor, LEF. An adjusted service duration, $tadj_{dur}$, is then calculated using the LEF in accordance with Equation (1.77).

$$tadj_{dur} = \left(1 - LEF\right) \cdot t_{insp} \tag{1.77}$$

For the example bundle above, if tubes were plugged during the September 2003 inspection, the recommended inspection interval would be increased by 10 % (see Table 8.6) to 18.8 years, or November 2010. The following calculation shows the effect of plugging tubes on service duration:

$$tadj_{dur} = \left(1 + LEF\right) \cdot t_{insp} = \left(1 + 0.1\right) \cdot 17.1 = 18.8\ \text{years}$$

8.6.6 Future Inspection Recommendation

Using the inspection adjusted failure rate curve as defined by the new Weibull parameters, the target date for the next inspection can be determined. This will be the date at which the risk calculated using Equation (1.66) exceeds the risk target, $Risk_{tgt}$, specified by the user. To maintain a risk level below the risk target, an inspection will be required prior to that date. The question that needs to be answered is what level of inspection is required to ensure that the risk target will not be exceeded during operation of the equipment.

This may best be illustrated using Figure 8.6. This figure shows the effect that inspections have had on the bundle in our example problem. With scheduled turnarounds March 2008 and March 2012, inspection will be required at the March 2008 shutdown since the target risk (or $P_{f,max}^{tube}$) will be exceeded in February 2009. If a “C” inspection is planned for the March 2008 shutdown, there is no guarantee that the slope of the curve will be modified enough to reduce the calculated risk below the target value by the March 2012 shutdown. Therefore, a level “B” inspection is recommended. Figure 8.5 shows the effect that the level “B” inspection has on the risk curve.

8.7 Bundle Inspect/Replacement Decisions Using Cost Benefit Analysis

8.7.1 General

The Weibull statistics can be 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.

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8.7.2 Decision to Inspect or Replace at Upcoming Shutdown

The methodology determines the risk reduction benefit from mitigating actions including various levels of inspection or bundle replacement. The cost benefit calculation includes the cost of the mitigating action to perform the selected activity (inspection or replacement). In addition, an optional hurdle cost or a rate of return, ROR, may be added to the cost of bundle replacement to encourage an inspection activity vs bundle replacement. A hurdle cost can be used to avoid excessive bundle replacement for borderline risk determinations that require action.

The decision to perform mitigating actions, such as bundle inspection or bundle replacement at an upcoming turnaround, can be made by comparing the incremental risk ($) associated with deferring the action to the cost associated with the action itself.

The expected incremental risk, EIR_{t1}^{t2}, associated with deferring the inspection or replacement of a bundle to a subsequent shutdown can be calculated using Equation (1.78).

$$EIR_{t1}^{t2} = C_f^{tube} \cdot \left(1 - \left[\frac{1 - P_f^{tube}(t_2)}{1 - P_f^{tube}(t_1)}\right]\right) \tag{1.78}$$

In Equation (1.80), t_1 is the service duration of the bundle at the upcoming shutdown (turnaround date 1) and t_2 is the service duration of the bundle at the subsequent shutdown (turnaround date 2).

The decision to perform an action, whether to inspect or to replace a bundle, can be made by comparing the expected incremental cost of deferral of the action using Equation (1.79) to the cost of the action itself. If the cost of the action (inspect or replace) is greater than the expected incremental risk, the action should be taken.

For example:

$$\text{If } \left(Cost_{insp} + Cost_{maint}\right) \cdot \left(1 + ROR\right) < EIR_{t1}^{t2} \text{ then inspect} \tag{1.79}$$

$$\text{If } \left(Cost_{bundle} + Cost_{maint}\right) \cdot \left(1 + ROR\right) < EIR_{t1}^{t2} \text{ then replace the bundle} \tag{1.80}$$

The equations provided above show a rate of return, ROR, or hurdle rate that adds an economic incentive to the decision process.

The owner–user is responsible for determining the costs that are unique to the operation and strategy. Where possible, the actual inspection costs should be used. Note that the maintenance costs to pull the bundles and make them available for the inspection should be added to the inspection costs to obtain the total cost of inspection; see Equation (1.81).

8.7.3 Decision for Type of Inspection

Once a decision has been made to inspect per Equation (1.79), an economic decision can be made as to the appropriate level of inspection with similar techniques as described in Section 8.7.2 comparing the cost of the various inspection techniques to the reduction in risk expected for the level of inspection.

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8.7.4 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 PM 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 [20].

For an exchanger bundle, the optimal replacement frequency can be determined by plotting the costs associated with bundle failure (increases with increasing replacement frequency) to the replacement costs associated with periodic planned shutdowns to replace the bundle (decreases with increasing replacement frequency). The replacement frequency at which these two costs reach a minimum value, when averaged over the expected bundle life, is the optimal replacement frequency.

The methodology in Shultz, 2001 [21] described below is recommended to determine the optimal frequency for replacing bundles.

a) Increasing Risk Cost of Unplanned Outage

If the planned replacement time frequency is defined by the variable, tr, the risk cost associated with an online failure (unplanned outage) to replace the bundle including business interruption and bundle replacement costs is calculated using Equation (1.81).

$$Risk_f^{tube}(tr) = C_f^{tube} \cdot P_f^{tube}(tr) \tag{1.81}$$

where

$$C_f^{tube} = Cost_{prod} + Cost_{env} + Cost_{bundle} + Cost_{maint} \tag{1.82}$$

The consequence of an unplanned outage due to a tube bundle failure, C_f^{tube}, is identical to Equation (1.64) and includes any environmental impact, $Cost_{env}$. The risk cost due to bundle failure increases with time since the POF, $P_f^{tube}(tr)$, as a function of replacement frequency 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 (1.83).

$$Cost_{pbr}(tr) = C_{f,plan}^{tube} \cdot \left[1 - P_f^{tube}(tr)\right] \tag{1.83}$$

where:

$$C_{f,plan}^{tube} = Unit_{prod} \cdot \left(\frac{Rate_{red}}{100}\right) \cdot D_{sd,plan} + Cost_{env} + Cost_{bundle} + Cost_{maint} \tag{1.84}$$

Note that the cost of bundle replacement at a planned frequency includes downtime and business interruption; however, the number of days for a planned outage, $D_{sd,plan}$, may be much less than if the outage were unplanned due to a bundle failure. An unplanned outage would require some additional lead time to get a replacement bundle on-site.

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c) Optimization of Total Cost

The total cost as a function of replacement time interval averaged over the service life of the bundle is computed using Equation (1.85).

$$Cost_{total}\left(tr\right)=\frac{Risk_{f}^{tube}\left(tr\right)+Cost_{pbr}\left(tr\right)}{365.24\cdot ESL_{n}} \tag{1.85}$$

The estimated service life as a function of replacement time interval may be approximated using an integration technique using Equation (1.86).

$$ESL_{n}=ESL_{fail,n}+ESL_{pass,n} \tag{1.86}$$

This approach adds the average life of the bundles that would have been expected to fail prior to the planned replacement time, ESL_{fail}, to the average life of the bundles that would not have been expected to fail prior to the planned replacement time, ESL_{pass}.

The average life of the bundles that would have been expected to fail prior to the planned replacement time is:

$$ESL_{f,n}=ESL_{f,n-1}+tr_{n}\left(P_{f,n}^{tube}-P_{f,n-1}^{tube}\right) \tag{1.87}$$

The average life of the bundles that would not have been expected to fail prior to the planned replacement time is:

$$ESL_{p,n}=t_{n}\left(1-P_{f,n}^{tube}\right) \tag{1.88}$$

To optimize the total cost, a low planned replacement frequency is initially chosen, and the costs associated with this frequency are calculated. This frequency is increased in small increments and the costs are calculated for each incremental step ($n = n + 1$). At some point, the costs will reach a minimum, indicating that an optimal replacement frequency has been found. The following steps are recommended.

1) STEP 2.1—Select an appropriate time step, t_s, in days. A value for t_s of 7 days should be sufficient. The initial calculation will be at increment $n = 1$. Subsequent calculations will increase the increment by 1 or ($n = n + 1$).

2) STEP 2.2—Determine the planned replacement frequency, tr_n, by multiplying the increment number, n, by the time step, t_s as follows:

$$tr_{n}=n\cdot t_{s} \tag{1.89}$$

3) STEP 2.3—Calculate the POF at the planned replacement frequency at increment n, $P_{f,n}^{tube}\left(tr_{n}\right)$, using Equation (1.58) and the updated Weibull parameters based on the latest inspection of the bundle. Note that the time unit in Equation (1.58) is years. The time value to use in Equation (1.58) is tr_n obtained in STEP 2.2.

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 (1.87).

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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 (1.88).

6) STEP 2.6—Calculate the estimated service life, ESL_n, using Equation (1.86). Note that for the initial increment (n = 1), when $tr = t_s$, $ESL_{f,n\text{-}1}$ = 0.0.

7) STEP 2.7—Calculate the risk cost associated with bundle failure at the replacement frequency, $Risk_f\,(tr)$, using Equation (1.81). This value will increase with increasing replacement frequency, tr.

8) STEP 2.8—Calculate the bundle replacement cost at the replacement frequency, $Cost_{pbr}(tr)$, using Equation (1.83). This value will decrease with increasing replacement frequency, tr.

9) STEP 2.9—Calculate the total costs at the replacement frequency averaged over the expected life of the bundle, $Cost_{total}(tr)$, using Equation (1.85).

10) STEP 2.10—Increase the increment number by 1 ($n = n + 1$) and repeat STEP 2.2 through STEP 2.9 until a minimum value of $Cost_{total}(tr)$ in STEP 2.9 is obtained.

11) STEP 2.11—The optimal bundle replacement frequency, t_{opt}, will be that value of tr that minimizes $Cost_{total}(tr)$.

8.8 Nomenclature

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 frequency, \$
$Cost_{bundle}$	is the replacement cost of the tube bundle, \$
$Cost_{env}$	is the environmental costs due to a bundle leak, \$
$Cost_{maint}$	is the cost of maintenance to pull the bundle and make it ready for inspection or replacement, \$
$Cost_{pbr}(tr)$	is the cost per year of bundle replacement at a planned frequency, tr, \$/year
$Cost_{prod}$	is the production losses as a result of shutting down to repair or replace a tube bundle, \$
$Cost_{total}$	is the cost to perform the inspection, \$
$Cost_{total}(tr)$	is the total cost of a bundle replacement program at a planned frequency, tr, \$/year
$D_{sd,plan}$	is the number of days required to shut a unit down to repair a bundle during a planned shutdown, days
D_{sd}	is the number of days required to shut a unit down to repair a bundle during an unplanned shutdown, days
D_{shell}	is the heat exchanger shell inside diameter, mm (in.)
EIR_{t1}^{t2}	is the expected incremental risk between turnaround dates t_1 and t_2, \$/year
ERL	is the estimated remaining life of the bundle, years

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ESL_n	is the estimated service life of a bundle as a function of replacement time interval, years
$ESL_{fail,n}$	is the average life of bundles that would have failed at the replacement time interval, years
$ESL_{pass,n}$	is the average life of bundles that would not have failed at the replacement time interval, years
L_{tube}	is the tube length of the bundle, m (ft)
LEF	is the bundle life extension factor
M_f	is the material cost factor
$MTTF$	is the mean time to failure, years
N	is the number of bundles in a heat exchangers past history
P_f^{tube}	is the probability of bundle failure, failures/year
$P_{f,max}^{tube}$	is the maximum acceptable probability of bundle failure based on the owner–user's risk target, failures/year
$P_{f,n}^{tube}$	is the probability of bundle failure calculated for the current (n) increment of the optimization procedure, failures/year
$P_{f,n-1}^{tube}$	is the probability of bundle failure calculated for the previous ($n-1$) increment of the optimization procedure, failures/year
PBL_{adj}	is the predicted bundle life adjusted based on inspection, years
pve	is a measure of goodness of fit for the Weibull distribution. The P-value correlation for a particular data set is the ranking of actual correlation among all the possible correlation values for the sample size of the data set and the model type selected.
$R(t)$	is the risk as a function of time, m^2/year (ft^2/year) or \$/year
r	is the number of failed bundles in a heat exchangers past history
r^2	is a correlation coefficient us as a measure of goodness of fit for the Weibull distribution
$Rate_{red}$	is the production rate reduction on a unit as a result of a bundle being out of service, %
$Risk_f^{tube}$	is the risk of failure of the tube bundle, \$/year
$Risk_f^{tube}(tr)$	is the risk of failure of the tube bundle at a planned bundle replacement frequency, tr, \$/year
$Risk_{tgt}$	is the risk target, \$/year
ROR	is the fractional rate of return
RWT_f	is the failure point defined as a fraction of remaining wall thickness

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t	is time, years
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_{dur}	is the bundle duration or time in service, years
$t_{dur,i}$	is the time in service for the i^{th} bundle in a heat exchanger, years
t_{insp}	is the inspection interval, years
t_{min}	is the minimum required thickness, mm (in.)
t_{rate}	is the thinning rate for the tube bundle, mm/year (in./year)
t_s	is the time step used in the optimization routine for bundle replacement frequency, days
$\bar{t}_{insp}$	is the average measured tube wall thickness, mm (in.)
$\bar{t}_{orig}$	is the average furnished tube wall thickness, mm (in.)
$tadj_{dur}$	is the bundle duration or time in service adjusted for life extension activities, years
tr	is the bundle planned replacement frequency, year
$Unit_{prod}$	is the daily production margin on the unit, \$/day
V_{bundle}	is the volume of a typically sized carbon steel bundle = 3.016 m^3 (106.5 ft^3)
β	is the Weibull shape parameter
η	is the Weibull characteristic life parameter, years
η_{mod}	is the Weibull modified characteristic life parameter, years
η_{upd}	is the Weibull updated characteristic life parameter, years
Γ	is the gamma function
$\Gamma(x)$	is the gamma function of x

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8.9 Tables

Table 8.1—Basic Data for Exchanger Bundle Risk Analysis

Bundle Attribute	Comments/Example Input	Required Bundle Failure Library Data
General Data		
Corporation	Corporation	No
Plant	Plant location	Yes
Unit	Process unit	Yes
Tag number	Bundle tag number, e.g. E101-T3, where E101 represents the exchanger ID or tag number and T3 represents the bundles that have been installed in the exchanger, T1 representing the original bundle, and T3 representing the third bundle	Yes
Description	Exchanger description found on the TEMA datasheet, e.g. debutanizer reboiler, crude overhead exchanger	No
Status	Active or Inactive (active bundles are still in service, inactive bundles are bundles removed from service)	No
Start date	Exchanger start date	No
TEMA type	TEMA type from datasheet e.g. AES, AET	Yes
Exchanger type	Exchanger type or function, e.g. steam generator, steam reboiler, vaporizer	Yes
Exchanger orientation	Horizontal or vertical	Yes
Shell diameter	Shell diameter, mm (in.)	No
Bundle Details		
Install date	Bundle installation date	Yes
Tube type	Type of tube, e.g. plain, finned tube or twisted tube	No
Tube quantity	Number of tubes (for statistical analysis and bundle cost estimate)	Yes
Tube OD	Tube outside diameter, mm (in.)	Yes
Tube length	Tube length, m (ft)	No
Number of tubeside passes	Number of passes in tubeside service	No
Tube furnished thickness	Average wall thickness, mm (in.)	Yes
Tube specification	Tube material specification and grade from TEMA datasheet and/or ASME manufacturer's form, e.g. SA-179, SA-213-TP304	No
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 Gr. 2, Aluminum Alloy	Yes
Tube coating	Location and type of coating, e.g. no coating, ID only, OD only, both ID and OD	No
U-tube postweld heat treatment (PWHT)	Yes or No	No
Impingement plate	Found in TEMA datasheet, Yes/No	No
Tube layout	Layout of tubes e.g. triangular, square, rotated square, unknown	No
Tube pitch	Tube pitch, mm (in.)	No

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Bundle Attribute	Comments/Example Input	Required Bundle Failure Library Data
Bundle Details *(Continued)*		
Baffle type	Type of baffle e.g. rolled only, seal welded, strength welded, unknown	No
Baffle cut	Baffle cut (%) found on the TEMA datasheet	No
Baffle spacing	Spacing between baffles found on TEMA datasheet, mm (in.)	No
Tube joint design	Tube joint design e.g. rolled only, seal welded, strength welded, unknown	Yes
Tubesheet material specification	Tubesheet material specification and grade found on TEMA datasheet and/or ASME manufacturer's form, e.g. SA-105-II, SA-182-F11, SA-240-316L, SA-516-70	No
Tubesheet material	Tubesheet material type e.g. Carbon Steel, 2.25 % Cr, 304L/321/347, 2205 Duplex SS, Alloy 20Cb3, 904L, Alloy 800, Nickel 200, Titanium Gr. 2, Aluminum Alloy	No
Tubesheet cladding material	Tubesheet cladding material type, e.g. Carbon Steel, 2.25 % Cr, 304L/321/347, 205 Duplex SS, Alloy 20Cb3, 904L, Alloy 800, Nickel 200,Titanium Gr. 2	No
Process/Operating Conditions (Tubeside and Shellside)		
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	Yes
Fluid name	Fluid name or description, e.g. crude, effluent, heavy gas oil (HGO), etc.	No
Fluid category	Fluid category e.g. heavy crude feed, medium distillate, rich amine, H_2S, hydrofluoric acid, well water, CO_2	Yes
Operating pressure	Operating pressure, kPa (psig)	Yes
Inlet temperature	Inlet temperature, °C (°F)	Yes
Outlet temperature	Outlet temperature, °C (°F)	Yes
Fluid phase	Fluid phase as gas, liquid, or two-phase	Yes
Fouling severity	Fouling severity as none, mild, moderate, severe, unknown	No
Flowrate	Fluid flowrate, kg/hr (lb/s)	No
Design velocity	Fluid design velocity from the TEMA datasheet including notes such as cooling water, amine, slurries, or other fluids where velocity may be an important parameter for corrosion or erosion	No
Process Fluid Damage Modifiers (Tubeside and Shellside)		
Free water	Does the tubeside or shellside fluid have any free water? Yes/No	Yes
Sulfidation	Is sulfidation a concern for the tubeside or shellside fluid? Yes/No	Yes
Dealloying	Is dealloying is a concern for the tubeside or shellside fluid? Yes/No	Yes
Naphthenic acid	Is naphthenic acid corrosion a concern for the tubeside or shellside fluid? Yes/No	Yes
Ammonium chloride	Is ammonium chloride a concern for the tubeside or shellside fluid? Yes/No	Yes
CO_2	Is CO_2 corrosion a concern for the tubeside or shellside fluid? Yes/No	Yes
Salt deposits	Are salt deposits likely on the tubeside or shellside? Yes/No	Yes
Weight % H_2S	If H_2S is present in tubeside or shellside fluid, provide amount (wt.%)	Yes
Mole % sulfur	If sulfur is present in tubeside or shellside fluid, provide amount (mole %)	Yes
Weight % acid	If acid is present in tubeside or shellside fluid, provide amount (wt.%)	Yes
Weight % caustic	If caustic is present in tubeside or shellside fluid, provide amount (wt.%)	Yes

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Bundle Attribute	Comments/Example Input	Required Bundle Failure Library Data
Process Fluid Damage Modifiers (Tubeside and Shellside) *(Continued)*		
Weight % ammonium bisulfide	If ammonium bisulfide is present in tubeside or shellside fluid, provide amount (mole %)	Yes
Cyanides	Are cyanides present in tubeside or shellside fluid? Yes/No	Yes
Erosive particles	Are erosive particles present in tubeside or shellside fluid? Yes/No	Yes
Brine	Does the tubeside or shellside fluid have any brine? Yes/No	Yes
Asphaltenes or polymer deposits	Does the tubeside or shellside fluid have any asphaltenes or polymer deposits? Yes/No	Yes
Oxidation	Is oxidation a concern for the tubeside or shellside fluid? Yes/No	Yes
Estimated corrosion severity	Expected corrosion rate, e.g. none, inert (<1 mpy), mildly corrosive (11 mpy to 5 mpy), moderately corrosive (5 mpy to 10 mpy), severely corrosive (10 mpy to 20 mpy), unpredictable or localized (>20 mpy)	Yes
Bundle Inspection History (Multiple Records for Each Bundle)		
Inspection date	Date inspection was performed	No
Event type	Planned shutdown, unplanned shutdown, bypass with no rate cut, rate cut online, unknown	No
Bundle leak	Was there a bundle leak discovered during the inspection? Yes/No/Unknown	No
Failure mode	Primary failure mode for each event, e.g. unknown, tube leak, floating head leak, general thinning	No
Action taken	Primary mitigation effort, e.g. none, minor repairs, rotated bundle 180°, partial retube, retube with new alloy	No
Number of tubes plugged during this shutdown	Number of tubes plugged during inspection that does not include any tubes plugged as a result of handling damage that should be documented in comments	No
Inspection method	Inspection method, e.g. visual, IRIS, remote field	No
Percent inspected	Percentage of bundle inspected, e.g. none, 20 % to 40 %, 60 % to 80 %	No
Inspection effectiveness	A, B, C, D, or E per Part 2, Annex 2.C, Table 2.C.3.1	No
% wall loss	Average measured wall thickness divided by the original furnished wall thickness	No
Remaining wall thickness	Average measured wall thickness from inspection, mm (in.)	No
Hydrotest	Was hydrotest performed? Yes/No	No
Primary damage	Primary damage mechanism e.g. none, corrosion, tube end thinning, cracking, vibration, erosion	No
Secondary damage	Secondary damage mechanism e.g. none. corrosion, tube end thinning, cracking, erosion	No
Tube joint leak on hydrotest	Were the tube joints hydrotested? Yes/No	No
Estimated remaining life (ERL)	ERL based on the inspection data, provide the ERL (required if remaining wall thickness or the % wall loss is not provided)	No
Baffles, tie-rods, and spacers	Condition of baffles, tie-rods, and spacers e.g. good, serviceable, mechanical damage, heavy corrosion	No

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Bundle Attribute	**Comments/Example Input**	**Required Bundle Failure Library Data**
Bundle Inspection History (Multiple Records for Each Bundle) ***(Continued)***		
ID/OD fouling	Fouling condition of bundle ID/OD, e.g. unknown, none, mild, general, heavy	No
ID/OD corrosion	Corrosion condition of bundle ID/OD, e.g. unknown, none, mild, general, heavy	No
Bundle Remaining Life Methodology		
Specified MTTF	User-specified MTTF for bundle, years to be used in calculation	No
Specified Weibull η	User-specified Weibull characteristic life (years) to be used in calculations (β must also be provided)	No
Specified Weibull β	User-specified Weibull slope parameter to be used in calculations (η must also be provided)	No
Bundle Life	Bundle life for the bundle being evaluated, years (required for inactive bundles)	Yes
Controlling damage mechanism	Controlling damage mechanism e.g. none, corrosion, tube end thinning, cracking, erosion, vibration	Yes
Consequences of Bundle Failure		
Financial risk target	User risk target, $/year	No
Tube wall failure fraction	Wall thickness fraction that constitutes bundle failure (0 and 1.0)	No
Production cost	Unit production costs, $/day (should be equal to the production rate, bbl/day × margin ($/bbl)	No
Production impact	Production impact, e.g. none, bypass, bypass with rate reduction, shutdown	No
Rate reduction	Rate reduction, % (required if production impact is bypass with rate reduction)	No
Planned shutdown days	Number of days required to repair or replace failed exchanger bundle when the shutdown is planned, days	No
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)	No
Environmental impact	Environmental costs associated with bundle failure that includes damage to cooling water system and towers	No
Lost opportunity cost	Additional cost beyond production losses or environmental costs as a result of bundle failure, $	No
Bundle cost	Cost of replacement bundle, $	No
Bundle installation cost	Cost of maintenance required to remove, clean, and re-install exchanger bundle, $	No
Hurdle cost	Additional cost above the economic breakeven point at which a decision to inspect or replace a bundle is made, $	No
Turnaround date 1	The date for the next scheduled turnaround from the RBI date (used as plan date for calculating risk)	No
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)	No

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Table 8.2—Example—Matching Bundles from Reliability Database

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

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Table 8.3—Bundle Material Cost Factors

Bundle Generic Material	Tube Material Cost Factor, Mf
Carbon Steel	1.0
C-$^1/_4$ Mo	2.0
1-$^1/_4$ Cr	2.0
2-$^1/_4$ Cr	2.8
5 Cr	3.2
9 Cr	3.3
12 Cr	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
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
Ferralium 255	7.0
Bimetallic	4.5
Ceramic	1.0
Plastic	1.0
Titanium Gr. 2	6.0
Titanium Gr. 12	10.0
Titanium Gr. 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.

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Table 8.4—Example Showing Time In-service as a Function of POF and Uncertainty

Method	**Time in Service** (years)						
	POF = 1 %	**2 %**	**5 %**	**10 %**	**20 %**	**50 %**	**90 %**
Weibull, raw data	M3.48	4.47	6.43	8.51	11.4	17.7	28.3
90 % LBC	1.51	2.24	3.76	5.57	8.31	14.3	21.3
90 %LBC with 5 % AU	1.44	2.13	3.57	5.29	7.89	13.54	20.2
90 %LBC with 10 % AU	1.36	2.01	3.38	5.01	7.48	12.8	19.2
90 %LBC with 20 % AU	1.21	1.79	3.00	4.46	6.65	11.4	17.0
90 %LBC with 30 % AU	1.06	1.57	2.63	3.9	5.82	9.98	14.9
90 %LBC with 50 % AU	0.76	1.12	1.88	2.79	4.15	7.13	10.6

NOTE 1 The values in this table are for example only and are specifically for a Weibull distribution with $\beta = 2.568$ and $\eta = 20.45$.

NOTE 2 LBC is lower bound condition.

NOTE 3 AU is additional uncertainty.

Table 8.5—Inspection Effectiveness and Uncertainty

Inspection Category	**Inspection Effectiveness Category**	**Inspection Confidence**	**Inspection Uncertainty**
A	Highly Effective	>95 %	<5 %
B	Usually Effective	>80 % to 95 %	<20 % to 5 %
C	Fairly Effective	>70 % to 80 %	<30 % to 20 %
D	Poorly Effective	>50 % to 70 %	<50 % to 30 %
E	Ineffective	≥50 %	≤50 %

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 operator–user to determine the cost numbers unique to their particular operation and strategy.

NOTE 2 Refer to Part 2, Annex 2.C, Section 2.C.4 for more information.

NOTE 3 The operator-user should consider applying confidence/uncertainty based upon the relationship between the following variables:

a) amount of the bundle inspected (percentage whole or percentage per pass),
b) examination method(s) used and degree of cleanliness,
c) metallurgy of the bundle,
d) damage mechanism(s) expected/found.

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Table 8.6—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 LEFs provided in this table are suggestions. It is the responsibility of the owner–user to define life extensions for use for the bundle life extension methods.

NOTE 2 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 3 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.

Table 8.7—Numerical Values Associated with POF and Financial-based COF Categories for Exchanger Bundles

Probability Category [1]		Consequence Category [2]	
Category	**Range**	**Category**	**Range** ($)
1	$POF \le 0.1$	A	$COF \le \$10,000$
2	$0.1 < POF \le 0.2$	B	$\$10,000 < COF \le \$50,000$
3	$0.2 < POF \le 0.3$	C	$\$50,000 < COF \le \$150,000$
4	$0.3 < POF \le 0.5$	D	$\$150,000 < COF \le \$1,000,000$
5	$0.5 < POF \le 1.0$	E	$COF > \$1,000,000$

NOTE 1 In terms of the total DF, see Part 2, Section 3.4.

NOTE 2 In terms of consequence area, see Part 3, Section 4.11.4.

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8.10 Figures

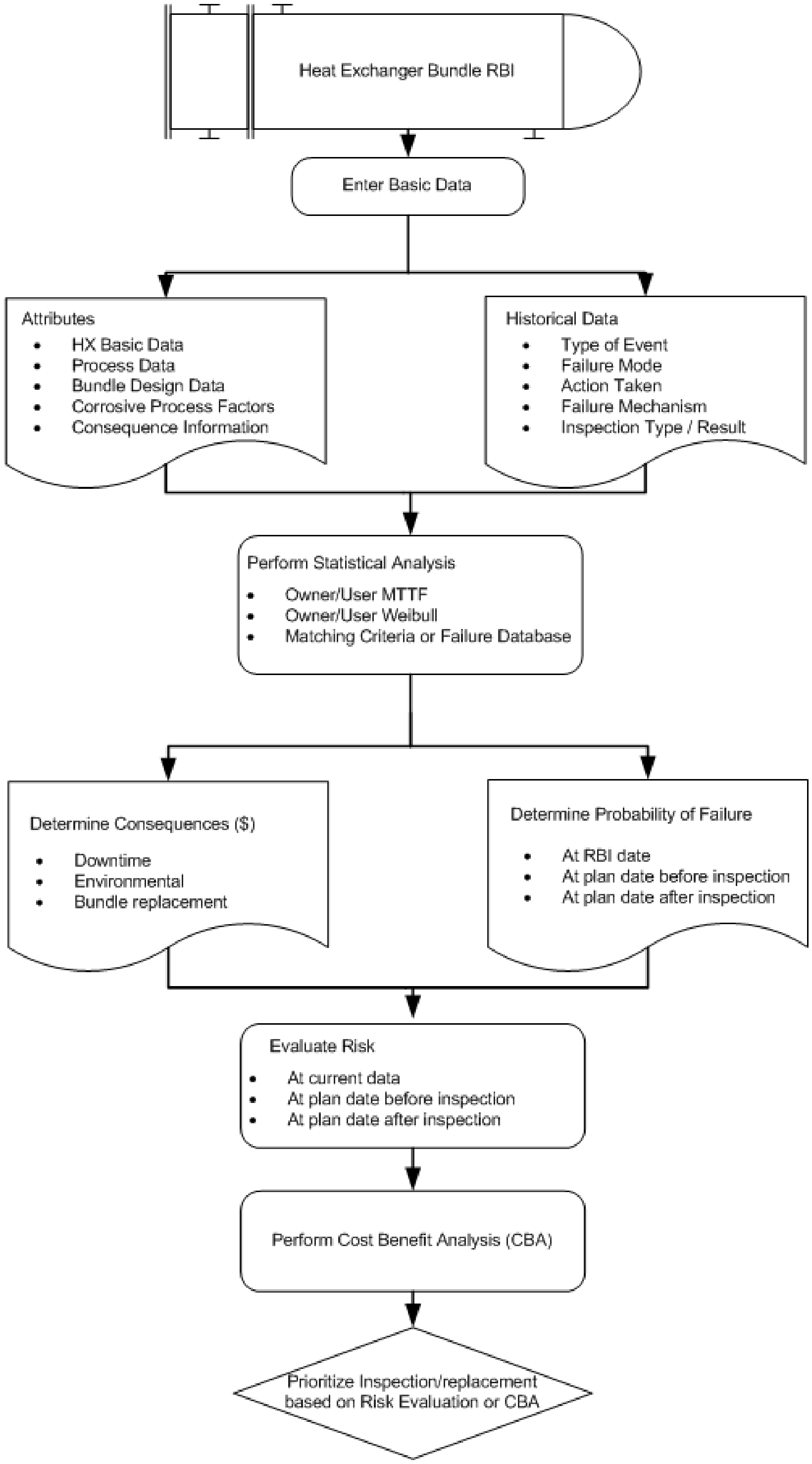

Figure 8.1—Flow Chart of Bundle Calculation Approach

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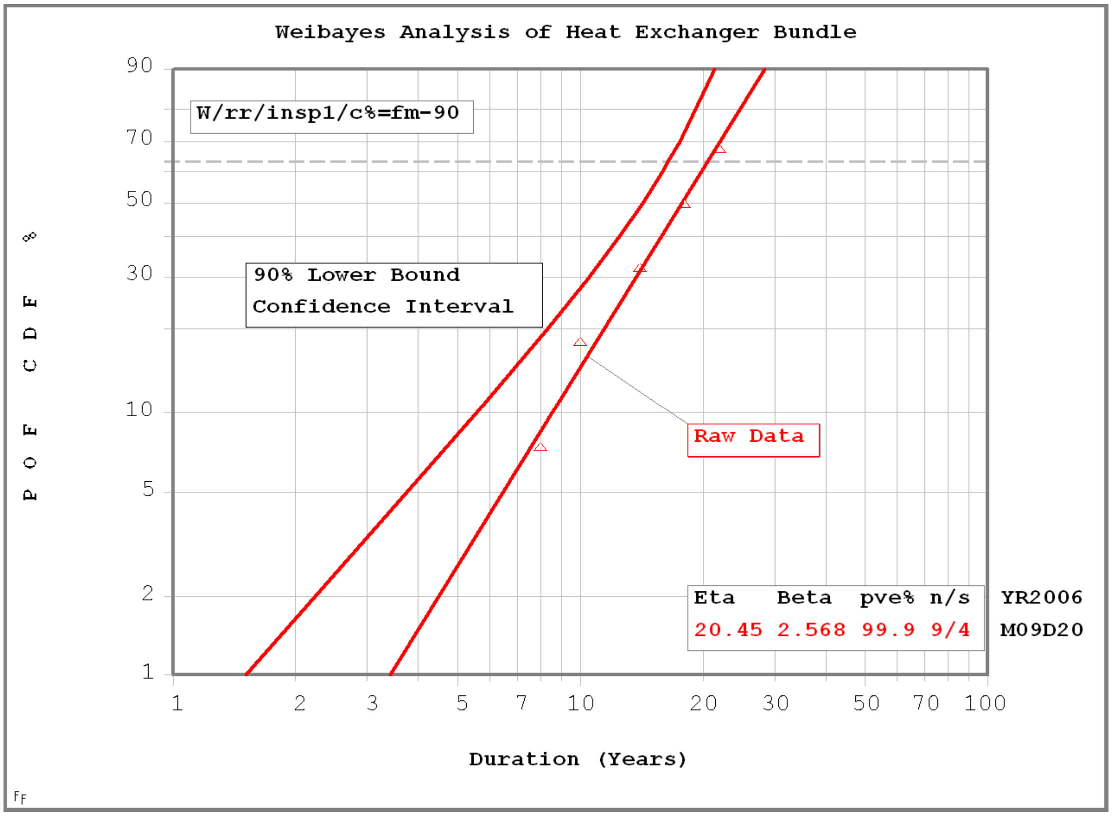

Figure 8.2—Weibull Plot of Similar Bundle Data

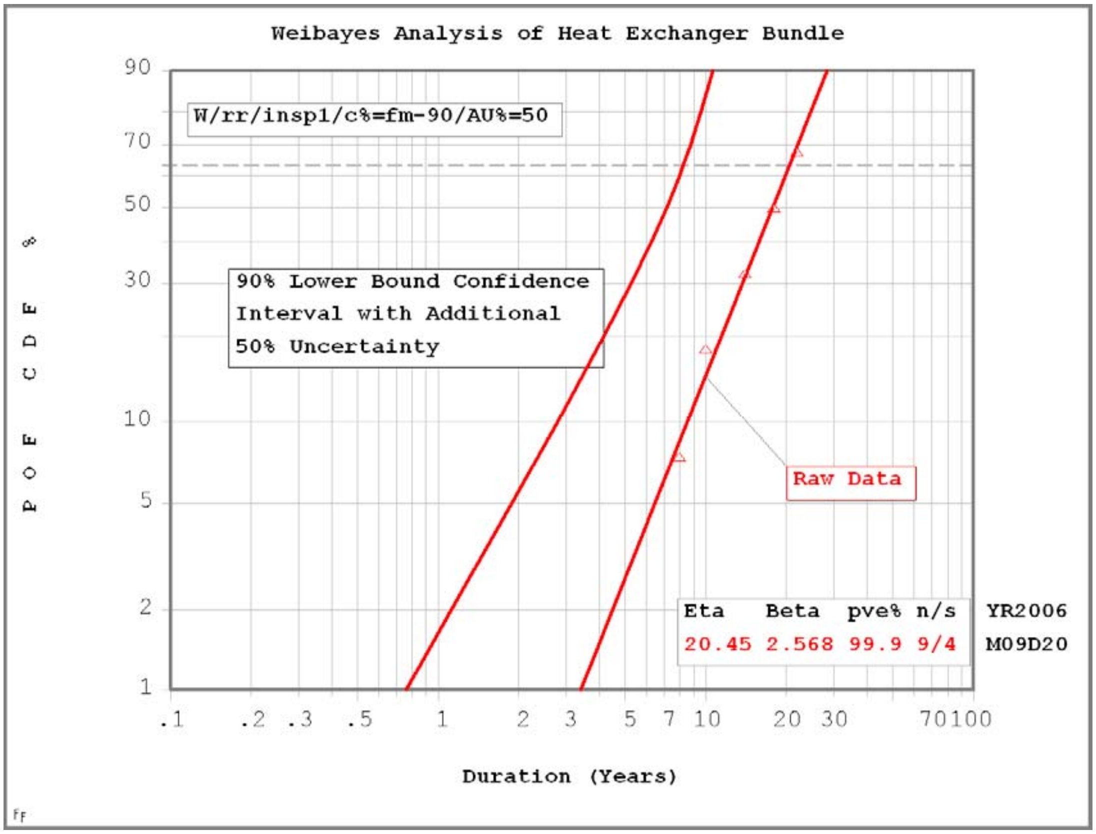

Figure 8.3—Weibull Plot of Similar Bundle Data with 50 % AU

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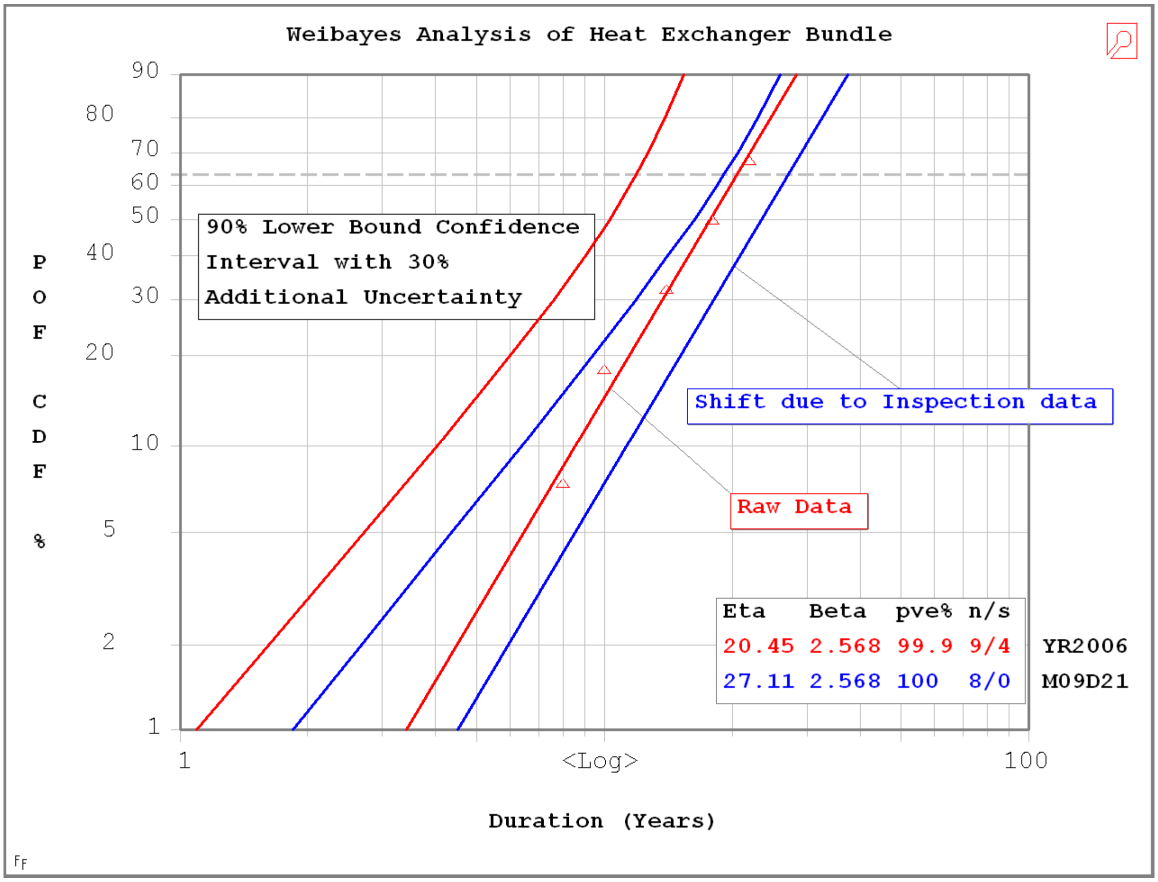

Figure 8.4—Weibull Plot Shifted for Inspection

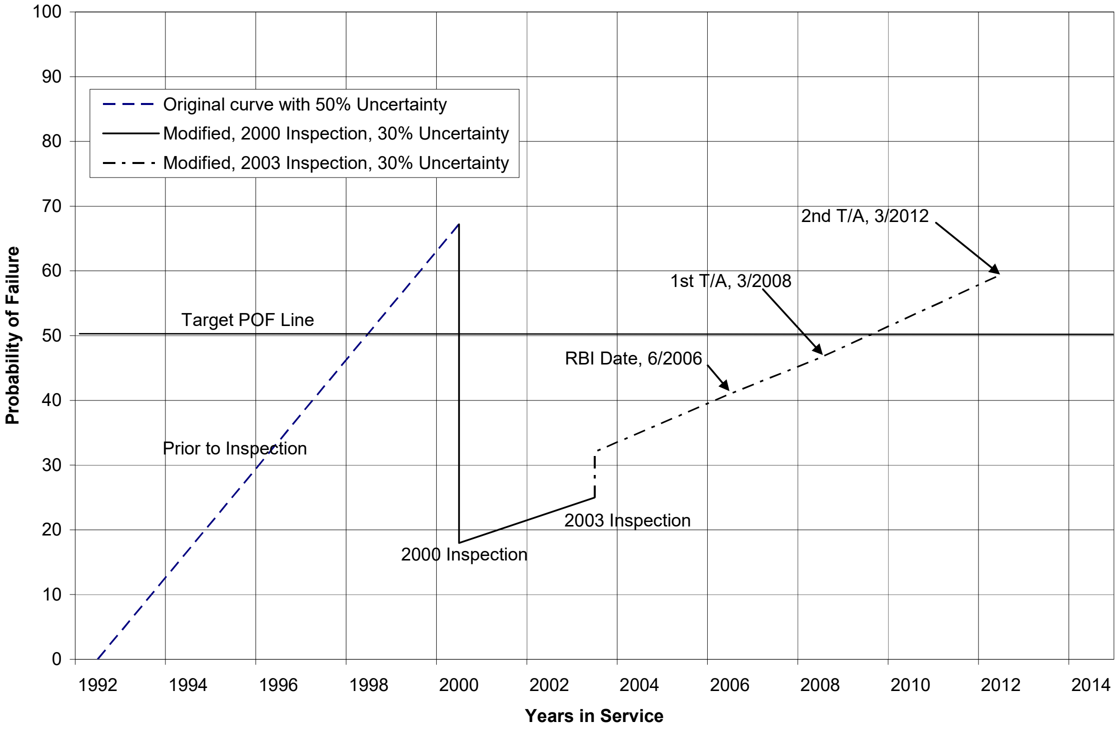

Figure 8.5—Example Problem Showing Effect of Inspection

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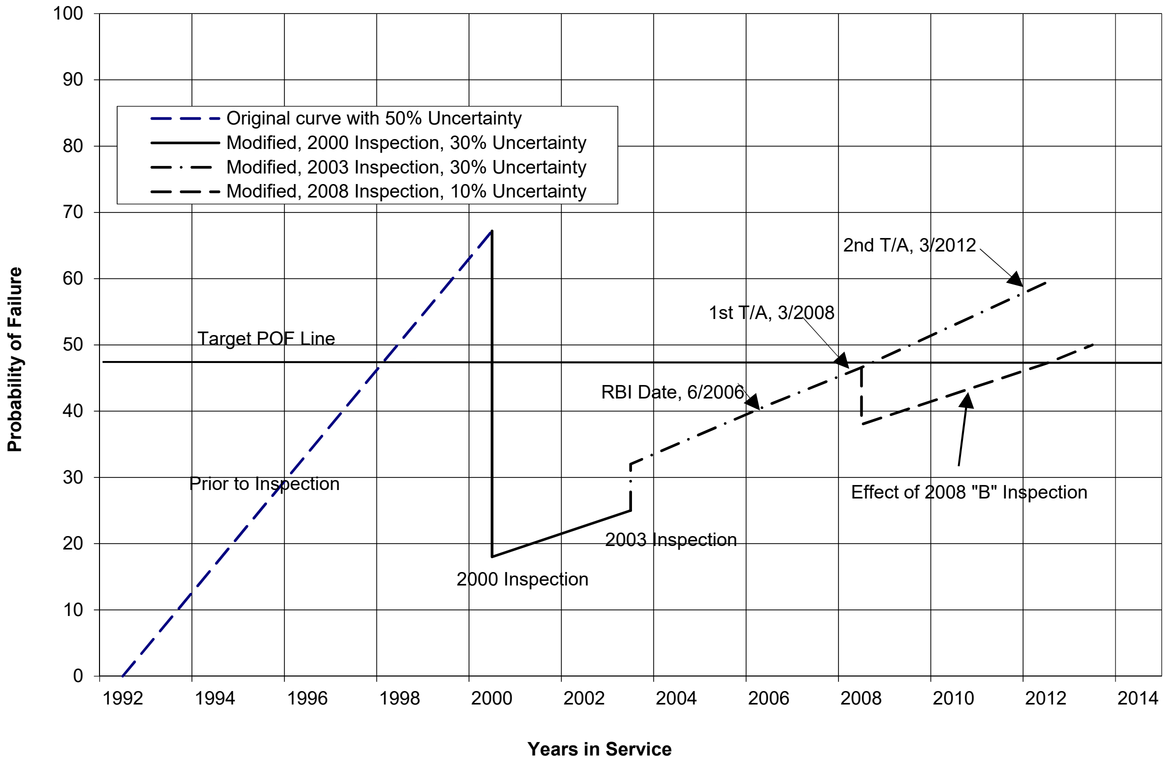

Figure 8.6—Example Problem Showing Effect of Future Inspection

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PART 2

PROBABILITY OF FAILURE METHODOLOGY

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PART 2 CONTENTS

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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 three-volume set presenting the API 581 methodology. The other two parts are: Part 1—Inspection Planning Methodology [15], and Part 3—Consequence of Failure Methodology [16].

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 References

2.1 Normative

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

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3 Probability of Failure (POF) Methodology

3.1 Overview

The POF is computed from Equation (2.1).

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

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 on the generic frequency of failure reflect differences between damage mechanisms and the reliability management processes within a plant. The DF adjusts the GFF based on the active damage mechanisms the component is subject to and considers the susceptibility to the damage mechanism and/or the rate at which the damage accumulates. The DF also takes into consideration historical inspection data and the effectiveness of both past and future inspections. The management systems factor adjusts 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 management systems factor is applied equally to all components within a plant.

Adjustment factors with a value greater than 1.0 will increase the POF, and those with a value less than 1.0 will decrease it. Both adjustment factors are always positive numbers.

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3.2 Calculation of POF

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

a) 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.

b) 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.

c) 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 non-zero 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 the component. The 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 or 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. The data presented in the Table 3.1 are based on the best available sources and experience to date from owner–users.

Adjustment factors are applied to the GFF to reflect departures from the industry data to account for damage mechanisms specific to the component's operating environment and for reliability management practices within a plant. The DF is applied to a component and damage mechanism specific basis, while the management systems factor (F_{MS}) is applied equally to all equipment within a plant. DFs with a value greater than 1.0 will increase the POF, and those with a value less than 1.0 will decrease it. Both adjustment factors are always positive numbers.

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 that may be present as a function of time in service and the effectiveness of an

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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

Damage factors for multiple mechanisms are assessed using the following statements:

a) Total DF, $D_{f\text{-}total}$—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.

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

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).

$$D_{f-total} = D_{f-gov}^{thin} + D_{f-gov}^{extd} + D_{f-gov}^{scc} + D_{f}^{htha} + D_{f-gov}^{brit} + D_{f}^{mfat} \tag{2.3}$$

Note that the summation of DFs can be less than or equal to 1.0. This means that the component can have a POF 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).

$$D_{f-gov}^{thin} = \min\left[D_{f}^{thin},\ D_{f}^{elin}\right] \quad \text{when an internal liner is present} \tag{2.4}$$

$$D_{f-gov}^{thin} = D_{f}^{thin} \quad \text{when an internal liner is not present} \tag{2.5}$$

c) Governing SCC DF, D_{f-gov}^{scc}—The governing SCC DF is determined by using Equation (2.6).

$$D_{f-gov}^{scc} = \max\left[\begin{matrix} D_{f}^{caustic},\ D_{f}^{amine},\ D_{f}^{ssc},\ D_{f}^{HIC/SOHIC-H_2S},\ D_{f}^{ACSCC}, \\ D_{f}^{PASCC}, D_{f}^{CLSCC}, D_{f}^{HSC-HF}, D_{f}^{HIC/SOHIC-HF} \end{matrix}\right] \tag{2.6}$$

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d) Governing external DF, D_{f-gov}^{extd} —The governing external DF is determined from Equation (2.7).

$$D_{f-gov}^{extd} = \max\left[D_f^{extf}, D_f^{CUIF}, D_f^{ext-CLSCC}, D_f^{CUI-CLSCC}\right] \tag{2.7}$$

e) Governing brittle fracture DF, D_{f-gov}^{brit} —The governing brittle fracture DF is determined from Equation (2.8). When performing the summation of DFs in Equation (2.8), if a DF is less than or equal to 1.0 (i.e. the damage is inactive), then this DF shall be set to zero in the summation.

$$D_{f-gov}^{brit} = \max\left[\left(D_f^{brit} + D_f^{tempe}\right), D_f^{885F}, D_f^{sigma}\right] \tag{2.8}$$

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 determined as a function of inspection effectiveness. A discussion of inspection effectiveness and example tables are provided in Annex 2.C. The inspection effectiveness categories are meant to be examples in order to provide a guideline for the user in assigning actual 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 to calculate the DF. The number and effectiveness of each inspection for thinning and external corrosion is included directly in the calculation of the DFs (see Sections 4, 15, and 16).

If multiple inspections have been performed, equivalent relationships are used for SCC, external damage [external chloride stress corrosion cracking (ExtClSCC), external chloride stress corrosion cracking under insulation (CUI ClSCC)], 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. 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. Compliance with PSM standards became mandatory in the United States in 1992 with the issue of OSHA 29 *CFR* 1910.119 [9].

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3.5.2 Overview

A management systems factor is used to adjust GFFs for differences in PSM systems. This factor is derived from the results of an evaluation of a facility or operating unit's management systems that affect plant risk. Different practices within units at a facility might create differences in the management systems factors between the units. However, within any one study, the management systems factor should be the same. The factor is applied equally to all components and, as a result, does not change the order of the risk-based ranking of the components. The management systems factor 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 PSM 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; the emphasis is on mechanical integrity issues. Mechanical integrity is the largest single section, and most of the questions in the other subject areas are either closely related to mechanical integrity or they have a bearing on total unit risk. The management systems evaluation is provided in Annex 2.A. It consists of numerous questions, most of which have multiple parts. Each possible answer to each question is given a weight, depending upon the appropriateness of the answer and the importance of the topic. This system provides a quantitative, reproducible score for the management systems evaluation. It also simplifies analysis of results, permitting the auditor to pinpoint areas of strength and weakness in the facility's PSM system. The number of questions and the breadth of subject matter enable the management systems evaluation to differentiate between PSM systems of different effectiveness.

There is no specific score that indicates compliance vs noncompliance. A score of 1000 equates to achieving excellence in PSM issues that affect mechanical integrity; see Table 3.2. Many of the measured issues may be well beyond what is required for compliance with regulations.

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;

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.

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The number of auditors involved is arbitrary, 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 people to be interviewed should be designated, and then a subset of questions should be selected from the total management systems evaluation to match the expertise of each person being interviewed. All audit questions should be answered, and there should be no hesitance to include some of the audit questions 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 people's perceptions can differ markedly.

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 scale recommended for converting a management systems evaluation score to a management systems factor is based on the assumption that the "average" plant would score 50 % (500 out of a possible score of 1000) on the management systems evaluation and that a 100 % score would equate to a one order-of-magnitude reduction in total unit risk. Based on this ranking, Equation (2.9) and Equation (2.10) are used to compute a management systems factor, F_{MS}, for any management systems evaluation score, $Score$. Note that the management score must first be converted to a percentage (between 0 and 100) as follows:

$$pscore = \frac{Score}{1000} \cdot 100 \;\; (\text{unit is } \%) \tag{2.9}$$

$$F_{MS} = 10^{(-0.02 \cdot pscore + 1)} \tag{2.10}$$

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

It should be remembered that the management systems factor applies equally to all components and therefore, does not change the risk ranking of components for inspection prioritization. The factor's value is in comparing one operating unit or plant site to another.

3.6 Nomenclature

D_f	for each mechanism and relevant section references are outlined in Table 3.2
$D_f(t)$	is the DF as a function of time, equal to $D_{f-total}$ evaluated at a specific time
D_f^{ACSCC}	is the DF for alkaline carbonate stress corrosion cracking (ACSCC)
D_f^{amine}	is the DF for amine cracking
D_f^{brit}	is the DF for brittle fracture
D_{f-gov}^{brit}	is the governing DF for brittle fracture
$D_f^{caustic}$	is the DF for caustic cracking

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D_f^{ClSCC}	is the DF for ClSCC
D_f^{CUIF}	is the DF for corrosion under insulation (CUI) for ferritic components
$D_f^{CUI-ClSCC}$	is the DF for CUI for austenitic stainless steel components subject to ExtClSCC
D_{f-gov}^{extd}	is the governing DF for external damage
D_f^{extcor}	is the DF for external corrosion
$D_f^{ext-ClSCC}$	is the DF for external corrosion for un-insulated austenitic stainless steel components subject to ExtClSCC
D_f^{elin}	is the DF when an internal liner is present
D_f^{htha}	is the DF for HTHA
$D_f^{HIC/SOHIC-HF}$	is the DF for hydrogen-induced cracking (HIC-HF) and stress-oriented hydrogen-induced cracking (SOHIC-HF) in hydrofluoric acid services
$D_f^{HIC/SOHIC-H_2S}$	is the DF for hydrogen-induced cracking (HIC-H_2S) and stress-oriented hydrogen-induced cracking (SOHIC-H_2S) in hydrogen sulfide services
D_f^{HSC-HF}	is the DF for hydrogen stress cracking (HSC)
D_f^{mfat}	is the DF for mechanical fatigue
D_f^{PASCC}	is the DF for polythionic acid stress corrosion cracking (PASCC)
D_f^{sigma}	is the DF for sigma phase embrittlement
D_f^{ssc}	is the DF for sulfide stress cracking (SSC)
D_{f-gov}^{scc}	is the governing DF for SCC
D_f^{tempe}	is the DF for Cr-Mo components subject to low alloy steel embrittlement
D_f^{thin}	is the DF for thinning
D_{f-gov}^{thin}	is the governing DF for thinning
$D_{f-total}$	is the total DF for a component
D_f^{885F}	is the DF for 885 °F embrittlement
F_{MS}	is the management systems factor

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gff	is the GFF for discrete hole sizes
gff_{total}	is the total GFF
$pscore$	is the management systems evaluation score expressed as a percentage
$P_f(t)$	is the POF as a function of time
$Score$	is the score obtained from the management systems evaluation

3.7 Tables

Table 3.1—Suggested Component Generic Failure Frequencies

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
Tank650	TANKBOTTOM	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
Vessel/FinFan	KODRUM, COLBTM, FINFAN, FILTER, DRUM, REACTOR, COLTOP, COLMID	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05

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

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Table 3.2—Damage Factor Section References

DF Variable	DF Description	Section
D_f^{thin}	DF for general and localized thinning	4
D_f^{elin}	DF of internal inorganic, organic, and strip linings for all component types	5
$D_f^{caustic}$	DF for caustic cracking	6
D_f^{amine}	DF for amine cracking	7
D_f^{ssc}	DF for SSC	8
$D_f^{HIC/SOHIC-H_2S}$	DF for HIC/SOHIC cracking in H_2S environments	9
D_f^{ACSCC}	DF for ACSCC	10
D_f^{PTA}	DF for polythionic acid cracking in austenitic stainless steel and nonferrous alloy components	11
D_f^{ClSCC}	DF for ClSCC	12
D_f^{HSC-HF}	DF for HSC in HF environments	13
$D_f^{HIC/SOHIC-HF}$	DF for HIC/SOHIC cracking in HF environments	14
D_f^{extcor}	DF for external corrosion on ferritic components	15
D_f^{CUIF}	DF for CUI on insulated ferritic components	16
$D_f^{ext-ClSCC}$	DF for ExtClSCC on austenitic stainless steel components	17
$D_f^{CUI-ClSCC}$	DF for CUI ClSCC on austenitic stainless steel insulated components	18
D_f^{htha}	DF for HTHA	19
D_f^{brit}	DF for brittle fracture of carbon steel and low alloy components	20
D_f^{tempe}	DF for low alloy steel embrittlement of Cr-Mo low alloy components	21
D_f^{885F}	DF for 885 °F embrittlement	22
D_f^{sigma}	DF for sigma phase embrittlement	23
D_f^{mfat}	DF for mechanical fatigue	24

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Table 3.3—Management Systems Evaluation

Table	Title	Questions	Points
2.A.1	Leadership and Administration	6	70
2.A.2	Process Safety Information	10	80
2.A.3	Process Hazard Analysis	9	100
2.A.4	Management of Change	6	80
2.A.5	Operating Procedures	7	80
2.A.6	Safe Work Practices	8	85
2.A.7	Training	8	100
2.A.8	Mechanical Integrity	20	120
2.A.9	Pre-start-up Safety Review	5	60
2.A.10	Emergency Response	6	65
2.A.11	Incident Investigation	9	75
2.A.12	Contractors	5	45
2.A.13	Audits	4	40
Total		**103**	**1000**

NOTE Tables 2.A.1 through 2.A.13 are located in Annex 2.A.

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. Thinning associated with external corrosion and CUI should be evaluated according to the procedures in Section 15.6.4 and Section 16.6.3, 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 4.5.3). 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.

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The DF is calculated using structural reliability theory. 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 on-line monitoring that has been performed (see Section 4.4.2). 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 on-line 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 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.

4.5 Determination of the DF

4.5.1 Overview

A flow chart of the steps required to determine the DF for thinning is shown in Figure 4.1. The following sections provide additional information and the calculation procedure to determine DF.

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 and API 570 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 and API 570 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.

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

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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. For general thinning, the reliability of the information sources used to establish a corrosion rate can be put into the following three categories.

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 probability of three damage states being present. The three damage states used in Section 4.5.7 are defined as follows.

a) Damage State 1—Damage is no worse than expected, or a factor of 1 applied to the expected corrosion rate.

b) Damage State 2—Damage is somewhat worse than expected, or a factor of 2 applied to the expected corrosion rate.

c) 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. Note that 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

Whether the thinning is expected to be localized wall loss or general and uniform in nature, this thinning type is used to define the inspection to be performed. 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. If multiple thinning mechanisms are possible and both general and localized thinning mechanisms are assigned, the localized thinning type should be used.

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).

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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 to use.

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 localized).

Examples of inspection activities for specific applications are provided in Annex 2.C for:

a) general and localized thinning that are either intrusive or nonintrusive in Table 2.C.8.1 and Table 2.C.8.2,

b) buried components in Table 2.C.7.1,

c) general and localized thinning applied to AST shell courses and bottoms in Tables 2.C.5.1 through 2.C.5.3.

For localized 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.C, 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.

Note that for AST bottoms, credit is given for only one inspection.

4.5.7 Calculation of Thinning DF

The following procedure may be used to determine the DF for thinning; see Figure 4.1. Note that this procedure assumes that if cladding/weld overlay is present, it corrodes prior to any corrosion of the base material.

a) STEP 1—Determine the furnished thickness, t, and age, age, and cladding/weld overlay thickness, t_{cm}, if applicable for the component from the installation date.

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b) STEP 2—Determine the corrosion rate for the base material, $C_{r,bm}$, 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. For a component with cladding/weld overlay, the cladding/weld overlay corrosion rate, $C_{r,cm}$, must be determined.

c) STEP 3—Determine the time in service, age_{tk}, since the last inspection known thickness , t_{rdi}. The t_{rdi} is the starting thickness with respect to wall loss associated with internal corrosion (see Section 4.5.5). If no measured thickness is available, set $t_{rdi} = t$ and $age_{tk} = age$.

d) STEP 4—For cladding/weld overlay pressure vessel components, calculate the age from the date of the starting thickness from STEP 3 required to corrode away the cladding/weld overlay material, age_{rc}, using Equation (2.11).

$$age_{rc} = \max\left[\left(\frac{t_{cm}}{C_{r,cm}}\right), \ 0.0\right] \tag{2.11}$$

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

e) STEP 5—Determine t_{min} using one of the following methods.

1) For cylindrical, spherical, or head components, determine the allowable stress, S, 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) If the component is a tank bottom, use t_{min} = 0.1 in. if the AST does not have a release prevention barrier (RPB) or t_{min} = 0.05 in. if the AST has a RPB, in accordance with API 653 [11].

4) A specific t_{min} calculated by another method and documented in the asset management program may be used at the owner–user's discretion.

f) STEP 6—Determine the A_{rt} parameter using Equations (2.12), (2.13), (2.14), or (2.15), as appropriate, based on t from STEP 1, $C_{r,bm}$ and $C_{r,cm}$ from STEP 2, age_{tk} and t_{rdi} from STEP 3, and the age required to corrode away the cladding/weld overlay, age_{rc}, if applicable, from STEP 4. Note that the age parameter in these equations is equal to age_{tk} from STEP 3.

1) For tank bottom components, calculate the A_{rt} parameter using Equation (2.12) and skip to STEP 13.

$$A_{rt} = \max\left[\left(1 - \frac{t_{rdi} - (C_{r,bm} \cdot age_{tk})}{t_{min} + CA}\right), \ 0.0\right] \tag{2.12}$$

2) For components with or without cladding/weld overlay, use Equation (2.13).

$$A_{rt} = \max\left(\frac{C_{r,bm} \cdot \left(age_{tk} - age_{rc}\right)}{t_{rdi}}, 0\right) \tag{2.13}$$

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g) STEP 7—Calculate the flow stress, FS^{Thin}, using E from STEP 5 and Equation (2.14).

$$FS^{Thin} = \frac{(YS + TS)}{2} \cdot E \cdot 1.1 \tag{2.14}$$

NOTE Use flow stress (FS^{Thin}) at design temperature for conservative results, using the appropriate Equation (2.15) or Equation (2.16).

h) STEP 8—Calculate the strength ratio parameter, SR_P^{Thin}, using the appropriate Equation (2.15) or Equation (2.16). Using Equation (2.15) with t_{rdi} from STEP 3, t_{min} or t_c from STEP 5, S and E from STEP 5, and flow stress, FS^{Thin}, from STEP 7.

$$SR_P^{Thin} = \frac{S \cdot E}{FS^{Thin}} \cdot \frac{\max(t_{min}, t_c)}{t_{rdi}} \tag{2.15}$$

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 should be used when appropriate.

Using Equation (2.16) with t_{rdi} from STEP 3 and FS^{Thin} from STEP 7.

$$SR_P^{Thin} = \frac{P \cdot D}{\alpha \cdot FS^{Thin} \cdot t_{rdi}} \tag{2.16}$$

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 (2.15) should be used.

i) STEP 9—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.

j) STEP 10—Calculate the inspection effectiveness factors, I_1^{Thin}, I_2^{Thin}, and I_3^{Thin}, using Equation (2.17), 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 9.

$$\begin{aligned}
I_1^{Thin} &= Pr_{p1}^{Thin}\left(Co_{p1}^{ThinA}\right)^{N_A^{Thin}}\left(Co_{p1}^{ThinB}\right)^{N_B^{Thin}}\left(Co_{p1}^{ThinC}\right)^{N_C^{Thin}}\left(Co_{p1}^{ThinD}\right)^{N_D^{Thin}}\\
I_2^{Thin} &= Pr_{p2}^{Thin}\left(Co_{p2}^{ThinA}\right)^{N_A^{Thin}}\left(Co_{p2}^{ThinB}\right)^{N_B^{Thin}}\left(Co_{p2}^{ThinC}\right)^{N_C^{Thin}}\left(Co_{p2}^{ThinD}\right)^{N_D^{Thin}}\\
I_3^{Thin} &= Pr_{p3}^{Thin}\left(Co_{p3}^{ThinA}\right)^{N_A^{Thin}}\left(Co_{p3}^{ThinB}\right)^{N_B^{Thin}}\left(Co_{p3}^{ThinC}\right)^{N_C^{Thin}}\left(Co_{p3}^{ThinD}\right)^{N_D^{Thin}}
\end{aligned} \tag{2.17}$$

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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.

k) STEP 11—Calculate the posterior probabilities, Po_{p1}^{Thin}, Po_{p2}^{Thin}, and Po_{p3}^{Thin}, using Equation (2.18) with I_1^{Thin}, I_2^{Thin}, and I_3^{Thin} in STEP 10.

$$
\begin{aligned}
Po_{p1}^{Thin} &= \frac{I_1^{Thin}}{I_1^{Thin}+I_2^{Thin}+I_3^{Thin}} \\
Po_{p2}^{Thin} &= \frac{I_2^{Thin}}{I_1^{Thin}+I_2^{Thin}+I_3^{Thin}} \\
Po_{p3}^{Thin} &= \frac{I_3^{Thin}}{I_1^{Thin}+I_2^{Thin}+I_3^{Thin}}
\end{aligned}
\tag{2.18}
$$

l) STEP 12—Calculate the parameters, β_1^{Thin}, β_2^{Thin}, and β_3^{Thin}, using Equation (2.19) and assigning $COV_{\Delta t} = 0.20$, $COV_{S_f} = 0.20$, and $COV_p = 0.05$.

$$
\begin{aligned}
\beta_1^{Thin} &= \frac{1-D_{S_1}\cdot A_{rt}-SR_p^{Thin}}{\sqrt{D_{S_1}{}^2\cdot A_{rt}{}^2\cdot COV_{\Delta t}{}^2+\left(1-D_{S_1}\cdot A_{rt}\right)^2\cdot COV_{S_f}{}^2+(SR_p^{Thin})^2\cdot COV_P{}^2}}, \\
\beta_2^{Thin} &= \frac{1-D_{S_2}\cdot A_{rt}-SR_p^{Thin}}{\sqrt{D_{S_2}{}^2\cdot A_{rt}{}^2\cdot COV_{\Delta t}{}^2+\left(1-D_{S_2}\cdot A_{rt}\right)^2\cdot COV_{S_f}{}^2+(SR_p^{Thin})^2\cdot COV_P{}^2}}, \\
\beta_3^{Thin} &= \frac{1-D_{S_3}\cdot A_{rt}-SR_p^{Thin}}{\sqrt{D_{S_3}{}^2\cdot A_{rt}{}^2\cdot COV_{\Delta t}{}^2+\left(1-D_{S_3}\cdot A_{rt}\right)^2\cdot COV_{S_f}{}^2+(SR_p^{Thin})^2\cdot COV_P{}^2}}.
\end{aligned}
\tag{2.19}
$$

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 [31]. Note that 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 $0.10 \le COV_{\Delta t} \le 0.20$, with a recommended conservative value of $COV_{\Delta t} = 0.20$.

m) STEP 13—For tank bottom components, determine the base DF for thinning, D_{fB}^{thin}, using Table 4.7 and based on the A_{rt} parameter from STEP 6, and skip to STEP 15.

n) STEP 14—For all components (excluding tank bottoms covered in STEP 13), calculate the base DF, D_{fB}^{thin}.

$$
D_{fb}^{Thin} = \left[\frac{\left(Po_{p1}^{Thin}\Phi\left(-\beta_1^{Thin}\right)\right)+\left(Po_{p2}^{Thin}\Phi\left(-\beta_2^{Thin}\right)\right)+\left(Po_{p3}^{Thin}\Phi\left(-\beta_3^{Thin}\right)\right)}{1.56\text{E-04}}\right]
\tag{2.20}
$$

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

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o) STEP 15—Determine the DF for thinning, D_f^{Thin}, using Equation (2.21).

$$D_f^{Thin} = \max\left[\left(\frac{D_{fB}^{Thin} \cdot F_{IP} \cdot F_{DL} \cdot F_{WD} \cdot F_{AM} \cdot F_{SM}}{F_{OM}}\right),\ 0.1\right] \tag{2.21}$$

The adjustment factors in are determined as described below.

1) Adjustment to DF for On-line Monitoring, F_{OM}—In addition to inspection, on-line monitoring of corrosion (or key process variables affecting corrosion) is commonly used in many processes to prevent corrosion failures. The advantage of on-line 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 on-line 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 on-line monitoring, determine the on-line monitoring factor from Table 4.8. 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 a highly effective inspection specifically for injection/mix point corrosion within the injection point circuit (according to API 570) is performed, then an adjustment is not necessary, or 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 a highly effective inspection method is used to address the potential of localized corrosion in the dead-leg, then an adjustment is not necessary, or F_{DL} = 3.

4) Adjustment for Welded Construction, F_{WD}—Applicable only to ASTs. If the component is welded (i.e. not riveted), then F_{WD} = 1; otherwise, F_{WD} = 10.

5) Adjustment for Maintenance in Accordance with API 653, F_{AM}—Applicable only to AST. If the AST is maintained in accordance with API 653, then F_{AM} = 1; otherwise, F_{AM} = 5.

6) Adjustment for Settlement, F_{SM}—Applicable only to AST bottoms. It is determined based on the following criteria:

   - recorded settlement exceeds API 653 criteria—F_{SM} = 2,

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- recorded settlement meets API 653 criteria—F_{SM} = 1,
- settlement never evaluated—F_{SM} = 1.5,
- concrete foundation, no settlement—F_{SM} = 1.

4.6 Nomenclature

age	is the in-service time that the damage is applied
age_{rc}	is the remaining life of the cladding/weld overlay associated with the date of the starting thickness
age_{tk}	is the component in-service time since the last inspection thickness measurement or service start date
A_{rt}	is the component wall loss fraction since last inspection thickness measurement or service start date
$C_{r,bm}$	is the corrosion rate for the base material
$C_{r,cm}$	is the corrosion rate for the cladding/weld overlay
CA	is the corrosion allowance
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_{S_f}	is the flow stress coefficient of variance
$COV_{\Delta t}$	is the thinning coefficient of variance
D	is the component inside diameter
D_{S_1}	is the corrosion rate factor for damage state 1
D_{S_2}	is the corrosion rate factor for damage state 2
D_{S_3}	is the corrosion rate factor for damage state 3
D_f^{Thin}	is the DF for thinning
D_{fB}^{Thin}	is the base value of the DF for thinning
E	is the weld joint efficiency or quality code from the original construction code

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F_{AM}	is the DF adjustment for AST maintenance per API 653
F_{DL}	is the DF adjustment for dead-legs
F_{IP}	is the DF adjustment for injection points
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
FS^{Thin}	is the flow stress
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.)
Po_{p1}^{Thin}	is the posterior probability for damage state 1
Po_{p2}^{Thin}	is the posterior probability for damage state 2
Po_{p3}^{Thin}	is the posterior probability for damage state 3
Pr_{p1}^{Thin}	is the prior probability of corrosion rate data confidence for damage state 1
Pr_{p2}^{Thin}	is the prior probability of corrosion rate data confidence for damage state 2
Pr_{p3}^{Thin}	is the prior probability of corrosion rate data confidence for damage state 3
S	is the allowable stress
SR_P^{Thin}	is the strength ratio parameter defined as the ratio of hoop stress to flow stress

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t	is the furnished thickness of the component calculated as the sum of the base material and cladding/weld overlay thickness, as applicable
t_{bm}	is the furnished or remaining base materials thickness of the component
t_c	is the minimum structural thickness of the component base material
t_{cm}	is the furnished or remaining cladding/weld overlay material thickness of the component
t_{min}	is the minimum required thickness based on the applicable construction code
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
TS	is the tensile strength at design temperature
YS	is the yield strength at design temperature
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

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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, mm (in.)	The thickness used for the DF calculation that is either the furnished thickness or the measured thickness (see Section 4.5.5).
Corrosion allowance, mm (in.)	The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current service.
Design temperature, °C (°F)	The design temperature, shell side and tube side for a heat exchanger.
Design pressure, MPa (psi)	The design pressure, shell side and tube side for a heat exchanger.
Operating temperature, °C (°F)	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, MPa (psi)	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, MPa (psi)	The design yield strength of the material based on material specification.
Tensile strength, MPa (psi)	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
Tank650	TANKBOTTOM	PLT
Tank650	COURSE-1-10	CYL
Vessel/FinFan	KODRUM, COLBTM, FINFAN, FILTER, DRUM, REACTOR, COLTOP, COLMID	CYL, ELB, SPH, HEM, ELL, TOR, CON, NOZ

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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 (IR) — Knuckle (IR) — Volume
CON	Conical shell	— Diameter — Length — Cone angle — Volume
NOZ	Nozzle	— Diameter — Length — Volume

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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 1.27 mm (50 mils). Localized corrosion is defined as affecting less than 10 % of the surface area or a wall thickness variation greater than 1.27 mm (50 mils).
Corrosion rate (mmpy or mpy)	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.
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).
On-line monitoring	The types of proactive on-line 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 on-line 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.
Welded construction	Applicable to ASTs only, ASTs may be welded or riveted construction. Is the AST of welded construction? (Yes or No)
Maintained to API 653	Applicable to ASTs only. Is the AST maintained in accordance with API 653 [11]? (Yes or No)
Settlement	Applicable to ASTs only, ASTs may be welded or riveted construction. What is the settlement history of the AST: — recorded settlement exceeds API 653 criteria; — recorded settlement meets API 653 criteria; — settlement never evaluated; — concrete foundation, no settlement.

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Table 4.5—Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidence Data	Medium Confidence Data	High Confidence Data
Pr_{p1}^{Thin}	0.5	0.7	0.8
Pr_{p2}^{Thin}	0.3	0.2	0.15
Pr_{p3}^{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
Co_{p1}^{Thin}	0.33	0.4	0.5	0.7	0.9
Co_{p2}^{Thin}	0.33	0.33	0.3	0.2	0.09
Co_{p3}^{Thin}	0.33	0.27	0.2	0.1	0.01

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Table 4.7—Thinning DFs for AST Bottom

A_{rt}	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	0.4
0.10	14	3	1	0.7	0.7
0.15	32	8	2	1	1
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

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Table 4.8—On-line Monitoring Adjustment Factors

Thinning Mechanism	**Adjustment Factors As a Function of On-line 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_2S/H_2 corrosion	1	10	1
Sulfuric acid (H_2S/H_2) corrosion Low velocity ≤3 ft/s for CS ≤5 ft/s for SS ≤7 ft/s for higher alloys	20	10	2
High velocity >3 ft/s for CS >5 ft/s for SS >7 ft/s for higher alloys	10 (20 if in conjunction with probes)	10	1
Hydrofluoric acid (HF) corrosion	10	1	1
Sour water corrosion Low velocity ≤20 ft/s	20	10	2
High velocity >20 ft/s	10	2	2
Amine Low velocity	20	10	2
High velocity	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 on-line 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 on-line 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, H_2S 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 effectivness of other on-line corrosion monitoring methods (e.g. hydrogen flux, FSM, LP probe) shall be evaluated by a corrosion engineer or other knowledgeable specialist.

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4.8 Figures

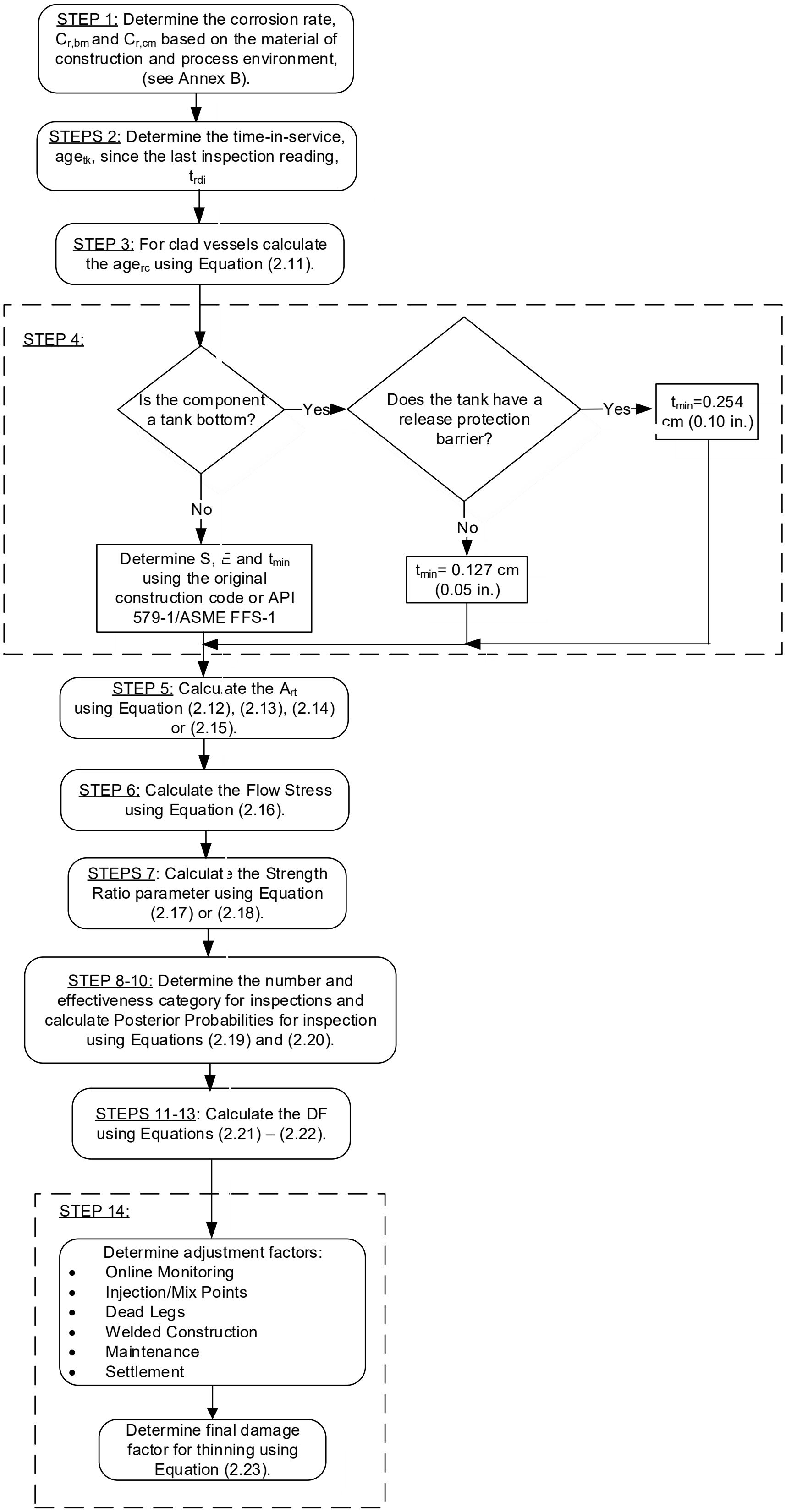

Figure 4.1—Determination of the Thinning DF

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5 Component Lining DF

5.1 Scope

A general approach for computing the DF for a component that has a protective internal lining is covered in this section. It is common practice to construct a component with a material that is known to be subject to damage in the operating environment, but to protect the material from the environment with a lining that is resistant as described in Table 5.1. The lining types covered in this section are shown in Table 5.2.

A general approach for lined components involves assessing the severity of damage that would be expected to occur on the base material, and then give credit for the existence of a lining. The degradation rate of the lining itself is not addressed. Evaluations of lining effectiveness at preventing damage are based on expert opinion.

5.2 Screening Criteria

If the component has an inorganic or organic lining, then the component should be evaluated for lining damage.

5.3 Required Data

The data required for analysis are given in Table 4.1, and the specific data required for determination of the lining DF are shown in Table 5.3.

5.4 Basic Assumptions

All linings afford some degree of protection from the operating environment. Many linings will last for an indefinite period of time, essentially being immune to damage mechanisms that may otherwise occur. Other linings will slowly degrade with time and have a finite life. In such cases, the age of the lining (or the years since the last inspection) becomes important in assigning a factor. Particularly in the case of organic linings, the assumption is made that the lining is compatible with the environment, has operated within design temperature limits (including steam out), and was properly applied with appropriate curing.

5.5 Determination of the DF

5.5.1 Overview

A flow chart of the steps required to determine the DF for linings is shown in Figure 5.1. The following sections provide additional information and the calculation procedure.

The basic approach is that the type of lining and the age or years since last inspection determines a lining failure factor. This is adjusted for a qualitative description of the lining condition. It is further adjusted based on the probability of component failure upon lining failure (i.e. if the lining fails, does the component fail rapidly, or will it be expected to last for a considerable time?). A final credit is made for on-line monitoring that can provide early detection of a lining failure.

After a lining DF is computed, it is then compared to the thinning DF determined for the base material. The minimum of the two values is used. The basis for this is that if the thinning damage is small compared to the lining DF, then it does not yet matter if the lining has failed or not. This also provides a check that lining failure is not necessarily equated with a component.

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5.5.2 Inspection Effectiveness

Inspection is ranked according to the effectiveness of the methods and coverage for detecting a specific damage mechanism. Although inspection effectiveness is not currently used in the calculation of the lining DF, examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in Annex 2.C, Table 2.C.6.1.

5.5.3 Calculation of the DF

The following procedure may be used to determine the DF for lining damage; see Figure 5.1.

a) STEP 1—Determine the lining type and time in service, age, of the lining based on the lining installation date or date of last A or B effectiveness inspection.

b) STEP 2—Determine the base value of the lining DF, D_{fB}^{elin}, using Table 5.4 and Table 5.5, as applicable, based on the age and lining type from STEP 1.

c) STEP 3—Determine the DF for lining damage, D_f^{elin}, using Equation (2.22).

$$D_f^{elin} = D_{fB}^{elin} \cdot F_{LC} \cdot F_{OM} \tag{2.22}$$

The adjustment factors are determined as described below.

1) Adjustment for Lining Condition, F_{LC}—The adjustment factors are given in Table 5.6 based on a qualitative assessment of the lining condition.

2) Adjustment for On-line Monitoring, 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 on-line 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).

5.6 Nomenclature

age	is the time since the last A or B effective lining inspection
D_f^{elin}	is the DF for liners
D_{fB}^{elin}	is the base value of the DF for liners
F_{LC}	is the DF adjustment for lining condition
F_{OM}	is the DF adjustment for online monitoring

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5.7 Tables

Table 5.1—Typical Examples of Protective Internal Linings

Lining Series ID	Environment (Damage Mechanisms of Base Material)	Example Lining
Alloy linings	Corrosive (thinning)	Strip lined alloy
Organic coatings	Corrosive (thinning)	Organic coating or lining
Refractory	High temperature (thinning, creep, erosion)	Castable refractory Plastic refractory Refractory brick Ceramic fiber refractory Refractory/alloy combination
Glass lined	Corrosive (thinning)	Glass lined
Acid brick	Corrosive (thinning)	Brick/mortar

Table 5.2—Lining Types and Resistance

Description	Resistance
Strip lined alloy ("wall papered")	Typically subject to failure at seams
Organic coating: Spray applied to 1 mm (40 mils) dry film thickness. Trowel applied to 2 mm (80 mils) dry film thickness Reinforced, trowel applied ≥2 mm (≥80 mils) dry film thickness	Limited life
Thermal resistance service: Castable refractory Plastic refractory Refractory brick	Subject to occasional spalling or collapse
Severe/abrasive service: Castable refractory Ceramic tile	Limited life in highly abrasive service
Glass linings	Complete protection, subject to failure due to thermal or mechanical shock
Acid brick	Partial protection. The brick provides thermal protection, but is not intended to keep the fluid away from the base material.

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Table 5.3—Data Required for Determination of the Lining DF

Required Data	Comments
Type of lining	See Table 5.4 and Table 5.5, as applicable
Age of lining (years)	Age of lining, or years since last A or B effective inspection (i.e. since last thorough visual inspection or other appropriate method)
Lining condition	Condition of lining based on Table 5.6
On-line monitoring for lining failure	On-line monitoring
Damage factor	Thinning DF determined as in Section 4

Table 5.4—Lining DFs—Inorganic Linings

Years Since Last Thorough Visual Inspection	DF As a Function of Inorganic Lining Type					
	Strip Lined Alloy (Resistant)	Castable Refractory	Castable Refractory Severe Conditions	Glass Lined	Acid Brick	Fiberglass
1	0.3	0.5	9	3	0.01	1
2	0.5	1	40	4	0.03	1
3	0.7	2	146	6	0.05	1
4	1	4	428	7	0.15	1
5	1	9	1017	9	1	1
6	2	16	1978	11	1	1
7	3	30	3000	13	1	2
8	4	53	3000	16	1	3
9	6	89	3000	20	2	7
10	9	146	3000	25	3	13
11	12	230	3000	30	4	26
12	16	351	3000	36	5	47
13	22	518	3000	44	7	82
14	30	738	3000	53	9	139
15	40	1017	3000	63	11	228
16	53	1358	3000	75	15	359
17	69	1758	3000	89	19	548
18	89	2209	3000	105	25	808
19	115	2697	3000	124	31	1151
20	146	3000	3000	146	40	1587
21	184	3000	3000	170	50	2119
22	230	3000	3000	199	63	2743
23	286	3000	3000	230	78	3000
24	351	3000	3000	266	97	3000
25	428	3000	3000	306	119	3000

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Table 5.5—Lining DFs—Organic Linings

Years in Service	Low-quality Immersion Grade Coating (Spray Applied, to 40 mils)	Medium-quality Immersion Grade Coating (Filled, Trowel Applied, to 80 mils)	High-quality Immersion Grade Coating (Reinforced, Trowel Applied, ≥80 mils)
1	30	1	0.1
2	89	4	0.13
3	230	16	0.15
4	518	53	0.17
5	1017	146	0.2
6	1758	351	1
7	2697	738	4
8	3000	1358	16
9	3000	2209	53
10	3000	3000	146
11	3000	3000	351
12	3000	3000	738
13	3000	3000	1358
14	3000	3000	2209
15	3000	3000	3000
16	3000	3000	3000
17	3000	3000	3000
18	3000	3000	3000
19	3000	3000	3000
20	3000	3000	3000
21	3000	3000	3000
22	3000	3000	3000
23	3000	3000	3000
24	3000	3000	3000
25	3000	3000	3000

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Table 5.6—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.	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

5.8 Figures

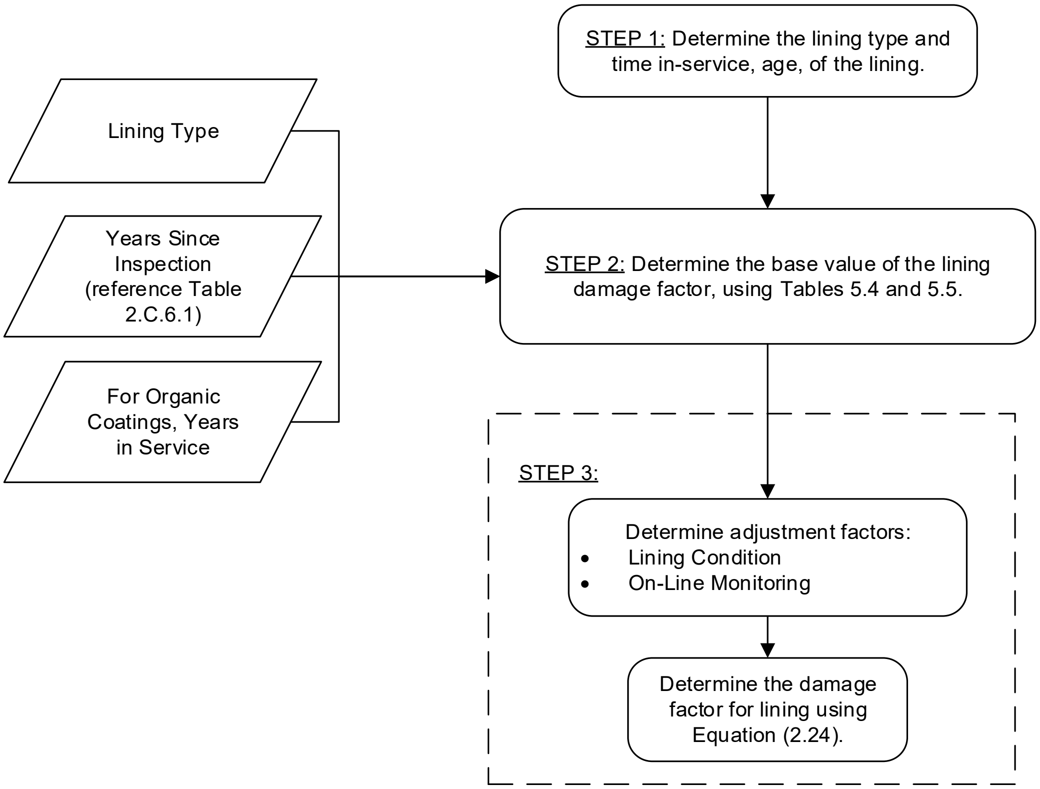

Figure 5.1—Determination of the Lining DF

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6 Stress Corrosion Cracking (SCC) DF—Caustic Cracking

6.1 Scope

The DF calculation for components subject to caustic cracking is covered in this section.

6.2 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 6.1. Caustic cracking of carbon steel is not anticipated at metal temperatures less than about 46 °C (115 °F). In the 46 °C to 82 °C (115 °F to 180 °F) range, cracking susceptibility is a function of the caustic concentration. Above 82 °C (180 °F), cracking susceptibility is a function of the caustic concentration. Above 82 °C (180 °F), 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 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 621 °C (1150 °F) 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.

6.3 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.

6.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the caustic cracking DF are provided in Table 6.1.

6.5 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

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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.

Note that a high susceptability 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 susceptability should be maintained until subsequent inspections of adequate effectiveness reveal no cracking detected. Cracking susceptability 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].

6.6 Determination of the DF

6.6.1 Overview

A flow chart of the steps required to determine the DF for caustic cracking is shown in Figure 6.2. The following sections provide additional information and the calculation procedure.

6.6.2 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.C, Table 2.C.9.3. 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 Section 3.4.3.

6.6.3 Calculation of the DF

The following procedure may be used to determine the DF for caustic cracking; see Figure 6.2.

a) STEP 1—Determine the susceptibility for cracking using Figure 6.2. Note that 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 6.2.

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 Section 6.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

e) STEP 5—Determine the base DF for caustic cracking, $D_{fB}^{caustic}$, using Table 6.3 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 (2.23). 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.

$$D_f^{caustic} = \min\left(D_{fB}^{caustic} \cdot \left(\max[age, 1.0]\right)^{1.1}, 5000\right) \tag{2.23}$$

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6.7 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

6.8 References

See References [34], [35] (pp. 583–587), [36], and [37] in Section 2.2.

6.9 Tables

Table 6.1—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, °C (°F)	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.

Table 6.2—Determination of Severity Index—Caustic Cracking

Susceptibility	Severity Index—S_{VI}
High	5000
Medium	500
Low	50
None	0

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Table 6.3—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

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6.10 Figures

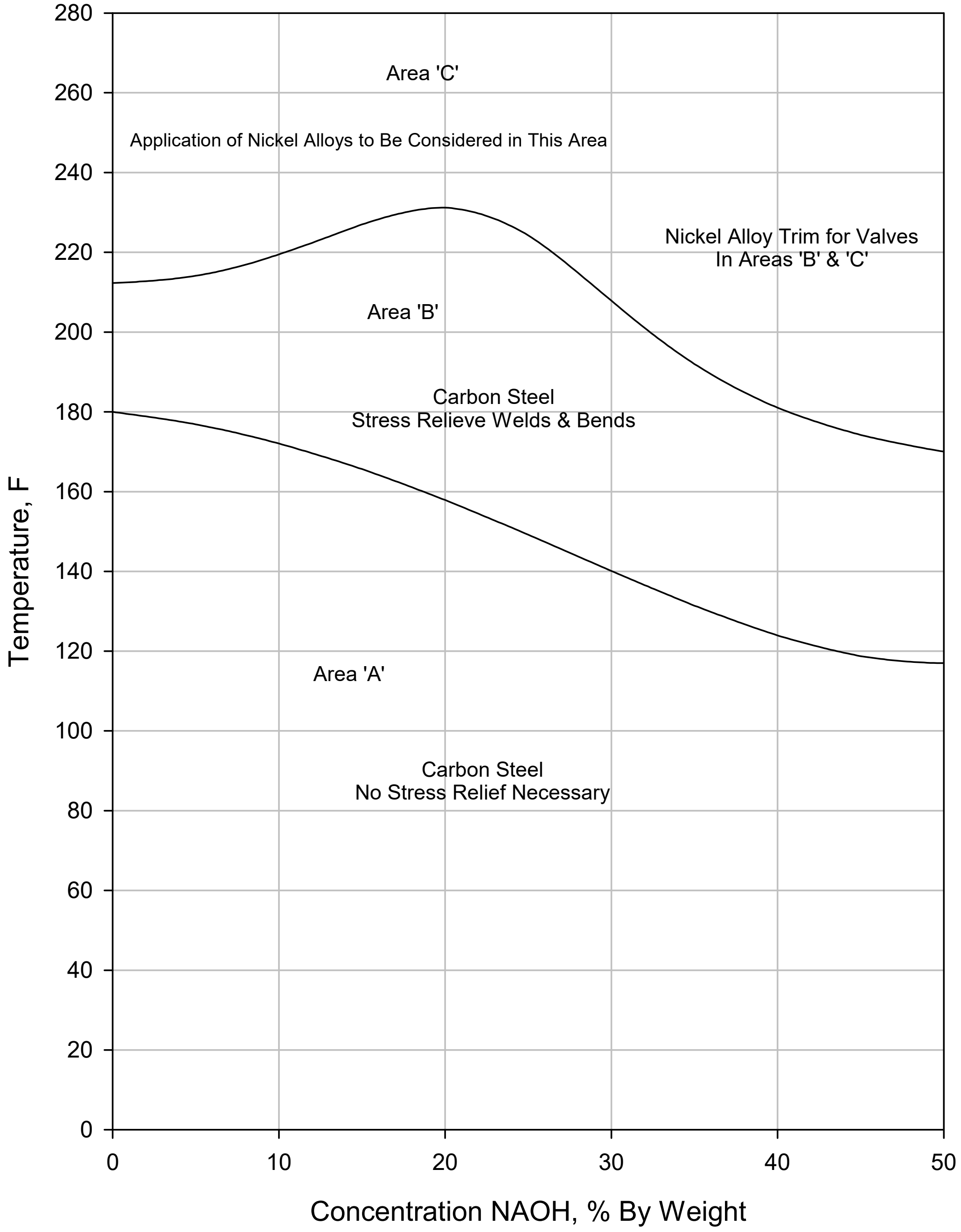

Figure 6.1—Susceptibility of Caustic Cracking in Carbon Steel

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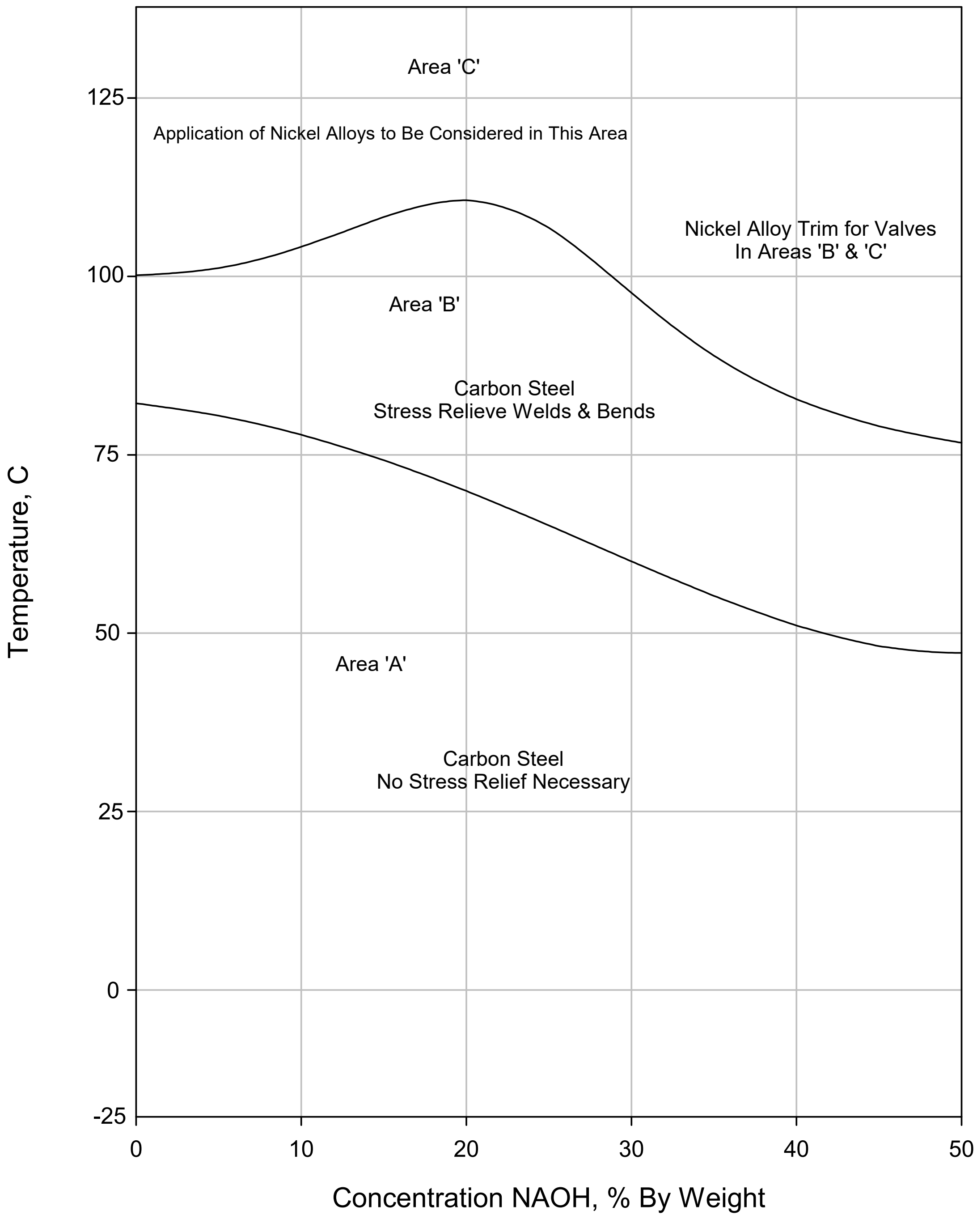

Figure 6.1M—Susceptibility of Caustic Cracking in Carbon Steel

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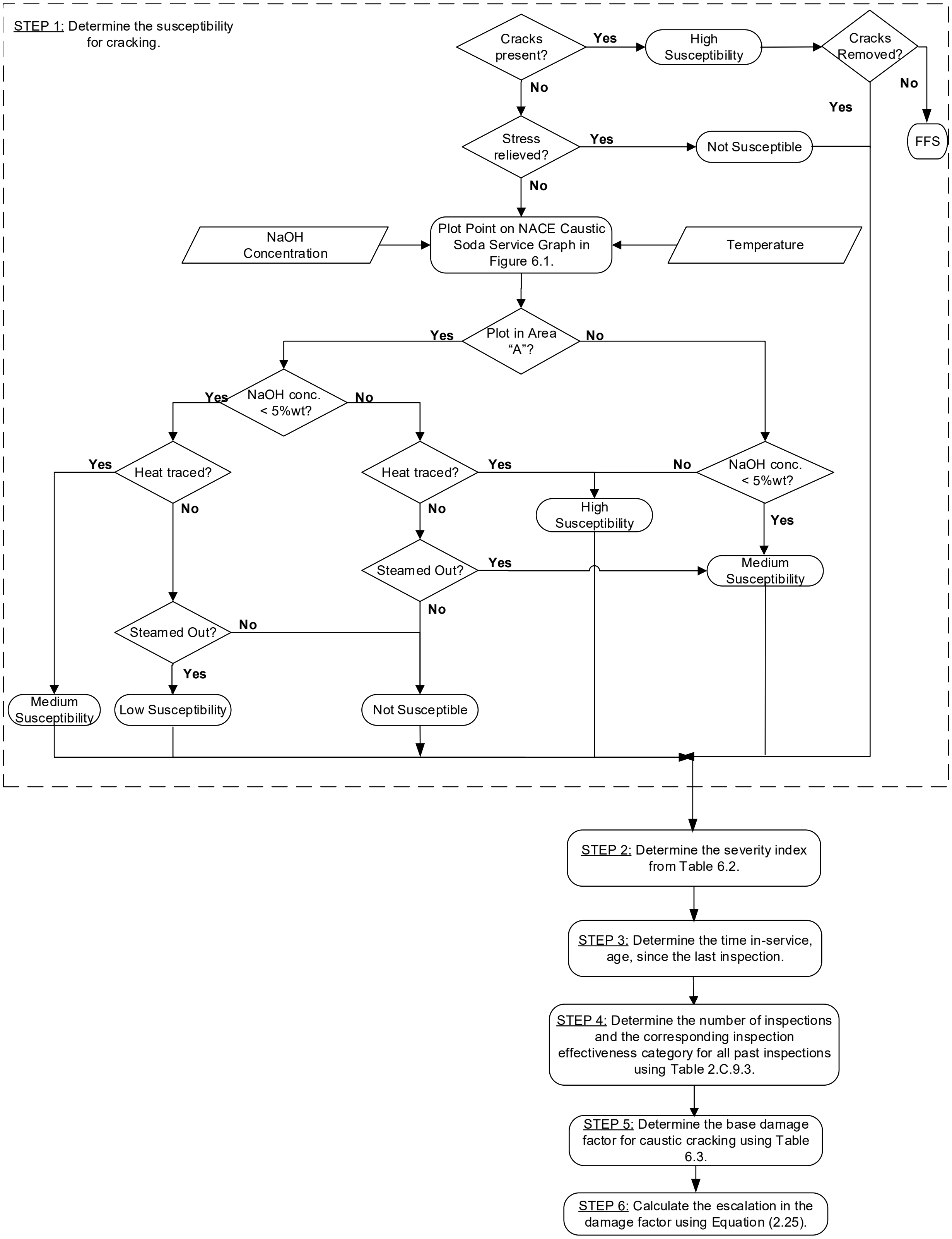

Figure 6.2—Determination of the Caustic Cracking DF

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7 SCC DF—Amine Cracking

7.1 Scope

The DF calculation for components subject to amine cracking is covered in this section.

7.2 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 monoethanolamine (MEA) and diisopropanolamine (DIPA) units and to a somewhat lesser extent in diethanolamine (DEA) units. Cracking is much less prevalent in methyldiethanolamine (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 621 °C (1150 °F) 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 this Part.

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7.3 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.

7.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the amine cracking DF are provided in Table 7.1.

7.5 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].

7.6 Determination of the DF

7.6.1 Overview

A flow chart of the steps required to determine the DF for amine cracking is shown in Figure 7.1. The following sections provide additional information and the calculation procedure.

7.6.2 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.C, Table 2.C.9.1.

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 Section 3.4.3.

7.6.3 Calculation of the DF

The following procedure may be used to determine the DF for amine cracking; see Figure 7.1.

a) STEP 1—Determine the susceptibility for cracking using Figure 7.1. Note that 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 7.2.

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 Section 7.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

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e) STEP 5—Determine the base DF for amine cracking, D_{fB}^{amine}, using Table 6.3 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 (2.24). 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.

$$D_f^{amine} = \min\left(D_{fB}^{amine} \cdot \left(\max[age, 1.0]\right)^{1.1}, 5000\right) \tag{2.24}$$

7.7 Nomenclature

age	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

7.8 References

See References [38], [39], [40], [41], [42], [43], and [44] in Section 2.2.

7.9 Tables

Table 7.1—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_2S or CO_2. Lean amine contains low levels of H_2S or CO_2. Rich amine contains high levels of H_2S or CO_2. For components exposed to both lean and rich amine solutions (i.e. amine contactors and regenerators), indicate lean.
Maximum process temperature, °C (°F)	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.

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Table 7.2—Determination of Severity Index—Amine Cracking

Susceptibility	**Severity Index—S_{VI}**
High	1000
Medium	100
Low	10
None	0

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7.10 Figures

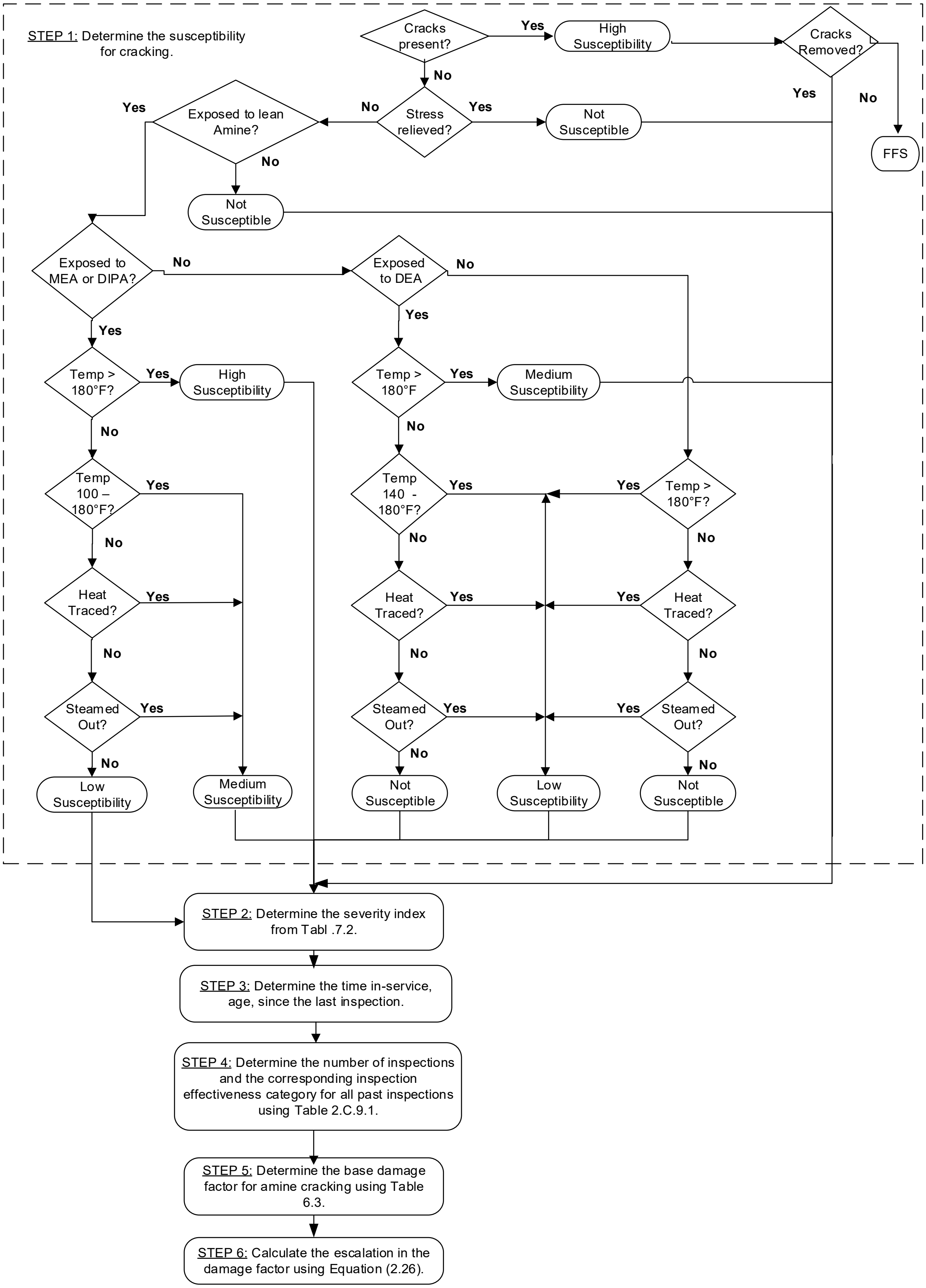

Figure 7.1—Determination of the Amine Cracking DF

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8 SCC DF—Sulfide Stress Cracking (SSC)

8.1 Scope

The DF calculation for components subject to SSC is covered in this section.

8.2 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 heat-affected zones (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. 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.

8.3 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.

8.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the SSC DF are provided in Table 8.1.

8.5 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].

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8.6 Determination of the DF

8.6.1 Overview

A flow chart of the steps required to determine the DF for SSC is shown in Figure 8.1. The following sections provide additional information and the calculation procedure.

8.6.2 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.C, Table 2.C.9.6.

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 Section 3.4.3.

8.6.3 Calculation of the DF

The following procedure may be used to determine the DF for SCC; see Figure 8.1.

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 8.2.

b) STEP 2—Determine the susceptibility for cracking using Figure 8.1 and Table 8.3 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 that a High susceptibility should be used if cracking is confirmed to be present.

c) STEP 3—Based on the susceptibility in STEP 3, determine the Severity Index, S_{VI}, from Table 8.4.

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 Section 8.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

f) STEP 6—Determine the base DF for SCC, D_{fB}^{ssc}, using Table 6.3 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 (2.25). 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.

$$D_f^{ssc} = \min\left(D_{fB}^{ssc} \cdot \left(\max[age, 1.0]\right)^{1.1}, 5000\right) \tag{2.25}$$

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8.7 Nomenclature

age 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

8.8 References

See References [17], [35] (pp. 541–559), [45], [46], [47], and [48] in Section 2.2.

8.9 Tables

Table 8.1—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_2S content of water	Determine the H_2S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore [45].
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.

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Table 8.2—Environmental Severity—SSC

pH of Water	Environmental Severity As a Function of H_2S Content of Water			
	<50 ppm	50 to 1,000 ppm	1,000 to 10,000 ppm	>10,000 ppm
<5.5	Low	Moderate	High	High
5.5 to 7.5	Low	Low	Low	Moderate
7.6 to 8.3	Low	Moderate	Moderate	Moderate
8.4 to 8.9	Low	Moderate	Moderate [1]	High [1]
>9.0	Low	Moderate	High [1]	High [1]

NOTE 1 If cyanides are present, increase the susceptibility to SSC one category for pH > 8.3 and H_2S concentrations greater than 1,000 ppm.

Table 8.3—Susceptibility to SSC—SSC

Environmental Severity	Susceptibility to SSC As a Function of Heat Treatment					
	As-welded Max Brinnell Hardness [1]			PWHT Max Brinnell Hardness [1]		
	<200	200 to 237	>237	<200	200 to 237	>237
High	Low	Medium	High	Not	Low	Medium
Moderate	Low	Medium	High	Not	Not	Low
Low	Low	Low	Medium	Not	Not	Not

NOTE 1 Actually tested as Brinnell, not converted from finer techniques, e.g. Vickers, Knoop, etc.

Table 8.4—Determination of Severity Index—SSC

Susceptibility	Severity Index—S_{VI}
High	100
Medium	10
Low	1
None	0

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8.10 Figures

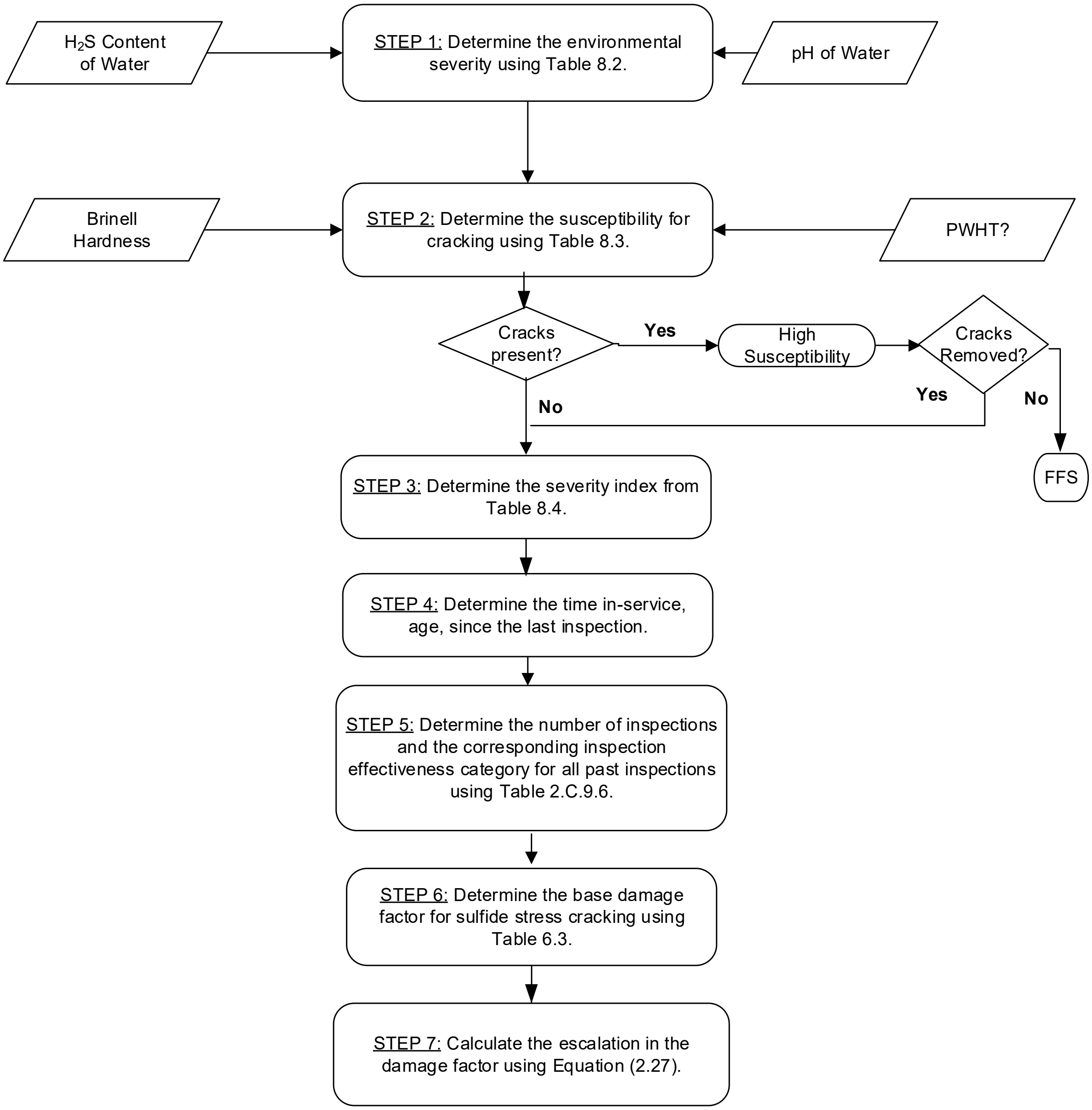

Figure 8.1—Determination of the SSC DF

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9 SCC DF—Hydrogen-induced Cracking and Stress-oriented Hydrogen-induced Cracking in Hydrogen Sulfide Services (HIC/SOHIC-H_2S)

9.1 Scope

The DF calculation for components subject to HIC/SOHIC-H_2S is covered in this section.

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 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. Presence of cyanides at elevated pH can further aggravate the hydrogen penetration into the steel. Hydrogen permeation 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 50 ppm of H_2S 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 rare earth minerals (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-H_2S.

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.

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9.3 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 HIC/SOHIC-H_2S cracking.

9.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the HIC/SOHIC-H_2S cracking DF are provided in Table 9.1.

9.5 Basic Assumptions

The main assumption in determining the DF for HIC/SOHIC-H_2S 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].

9.6 Determination of the DF

9.6.1 Overview

A flow chart of the steps required to determine the DF for HIC/SOHIC-H_2S cracking is shown in Figure 9.1. The following sections provide additional information and the calculation procedure.

9.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting for HIC/SOHIC-H_2S. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in Annex 2.C, Table 2.C.9.9.

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 Section 3.4.3.

9.6.3 Adjustment for On-line Monitoring

In addition to inspection, on-line monitoring using hydrogen probes and/or key process variables provides a better understanding of HIC/SOHIC-H_2S susceptibility. The advantage of on-line 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-H_2S, an on-line 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 on-line monitoring factor of 4 is applied.

9.6.4 Calculation of the DF

The following procedure may be used to determine the DF for HIC/SOHIC-H_2S cracking; see Figure 9.1.

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 9.2. Note that a High environmental severity should be used if cracking is confirmed to be present.

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b) STEP 2—Determine the susceptibility for cracking using Figure 9.1 and Table 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 9.4.

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 Section 9.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

f) STEP 6—Determine the base DF for HIC/SOHIC-H_2S cracking, $D_{fB}^{HIC/SOHIC-H_2S}$, using Table 6.3 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 on-line adjustment factor, F_{OM}, from Table 9.5.

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 (2.26). 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 on-line monitoring.

$$D_f^{HIC/SOHIC-H_2S} = \min\left(\frac{D_{fB}^{HIC/SOHIC-H_2S}\cdot\left(\max[age,1.0]\right)^{1.1}}{F_{OM}}, 5000\right) \tag{2.26}$$

9.7 Nomenclature

age	is the component in-service time since the last cracking inspection or service start date
$D_f^{HIC/SOHIC-H_2S}$	is the DF for HIC/SOHIC-H_2S cracking
$D_{fB}^{HIC/SOHIC-H_2S}$	is the base value of the for HIC/SOHIC-H_2S cracking
F_{OM}	is the on-line monitoring adjustment factor
S_{VI}	is the Severity Index

9.8 References

See References [45], [46], [48], [49], [50], [51], [52], and [53] in Section 2.2.

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9.9 Tables

Table 9.1—Data Required for Determination of the DF—HIC/SOHIC-H_2S 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_2S content of water	Determine the H_2S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore [45].
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 material test reports (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.
On-line 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.

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Table 9.2—Environmental Severity—HIC/SOHIC-H_2S Cracking

pH of Water	Environmental Severity As a Function of H_2S Content of Water			
	<50 ppm	50 to 1,000 ppm	1,000 to 10,000 ppm	>10,000 ppm
<5.5	Low	Moderate	High	High
5.5 to 7.5	Low	Low	Low	Moderate
7.6 to 8.3	Low	Moderate	Moderate	Moderate
8.4 to 8.9	Low	Moderate	Moderate [1]	High [1]
>9.0	Low	Moderate	High [1]	High [1]

NOTE 1 If cyanides are present, increase the susceptibility to HIC/SOHIC-H_2S one category for pH > 8.3 and H_2S concentrations greater than 1,000 ppm.

Table 9.3—Susceptibility to Cracking—HIC/SOHIC-H_2S

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 9.4—Determination of Severity Index—HIC/SOHIC-H_2S Cracking

Susceptibility	Severity Index—S_{VI}
High	100
Medium	10
Low	1
None	0

Table 9.5—On-line Monitoring Adjustment Factors for HIC/SOHIC-H_2S

On-line Monitoring Method	Adjustment Factors As a Function of On-line 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 on-line monitoring methods. Factors based on the user's experience can be used as a substitute for the values presented in this table.

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9.10 Figures

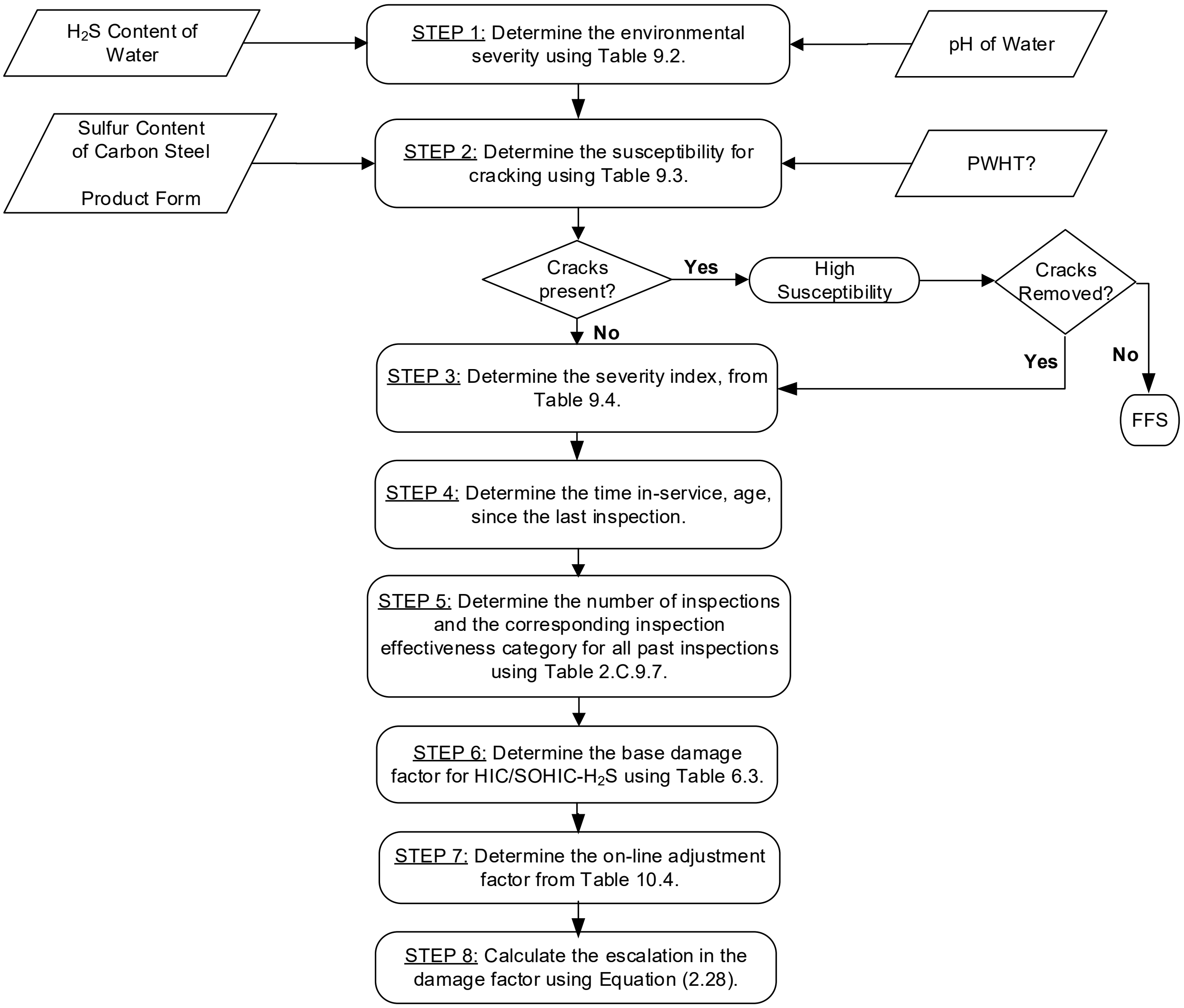

Figure 9.1—Determination of the HIC/SOHIC-H_2S DF

10 SCC DF—Alkaline Carbonate Stress Corrosion Cracking (ACSCC)

10.1 Scope

The DF calculation for components subject to ACSCC is covered in this section.

10.2 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 (CO_3).

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 HAZs.

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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 designs, Catacarb/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 nonrefining 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 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 carbonates in the alkaline water will be more susceptible to ACSCC at a lower pH.

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 alkaline 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. PWHT) is the most commonly used method of preventing ACSCC in carbon and low alloy steels. A heat treatment of about 649 °C to 663 °C (1200 °F to 1225 °F) 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.

10.3 Screening Criteria

If the component's material of construction of the component is carbon or low alloy steel and the process environment contains alkaline water at 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 [59].

10.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the ACSCC DF are provided in Table 10.1.

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10.5 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. 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].

10.6 Determination of the DF

10.6.1 Overview

A flow chart of the steps required to determine the DF for ACSCC is shown in Figure 10.1. The following sections provide additional information and the calculation procedure.

10.6.2 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.C, Table 2.C.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 Section 3.4.3.

10.6.3 Calculation of the DF

The following procedure may be used to determine the DF for ACSCC; see Figure 10.1.

a) STEP 1—Determine the susceptibility for cracking using Figure 10.1 and Table 10.2 based on the pH of the water, and CO_3 concentration, and knowledge of whether the component was subject to PWHT. Note that 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 10.3.

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 Section 10.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

e) STEP 5—Determine the base DF for ACSCC, D_{fB}^{ACSCC}, using Table 6.3 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 (2.27). 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.

$$D_f^{ACSCC} = \min\left(D_{fB}^{ACSCC} \cdot \left(\max[age, 1.0]\right)^{1.1}, 5000\right) \tag{2.27}$$

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10.7 Nomenclature

age	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

10.8 References

See References [10], [13], [49], [51], [54], [55], [56], [57] (see Appendix D), [58], [59], and [60] in Section 2.2.

10.9 Tables

Table 10.1—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 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 concentration in water	Determine the carbonate 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.

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Table 10.2—Susceptibility to Cracking—ACSCC

pH of Water	Susceptibility to Cracking As a Function of CO_3 Concentration in Water [1]		
	PWHT, Possible Cold Working	No PWHT, Possible Cold Working	
	CO_3 All Concentrations	$CO_3 < 100$ ppm	$CO_3 \geq 100$ ppm
<7.5	None	None	None
≥7.5 to 8.0	None	Low	Medium
≥8.0 to 9.0	None	Low	High
≥9.0	None	High	High

NOTE 1 Traditional alkalinity titration methods (P,M alkalinity) are not effective for measurement of CO_3 in sour water.

Table 10.3—Determination of Severity Index—ACSCC

Susceptibility	Severity Index—S_{VI}
High	1000
Medium	100
Low	10
None	0

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10.10 Figures

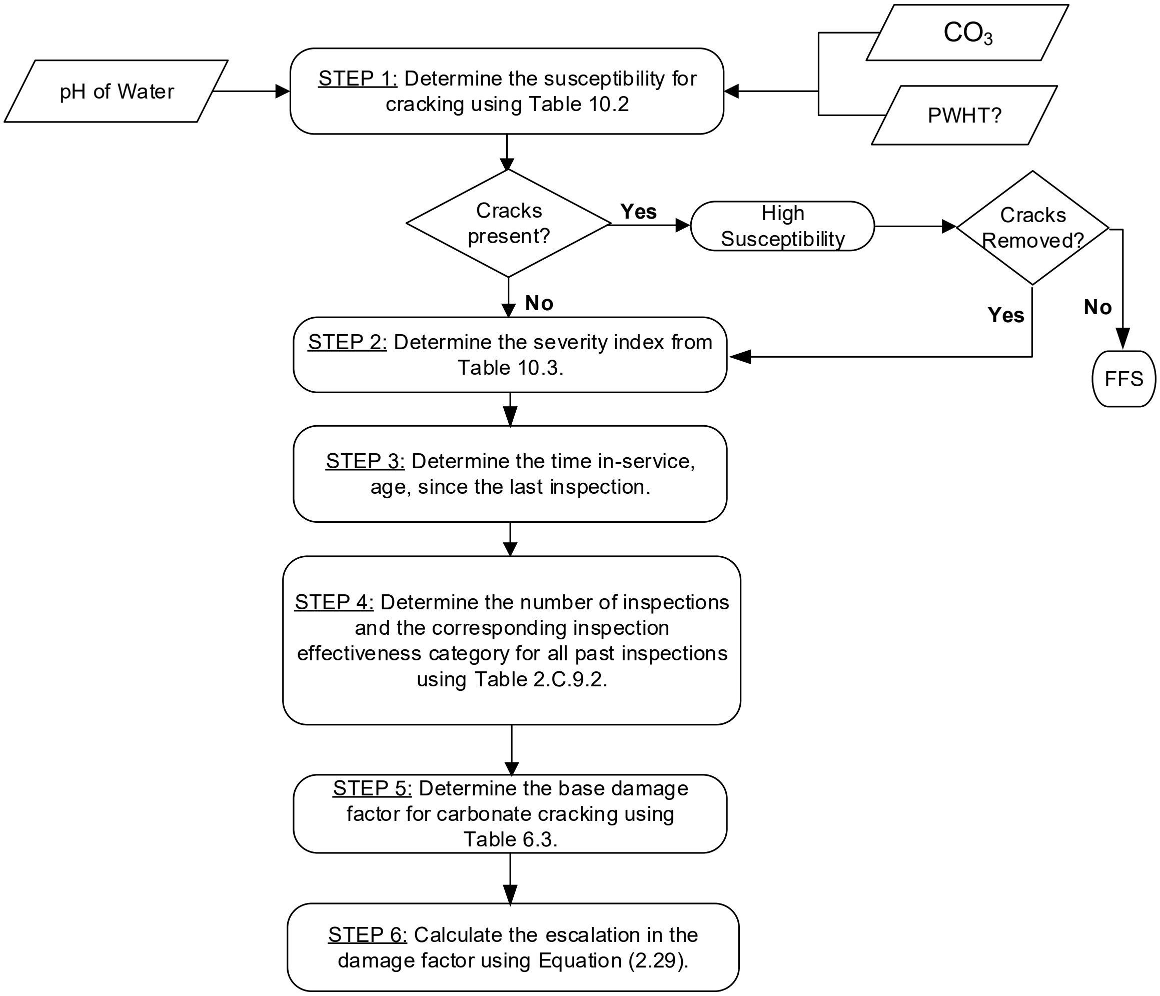

Figure 10.1—Determination of the ACSCC DF

11 SCC DF—Polythionic Acid Stress Corrosion Cracking (PASCC)

11.1 Scope

The DF calculation for components subject to PASCC is covered in this section.

11.2 Description of Damage

PA 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).

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PA 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 427 °C (800 °F). 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.

11.3 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.

11.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the PASCC DF are provided in Table 11.1.

11.5 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].

11.6 Determination of the DF

11.6.1 Overview

A flow chart of the steps required to determine the DF for PASCC is shown in Figure 11.1. The following sections provide additional information and the calculation procedure.

11.6.2 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.C, Table 2.C.9.5.

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 Section 3.4.3.

11.6.3 Calculation of the DF

The following procedure may be used to determine the DF for PASCC; see Figure 11.1.

a) STEP 1—Determine the susceptibility for cracking using Figure 11.1 and Table 11.2 based on the operating temperature and material of construction. Note that a High susceptibility should be used if cracking is confirmed to be present.

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b) STEP 2—Based on the susceptibility in STEP 1, determine the Severity Index, S_{VI}, from Table 11.3.

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 Section 12.9.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

e) STEP 5—Determine the base DF for PASCC, D_{fB}^{PASCC}, using Table 6.3 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 (2.28). 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.

$$D_f^{PASCC} = \min\left(D_{fB}^{PASCC} \cdot \left(\max[age, 1.0]\right)^{1.1}, 5000\right) \tag{2.28}$$

11.7 Nomenclature

age	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

11.8 References

See References [10], [61], [62], [63], [64], [65], [66], [67], [68], [69], [70], [71], and [72] in Section 2.2.

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11.9 Tables

Table 11.1—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, °C (°F)	Determine the maximum operating temperature 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.

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Table 11.2—Susceptibility to Cracking—PASCC

Operating Temperatures <427 °C (800 °F)			
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 ≥427 °C (800 °F)			
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 427 °C (800 °F), then sensitization is present in the as-welded condition only. If the process operating temperature is greater than or equal to 427 °C (800 °F), then sensitization can occur during operation.			

Table 11.3—Determination of Severity Index—PASCC

Susceptibility	**Severity Index—S_{VI}**
High	5000
Medium	500
Low	50
None	0

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11.10 Figures

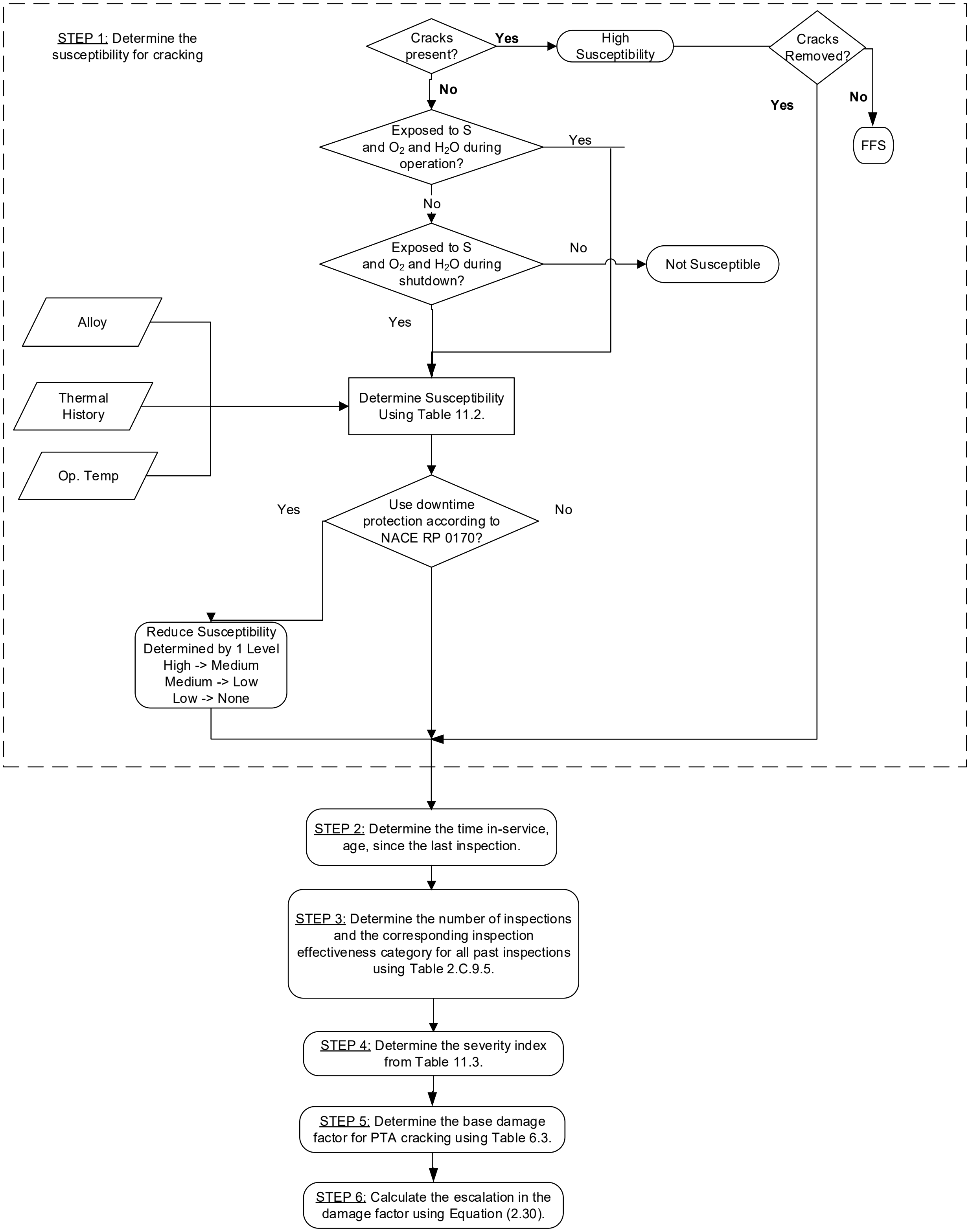

Figure 11.1—Determination of the PASCC DF

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12 SCC DF—Chloride Stress Corrosion Cracking (ClSCC)

12.1 Scope

The DF calculation for components subject to ClSCC is covered in this section.

12.2 Description of Damage

ClSCC of austenitic stainless steels can occur in a chloride-containing aqueous environment. The susceptibility to ClSCC is dependent on the concentration of the chloride ions, the temperature, and other factors outlined in the basic data in Table 12.1. 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 ClSCC susceptibility. ClSCC is more likely to occur at metal temperatures above 66 °C (150 °F).

Examples of common sources of chlorides in refineries and petrochemical plants are as follows.

a) Chloride salts from crude oil, produced water, and ballast water.

b) Water condensed from a process stream (process water).

c) Boiler feed water and stripping system.

d) Catalyst.

e) Insulation.

f) Residue from hydrotest water and other manufacturing operations.

g) Fumes from chemicals containing either organic or inorganic chlorides.

ClSCC may occur during in-service or shutdown periods, if chloride-containing solutions are present, especially at temperatures above 66 °C (150 °F). ClSCC can occur internally (e.g. by wash-up water or fire water). ClSCC is typically transgranular and highly branched. The greatest susceptibility to ClSCC is exhibited by austenitic stainless steels with a nickel content of 8 % (e.g. Type 300 series, 304, 316 stainless steel, etc.). Greater resistance is generally shown by alloys of either lower or higher nickel contents.

Duplex stainless steels with low nickel contents are generally immune to ClSCC, as are alloys with greater than 42 % nickel.

12.3 Screening Criteria

If all of the following are true, then the component should be evaluated for susceptibility to ClSCC.

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 considering upsets and hydrotest water remaining in component, and cooling tower drift (consider both under insulation and process conditions.

c) The operating temperature is above 38 °C (100 °F).

12.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the ClSCC DF are provided in Table 12.1.

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12.5 Basic Assumptions

The main assumption in determining the DF for ClSCC 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].

12.6 Determination of the DF

12.6.1 Overview

A flow chart of the steps required to determine the DF for ClSCC is shown in Figure 12.1. The following sections provide additional information and the calculation procedure.

12.6.2 Inspection Effectiveness

Inspections are ranked according to their expected effectiveness at detecting for ClSCC. Examples of inspection activities that are both intrusive (requires entry into the equipment) and nonintrusive (can be performed externally) are provided in Annex 2.C, Table 2.C.9.6.

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 Section 3.4.3.

12.6.3 Calculation of the DF

The following procedure may be used to determine the DF for ClSCC; see Figure 12.1.

a) STEP 1—Determine the susceptibility for cracking using Figure 12.1 and Table 12.2 based on the operating temperature and concentration of the chloride ions. Note that 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 12.3.

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 Section 12.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

e) STEP 5—Determine the base DF for ClSCC, D_{fB}^{ClSCC}, using Table 6.3 based on the number of inspections and the highest inspection effectiveness determined in STEP 4 and the Severity Index, S_{VI}, from STEP 2.

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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 (2.29). 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.

$$D_f^{ClSCC} = \min\left(D_{fB}^{ClSCC} \cdot \left(\max[age, 1.0]\right)^{1.1}, 5000\right) \tag{2.29}$$

12.7 Nomenclature

age	is the component in-service time since the last cracking inspection or service start date
D_f^{ClSCC}	is the DF for ClSCC
D_{fB}^{ClSCC}	is the base value of the DF for ClSCC
S_{VI}	is the Severity Index

12.8 References

See References [10], [35], [62], and [73] in Section 2.2.

12.9 Tables

Table 12.1—Data Required for Determination of the DF—ClSCC

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, °C (°F)	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.

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Table 12.2—Susceptibility to Cracking—ClSCC

pH ≤ 10				
Temperature (°F)	Susceptibility to Cracking As a Function of Chloride Ion (ppm)			
	1 to 10	11 to 100	101 to 1000	>1000
≤100	Low	Low	Low	Medium
>100 to 150	Low	Medium	Medium	High
>150 to 200	Medium	Medium	High	High
>200 to 300	Medium	High	High	High
>300	High	High	High	High
pH > 10				
Temperature (°F)	Susceptibility to Cracking As a Function of Chloride Ion (ppm)			
	1 to 10	11 to 100	101 to 1000	>1000
≤100	None	None	None	None
>100 to 200	Low	Low	Low	Low
>200 to 300	Low	Low	Low	Medium
>300	Medium	Medium	Medium	High

Table 12.2M—Susceptibility to Cracking—ClSCC

pH ≤ 10				
Temperature (°C)	Susceptibility to Cracking As a Function of Chloride Ion (ppm)			
	1 to 10	11 to 100	101 to 1000	>1000
≤38	Low	Low	Low	Medium
>38 to 66	Low	Medium	Medium	High
>66 to 93	Medium	Medium	High	High
>93 to 149	Medium	High	High	High
>149	High	High	High	High
pH > 10				
Temperature (°C)	Susceptibility to Cracking As a Function of Chloride Ion (ppm)			
	1 to 10	11 to 100	101 to 1000	>1000
≤38	None	None	None	None
>38 to 93	Low	Low	Low	Low
93 to 149	Low	Low	Low	Medium
>149	Medium	Medium	Medium	High

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Table 12.3—Determination of Severity Index—CISCC

Susceptibility	Severity Index—S_{VI}
High	5000
Medium	500
Low	50
None	0

12.10 Figures

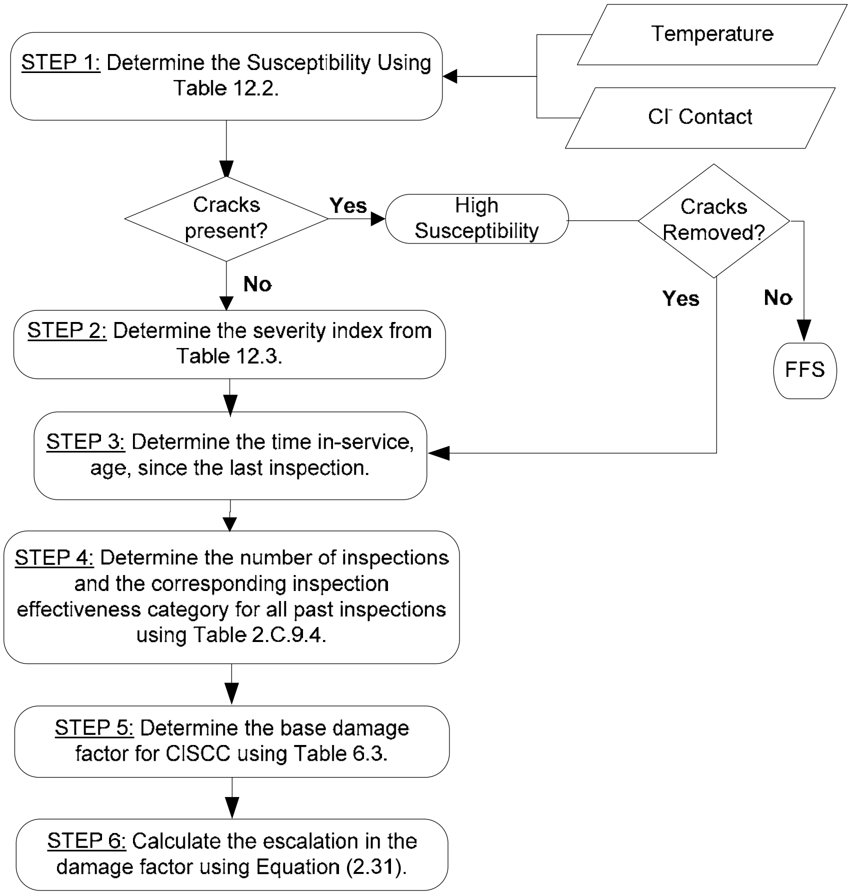

Figure 12.1—Determination of the CISCC DF

13 SCC DF—Hydrogen Stress Cracking in Hydrofluoric Acid (HSC-HF)

13.1 Scope

The DF calculation for components subject to HSC-HF covered in this section.

13.2 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 8) or from exposure to HF. HSC-HF occurs in high-strength (high hardness)

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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 66 °C (150 °F) to approximately 178 °C (350 °F), Alloy 400 is used. Corrosion in 80 % and stronger HF-in-water solutions is equivalent to corrosion in anhydrous hydrofluoric acid (AHF; <200 ppm H_20) 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 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.

13.3 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.

13.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the HSC-HF DF are provided in Table 13.1.

13.5 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].

13.6 Determination of the DF

13.6.1 Overview

A flow chart of the steps required to determine the DF for HSC-HF is shown in Figure 13.1. The following sections provide additional information and the calculation procedure.

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13.6.2 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.C, Table 2.C.9.8.

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 Section 3.4.3.

13.6.3 Calculation of the DF

The following procedure may be used to determine the DF for HSC-HF; see Figure 13.1.

a) STEP 1—Determine the susceptibility for cracking using Figure 13.1 and Table 13.2 based on the maximum Brinnell hardness of weldments and knowledge of whether the component was subject to PWHT. Note that 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 13.3.

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 Section 13.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

e) STEP 5—Determine the base DF for HSC-HF, D_{fB}^{HSC-HF}, using Table 6.3 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 (2.30). 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.

$$D_f^{HSC-HF} = \min\left(D_{fB}^{HSC-HF} \cdot \left(\max[age, 1.0]\right)^{1.1}, 5000\right) \tag{2.30}$$

13.7 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

13.8 References

See References [10], [74], and [75] in Section 2.2.

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13.9 Tables

Table 13.1—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 13.2—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

Table 13.3—Determination of Severity Index—HSC-HF

Susceptibility	Severity Index—S_{VI}
High	100
Medium	10
Low	1
None	0

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13.10 Figures

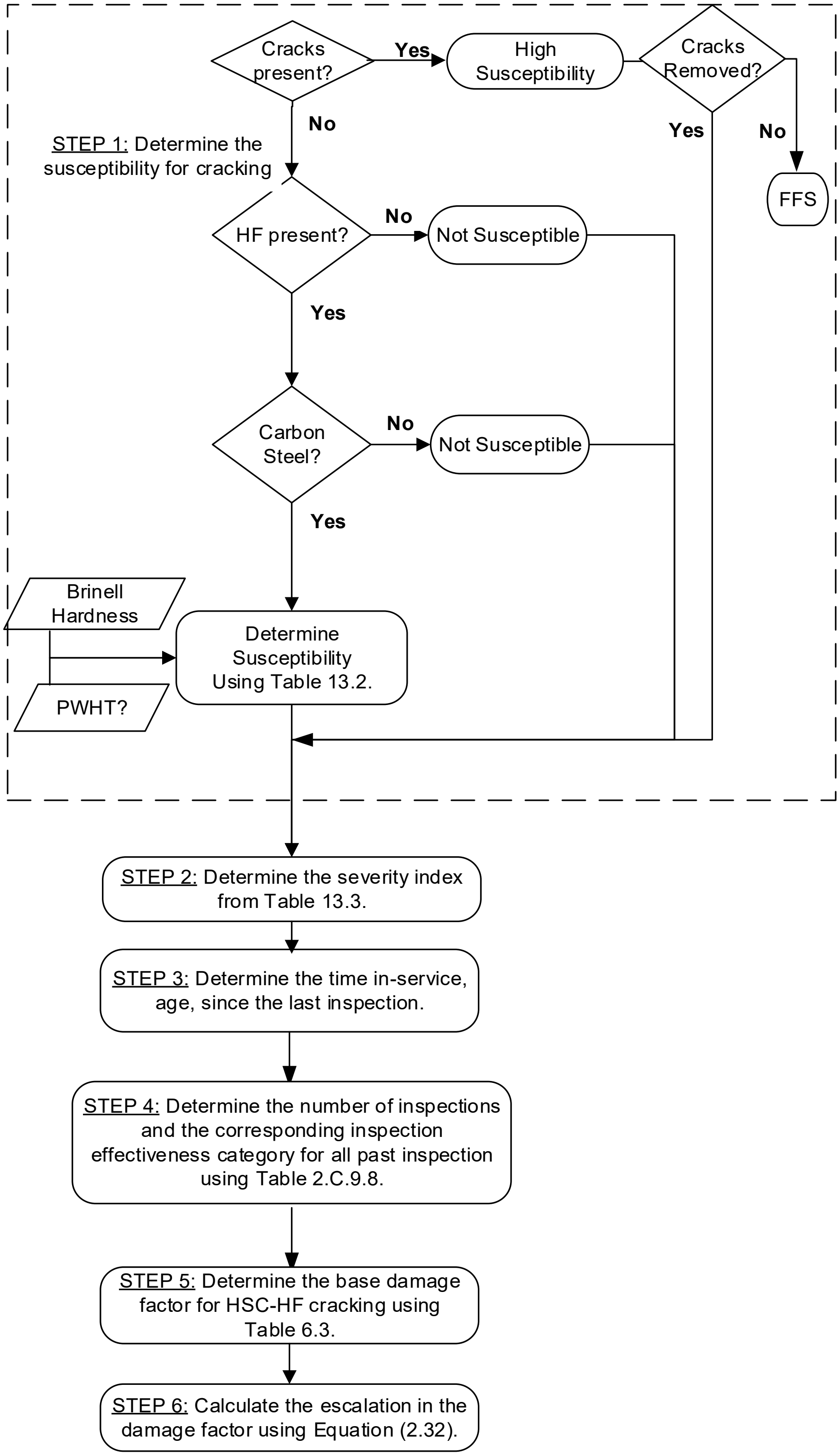

Figure 13.1—Determination of the HSC-HF Cracking DF

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14 SCC DF—Hydrogen-induced Cracking and Stress-oriented Hydrogen-induced Cracking in Hydrofluoric Acid Services (HIC/SOHIC-HF)

14.1 Scope

The DF calculation for components subject to HIC/SOHIC-HF is covered in this section.

14.2 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 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 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.

14.3 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.

14.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the HIC/SOHIC-HF DF are provided in Table 14.1.

14.5 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.

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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 14.4. 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].

14.6 Determination of the DF

14.6.1 Overview

A flow chart of the steps required to determine the DF for HIC/SOHIC-HF is shown in Figure 14.1. The following sections provide additional information and the calculation procedure.

14.6.2 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.C, Table 2.C.9.9.

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 Section 3.4.3.

14.6.3 Adjustment for On-line Monitoring

In addition to inspection, on-line monitoring using hydrogen probes and/or key process variables provides a better understanding of HIC/SOHIC-HF susceptibility. The advantage of on-line 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 on-line 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 on-line monitoring factor of 4 is applied.

14.6.4 Calculation of the DF

The following procedure may be used to determine the DF for HIC/SOHIC-HF; see Figure 14.1.

a) STEP 1—Determine the susceptibility for cracking using Figure 14.1 and Table 14.2 based on the material of construction and knowledge of whether the component was subject to PWHT. Note that 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 14.3. 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.

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d) STEP 4—Determine the number of inspections and the corresponding inspection effectiveness category using Section 14.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

e) STEP 5—Determine the base DF for HIC/SOHIC-HF, $D_{fB}^{HIC/SOHIC-HF}$, using Table 6.3 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 on-line adjustment factor, F_{OM}, from Table 14.4.

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 (2.31). 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 on-line monitoring.

$$D_f^{HIC/SOHIC-HF} = \min\left(\frac{D_{fB}^{HIC/SOHIC-HF} \cdot \left(\max[age, 1.0]\right)^{1.1}}{F_{OM}}, 5000 \right) \tag{2.31}$$

14.7 Nomenclature

age	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 on-line monitoring adjustment factor
S_{VI}	is the Severity Index

14.8 References

See References [10], [74], and [75] in Section 2.2.

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14.9 Tables

Table 14.1—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 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.
On-line 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 14.2—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.

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Table 14.3—Determination of Severity Index—HIC/SOHIC-HF

Susceptibility	Severity Index—S_{VI}
High	100
Medium	10
Low	1
None	0

Table 14.4—On-line Monitoring Adjustment Factors for HIC/SOHIC-HF

On-line Monitoring Method	Adjustment Factors As a Function of On-line 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 on-line monitoring methods. Factors based on the user's experience can be used as a substitute for the values presented in this table.

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14.10 Figures

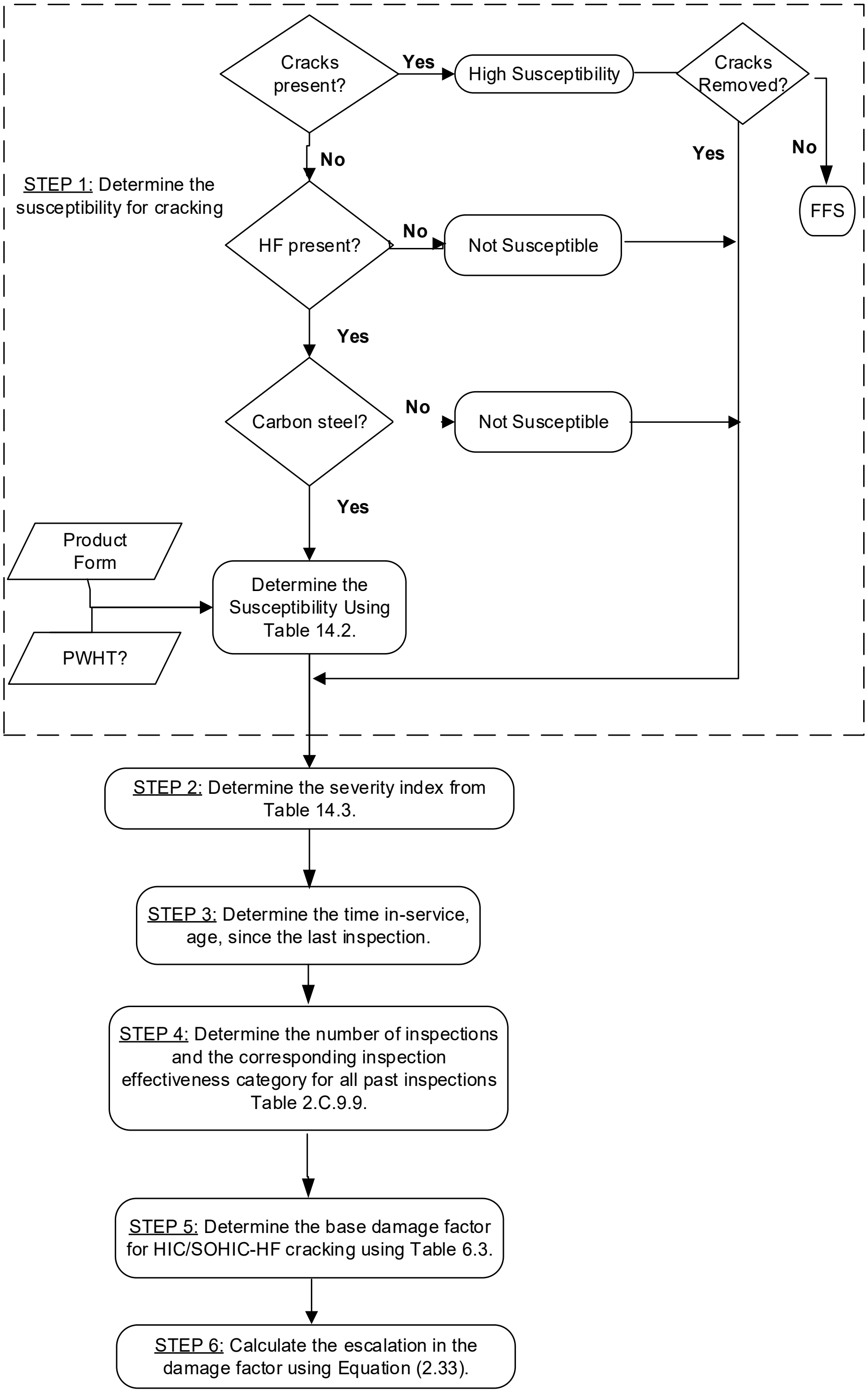

Figure 14.1—Determination of the HIC/SOHIC-HF Cracking DF

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15 External Corrosion DF—Ferritic Component

15.1 Scope

The DF calculation for ferritic components subject to external corrosion is covered in this section.

15.2 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.

15.3 Screening Criteria

If the component is un-insulated 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 −12 °C and 177 °C (10 °F and 350 °F). External corrosion is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture.

f) Systems that do not normally operate between −12 °C and 177 °C (10 °F and 350 °F) 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) Un-insulated nozzles or other protrusions components of insulated equipment in cold service conditions.

15.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the DF for external corrosion are provided in Table 15.1.

15.5 Basic Assumption

The DF for external corrosion is based on the method for general thinning covered in Section 4.

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15.6 Determination of the DF

15.6.1 Overview

A flow chart of the steps required to determine the DF for external corrosion is shown in Figure 15.1. The following sections provide additional information and the calculation procedure.

15.6.2 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. >2250 mm/year (100 in./year)]; frequent deluge testing; highly corrosive industrial atmosphere; in a coastal zone with very high atmospheric chloride content (e.g. >1500 mg/m^2/day).

b) Moderate—Frequently wet (e.g. 30 % to 60 % of time); downwind of a cooling tower; high rainfall [e.g. 1524 to 2250 mm/year (60 to 100 in./year)]; corrosive industrial atmosphere; near the coast with high chloride content in rainwater (e.g. 300 to 1500 mg/m^2/day).

c) Mild—Occasionally wet (e.g. <30 % of time); moderate rainfall [e.g. 762 to 1524 mm/year (20 to 60 in./year)]; low chloride content in rainwater (e.g. 60 to 300 mg/m^2/day).

d) Dry—Very dry or cold zone with very low pollution and time of wetness; low rainfall [e.g. <508 mm/year (<20 in./year)]; inside building (operating above dew point); low chloride content in rainwater (e.g. <60 mg/m^2/day).

15.6.3 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.C, Table 2.C.10.1.

The number and effectiveness categories for inspection history will be used to determine the DF.

15.6.4 Calculation of the DF

The following procedure may be used to determine the DF for external corrosion; see Figure 15.1.

a) STEP 1—Determine the furnished thickness, t, and age, age, for the component from the installation date.

b) STEP 2—Determine the base corrosion rate, C_{rB}, based on the driver and operating temperature using Table 15.2.

c) STEP 3—Calculate the final corrosion rate, C_r, using Equation (2.32).

$$C_r = C_{rB} \cdot \max\left[F_{EQ},\ F_{IF}\right] \tag{2.32}$$

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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.

d) STEP 4—Determine the time in service, age_{tke}, since the last known inspection thickness, t_{rde} (see 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 (2.33).

$$t_{rde} = t - L_e \tag{2.33}$$

NOTE When using Equation (2.33), age_{tke}, is the time in service since L_e was measured.

e) STEP 5—Determine the in-service time, age_{coat}, since the coating has been installed using Equation (2.34).

$$age_{coat} = Calculation\ Date - Coating\ Installation\ Date \tag{2.34}$$

f) STEP 6—Determine coating adjustment, $Coat_{adj}$, using Equations (2.35) through (2.40).

If $age_{tke} \geq age_{coat}$:

$$Coat_{adj} = 0 \qquad \text{No Coating or Poor Coating Quality} \tag{2.35}$$

$$Coat_{adj} = \min\left[5,\ age_{coat}\right] \qquad \text{Medium Coating Quality} \tag{2.36}$$

$$Coat_{adj} = \min\left[15,\ age_{coat}\right] \qquad \text{High Coating Quality} \tag{2.37}$$

If $age_{tke} < age_{coat}$:

$$Coat_{adj} = 0 \qquad \text{No Coating or Poor Coating Quality} \tag{2.38}$$

$$Coat_{adj} = \min\left[5,\ age_{coat}\right] - \min\left[5,\ age_{coat} - age_{tke}\right] \qquad \text{Medium Coating Quality} \tag{2.39}$$

$$Coat_{adj} = \min\left[15,\ age_{coat}\right] - \min\left[15,\ age_{coat} - age_{tke}\right] \qquad \text{High Coating Quality} \tag{2.40}$$

g) STEP 7—Determine the in-service time, age, over which external corrosion may have occurred using Equation (2.41).

$$age = age_{tke} - Coat_{adj} \tag{2.41}$$

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h) STEP 8—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.

i) STEP 9—Determine the A_{rt} parameter using Equation (2.42) based on the age and t_{rde} from STEP 4 and C_r from STEP 3.

$$A_{rt} = \frac{C_r \cdot age}{t_{rde}} \tag{2.42}$$

j) STEP 10—Calculate the flow stress, $FS^{extcorr}$, using S from STEP 8 and Equation (2.43).

$$FS^{extcorr} = \frac{(YS + TS)}{2} \cdot E \cdot 1.1 \tag{2.43}$$

NOTE Use flow stress (FS^{Thin}) at design temperature for conservative results, using the appropriate Equation (2.44) or Equation (2.45).

k) STEP 11—Calculate the strength ratio parameter, SR_P^{Thin}, using Equation (2.44) or (2.45).

1) Use Equation (2.44) with t_{rde} from STEP 3, t_{min} or t_c, S, and E from STEP 8, and $FS^{extcorr}$ from STEP 10.

$$SR_P^{extcorr} = \frac{S \cdot E}{FS^{extcorr}} \cdot \frac{\max(t_{min}, t_c)}{t_{rde}} \tag{2.44}$$

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 (2.45) with t_{rde} from STEP 4 and $FS^{extcorr}$ from STEP 10.

$$SR_P^{extcorr} = \frac{P \cdot D}{\alpha \cdot FS^{extcorr} \cdot t_{rde}} \tag{2.45}$$

where α is the shape factor for the component type. α = 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 (2.44) should be used.

l) STEP 12—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 15.6.2 for past inspections performed during the in-service time (see Section 4.5.5).

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m) STEP 13—Determine the inspection effectiveness factors, $I_1^{extcorr}$, $I_2^{extcorr}$, and $I_3^{extcorr}$, using Equation (2.46), prior probabilities, $Pr_{p1}^{extcorr}$, $Pr_{p2}^{extcorr}$, and $Pr_{p3}^{extcorr}$, from Table 4.5, conditional probabilities (for each inspection effectiveness level), $Co_{p1}^{extcorr}$, $Co_{p2}^{extcorr}$, and $Co_{p3}^{extcorr}$, from 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 12.

$$\begin{aligned}
I_1^{extcorr} &= Pr_{p1}^{extcorr}\left(Co_{p1}^{extcorrA}\right)^{N_A^{extcorr}}\left(Co_{p1}^{extcorrB}\right)^{N_B^{extcorr}}\left(Co_{p1}^{extcorrC}\right)^{N_C^{extcorr}}\left(Co_{p1}^{extcorrD}\right)^{N_D^{extcorr}}\\
I_2^{extcorr} &= Pr_{p2}^{extcorr}\left(Co_{p2}^{extcorrA}\right)^{N_A^{extcorr}}\left(Co_{p2}^{extcorrB}\right)^{N_B^{extcorr}}\left(Co_{p2}^{extcorrC}\right)^{N_C^{extcorr}}\left(Co_{p2}^{extcorrD}\right)^{N_D^{extcorr}}\\
I_3^{extcorr} &= Pr_{p3}^{extcorr}\left(Co_{p3}^{extcorrA}\right)^{N_A^{extcorr}}\left(Co_{p3}^{extcorrB}\right)^{N_B^{extcorr}}\left(Co_{p3}^{extcorrC}\right)^{N_C^{extcorr}}\left(Co_{p3}^{extcorrD}\right)^{N_D^{extcorr}}
\end{aligned}\tag{2.46}$$

p) STEP 14—Calculate the posterior probabilities, $Po_{p1}^{extcorr}$, $Po_{p2}^{extcorr}$, and $Po_{p3}^{extcorr}$, using Equation (2.47) with $I_1^{extcorr}$, $I_2^{extcorr}$, and $I_3^{extcorr}$ in STEP 12.

$$\begin{aligned}
Po_{p1}^{extcorr} &= \frac{I_1^{extcorr}}{I_1^{extcorr}+I_2^{extcorr}+I_3^{extcorr}}\\
Po_{p2}^{extcorr} &= \frac{I_2^{extcorr}}{I_1^{extcorr}+I_2^{extcorr}+I_3^{extcorr}}\\
Po_{p3}^{extcorr} &= \frac{I_3^{extcorr}}{I_1^{extcorr}+I_2^{extcorr}+I_3^{extcorr}}
\end{aligned}\tag{2.47}$$

q) STEP 15—Calculate the parameters, $\beta_1^{extcorr}$, $\beta_2^{extcorr}$, and $\beta_3^{extcorr}$, using Equation (2.48) and assigning $COV_{\Delta t}$ = 0.20, COV_{S_f} = 0.20, and COV_P = 0.05.

$$\begin{aligned}
\beta_1^{extcorr} &= \frac{1-D_{S_1}\cdot A_{rt}-SR_p^{extcorr}}{\sqrt{D_{S_1}{}^2\cdot A_{rt}{}^2\cdot COV_{\Delta t}{}^2+\left(1-D_{S_1}\cdot A_{rt}\right)^2\cdot COV_{S_f}{}^2+(SR_p^{extcorr})^2\cdot COV_P{}^2}},\\
\beta_2^{extcorr} &= \frac{1-D_{S_2}\cdot A_{rt}-SR_p^{extcorr}}{\sqrt{D_{S_2}{}^2\cdot A_{rt}{}^2\cdot COV_{\Delta t}{}^2+\left(1-D_{S_2}\cdot A_{rt}\right)^2\cdot COV_{S_f}{}^2+(SR_p^{extcorr})^2\cdot COV_P{}^2}},\\
\beta_3^{extcorr} &= \frac{1-D_{S_3}\cdot A_{rt}-SR_p^{extcorr}}{\sqrt{D_{S_3}{}^2\cdot A_{rt}{}^2\cdot COV_{\Delta t}{}^2+\left(1-D_{S_3}\cdot A_{rt}\right)^2\cdot COV_{S_f}{}^2+(SR_p^{extcorr})^2\cdot COV_P{}^2}}.
\end{aligned}\tag{2.48}$$

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 [31]. Note that 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 ≤ $COV_{\Delta t}$ ≤ 0.20, with a recommended conservative value of $COV_{\Delta t}$ = 0.20.

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r) STEP 16—Calculate $D_f^{extcorr}$ using Equation (2.49).

$$D_f^{extcorr} = \left[\frac{\left(Po_{p1}^{extcorr} \Phi\left(-\beta_1^{extcorr}\right)\right) + \left(Po_{p2}^{extcorr} \Phi\left(-\beta_2^{extcorr}\right)\right) + \left(Po_{p3}^{extcorr} \Phi\left(-\beta_3^{extcorr}\right)\right)}{1.56\text{E-}04} \right] \tag{2.49}$$

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

15.7 Nomenclature

age	is the in-service time that damage is applied
age_{coat}	is the in-service time since the coating installation
age_{tk}	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
A_{rt}	is the expected metal loss fraction since last inspection
$Coat_{adj}$	is the coating adjustment
C_r	is the corrosion rate
C_{rB}	is the base value of the corrosion rate
CA	is the corrosion allowance
Co_{p1}^{extcor}	is the conditional probability of inspection history inspection effectiveness for damage state 1
Co_{p2}^{extcor}	is the conditional probability of inspection history inspection effectiveness for damage state 2
Co_{p3}^{extcor}	is the conditional probability of inspection history inspection effectiveness for damage state 3
COV_P	is the pressure variance
COV_{S_f}	is the flow stress variance
$COV_{\Delta t}$	is the thinning variance
D	is the component inside diameter
D_{S_1}	is the corrosion rate factor for damage state 1
D_{S_2}	is the corrosion rate factor for damage state 2
D_{S_3}	is the corrosion rate factor for damage state 3
$D_f^{extcorr}$	is the DF for external corrosion
$Date$	is the coating installation adjusted date

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$DF_p^{extcorr}$	is the DF parameter defined as the ratio of hoop stress to flow stress
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
$N_A^{extcorr}$	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.) used to calculate the limit state function for POF
$Po_{p1}^{extcorr}$	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
$SR_P^{extcorr}$	is the strength ratio parameter defined as the ratio of hoop stress to flow stress

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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 applicable construction code
t_{rde}	is the measured thickness reading from previous inspection with respect to wall loss associated with external corrosion
TS	is the tensile strength
YS	is the yield strength
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

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15.8 Tables

Table 15.1—Data Required for Determination of the DF—External Corrosion

Required Data	Comments
Driver	The drivers for external corrosion. See Section 15.6.2 for driver descriptions and selection.
Corrosion rate (mm/yr:mpy)	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.
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.	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 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.

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Table 15.2—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 Part 2, Section 15.6.2 for explanation of drivers.

NOTE 2 Interpolation may be used for intermediate values of temperature.

NOTE 3 A time-weighted average corrosion rate may be used for systems that are in intermittent service or that operate at 2 or more temperatures.

Table 15.2M—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 Part 2, Section 15.6.2 for explanation of drivers.

NOTE 2 Interpolation may be used for intermediate values of temperature.

NOTE 3 A time-weighted average corrosion rate may be used for systems that are in intermittent service or that operate at 2 or more temperatures.

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15.9 Figures

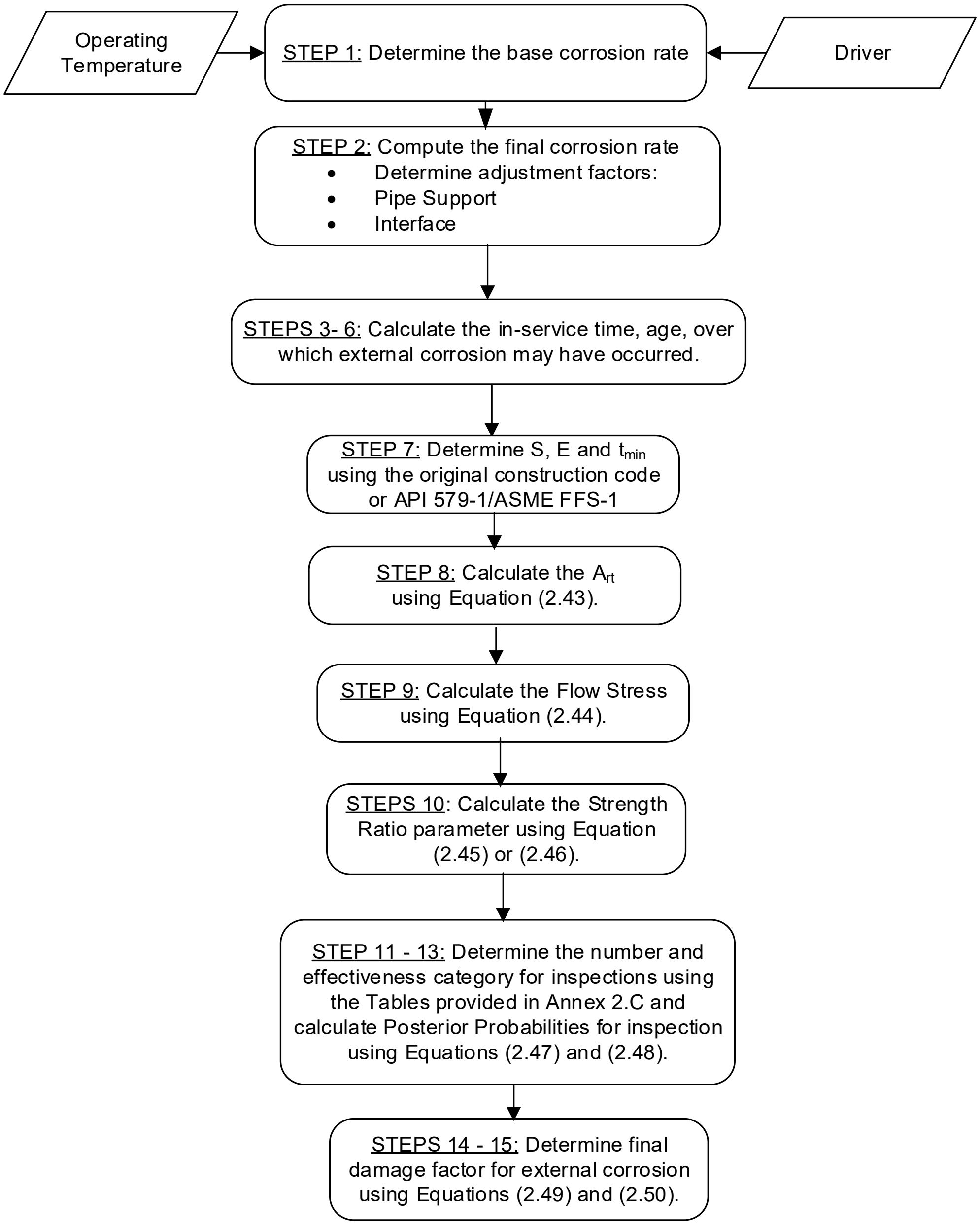

Figure 15.1—Determination of the External Corrosion DF

16 Corrosion Under Insulation (CUI) DF—Ferritic Component

16.1 Scope

The DF calculation for ferritic components subject to CUI is covered in this section.

16.2 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

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generally occurs in the temperature range between −12 °C and 175 °C (10 °F and 350 °F), with the temperature range of 77 °C to 110 °C (170 °F to 230 °F) 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.

16.3 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.

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The following are some examples of other suspect areas that should be considered when performing inspection for CUI.

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) Insulation jacketing seams located on top of horizontal vessels or improperly lapped or sealed insulation systems,

f) 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 re-evaporation of atmospheric moisture.

g) Carbon steel systems that normally operate in services above 175 °C (350 °F) but are in intermittent service or are subjected to frequent outages.

h) 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.

i) Systems in which vibration has a tendency to inflict damage to insulation jacketing providing paths for water ingress.

j) Steam traced systems experiencing tracing leaks, especially at tubing fittings beneath the insulation.

k) Systems with deteriorated coating and/or wrappings.

l) Cold service equipment consistently operating below the atmospheric dew point.

m) 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.

16.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the DF for CUI are provided in Table 16.1.

16.5 Basic Assumption

The DF for CUI is based on the method for general thinning covered in Section 4.

16.6 Determination of the DF

16.6.1 Overview

A flow chart of the steps required to determine the DF for CUI is shown in Figure 16.1. The following sections provide additional information and the calculation procedure.

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16.6.2 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.C, Table 2.C.10.3.

The number and category of the highest effective inspection will be used to determine the DF**.**

16.6.3 Calculation of the DF

The following procedure may be used to determine the DF for CUI; see Figure 16.1.

a) STEP 1—Determine the furnished thickness, t, and age, age, for the component from the installation date.

b) STEP 2—Determine the base corrosion rate, C_{rB}, based on the driver and operating temperature using Table 16.2.

c) STEP 3—Compute the final corrosion rate using Equation (2.50).

$$C_r = C_{rB} \cdot F_{INS} \cdot F_{CM} \cdot F_{IC} \cdot \max\left[F_{EQ},\ F_{IF}\right] \tag{2.50}$$

The adjustment factors are determined as follows.

1) Adjustment for insulation type; F_{INS}, based on Table 16.3.

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, $F_{IF} = 1$.

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d) STEP 4—Determine the time in service, age_{tk}, since the last known thickness, t_{rde} (see Section 4.5.5). The t_{rde} is the starting thickness with respect to wall loss associated with external corrosion (see 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 (2.51).

$$t_{rde} = t - L_e \tag{2.51}$$

NOTE When using Equation (2.51), age_{tk} is the time in service since L_e was measured.

e) STEP 5—Determine the in-service time, age_{coat}, since the coating has been installed using Equation (2.52).

$$age_{coat} = Calculation\ Date - Coating\ Installation\ Date \tag{2.52}$$

f) STEP 6—Determine the coating adjustment, $Coat_{adj}$, using Equations (2.53) through (2.58).

If $age_{tke} \geq age_{coat}$:

$$Coat_{adj} = 0 \qquad \text{No Coating or Poor Coating Quality} \tag{2.53}$$

$$Coat_{adj} = \min\left[5,\ age_{coat}\right] \qquad \text{Medium Coating Quality} \tag{2.54}$$

$$Coat_{adj} = \min\left[15,\ age_{coat}\right] \qquad \text{High Coating Quality} \tag{2.55}$$

If $age_{tke} < age_{coat}$:

$$Coat_{adj} = 0 \qquad \text{No Coating or Poor Coating Quality} \tag{2.56}$$

$$Coat_{adj} = \min\left[5,\ age_{coat}\right] - \min\left[5,\ age_{coat} - age_{tk}\right] \qquad \text{Medium Coating Quality} \tag{2.57}$$

$$Coat_{adj} = \min\left[15,\ age_{coat}\right] - \min\left[15,\ age_{coat} - age_{tk}\right] \qquad \text{High Coating Quality} \tag{2.58}$$

g) STEP 7—Determine the in-service time, age, over which CUI may have occurred using Equation (2.59).

$$age = age_{tke} - Coat_{adj} \tag{2.59}$$

h) STEP 8—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.

i) STEP 9—Determine the A_{rt} parameter using Equation (2.60) based on the age and t_{rde} from STEP 4, C_r from STEP 3.

$$A_{rt} = \frac{C_r \cdot age}{t_{rde}} \tag{2.60}$$

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j) STEP 10—Calculate the flow stress, FS^{CUIF}, using E from STEP 8 and Equation (2.61).

$$FS^{CUIF} == \frac{(YS+TS)}{2}\cdot E\cdot 1.1 \tag{2.61}$$

NOTE Use flow stress (FS^{Thin}) at design temperature for conservative results, using the appropriate Equation (2.62) or Equation (2.63).

k) STEP 11—Calculate strength ratio parameter, SR_P^{Thin}, using Equation (2.62) or Equation (2.63).

1) Use Equation (2.62) with t_{rde} from STEP 4, S, E, and t_{min} or t_c from STEP 8, and flow stress FS^{CUIF} from STEP 10.

$$SR_P^{CUIF} = \frac{S\cdot E}{FS^{CUIF}}\cdot\frac{\min(t_{min},t_c)}{t_{rde}} \tag{2.62}$$

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) Use Equation (2.63) with t_{rde} from STEP 3 and flow stress FS^{CUIF} from STEP 10.

$$SR_P^{CUIF} = \frac{P\cdot D}{\alpha\cdot FS^{CUIF}\cdot t_{rde}} \tag{2.63}$$

where α is the shape factor for the component type. α = 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 (2.62) should be used.

l) STEP 12—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 16.6.2 for all past inspections.

m) STEP 13—Determine the inspection effectiveness factors, I_1^{CUIF}, I_2^{CUIF}, and I_3^{CUIF}, using Equation (2.64), prior probabilities, Pr_{p1}^{CUIF}, Pr_{p2}^{CUIF}, and Pr_{p3}^{CUIF}, from Table 5.6, conditional probabilities (for each inspection effectiveness level), $Co_{p1}^{CUIF}, Co_{p2}^{CUIF}$ and Co_{p3}^{CUIF}, from Table 5.7, 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 12.

$$\begin{aligned}
I_1^{CUIF} &= Pr_{p1}^{CUIF}\left(Co_{p1}^{CUIFA}\right)^{N_A^{CUIF}}\left(Co_{p1}^{CUIFB}\right)^{N_B^{CUIF}}\left(Co_{p1}^{CUIFC}\right)^{N_C^{CUIF}}\left(Co_{p1}^{CUIFD}\right)^{N_D^{CUIF}}\\
I_2^{CUIF} &= Pr_{p2}^{CUIF}\left(Co_{p2}^{CUIFA}\right)^{N_A^{CUIF}}\left(Co_{p2}^{CUIFB}\right)^{N_B^{CUIF}}\left(Co_{p2}^{CUIFC}\right)^{N_C^{CUIF}}\left(Co_{p2}^{CUIFD}\right)^{N_D^{CUIF}}\\
I_3^{CUIF} &= Pr_{p3}^{CUIF}\left(Co_{p3}^{CUIFA}\right)^{N_A^{CUIF}}\left(Co_{p3}^{CUIFB}\right)^{N_B^{CUIF}}\left(Co_{p3}^{CUIFC}\right)^{N_C^{CUIF}}\left(Co_{p3}^{CUIFD}\right)^{N_D^{CUIF}}
\end{aligned} \tag{2.64}$$

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n) STEP 14—Calculate the posterior probabilities, Po_{p1}^{CUIF}, Po_{p2}^{CUIF}, and Po_{p3}^{CUIF}, using Equation (2.65) with I_1^{CUIF}, I_2^{CUIF} and I_3^{CUIF} in STEP 13.

$$Po_{p1}^{CUIF}=\frac{I_1^{CUIF}}{I_1^{CUIF}+I_2^{CUIF}+I_3^{CUIF}}$$
$$Po_{p2}^{CUIF}=\frac{I_2^{CUIF}}{I_1^{CUIF}+I_2^{CUIF}+I_3^{CUIF}} \tag{2.65}$$
$$Po_{p3}^{CUIF}=\frac{I_3^{CUIF}}{I_1^{CUIF}+I_2^{CUIF}+I_3^{CUIF}}$$

o) STEP 15—Calculate the parameters, β_1^{CUIF}, β_2^{CUIF}, and β_3^{CUIF}, using Equation (2.66) and assigning $COV_{\Delta t}$ = 0.20, COV_{S_f} = 0.20, and COV_p = 0.05.

$$\beta_1^{CUIF}=\frac{1-D_{S_1}\cdot A_{rt}-SR_p^{CUIF}}{\sqrt{D_{S_1}^2\cdot A_{rt}^2\cdot COV_{\Delta t}^2+\left(1-D_{S_1}\cdot A_{rt}\right)^2\cdot COV_{S_f}^2+(SR_p^{CUIF})^2\cdot COV_P^2}},$$
$$\beta_2^{CUIF}=\frac{1-D_{S_2}\cdot A_{rt}-SR_p^{CUIF}}{\sqrt{D_{S_2}^2\cdot A_{rt}^2\cdot COV_{\Delta t}^2+\left(1-D_{S_2}\cdot A_{rt}\right)^2\cdot COV_{S_f}^2+(SR_p^{CUIF})^2\cdot COV_P^2}}, \tag{2.66}$$
$$\beta_3^{CUIF}=\frac{1-D_{S_3}\cdot A_{rt}-SR_p^{CUIF}}{\sqrt{D_{S_3}^2\cdot A_{rt}^2\cdot COV_{\Delta t}^2+\left(1-D_{S_3}\cdot A_{rt}\right)^2\cdot COV_{S_f}^2+(SR_p^{CUIF})^2\cdot COV_P^2}}.$$

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 [31]. Note that 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 ≤ $COV_{\Delta t}$ ≤ 0.20, with a recommended conservative value of $COV_{\Delta t}$ = 0.20.

p) STEP 16—Calculate D_f^{CUIF} using Equation (2.67).

$$D_f^{CUIF}=\left[\frac{\left(Po_{p1}^{CUIF}\,\Phi\left(-\beta_1^{CUIF}\right)\right)+\left(Po_{p2}^{CUIF}\,\Phi\left(-\beta_2^{CUIF}\right)\right)+\left(Po_{p3}^{CUIF}\,\Phi\left(-\beta_3^{CUIF}\right)\right)}{\text{1.56E-04}}\right] \tag{2.67}$$

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

16.7 Nomenclature

age	is the in-service time that damage is applied
age_{coat}	is the in-service time since the coating installation
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
A_{rt}	is the expected metal loss fraction since last inspection

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$Coat_{adj}$	is the coating adjustment
C_r	is the corrosion rate
C_{rB}	is the base value of the corrosion rate
CA	is the corrosion allowance
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
COV_P	is the pressure variance
COV_{S_f}	is the flow stress variance
$COV_{\Delta t}$	is the thinning variance
D	is the component inside diameter
D_{S_1}	is the corrosion rate factor for damage state 1
D_{S_2}	is the corrosion rate factor for damage state 2
D_{S_3}	is the corrosion rate factor for damage state 3
D_f^{CUIF}	is the DF for CUI for ferritic components
$Date$	is the coating installation adjusted date
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
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
N_A^{CUIF}	is the number of A level inspections

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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
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
TS	is the tensile strength
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_3^{CUIF}	is the β reliability indices for damage state 3
Φ	is the standard normal cumulative distribution function

16.8 References

See Reference [76] in Section 2.2.

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16.9 Tables

Table 16.1—Data Required for Determination of the DF—CUI

Required Data	Comments
Insulation type	Type of insulation per Table 17.3.
Driver	The drivers for external CUI corrosion. See Section 15.6.2 for driver descriptions and selection.
Corrosion rate (mm/yr:mpy)	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 that 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.

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Table 16.1—Data Required for Determination of the DF—CUI (Continued)

Required Data	Comments
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.
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 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 16.2—Corrosion Rates for Calculation of the DF—CU

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 Part 2, Section 15.6.2 for explanation of drivers.

NOTE 2 Interpolation may be used for intermediate values of temperature.

NOTE 3 A time-weighted average corrosion rate may be used for systems that are in intermittent service or that operate at 2 or more temperatures.

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Table 16.2M—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 Part 2, Section 15.6.2 for explanation of drivers.

NOTE 2 Interpolation may be used for intermediate values of temperature.

NOTE 3 A time-weighted average corrosion rate may be used for systems that are in intermittent service or that operate at 2 or more temperatures.

Table 16.3—Corrosion Rate Adjustment Factor for Insulation Type

Insulation Type	Adjustment Factor, F_{INS}
Unknown/unspecified	1.25
Foamglass	0.75
Pearlite	1.0
Fiberglass	1.25
Mineral wool	1.25
Calcium silicate	1.25
Asbestos	1.25

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16.10 Figures

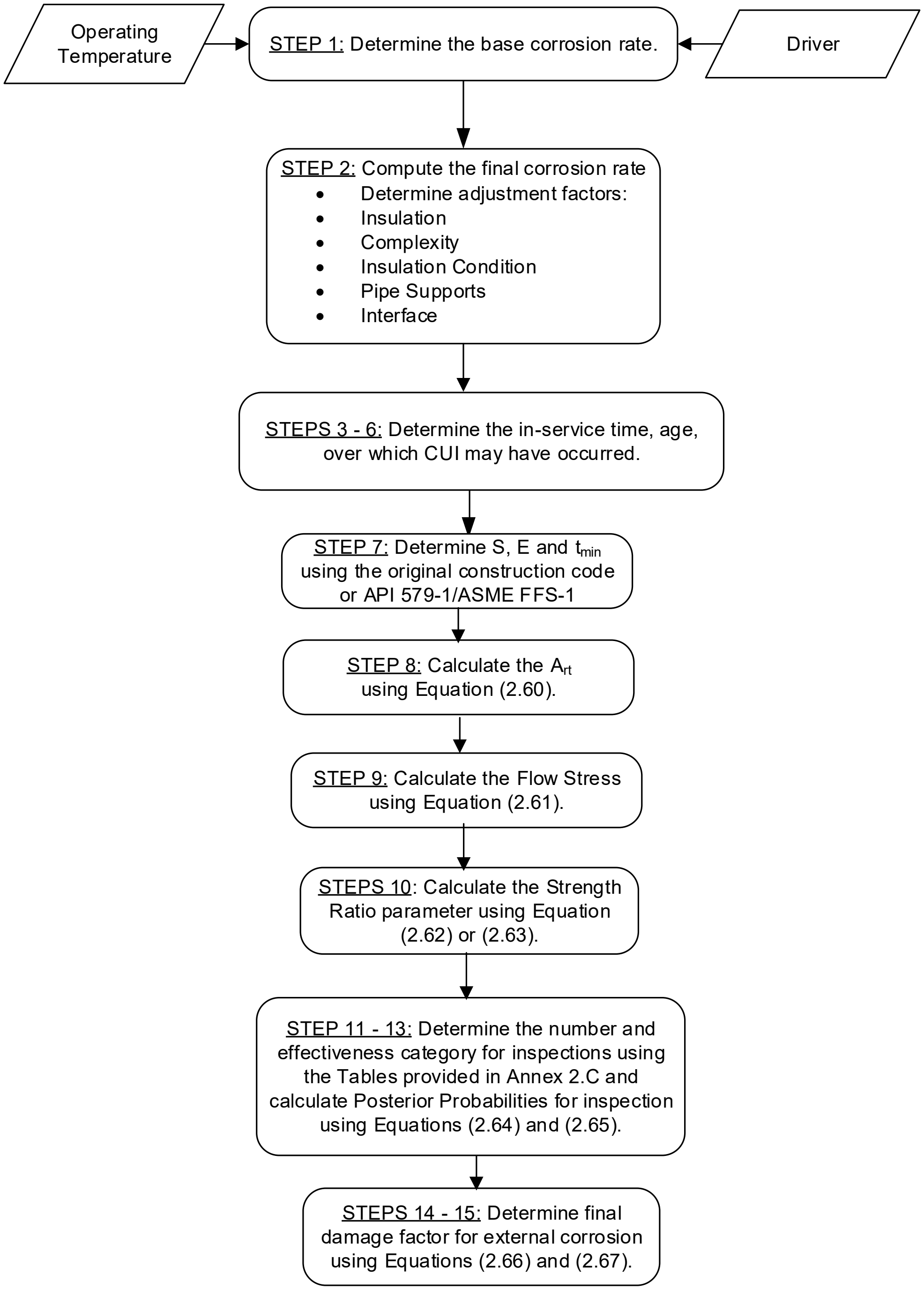

Figure 16.1—Determination of the CUI DF

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17 External Chloride Stress Corrosion Cracking (ExtClSCC) DF—Austenitic Component

17.1 Scope

The DF calculation for un-insulated austenitic stainless steel components subject to ExtClSCC is covered in this section.

17.2 Description of Damage

Un-insulated austenitic stainless steel components located in process plants may be subject to ExtClSCC (see Section 12) 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 50 °C to 150 °C (120 °F to 300 °F). Heating and/or cooling intermittently into this range will present an opportunity for ClSCC to occur.

Mitigation of ExtClSCC is best accomplished by preventing chloride accumulation on the stainless steel surface. On un-insulated 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, un-insulated stainless steels could be protected externally by a coating. If intermittent conditions exist, then both normal operating and intermittent temperatures should be considered.

17.3 Screening Criteria

If all of the following are true, then the component should be evaluated for susceptibility to ExtClSCC.

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 50 °C and 150 °C (120 °F and 300 °F) or the system heats or cools into this range intermittently.

17.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the DF for ExtClSCC are provided in Table 17.1.

17.5 Basic Assumption

The DF for ExtClSCC is based on the method in Section 12.

17.6 Determination of the DF

17.6.1 Overview

A flow chart of the steps required to determine the DF for ExtClSCC is shown in Figure 17.1. The following sections provide additional information and the calculation procedure.

17.6.2 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.C, Table 2.C.10.2.

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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 Section 3.4.3.

17.6.3 Calculation of the DF

The following procedure may be used to determine the DF for ExtClSCC; see Figure 17.1.

a) STEP 1—Determine the susceptibility using Table 17.2 based on the driver and the operating temperature. Note that a High susceptibility should be used if cracking is confirmed to be present.

b) STEP 2—Determine the Severity Index, S_{VI}, using Table 17.3 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 (2.68).

$$age_{coat} = Calculation\ Date - Coating\ Installation\ Date \tag{2.68}$$

e) STEP 5—Determine the coating adjustment, $Coat_{adj}$, using Equations (2.69) through (2.74).

If $age_{crack} \geq age_{coat}$:

$$Coat_{adj} = 0 \qquad \text{No Coating or Poor Coating Quality} \tag{2.69}$$

$$Coat_{adj} = \min\left[5,\ age_{coat}\right] \qquad \text{Medium Coating Quality} \tag{2.70}$$

$$Coat_{adj} = \min\left[15,\ age_{coat}\right] \qquad \text{High Coating Quality} \tag{2.71}$$

If $age_{crack} < age_{coat}$:

$$Coat_{adj} = 0 \qquad \text{No Coating or Poor Coating Quality} \tag{2.72}$$

$$Coat_{adj} = \min\left[5,\ age_{coat}\right] - \min\left[5,\ age_{coat} - age_{crack}\right] \qquad \text{Medium Coating Quality} \tag{2.73}$$

$$Coat_{adj} = \min\left[15,\ age_{coat}\right] - \min\left[15,\ age_{coat} - age_{crack}\right] \qquad \text{High Coating Quality} \tag{2.74}$$

f) STEP 6—Determine the in-service time, age, over which ExtClSCC may have occurred using Equation (2.75).

$$age = age_{crack} - Coat_{adj} \tag{2.75}$$

g) STEP 7—Determine the number of inspections performed with no cracking detected or cracking was repaired and the corresponding inspection effectiveness category using Section 17.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.

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h) STEP 8—Determine the base DF for ExtClSCC, $D_{fB}^{ext-ClSCC}$, using Table 6.3 based on the number of inspections and the highest inspection effectiveness determined in STEP 7 and the Severity Index, S_{VI}, from STEP 2.

i) STEP 9—Calculate the escalation in the DF based on the time in service since the last inspection using the age from STEP 6 and Equation (2.76). 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.

$$D_f^{ext-ClSCC} = \min\left(D_{fB}^{ext-ClSCC} \cdot \left(\max[age, 1.0]\right)^{1.1}, 5000\right) \tag{2.76}$$

17.7 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 ClSCC inspection
$Coat_{adj}$	is the coating adjustment
$D_f^{ext-ClSCC}$	is the DF for ExtClSCC
$D_{fB}^{ext-ClSCC}$	is the base value of the DF for ExtClSCC
S_{VI}	is the Severity Index

17.8 Tables

Table 17.1—Data Required for Determination of the DF—External ClSCC

Required Data	Comments
Driver	The drivers for ExtClSCC. See Section 15.6.2 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, °C (°F)	Determine the expected operating temperature (consider normal and non-normal operating conditions).

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Table 17.2—SCC Susceptibility—External ClSCC

Operating Temperature		SCC Susceptibility As a Function of Driver [1]			
°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 1 Driver is defined as the atmospheric condition causing the SCC.

Table 17.3—Severity Index—External ClSCC

Susceptibility	Severity Index—S_{VI}
High	50
Medium	10
Low	1
None	0

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17.9 Figures

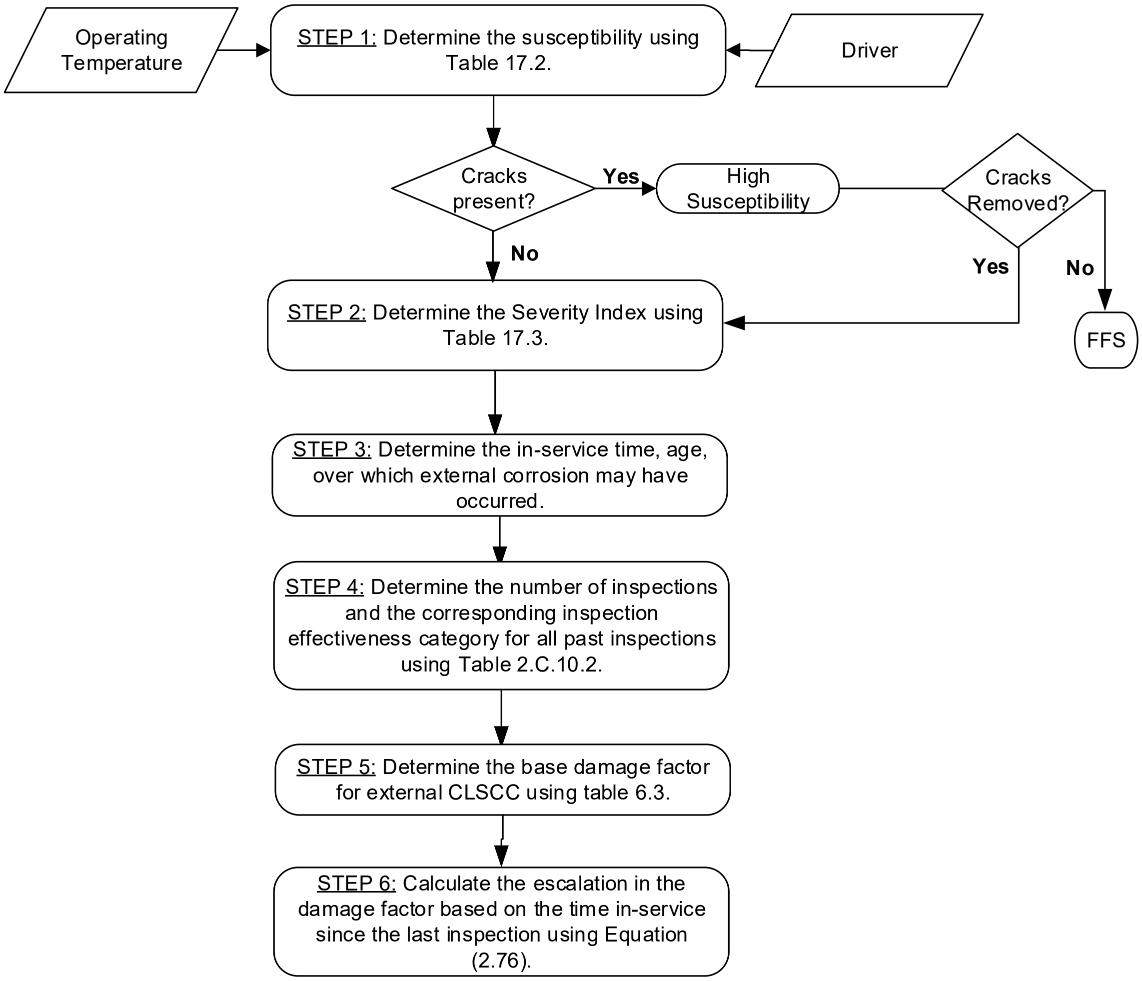

Figure 17.1—Determination of the External CISCC DF

18 External CUI CISCC DF—Austenitic Component

18.1 Scope

The DF calculation for insulated austenitic stainless steel components subject to CUI CISCC is covered in this section.

18.2 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

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protection. However, wrapping of the stainless steel with aluminum foil that serves as both a barrier coating and a cathodic protection (CP) anode has also proven to be effective.

CUI damage in austenitic stainless steels occurs at temperatures between 50 °C and 175 °C (120 °F and 350 °F) 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 ExtClSCC 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 ClSCC to occur.

18.3 Screening Criteria

If all of the following are true, then the component should be evaluated for susceptibility to CUI ClSCC.

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 50 °C and 150 °C (120 °F and 300 °F) or intermittently operated in this range.

18.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the DF for CUI ClSCC are provided in Table 18.1.

18.5 Basic Assumption

The DF for external CUI ClSCC is based on the method in Section 12.

18.6 Determination of the DF

18.6.1 Overview

A flow chart of the steps required to determine the DF for external CUI ClSCC is shown in Figure 18.1. The following sections provide additional information and the calculation procedure.

18.6.2 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.C, Table 2.C.10.4.

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 Section 3.4.3.

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18.6.3 Calculation of the DF

The following procedure may be used to determine the DF for CUI ClSCC; see Figure 18.1. Note that a high susceptibility should be used if cracking is known to be present.

a) STEP 1—Determine the susceptibility using Table 18.2 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 that a high susceptibility should be used if cracking is confirmed to be present.

b) STEP 2—Determine the Severity Index, S_{VI}, using Table 17.3, 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 (2.77).

$$age = Calculation\ Date - Coating\ Installation\ Date \tag{2.77}$$

e) STEP 5—Determine the coating adjustment, $Coat_{adj}$, using Equations (2.78) through (2.83).

If $age_{crack} \geq age_{coat}$:

$$Coat_{adj} = 0 \quad \text{No Coating or Poor Coating Quality} \tag{2.78}$$

$$Coat_{adj} = \min\left[5,\ age_{coat}\right] \quad \text{Medium Coating Quality} \tag{2.79}$$

$$Coat_{adj} = \min\left[15,\ age_{coat}\right] \quad \text{High Coating Quality} \tag{2.80}$$

If $age_{crack} < age_{coat}$:

$$Coat_{adj} = 0 \quad \text{No Coating or Poor Coating Quality} \tag{2.81}$$

$$Coat_{adj} = \min\left[15,\ age_{coat}\right] - \min\left[15,\ age_{coat} - age_{crack}\right] \quad \text{High Coating Quality} \tag{2.82}$$

$$Coat_{adj} = \min\left[5,\ age_{coat}\right] - \min\left[5,\ age_{coat} - age_{crack}\right] \quad \text{Medium Coating Quality} \tag{2.83}$$

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f) STEP 6—Determine the in-service time, age, over which external CUI ClSCC may have occurred using Equation (2.84).

$$age = age_{crack} - Coat_{adj} \tag{2.84}$$

g) STEP 7—Determine the number of inspections performed with no cracking detected or cracking was repaired and the corresponding inspection effectiveness category using Section 18.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.

h) STEP 8—Determine the base DF for CUI ClSCC, $D_{fB}^{CUI-ClSCC}$, using Table 6.3 based on the number of inspections and the highest inspection effectiveness determined in STEP 7 and the Severity Index, S_{VI}, from STEP 2.

i) STEP 9—Calculate the escalation in the DF based on the time in service since the last inspection using the age from STEP 6 and Equation (2.85). 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.

$$D_{f}^{CUI-ClSCC} = \min\left(D_{fB}^{CUI-ClSCC} \cdot \left(\max[age, 1.0]\right)^{1.1}, 5000\right) \tag{2.85}$$

18.7 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 ClSCC inspection
$Coat_{adj}$	is the coating adjustment
$D_{f}^{CUI-ClSCC}$	is the DF for CUI ClSCC
$D_{fB}^{CUI-ClSCC}$	is the base value of the DF for CUI ClSCC
S_{VI}	is the Severity Index

18.8 References

See Reference [76] in Section 2.2.

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18.9 Tables

Table 18.1—Data Required for Determination of the DF—CUI CISCC

Required Data	Comments
Driver	The drivers for CUI ClSCC. See Section 15.6.2 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 that 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, °C (°F)	Determine the highest operating temperature expected during operation (consider normal and non-normal operating conditions).

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Table 18.2—SCC Susceptibility—CUI CISCC

Operating Temperature		SCC Susceptibility As a Function of Driver [1]			
°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 1 Driver is defined as the atmospheric condition causing the SCC.

18.10 Figures

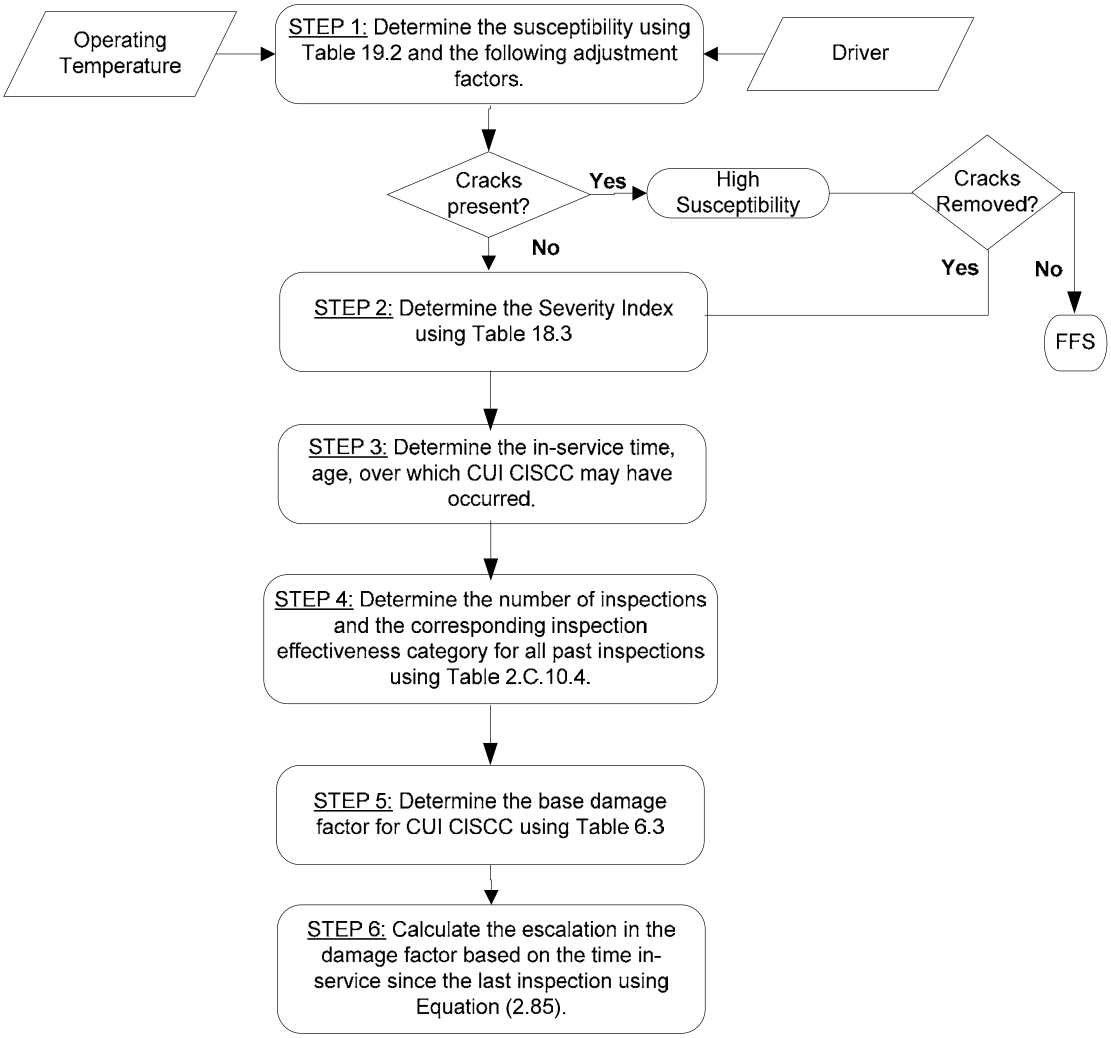

Figure 18.1—Determination of the CUI CISCC DF

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19 High Temperature Hydrogen Attack (HTHA) DF

19.1 Scope

The DF calculation for carbon steel, C-½ Mo, and Cr-Mo low alloy steel components subject to HTHA is covered in this section.

19.2 Description of Damage

HTHA occurs in carbon steel, C-½ 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, H_2, must dissociate to form atomic hydrogen, H, which can diffuse through steel.

$$H_2 \Leftrightarrow 2H \qquad \text{(hydrogen dissociation)}$$

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.

$$4H + MC \Leftrightarrow CH_4 + M$$

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-½ 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 Fe_3C 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.

19.3 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.

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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*—is being revised. 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–user to flag components potentially affected by HTHA (see Section 19.4) 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 19.4;

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–user'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.

19.4 Screening Criteria for Carbon and C-½ 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-½ Mo, or a Cr-Mo low alloy steel (such as ½ Cr-½ Mo, 1 Cr-½ Mo, 1¼ Cr-½ Mo, 2¼ Cr-1 Mo, 3 Cr-1 Mo, 5 Cr-½ Mo, 7 Cr-1 Mo, and 9 Cr-1 Mo).

b) The operating temperature is greater than 177 °C (350 °F).

c) The operating hydrogen partial pressure is greater than 0.345 MPa (50 psia).

19.5 Required Data

The basic data required for analysis are provided in Table 4.1, and the specific data required for determination of the DF for HTHA are provided in Table 19.1.

19.6 Determination of the Damage Factor

19.6.1 Overview

A flow chart of the steps required to determine the DF for HTHA is shown in Figure 19.2. The following sections provide additional information and the calculation procedure.

19.6.2 Inspection Effectiveness

Currently there is no level of inspection effectiveness (LoIE) for HTHA damage.

19.6.3 Calculation of the Damage Factor

The following procedure may be used to determine the DF for HTHA; see Figure 19.2.

a) STEP 1—Determine the material of construction, exposure temperature, T, and the exposure hydrogen partial pressure, P_{H_2}.

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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 re-evaluated 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-½ Mo Alloy Steels.

      a) If the exposure temperature is >177 °C (350 °F) and the exposure hydrogen partial pressure is >0.345 MPa (50 psia), assign a high susceptibility to HTHA.

      b) If exposure temperature is ≤177 °C (350 °F) and the exposure hydrogen partial pressure is ≤0.345 MPa (50 psia), assign HTHA susceptibility to None.

   2) For All Other Cr-Mo Low Alloy Steels.

      a) If the exposure temperature is >177 °C (>350 °F) and exposure hydrogen partial pressure is >0.345 MPa (>50 psia), calculate ΔT proximity to the API 941 curve using T and $P_{H_2}$from STEP 1. Assign HTHA susceptibility using Figure 19.1.

      Note that the approach used in Figure 19.1 is an example guideline using 27.7 °C (50 °F) increments. The 27.7 °C (50 °F) increments were used to represent relative changes in susceptibility. It is the owner–user'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 19.2 based on the susceptibility from STEP 2 or STEP 3.

19.6.4 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–user may choose more conservative guidelines by increasing the susceptibilities in Table 19.2.

19.7 Nomenclature

D_f^{HTHA}	is the DF for HTHA
P_{H_2}	is the hydrogen partial pressure, MPa (psia)
T	is the operating temperature, °C (°F)

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19.8 Tables

Table 19.1—Data Required for Determination of Susceptibility to HTHA

Required Data	Comments
Material of construction	The component generic construction material (e.g. carbon steel, C-½ Mo, 2 ¼ 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, °C (°F)	The temperature of exposure.

Table 19.2—DF—HTHA

Susceptibility	DF
Damage Observed	5000
High Susceptibility	5000
Medium Susceptibility	2000
Low Susceptibility	100
No Susceptibility	0

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19.9 Figures

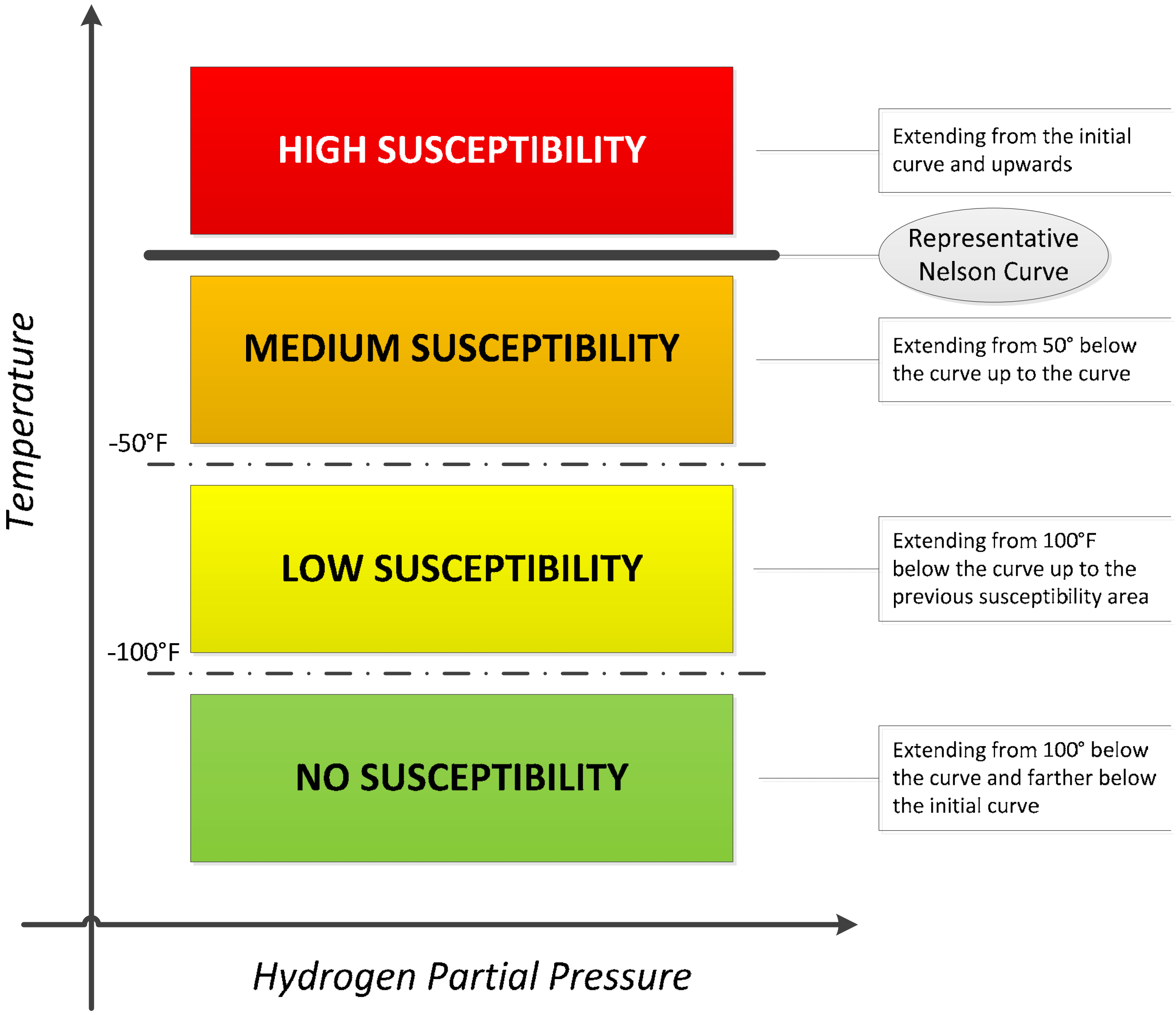

Figure 19.1—Example of HTHA Susceptibility Rankings for Cr-Mo Low Alloy Steels

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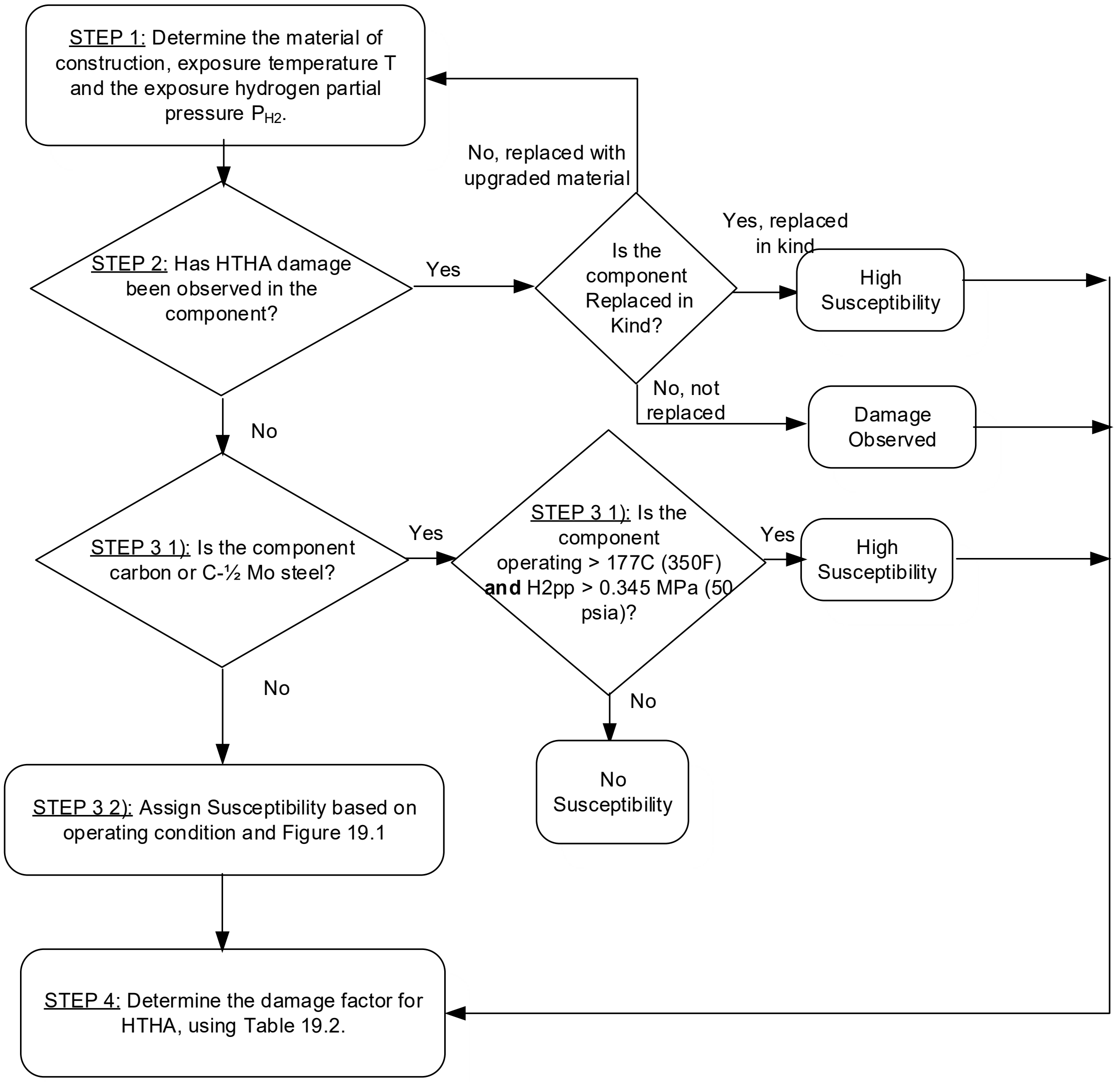

Figure 19.2—Determination of the HTHA DF

20 Brittle Fracture DF

20.1 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 21.

20.2 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.

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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 149 °C (300 °F).

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.

20.3 Screening Criteria

If both of the following are true, then the component should be evaluated for susceptibility to brittle fracture.

a) The material is carbon steel or a low alloy steel; see Table 20.1.

b) 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.

20.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the DF for brittle fracture are provided in Table 20.2.

20.5 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.

20.6 Determination of the DF

20.6.1 Overview

A flow chart of the steps required to determine the DF for brittle fracture is shown in Figure 20.1. The following sections provide additional information and the calculation procedure.

20.6.2 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 pre-existing 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 pre-existing 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.

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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.

20.6.3 Calculation of the DF

The following procedure may be used to determine the DF for brittle fracture; see Figure 20.1.

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 Part 3, API 579-1/ASME FFS-1.

c) STEP 3—Determine the reference temperature, T_{ref}, using the material yield strength, YS, from Table 20.3 and ASME Exemption Curve from Table 20.1, 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 20.4 or Table 20.5 based on the component PWHT condition and $CET - T_{ref}$ from STEP 4.

f) STEP 6—Determine the DF, D_f^{brit}, using Equation (2.86).

$$D_f^{brit} = D_{fb}^{brit} \cdot F_{SE} \tag{2.86}$$

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 12.7 mm (0.5 in.) 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 343 °C (650 °F).

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 −29 °C (−20 °F) if it is a pressure vessel or −104 °C (−155 °F) if it is a piping circuit.

5) The nominal uncorroded thickness is not greater than 50.8 mm (2 in.).

6) Cyclic service, fatigue, or vibration service is not a design requirement per design code.

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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.

20.7 Nomenclature

CET	is the critical exposure temperature as defined in API 579-1/ASME FFS-1, °C (°F)
D^{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	is the component thickness, mm (in.)
T_{MAT}	is the MAT as defined in API 579-1/ASME FFS-1, °C (°F)
T_{MDMT}	is the MDMT as defined by construction code, °C (°F)
T_{ref}	is the reference temperature as defined in API 579-1/ASME FFS-1, °C (°F)
YS	is the material yield strength, MPa (ksi)

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20.8 Tables

Table 20.1—Assignment of Materials to the Material Temperature Exemption Curves

Curve	Material [1, 2, 6]
A	1. All carbon and all low alloy steel plates, structural shapes, and bars not listed in Curves B, C, and D below. 2. 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. 3. The following specifications for obsolete materials: A7, A10, A30, A70, A113, A149, A150. [3] 4. The following specifications for obsolete materials from the 1934 edition of the ASME Code, Section VIII: S1, S2, S25, S26, and S27. [4] 5. A201 and A212 unless it can be established that the steel was produced by a fine-grain practice. [5]
B	1. 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. 2. 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. 3. All pipe, fittings, forgings, and tubing not listed for Curves C and D below. 4. 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. 5. A201 and A212 if it can be established that the steel was produced by a fine-grain practice.
C	1. 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. 2. All material of Curve B if produced to fine-grain practice and normalized and not listed for Curve D below.

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Table 20.1—Assignment of Materials to the Material Temperature Exemption Curves (Continued)

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 *API Code for Unfired Pressure Vessels* (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 Code 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 *API Code for Unfired Pressure Vessels*.

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 20.2—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, °C (°F)	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).

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Table 20.3—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

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Table 20.3M—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

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Table 20.4—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 20.4M—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	0.9	1.1	1.2
44	0.0	0.0	0.0	0.8	1.1	2	2	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

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Table 20.5—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 20.5M—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

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20.9 Figures

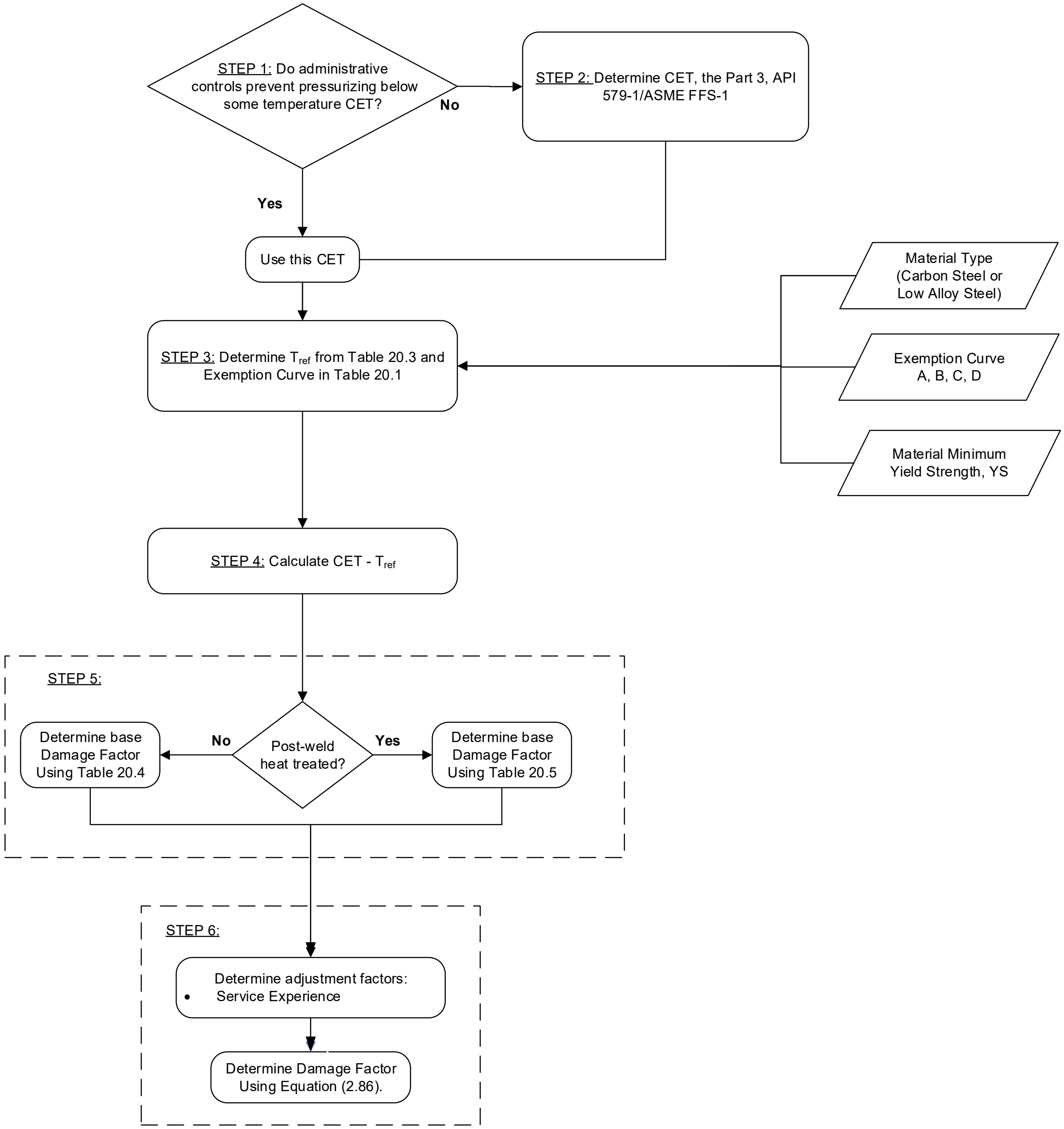

Figure 20.1—Determination of the Brittle Fracture DF

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21 Low Alloy Steel Embrittlement Damage Factor

21.1 Scope

The DF calculation for low alloy Cr-Mo steel components subject to embrittlement is covered in this section.

21.2 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 343 °C to 577 °C (650 °F to 1070 °F). 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 149 °C to 177 °C (300 °F to 350 °F) 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 2.25 Cr-1Mo and 3 Cr-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 (2.87) and Equation (2.88). 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.

$$\text{J-factor} = (\%\text{Si} + \%\text{Mn}) \cdot (\%\text{P} + \%\text{Sn}) \cdot 10^{4} \tag{2.87}$$

$$\text{X-bar} = (10\%\text{P} + 5\%\text{Sb} + 4\%\text{Sn} + \%\text{As}) \cdot 100 \tag{2.88}$$

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.

21.3 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 343 °C and 577 °C (650 °F and 1070 °F).

21.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the DF for low alloy steel embrittlement are provided in Table 21.1.

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21.5 Basic Assumption

Low alloy steel embrittlement is evaluated in the same way as brittle fracture (see Section 20.2) except that a shift in the reference temperature is made to account for embrittlement.

21.6 Determination of the Damage Factor

21.6.1 Overview

A flow chart of the steps required to determine the DF for low alloy steel embrittlement is shown in Figure 21.1. The following sections provide additional information and the calculation procedure.

21.6.2 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.

21.6.3 Calculation of the Damage Factor

The following procedure may be used to determine the DF for low alloy steel embrittlement; see Figure 21.1.

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_{MPT} as estimated by the process engineer, including upsets.

c) STEP 3—Determine the reference temperature, T_{ref}, from Table 20.3 using material yield strength, YS, and the material specification from Table 20.1 [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 (2.89) where age is the operating time in hours and SCE is the specified change in $FATT$.

$$\Delta FATT = 0.67 \cdot \left(\log\left[age - 0.91 \right] \cdot SCE \right) \qquad (2.89)$$

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3) Determined by chemical composition correlations. Use the chemical composition to determine the J-factor or X-bar factor using Equation (2.87) and Equation (2.88). 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 (2.90) and Equation (2.91), respectively.

$$\Delta FATT = -77.321 + (0.57570 \cdot \text{J-factor}) - (5.5147 \cdot (10^{4}) \times (\text{J-factor}^{2})) \tag{2.90}$$

$$\Delta FATT = -87.335 + (11.437 \cdot \text{X-bar}) - (0.1472 \cdot (\text{X-bar}^{2})) \tag{2.91}$$

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): 66 °C (150 °F);
- third generation equipment (1981 to 1987): 121 °C (250 °F);
- second generation equipment (1973 to 1980): 149 °C (300 °F);
- first generation equipment (1965 to 1972): 177 °C (350 °F).

e) STEP 5—Calculate $T_{ref} + \Delta FATT$ using T_{ref} from STEP 3 and $\Delta FATT$ from STEP 4.

f) STEP 6—Calculate the DF, D_f^{tempe}, using Table 20.4 or Table 20.5 based on the component PWHT condition and where $T_{ref} + \Delta FATT$ is from STEP 5.

NOTE Use $T_{MPT} - (T_{ref} + \Delta FATT)$ in place of $CET - T_{ref}$ with T_{MPT} from STEP 1 or STEP 2, as applicable.

21.7 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, °C (°F)
T_{MPT}	is the minimum pressurization temperature, °C (°F)
T_{ref}	is the reference temperature, °C (°F)
YS	is the material yield strength
$\Delta FATT$	is the change in the fracture appearance transition temperature, °C for equations in this section

21.8 References

See References [77], [78], [79], [80], [81], [82], [83], and [84] in Section 2.2.

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21.9 Table

Table 21.1—Data Required for Determination of the DF—Low Alloy Steel Embrittlement

Required Data	Comments
Impact test temperature, °C (°F)	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, °C (°F)	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.
$\Delta FATT$, °C (°F)	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-1M0 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 (SCE) test.
SCE specified delta temperature, °C (°F)	The delta temperature specified for SCE tests.

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21.10 Figures

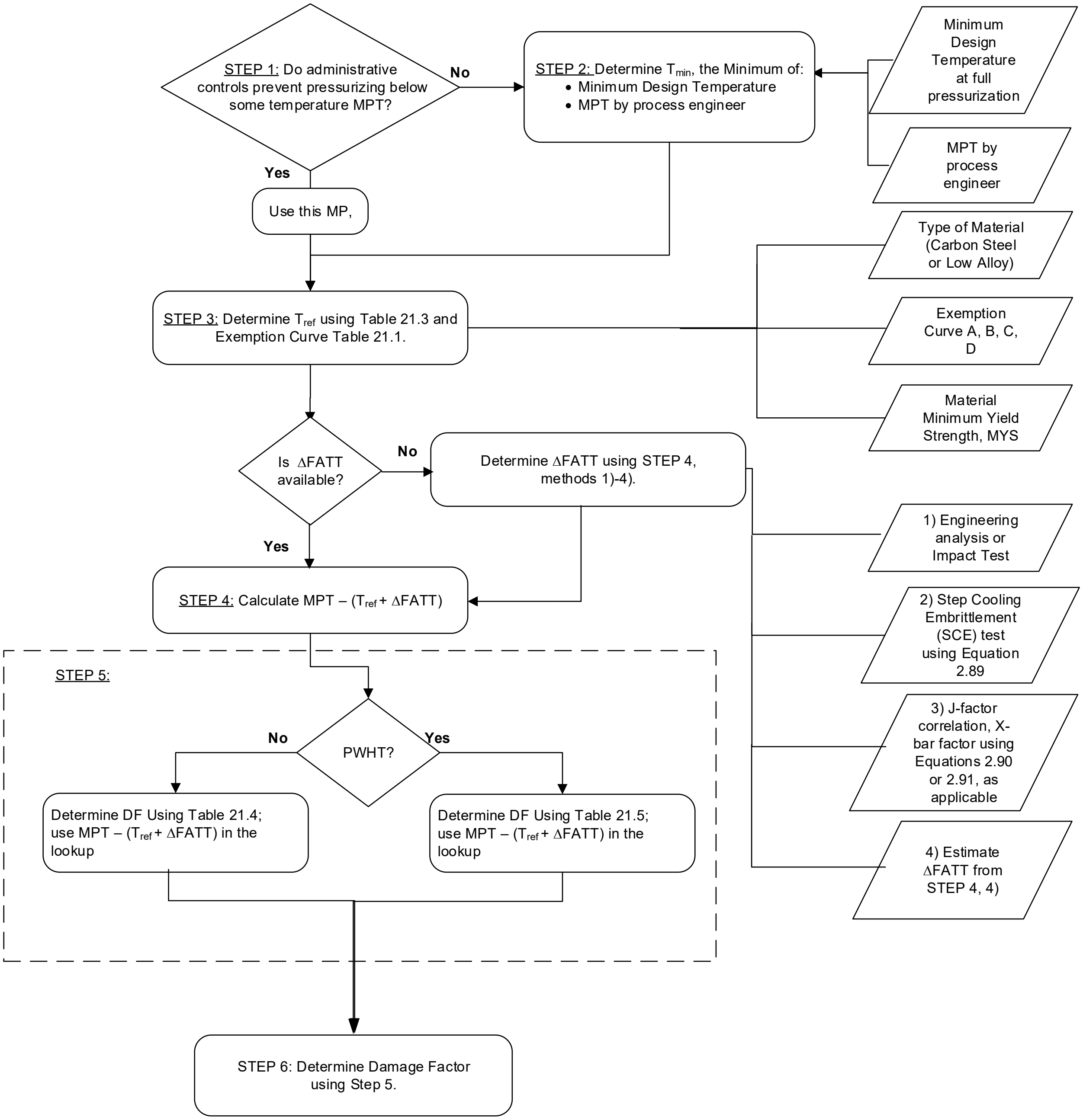

Figure 21.1—Determination of the Low Alloy Steel Embrittlement DF

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22 885 °F Embrittlement DF

22.1 Scope

The DF calculation for components subject to 885 °F embrittlement is covered in this section.

22.2 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 371 °C and 538 °C (700 °F and 1000 °F). 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 474 °C (885 °F), 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 760 °C to 816 °C (1400 °F to 1500 °F), so this may not be practical for many components.

22.3 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 371 °C and 566 °C (700 °F and 1050 °F).

22.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the DF for 885 °F embrittlement are provided in Table 22.1.

22.5 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 22.2 that have been exposed to temperatures in the 371 °C to 538 °C (700 °F to 1000 °F) range are affected.

API 579-1/ASME FFS-1 [10] recommends that for embrittled materials, the toughness should be determined by the K_{Ir} (fracture arrest) curves, truncated at 38 °C (100 °F). 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 10 °C to 38 °C (50 °F to 100 °F) range.

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22.6 Determination of the Damage Factor

22.6.1 Overview

A flow chart of the steps required to determine the DF for 885 °F embrittlement is shown in Figure 22.1. The following sections provide additional information and the calculation procedure.

22.6.2 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.

22.6.3 Calculation of the DF

The following procedure may be used to determine the DF for 885 °F embrittlement; see Figure 22.1.

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_{ref} = 28 °C (80 °F) unless the actual ductile to brittle transition temperature is known.

d) STEP 4—Determine $T_{min} - T_{ref}$, 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^{885F} , using Table 22.3 based on $T_{min} - T_{ref}$ from STEP 4.

22.7 Nomenclature

D_f^{885F}	is the DF for 885 °F embrittlement
T_{min}	is the minimum temperature, °C (°F)
T_{ref}	is the reference temperature, °C (°F)

22.8 References

See References [85] and [86] in Section 2.2.

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22.9 Tables

Table 22.1—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, °C (°F)	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}, °C (°F)	The original transition temperature.

Table 22.2—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 22.3—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

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22.10 Figures

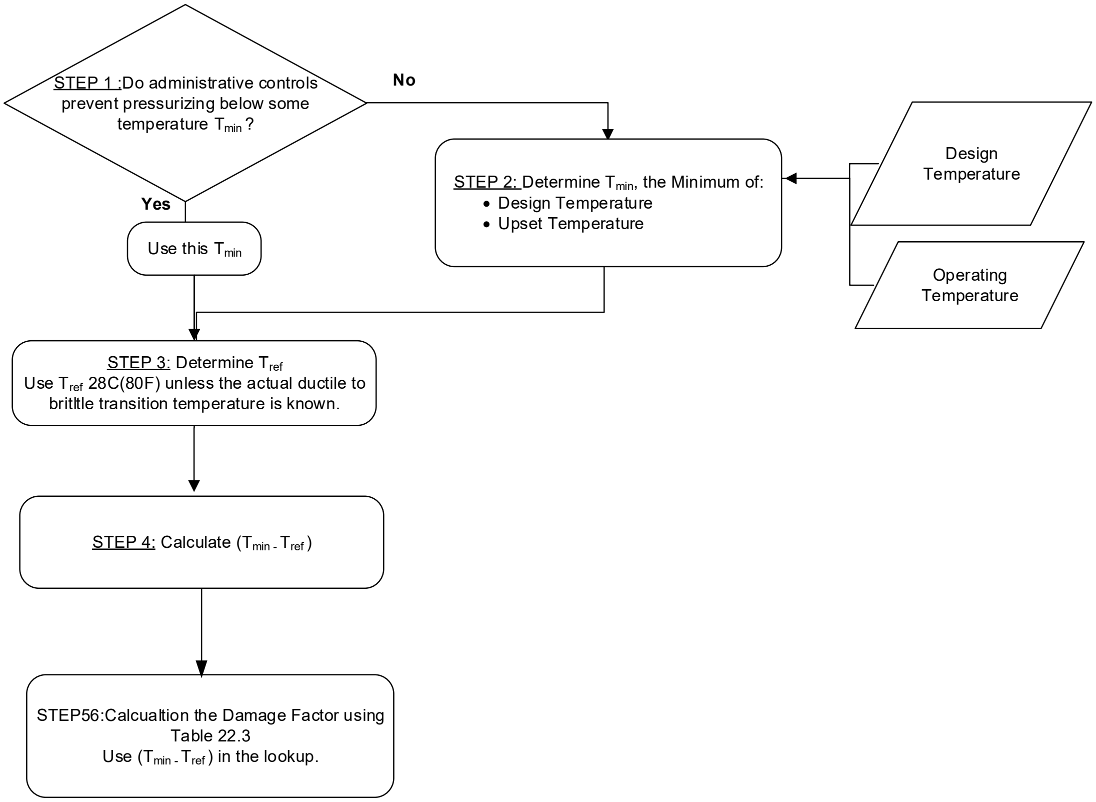

Figure 22.1—Determination of the 885 °F Embrittlement DF

23 Sigma Phase Embrittlement DF

23.1 Scope

The DF calculation for components subject to sigma phase embrittlement is covered in this section.

23.2 Description of Damage

Sigma phase is a hard, brittle intermetallic compound of iron and chromium with an approximate composition of $Fe_{0.6}Cr_{0.4}$. It occurs in ferritic (Fe-Cr), martensitic (Fe-Cr), and austenitic (Fe-Cr-Ni) stainless steels when exposed to temperatures in the range of 593 °C to 927 °C (1100 °F to 1700 °F). 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 747 °C (1377 °F). 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 691 °C (1275 °F). Sigma is unstable at temperatures above 899 °C (1650 °F), and austenitic stainless steel components can be de-sigmatized by solution annealing at 1066 °C (1950 °F) for 4 hours followed by a water quench.

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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 538 °C (1000 °F) 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 53 joules at 649 °C (39 ft-lb at 1200 °F). This would be considered adequate for most steels, but is much less than the 258 joules (190 ft-lb) 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 649 °C (1200 °F). 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 23.2 summarizes impact property data found for Type 304 and 321 stainless steels.

23.3 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 between 593 °C and 927 °C (1100 °F and 1700 °F).

23.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the DF for sigma phase embrittlement are provided in Table 23.1.

23.5 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 $330\ \text{MPa}\sqrt{\text{m}}\ (300\ \text{ksi}\sqrt{\text{in}}.)$.

The references were searched for additional test data, which were scarce and exhibited considerable scatter. The test data found are shown in Table 23.2. 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).

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23.6 Determination of the DF

23.6.1 Overview

A flow chart of the steps required to determine the DF for sigma phase embrittlement is shown in Figure 23.1. The following sections provide additional information and the calculation procedure.

23.6.2 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.

23.6.3 Calculation of the DF

The following procedure may be used to determine the DF for sigma phase embrittlement; see Figure 23.1.

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 23.3 based on T_{min} from STEP 1 and the estimated % sigma from STEP 2.

23.7 Nomenclature

D_f^{sigma}	is the DF for sigma phase embrittlement
T_{min}	is the minimum temperature, °C (°F)

23.8 References

See References [77], [85], [87], [88], [89], [90], [91], [92], [93], [94], and [95] in Section 2.2.

23.9 Tables

Table 23.1—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, °C (°F)	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 (≥5 %, <10 %) High (≥10 %)

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Table 23.2—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 23.3—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

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23.10 Figures

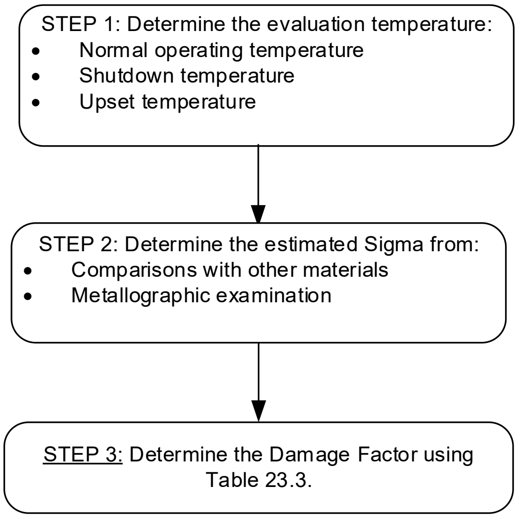

Figure 23.1—Determination of the Sigma Phase Embrittlement DF

24 Piping Mechanical Fatigue DF

24.1 Scope

The DF calculation for piping components subject to mechanical fatigue is covered in this section.

24.2 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 a management of change program can reduce the POF.

24.3 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 15.24 m (50 ft) 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.

24.4 Required Data

The basic component data required for analysis are given in Table 4.1, and the specific data required for determination of the DF for mechanical fatigue are provided in Table 24.1.

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24.5 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.

24.6 Determination of the DF

24.6.1 Overview

A flow chart of the steps required to determine the DF for mechanical fatigue is shown in Figure 24.1. The following sections provide additional information and the calculation procedure.

24.6.2 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.

a) Visual examination of pipe supports to assure that all supports are functioning properly (i.e. they are actually supporting the pipe).

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b) 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.

c) 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.

d) 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.

e) Surface inspection methods [penetrant testing (PT), MT] can be effective in a focused and frequent inspection plan.

f) 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.

g) 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.

h) Visual inspection of a unit during transient conditions and different operating scenarios (e.g. start-ups, shutdowns, upsets, etc.) looking for intermittent vibrating conditions.

i) Checking for audible sounds of vibration emanating from piping components such as control valves and fittings.

24.6.3 Calculation of the DF

The following procedure may be used to determine the DF for mechanical fatigue; see Figure 24.1.

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

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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 15.24 m (50 ft) 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 (2.92).

$$D_{fB}^{mfat} = \max\left[D_{fB}^{PF}, \left(D_{fB}^{AS} \cdot F_{fB}^{AS}\right), D_{fB}^{CF}\right] \tag{2.92}$$

f) STEP 6—Determine the final value of the DF using Equation (2.93).

$$D_{f}^{mfat} = D_{fb}^{mfat} \cdot F_{CA} \cdot F_{PC} \cdot F_{CP} \cdot F_{JB} \cdot F_{BD} \tag{2.93}$$

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.

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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.

24.7 Nomenclature

D_{fB}^{AS}	is the base DF for shaking
D_{fB}^{CF}	is the base DF for cyclic loading type
D_{f}^{mfat}	is the DF for mechanical fatigue
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_{JB}	is the DF adjustment for joint type
F_{PC}	is the DF adjustment for pipe complexity
F_{fB}^{AS}	is the adjustment factor for audible shaking

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24.8 References

See Reference [96] in Section 2.2.

24.9 Tables

Table 24.1—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.

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Table 24.1—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 15.24 m (50 ft) 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?

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24.10 Figures

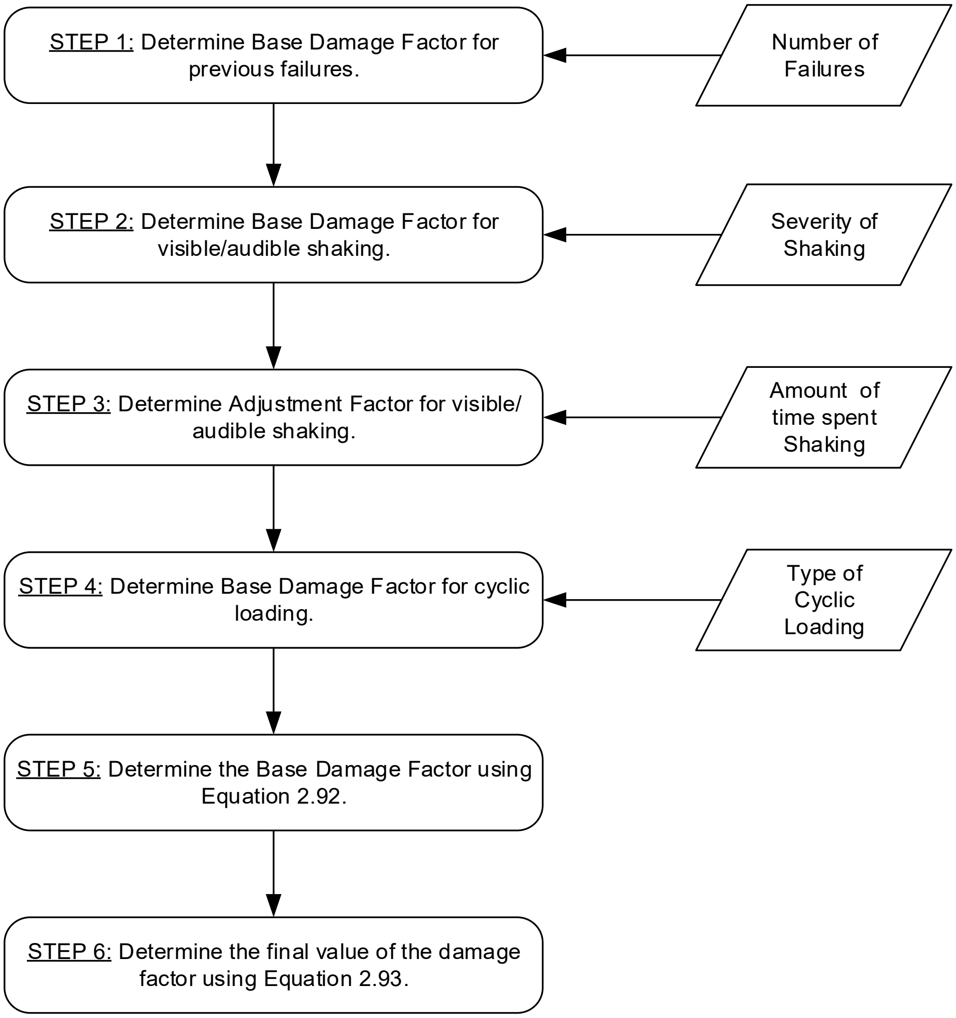

Figure 24.1—Determination of the Piping Mechanical Fatigue DF

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PART 2

ANNEX 2.A—MANAGEMENT SYSTEMS WORK BOOK

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PART 2, ANNEX A CONTENTS

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Risk-Based Inspection Methodology
Part 2—Probability of Failure Methodology
Annex 2.A—Management Systems Workbook

Table 2.A.1—Leadership and Administration

	Questions	**Possible Score**	**Actual Score**
1	Does the organization at the corporate or local level have a general policy statement reflecting management's commitment to process safety management and emphasizing safety and loss control issues?	10	
2	Is the general policy statement:		
	a. contained in manuals?	2	
	b. posted in various locations?	2	
	c. included as a part of all rule booklets?	2	
	d. referred to in all major training programs?	2	
	e. used in other ways? (Describe)	2	
3	Are responsibilities for process safety and health issues clearly defined in every manager's job description?	10	
4	Are annual objectives in the area of process safety and health issues established for all management personnel and are they then included as an important consideration in their regular annual appraisals?	15	
5	What percentage of the total management team has participated in a formal training course or outside conference or seminar on process safety management over the last 3 years?	% × 10	
6	Is there a site Safety Committee, or equivalent?	5	
	a. Does the committee makeup represent a diagonal slice of the organization?	5	
	b. Does the committee meet regularly and document that appropriate recommendations are implemented?	5	
	Total Points	**70**	

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Table 2.A.2—Process Safety Information

	Questions	Possible Score	Actual Score
1	Are material safety data sheets (MSDSs) available for all chemical substances used or handled in each unit?	5	
	a. Is the maximum on-site inventory of each of these chemicals listed?	2	
	b. Is this information available to operations and maintenance personnel and any appropriate contract personnel in the unit?	2	
	c. Are the hazardous effects, if any, of inadvertent mixing of the various materials on site clearly stated in the standard operating procedures (SOPs) and emphasized in operator training programs?	2	
2	Are quality control procedures in place and practiced to ensure that all identified materials meet specifications when received and used?	10	
3	Is up-to-date written information readily available in the unit that:		
	a. summarizes the process chemistry?	3	
	b. lists the safe upper and lower limits for such items as temperatures, pressures, flows, and compositions?	3	
	c. states the safety-related consequences of deviations from these limits?	3	
4	Is a block flow diagram or simplified process flow diagram available to aid in the operator's understanding of the process?	5	
5	Are P&IDs available for all units at the site?	10	
6	Does documentation show all equipment in the unit is designed and constructed in compliance with all applicable codes, standards, and generally accepted good engineering practices?	8	
7	Has all existing equipment been identified that was designed and constructed in accordance with codes, standards, or practices that are no longer in general use?	4	
	Has it been documented that the design, maintenance, inspection, and testing of such equipment will allow it to be operated in a safe manner?	4	
8	Have written records been compiled for each piece of equipment in the process, and do they include all of the following?		
	a. Materials of construction.	1	
	b. Design codes and standards employed.	1	
	c. Electrical classification.	1	
	d. Relief system design and design basis.	1	
	e. Ventilation system design.	1	
	f. Safety systems, including interlocks, detection, and suppression systems.	1	
9	Are procedures in place to ensure that each individual with responsibility for managing the process has a working knowledge of the process safety information appropriate to his or her responsibilities?	5	
10	Is a documented compilation of all the above process safety information maintained at the facility as a reference? The individual elements of the Information may exist in various forms and locations, but the compilation should confirm the existence and location of each element.	8	
	Total Points	**80**	

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Table 2.A.3—Process Hazard Analysis

	Questions	Possible Score	Actual Score
1	What percentage of all process units that handle hazardous chemicals at the facility have had a formal process hazard analysis (PHA) within the last 5 years?	% × 10	
2	Has a priority order been established for conducting future PHAs?	5	
	Does the basis for the prioritization address the following factors?		
	a. The quantity of toxic, flammable, or explosive material at the site.	1	
	b. The level of toxicity or reactivity of the materials.	1	
	c. The number of people in the immediate proximity of the facility, including both on-site and off-site locations.	1	
	d. Process complexity.	1	
	e. Severe operating conditions or conditions that can cause corrosion or erosion.	1	
3	Do the PHAs conducted to date address the following?		
	a. The hazards of the process.	2	
	b. A review of previous incident/accident reports from the unit being analyzed to identify any previous incidents that had a potential for catastrophic consequences.	2	
	c. Engineering and administrative controls applicable to the hazards and their interrelationships.	2	
	d. Consequences of failure of engineering and administrative controls.	2	
	e. Facilities siting.	2	
	f. Human factors.	2	
	g. A qualitative evaluation of the possible safety and health effects of failure.	2	
4	Based on the most recent PHA conducted:		
	a. was the team leader experienced in the technique being employed?	3	
	b. had the team leader received formal training in the method being employed?	3	
	c. was at least one member of the team an expert on the process being analyzed?	3	
	d. were all appropriate disciplines represented on the team or brought in as required during the analysis?	3	
	e. was at least one member of the team a person who did not participate in the original design of the facility?	3	

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Table 2.A.3—Process Hazard Analysis (Continued)

	Questions	Possible Score	Actual Score
5	Is a formal system in place to promptly address the findings and recommendations of a PHA to ensure that the recommendations are resolved in a timely manner and that the resolution is documented?	8	
	a. If so, are timetables established for implementation?	3	
	b. Does the system require that decisions concerning recommendations in PHAs and the status of implementation be communicated to all operations, maintenance, and other personnel who may be affected?	3	
6	Is the methodology used in past PHAs and/or planned future PHAs appropriate for the complexity of the process?	10	
7	Are the PHAs being led by an individual who has been trained in the methods being used?	12	
8	Based on the most recent PHAs conducted, are the average rates of analysis appropriate for the complexity of the systems being analyzed? (Typically, 2 to 4 P&IDs of average complexity will be analyzed per day.)	10	
9	After the process hazards have been identified, are the likelihood and consequences of the failure scenarios assessed using either qualitative or quantitative techniques?	5	
Total Points		**100**	

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Table 2.A.4—Management of Change

	Questions	Possible Score	Actual Score
1	Does the facility have a written management of change procedure that must be followed whenever new facilities are added or changes are made to a process?	9	
	Are authorization procedures clearly stated and at an appropriate level?	5	
2	Do the following types of "changes" invoke the management of change procedure?		
	a. Physical changes to the facility, other than replacement in kind (expansions, equipment modifications, instrument or alarm system revisions, etc.).	4	
	b. Changes in process chemicals (feedstocks, catalysts, solvents, etc.).	4	
	c. Changes in process conditions (operating temperatures, pressures, production rates, etc.).	4	
	d. Significant changes in operating procedures (start-up or shutdown sequences, unit staffing level or assignments, etc.).	4	
3	Is there a clear understanding at the facility of what constitutes a "temporary change?"	5	
	a. Does management of change handle temporary changes as well as permanent changes?	4	
	b. Are items that are installed as "temporary" tracked to ensure that they are either removed after a reasonable period of time or reclassified as permanent?	5	
4	Do the management of change procedures specifically require the following actions whenever a change is made to a process?		
	a. Require an appropriate PHA for the unit.	3	
	b. Update all affected operating procedures.	3	
	c. Update all affected maintenance programs and inspection schedules.	3	
	d. Modify P&IDs, statement of operating limits, MSDSs, and any other process safety information affected.	3	
	e. Notify all process and maintenance employees who work in the area of the change, and provide training as required.	3	
	f. Notify all contractors affected by the change.	3	
	g. Review the effect of the proposed change on all separate but interrelated upstream and downstream facilities.	3	
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?	10	
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?	5	
Total Points		**80**	

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Table 2.A.5—Operating Procedures

	Questions	Possible Score	Actual Score
1	Are written operating procedures available to operations and maintenance personnel in all units?	10	
	Do the operating procedures clearly define the position of the person or persons responsible for operation of each applicable area?	5	
2	Are the following operating considerations covered in all SOPs?		
	a. Initial start-up.	2	
	b. Normal (as well as emergency) operation.	2	
	c. Normal shutdown.	2	
	d. Emergency shutdown.	2	
	e. Is the position of the person or persons who may initiate these procedures defined?	2	
	f. Steps required to correct or avoid deviation from operating limits and consequences of the deviation.	2	
	g. Start-up following a turnaround.	2	
	h. Safety systems and their functions.	2	
3	Are the following safety and health considerations covered in all SOPs for the chemicals used in the process?		
	a. Properties of, and hazards presented by, the chemicals.	3	
	b. Precautions necessary to prevent exposure, including controls and personal protective equipment.	4	
	c. Control measures to be taken if physical contact occurs.	3	
4	Are the SOPs in the facility written in a clear and concise style to ensure effective comprehension and promote compliance of the users?	10	
5	Are there adequate procedures for handover/transfer of information between shifts?	10	
6	How frequently are operating procedures formally reviewed to ensure they reflect current operating practices and updated as required? (Choose one)		
	At least annually, or as changes occur.	11	
	Each 2 years.	6	
	Only when major process changes occur.	3	
	No schedule has been established.	0	
7	How often is an unbiased evaluation made of the level of compliance with written operating procedures? (Choose one)		
	Every 6 months.	8	
	Yearly.	4	
	Each 3 years.	2	
	Not done.	0	
Total Points		**80**	

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Table 2.A.6—Safe Work Practices

	Questions	Possible Score	Actual Score
1	Have safe work practices been developed and implemented for employees and contractors to provide for the control of hazards during operation or maintenance, including the following?		
	a. Hot work.	2	
	b. Line breaking procedures.	2	
	c. Lockout/tagout.	2	
	d. Confined space entry.	2	
	e. Opening process equipment or piping.	2	
	f. Entrance into a facility by maintenance, contract, laboratory, or other support personnel.	2	
	g. Vehicle entry.	2	
	h. Crane lifts.	2	
	i. Handling of particularly hazardous materials (toxic, radioactive, etc.).	2	
	j. Inspection or maintenance of in-service equipment.	2	
2	Do all the safe work practices listed in Question 1 require a work authorization form or permit prior to initiating the activity?	10	
3	If so, do the permit procedures include the following features?		
	a. Forms that adequately cover the subject area.	1	
	b. Clear instructions denoting the number of copies issued and who receives each copy.	1	
	c. Authority required for issuance.	1	
	d. Sign-off procedure at completion of work.	1	
	e. Procedure for extension or reissue after shift change.	1	
4	Is formal training provided to persons issuing each of the above permits?	10	
5	Are the affected employees trained in the above permit and procedure requirements?	10	
6	How often is an independent evaluation made (e.g. by Safety Department or similar group), with results communicated to appropriate management, to determine the extent of compliance with requirements for work permits and specialized procedures for major units within the organization? (Choose one)		
	Every 3 months.	7	
	Every 6 months.	4	
	Yearly.	2	
	Not done.	0	
7	Is a procedure in place that requires that all work permit procedures and work rules be formally reviewed at least every 3 years and updated as required?	10	
	Do records indicate that these reviews are being conducted on a timely basis?	5	
8	Have surveys been conducted to determine whether working environments are consistent with ergonomic standards?	4	
	Either no deficiencies were found in the above survey, or if they were, are they being corrected?	4	
Total Points		**85**	

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Table 2.A.7—Training

	Questions	Possible Score	Actual Score
1	Is there a written procedure that defines the general training in site-wide safety procedures, work practices, etc., that a newly hired employee will receive?	10	
2	Is there a written procedure that defines the amount and content of site-specific training, in addition to the general training provided in Question 1, that an employee newly assigned to an operations position will receive prior to assuming his duties?	10	
3	Does the procedure described in Question 2 require that the training include the following?		
	a. An overview of the process and its specific safety and health hazards.	3	
	b. Training in all operating procedures.	3	
	c. Training on site-emergency procedures.	3	
	d. Emphasis on safety-related issues such as work permits, importance of interlocks and other safety systems, etc.	3	
	e. Safe work practices.	3	
	f. Appropriate basic skills.	3	
4	At the completion of formal training of operations personnel, what method is used to verify that the employee understands the information presented? (Choose one)		
	Performance test followed by documented observation.	10	
	Performance test only.	7	
	Opinion of instructor.	3	
	No verification.	0	
5	How often are operations employees given formal refresher training? (Choose one)		
	At least once every 3 years.	10	
	Only when major process changes occur.	5	
	Never.	0	
6	What is the average amount of training given to each operations employee per year, averaged over all grades? (Choose one)		
	15 days/year or more.	10	
	11 to 14 days/year.	7	
	7 to 10 days/year.	5	
	3 to 6 days/year.	3	
	Less than 3 days/year.	0	
7	Has a systematic approach (e.g. employee surveys, task analysis, etc.) been used to identify the training needs of all employees at the facility, including the training programs referred to in Questions 1 and 2?	4	
	a. Have training programs been established for the identified needs?	4	
	b. Are training needs reviewed and updated periodically?	4	
8	Are the following features incorporated in the plant's formal training programs?		
	a. Qualifications for trainers have been established and are documented for each trainer.	5	
	b. Written lesson plans are used that have been reviewed and approved to ensure complete coverage of the topic.	5	
	c. Training aids and simulators are used where appropriate to permit "hands-on" training.	5	
	d. Records are maintained for each trainee showing the date of training and means used to verify that training was understood.	5	
	Total Points	**100**	

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Table 2.A.8—Mechanical Integrity

	Questions	Possible Score	Actual Score
1	Has a written inspection plan for the process unit been developed that includes the following elements?		
	a. All equipment needing inspection has been identified?	2	
	b. The responsibilities to conduct the inspections have been assigned?	2	
	c. Inspection frequencies have been established?	2	
	d. The inspection methods and locations have been specified?	2	
	e. Inspection reporting requirements have been defined?	2	
2	Does the inspection plan referred to in Question 1 include a formal, external visual inspection program for all process units?	2	
	a. Are all the following factors considered in the 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?	1	
	b. Based on the inspection plan referred to in Question 1, do all pressure vessels in the unit receive such a visual external inspection at least every 5 years?	2	
	c. Based on this inspection plan, do all on-site piping systems that handle volatile, flammable products, toxins, acids and caustics, and other similar materials receive a visual external inspection at least every 5 years?	2	
3	Based on the inspection plan, do all pressure vessels in the unit receive an internal or detailed inspection using appropriate nondestructive examination procedures at least every 10 years?	5	
4	Has each item of process equipment been reviewed by appropriate personnel to identify the probable causes of damage or failure?	5	
	a. Has this information been used to establish the inspection methods, locations, and frequencies and the preventive maintenance programs?	1	
	b. Have defect limits been established, based on fitness-for-service considerations?	1	
5	Is a formal program for thickness measurements of piping as well as vessels being used?	3	
	a. When the locations for thickness measurements are chosen,		
	1. Is the likelihood and consequence of failure a major factor?	1	
	2. Is localized corrosion and erosion a consideration?	1	
	b. Are thickness measurement locations clearly marked on inspection drawings and on the vessel or piping system to allow repetitive measurements at precisely the same locations?	2	
	c. Are thickness surveys up to date?	2	
	d. Are the results used to predict remaining life and adjust future inspection frequency?	2	

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Table 2.A.8—Mechanical Integrity (Continued)

	Questions	Possible Score	Actual Score
6	Has the maximum allowable working pressure (MAWP) been established for all piping systems, using applicable codes and current operating conditions?	3	
	Are the MAWP calculations updated after each thickness measurement, using the latest wall thickness and corrosion rate?	2	
7	Is there a written procedure that requires an appropriate level of review and authorization prior to any changes in inspection frequencies or methods and testing procedures?	5	
8	Have adequate inspection checklists been developed and are they being used?	3	
	Are they periodically reviewed and updated as equipment or processes change?	2	
9	Are all inspections, tests, and repairs performed on the process equipment being promptly documented?	3	
	Does the documentation include all of the following information?	3	
	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. The results of the inspection.		
	f. All recommendations resulting from the inspection.		
	g. A date and description of all maintenance performed.		
10	Is there a written procedure requiring that all process equipment deficiencies identified during an inspection be corrected in a safe and timely manner and are they tracked and followed up to assure completion?	5	
	a. Is a system used to help determine priorities for action?	1	
	b. If defects are noted, are decisions to continue to operate the equipment based on sound engineering assessments of fitness-for-service?	2	
11	Is there a complete, up-to-date, central file for all inspection program information and reports?	3	
	Is this file information available to everyone who works with the process?	2	
12	Have all employees involved in maintaining and inspecting the process equipment been trained in an overview of the process and its hazards?	5	
13	Have all employees involved in maintaining and inspecting the process equipment been trained in all procedures applicable to their job tasks to ensure that they can perform the job tasks in a safe and effective manner?	3	
	At completion of the training described above, are formal methods used to verify that the employee understands what he was trained on?	2	
14	Are inspectors certified for performance in accordance with applicable industry codes and standards (e.g. API 510, 570, and 653)?	5	
15	Are training programs conducted for contractors' employees where special skills or techniques unique to the unit or plant are required for these employees to perform the job safely?	5	

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Table 2.A.8—Mechanical Integrity (Continued)

	Questions	Possible Score	Actual Score
16	Has a schedule been established for the inspection or testing of all pressure-relief valves in the unit?	3	
	a. Is the schedule being met?	1	
	b. Are all inspections and repairs fully documented?	1	
	c. Are all repairs made by personnel fully trained and experienced in relief valve maintenance?	1	
17	Does the preventive maintenance program used at the facility meet the following criteria?		
	a. All safety-critical items and other key equipment, such as electrical switchgear and rotating equipment, are specifically addressed.	1	
	b. Checklists and inspection sheets are being used.	1	
	c. Work is being completed on time.	1	
	d. The program is continuously modified based on inspection feedback.	1	
	e. Repairs are identified, tracked, and completed as a result of the PM program.	1	
18	Does the facility have a quality assurance program for construction and maintenance to ensure the following?		
	a. Proper materials of construction are used.	1	
	b. Fabrication and inspection procedures are proper.	1	
	c. Equipment is maintained 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	
19	Is there a permanent and progressive record for all pressure vessels that includes all of the following?	5	
	a. Manufacturers' data reports and other pertinent data records.		
	b. Vessel identification numbers.		
	c. Relief valve information.		
	d. Results of all inspections, repairs, alterations, or re-ratings that have occurred to date.		
20	Are systems in place, such as written requirements, with supervisor sign-off, sufficient to ensure that all design repair and alteration done on any pressure vessel or piping system be done in accordance with the code to which the item was built or in-service repair and inspection code?	5	
	Total Points	**120**	

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Table 2.A.9—Pre-startup Safety Review

	Questions	Possible Score	Actual Score
1	Does company policy require a formal PHA at the conception and/or design stages of all new development, construction, and major modification projects?	10	
2	Is there a written procedure requiring that all of the following items have been accomplished before the start-up of new or significantly modified facilities?	10	
	a. Written operating procedures have been issued.		
	b. Training has been completed for all personnel involved in the process.		
	c. Adequate maintenance, inspection, safety, and emergency procedures are in place.		
	d. Any recommendations resulting from the formal PHA have been completed.		
3	Is there a written procedure requiring that all equipment be inspected prior to start-up to confirm that it has been installed in accordance with the design specifications and manufacturer's recommendations?	10	
	a. Does the procedure require formal inspection reports at each appropriate stage of fabrication and construction?	5	
	b. Does the procedure define the corrective action and follow-up needed when deficiencies are found?	5	
4	In the pre-start-up safety review, is it required that physical checks be made to confirm the following?		
	a. Leak tightness of all mechanical equipment prior to the introduction of highly hazardous chemicals to the process.	5	
	b. Proper operation of all control equipment prior to start-up.	5	
	c. Proper installation and operation of all safety equipment (relief valves, interlocks, leak detection equipment, etc.).	5	
5	Is there a requirement to formally document the completion of the items in Questions 1, 2, 3, and 4 prior to start-up, with a copy of the certification going to facility management?	5	
Total Points		**60**	

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Table 2.A.10—Emergency Response

	Questions	Possible Score	Actual Score
1	Does the facility have an emergency plan in writing to address all probable emergencies?	10	
2	Is there a requirement to formally review and update the emergency plan on a specified schedule?	5	
	a. Does the facility's management of change procedure include a requirement to consider possible impact on the facility emergency plan?	2	
	b. Are the results of all new or updated PHAs reviewed to determine whether any newly identified hazards will necessitate a change in the facility emergency plan?	2	
3	Does the emergency plan include at least the following?		
	a. Procedures to designate one individual as Coordinator in an emergency situation, with a clear statement of his or her responsibilities.	2	
	b. Emergency escape procedures and emergency escape route assignments.	2	
	c. Procedures to be followed by employees who remain to perform critical plant operations before they evacuate.	2	
	d. Procedures to account for all employees after emergency evacuation has been completed.	2	
	e. Rescue and medical duties for those employees who are to perform them.	2	
	f. Preferred means of reporting fires and other emergencies.	2	
	g. Procedures for control of hazardous materials.	2	
	h. A search and rescue plan.	2	
	i. An all-clear and re-entry procedure.	2	
4	Has an emergency control center been designated for the facility?	5	
	Does it have the following minimum resources?		
	a. Emergency power source.	2	
	b. Adequate communication facilities.	2	
	c. Copies of P&IDs, SOPs, MSDS, plot plans, and other critical safety information for all process units at the facility.	2	
5	Have persons been designated who can be contacted for further information or explanation of duties under the emergency plan?	5	
	Is this list of names posted in all appropriate locations (control rooms, security office, emergency control center, etc.)?	2	
6	Are regular drills conducted to evaluate and reinforce the emergency plan?	10	
Total Points		**65**	

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Table 2.A.11—Incident Investigation

	Questions	Possible Score	Actual Score
1	Is there a written incident/accident investigation procedure that includes both accidents and near misses?	10	
	Does the procedure require that findings and recommendations of investigations be addressed and resolved promptly?	5	
2	Does the procedure require that the investigation team include the following?		
	a. A member trained in accident investigation techniques.	3	
	b. The line supervisor or someone equally familiar with the process.	3	
3	Indicate whether the investigation procedure requires an investigation of the following items by the immediate supervisor with the results recorded on a standard form.		
	a. Fire and explosions.	2	
	b. Property losses at or above an established cost base.	2	
	c. All non-disabling injuries and occupational illnesses.	2	
	d. Hazardous substance discharge.	2	
	e. Other accidents/incidents (near misses).	2	
4	Is there a standard form for accident/incident investigation that includes the following information?		
	a. Date of incident.	2	
	b. Date investigation began.	2	
	c. Description of the incident.	2	
	d. Underlying causes of the incident.	2	
	e. Evaluation of the potential severity and probable frequency of recurrence.	2	
	f. Recommendations to prevent recurrence.	2	
5	Based on a review of plant records, to what degree does it appear that the established incident investigation procedures are being followed?	5	
6	If the incident/accident involved a failure of a component or piece of equipment, are appropriate inspection or engineering people required to be involved in a failure analysis to identify the conditions or practices that caused the failure?	10	
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	During the last 12 month period, have any incident or accident reports or report conclusions been transmitted to other sites that operate similar facilities within the company?	6	
9	Do the procedures for incident reporting and/or PHA require that the findings from all applicable incident reports be reviewed and incorporated into future PHAs?	6	
Total Points		**75**	

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Table 2.A.12—Contractors

	Questions	Possible Score	Actual Score
1	Do contractor selection procedures include the following prior to awarding the contract?		
	a. A review of the contractor's existing safety and health programs.	3	
	b. A review of the contractor's previous loss experience data.	3	
	c. A review of the documentation of the experience and skills necessary to reasonably expect the contractor to perform the work safely and efficiently.	3	
2	Before the start of work, is the contract employer advised in writing of the following?		
	a. All known potential hazards of the process and of the contractor's work.	2	
	b. Plant safe work practices.	2	
	c. Entry/access controls.	2	
	d. All applicable provisions of the emergency response plan.	2	
3	Are pre-job meetings held with contractors to review the scope of contract work activity plus the company's requirements for safety, quality assurance, and performance?	9	
4	Are periodic assessments performed to ensure that the contract employer is providing to his or her employees the training, instruction, monitoring, etc., required to ensure the contract employees abide by all facility safe work practices?	9	
5	Are all contractors who perform maintenance or repair, turnaround, major renovation or specialty work covered by all the procedures addressed in this section?	10	
Total Points		**45**	

Table 2.A.13—Management Systems Assessments

	Questions	Possible Score	Actual Score
1	How often is a formal written assessment conducted of the facility's Process safety management system? (Choose one)		
	Every year.	10	
	Every 3 years.	7	
	Not done.	0	
2	Has an action plan been developed to meet program needs as indicated by the last assessment?	10	
3	Based on the most recent assessment, did the assessment team include people with the following skills?		
	a. Formal training in assessment techniques.	5	
	b. In-depth knowledge of the process being assessed.	5	
4	Based on a review of the most recent assessment, was the breadth and depth of the assessment appropriate for the facility?	10	
Total Points		**40**	

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PART 2

ANNEX 2.B—DETERMINATION OF CORROSION RATES

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PART 2, ANNEX B CONTENTS

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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 localized). If this information is not known, then Table 2.B.1.2 lists the type of thinning (general or localized) expected for various thinning mechanisms. If both general and localized thinning mechanisms are possible, then the type of thinning should be designated as localized. The type of thinning designated will be used to determine the effectiveness of inspection performed.

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2.B.1.3 Tables

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

Screening Questions	Action
Hydrochloric Acid (HCl) Corrosion 1. Does the process contain HCl? 2. Is free water present in the process stream (including initial condensing condition)? 3. Is the pH < 7.0?	If Yes to all, proceed to Section 2.B.2
High Temperature Sulfidic/Naphthenic Acid Corrosion 1. Does the process contain oil with sulfur compounds? 2. Is the operating temperature > 204 °C (400 °F)?	If Yes to both, proceed to Section 2.B.3
High Temperature H_2S/H_2 Corrosion 1. Does the process contain H_2S and hydrogen? 2. Is the operating temperature > 204 °C (400 °F)?	If Yes to both, proceed to Section 2.B.4
Sulfuric Acid (H_2SO_4) Corrosion Does the process contain H_2SO_4?	If Yes, proceed to Section 2.B.5
Hydrofluoric Acid (HF) Corrosion Does the process stream contain HF?	If Yes, proceed to Section 2.B.6
Sour Water Corrosion Is free water with H_2S present?	If Yes, proceed to Section 2.B.7
Amine Corrosion Is equipment exposed to acid gas treating amines (MEA, DEA, DIPA, or MDEA)?	If Yes, proceed to Section 2.B.8
High Temperature Oxidation 1. Is the temperature ≥ 482 °C (900 °F)? 2. Is there oxygen present?	If Yes to both, proceed to Section 2.B.9
Acid Sour Water 1. Is free water with H_2S present and pH < 7.0? 2. Does the process contain < 50 ppm chlorides?	If Yes, 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 1. Is equipment in contact with soil (buried or partially buried)? 2. Is the material of construction carbon steel?	If Yes, proceed to Section 2.B.12
CO_2 Corrosion 1. Is free water with CO_2 present (including consideration for dew point condensation)? 2. Is the material of construction carbon steel or < 13 % Cr?	If Yes, proceed to Section 2.B.13
AST Bottom Is the equipment item an AST tank bottom?	If Yes, proceed to Section 2.B.14

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Table 2.B.1.2—Type of Thinning

Thinning Mechanism	Condition	Type of Thinning
Hydrochloric acid (HCl) corrosion	—	Local
High temperature sulfidic/naphthenic acid corrosion	TAN ≤ 0.5	General
	TAN > 0.5	Local
High temperature H_2S/H_2 corrosion	—	General
Sulfuric acid (H_2SO_4) corrosion	Low Velocity ≤0.61 m/s (2 ft/s) for carbon steel, ≤1.22 m/s (4 ft/s) for SS, and ≤1.83 m/s (6 ft/s) for higher alloys	General
	High Velocity ≥0.61 m/s (2 ft/s) for carbon steel, ≥1.22 m/s (4 ft/s) for SS, and ≥1.83 m/s (6 ft/s) for higher alloys	Local
Hydrofluoric acid (HF) corrosion	—	Local
Sour water corrosion	Low Velocity: ≤6.1 m/s (20 ft/s)	General
	High Velocity: >6.1 m/s (20 ft/s)	Local
Amine corrosion	Low Velocity <1.5 m/s (5 ft/s) rich amine <6.1 m/s (20 ft/s) lean amine	General
	High Velocity >1.5 m/s (5 ft/s) rich amine >6.1 m/s (20 ft/s) lean amine	Local
High temperature oxidation	—	General
Acid sour water corrosion	<1.83 m/s (6 ft/s) ≥1.83 m/s (6 ft/s)	General Local
Cooling water corrosion	≤0.91 m/s (3 ft/s) 0.91 to 2.74 m/s (3 to 9 ft/s) >2.74 m/s (9 ft/s)	Local General Local
Soil-side corrosion	—	Local
CO_2 corrosion	—	Local
AST bottom	Product side Soil side	Local Local

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2.B.2 Hydrochloric Acid 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 stainless steels will often suffer pitting attack and may experience crevice corrosion and/or CLSCC. 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 have 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 [61], [97], [98], [99], [100], and [101] in Section 2.2.

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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 stainless steels. Table 2.B.2.2 may be used to estimate pH from the Cl⁻ concentration if it is known. Note that 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, °C (°F)	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).

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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/y)

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

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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/y)

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.				

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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/y)

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

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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/y)

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

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2.B.2.6 Figures

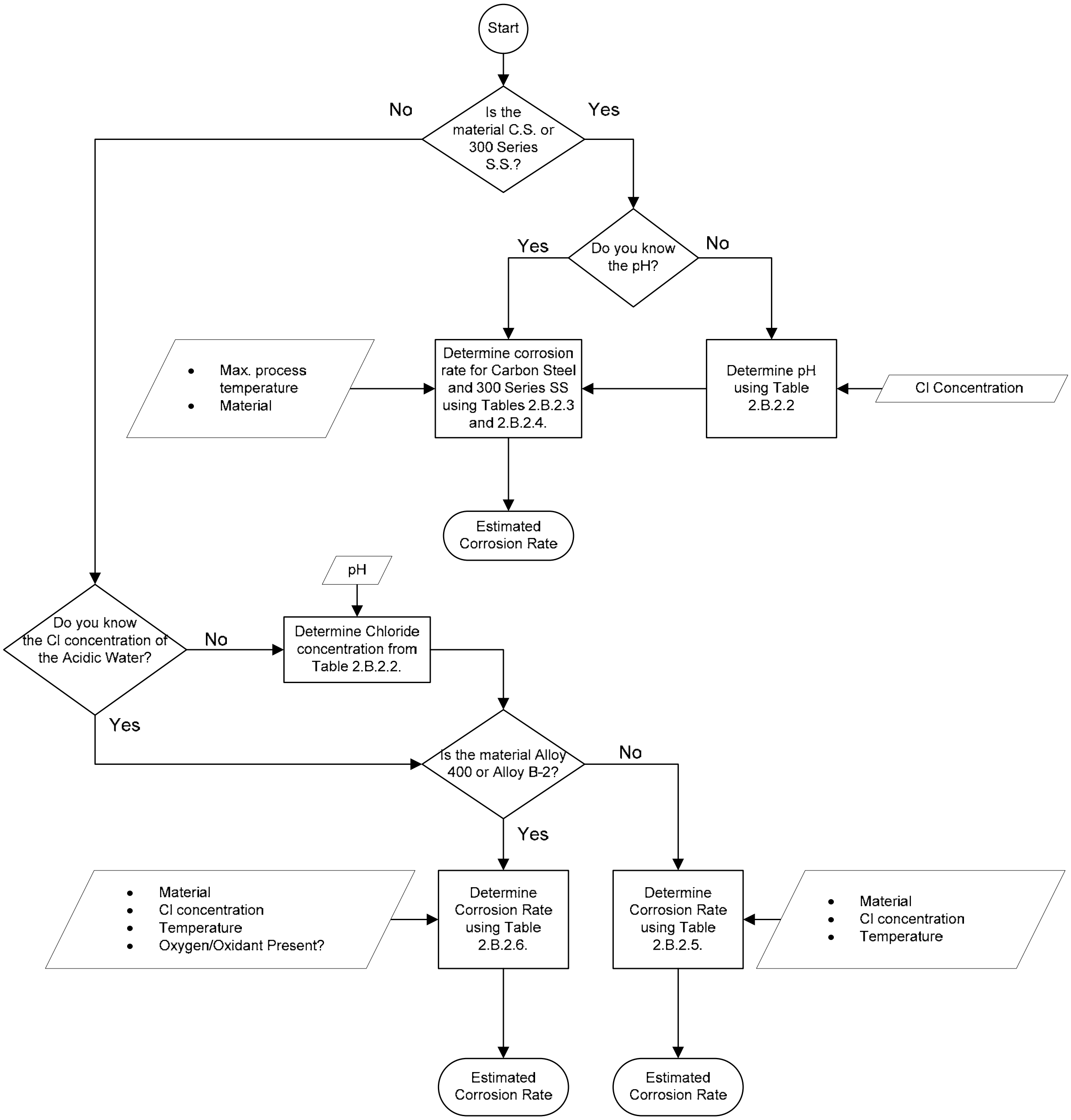

Figure 2.B.2.1—HCl Corrosion—Determination of Corrosion Rate

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2.B.3 High Temperature Sulfidic and Naphthenic Acid Corrosion

2.B.3.1 Description of Damage

High temperature sulfidic corrosion is a form of normally uniform corrosion that can occur at temperatures typically above about 204 °C (400 °F). 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 H_2S and hydrogen is covered in Section 2.B.4. 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 modify or 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.

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 summarize 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) Sulfidation 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 204 °C (400 °F). Naphthenic acid corrosion typically has been observed in the 204 °C to 399 °C (400 °F to 750 °F) temperature range although corrosion which exhibits naphthenic acid characteristics has been reported outside this temperature range. Above 399 °C (750 °F), 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 stainless steel offers some resistance to naphthenic acid corrosion at lower acid levels, but normally the molybdenum containing austenitic stainless steels (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 total acid number (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

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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.

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.3.2 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.3.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are shown in Figure 2.B.3.1. The corrosion rate may be determined using the basic data in Table 2.B.3.1 in conjunction with Tables 2.B.3.2 through 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 McConomy curves. 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. Consequently, the corrosion rate to be used when naphthenic acid is a factor is only an order-of-magnitude estimate of the corrosion rate. Once a corrosion rate is selected from the appropriate table, it should be multiplied by a factor of 5 if the velocity is >30.48 m/s (100 ft/s).

2.B.3.4 References

See References [102], [103] (Appendix 3), [104], and [105] in Section 2.2.

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2.B.3.5 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 wt%.
Maximum temperature, (°C:°F)	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.
Total acid number (TAN) (TAN = 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.

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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

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

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

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Table 2.B.3.3—High Temperature Sulfidic and Naphthenic Acid Corrosion—Estimated Corrosion Rates for 1 Cr-0.2 Mo, 1 Cr-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

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

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

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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

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

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

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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

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

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

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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

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

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

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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

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

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

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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 Austenitic stainless steels without Mo include 304, 304L, 321, 347, etc.

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

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 Austenitic stainless steels without Mo include 304, 304L, 321, 347, etc.

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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 Includes stainless steels with < 2.5 % Mo, e.g. 316, 316L, 316H, etc.

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

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 Includes stainless steels with < 2.5 % Mo, e.g. 316, 316L, 316H, etc.

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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

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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/y)

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

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2.B.3.6 Figures

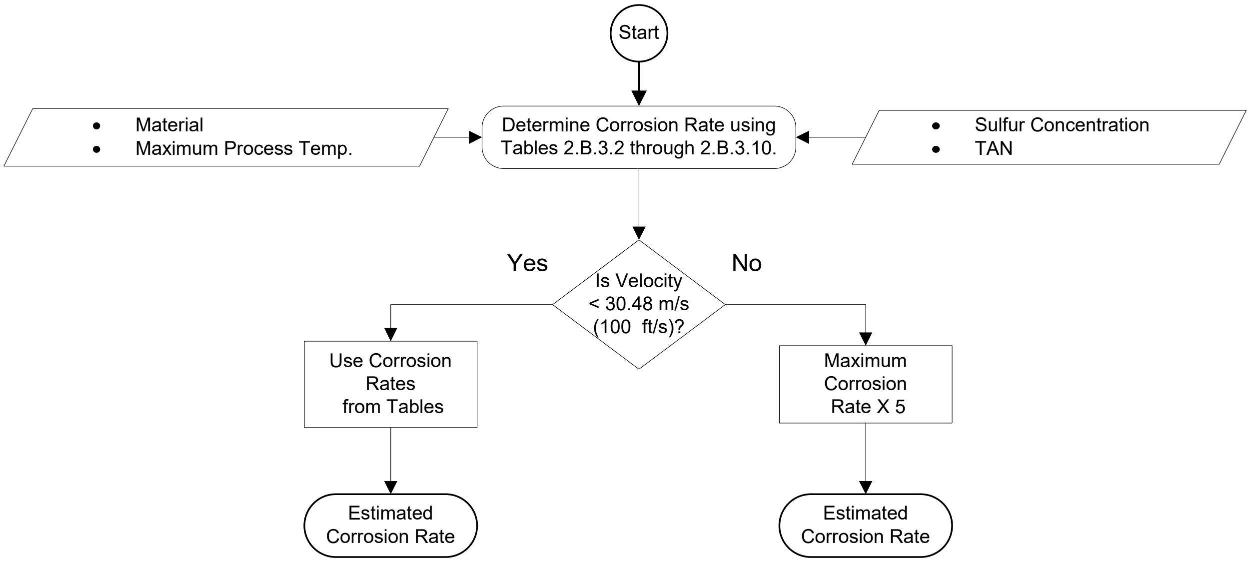

Figure 2.B.3.1—High Temperature Sulfidic and Naphthenic Acid Corrosion—Determination of Corrosion Rate

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2.B.4 High Temperature H_2S/H_2 Corrosion

2.B.4.1 Description of Damage

High temperature H_2S/H_2 corrosion is a form of normally uniform corrosion that can occur at temperatures typically above about 204 °C (400 °F). This form of sulfidation corrosion differs from high temperature sulfidic and naphthenic corrosion described in Section 2.B.3. H_2S/H_2 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 H_2S/H_2 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 H_2S.

In H_2S/H_2 environments, low levels of chromium (e.g. 5 to 9 % Cr) provide only a modest increase 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 H_2S/H_2 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 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 H_2S levels and temperatures, and the one set of data is satisfactory for risk-based inspection 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 H_2S/H_2 service. If precise data have 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.

2.B.4.4 References

See References [103], [106], [107], and [108] in Section 2.2.

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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 [103, 108]. 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 (°C:°F)	Determine the maximum process temperature.
H_2S content of the vapor (mole %)	Determine the H_2S content in the vapor. Note that mole% = volume % (not wt%)

Table 2.B.4.2—High Temperature H_2S/H_2 Corrosion—Estimated Corrosion Rates for Carbon Steel, 1 Cr-0.2 Mo, 1 Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mpy)

H_2S (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

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Table 2.B.4.2M—High Temperature H_2S/H_2 Corrosion—Estimated Corrosion Rates for Carbon Steel, 1 Cr-0.2 Mo, 1 Cr-0.5 Mo, 1.25Cr-0.5Mo, 2.25Cr-1Mo, and 3Cr-1Mo (mm/y)

H_2S (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

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Table 2.B.4.3—High Temperature H_2S/H_2 Corrosion—Estimated Corrosion Rates for 5Cr-0.5Mo (mpy)

H_2S (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

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Table 2.B.4.3M—High Temperature H_2S/H_2 Corrosion—Estimated Corrosion Rates for 5Cr-0.5Mo (mm/y)

H_2S (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

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Table 2.B.4.4—High Temperature H_2S/H_2 Corrosion—Estimated Corrosion Rates for 7Cr Steel (mpy)

H_2S (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

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Table 2.B.4.4M—High Temperature H_2S/H_2 Corrosion—Estimated Corrosion Rates for 7Cr Steel (mm/y)

H_2S (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

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Table 2.B.4.5—High Temperature H_2S/H_2 Corrosion—Estimated Corrosion Rates for 9Cr-1Mo (mpy)

H_2S (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

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Table 2.B.4.5M—High Temperature H_2S/H_2 Corrosion—Estimated Corrosion Rates for 9Cr-1Mo (mm/y)

H_2S (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 H_2S/H_2 Corrosion—Estimated Corrosion Rates for 12Cr Steels (mpy)

H_2S (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

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Table 2.B.4.6M—High Temperature H_2S/H_2 Corrosion—Estimated Corrosion Rates for 12Cr Steels (mm/y)

H_2S (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 H_2S/H_2 Corrosion—Estimated Corrosion Rates for Type 304, 304L, 316, 316L, 321, 347 Stainless Steel (mpy)

H_2S (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 H_2S/H_2 Corrosion—Estimated Corrosion Rates for Type 304, 304L, 316, 316L, 321, 347 Stainless Steel (mm/y)

H_2S (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

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2.B.4.6 Figures

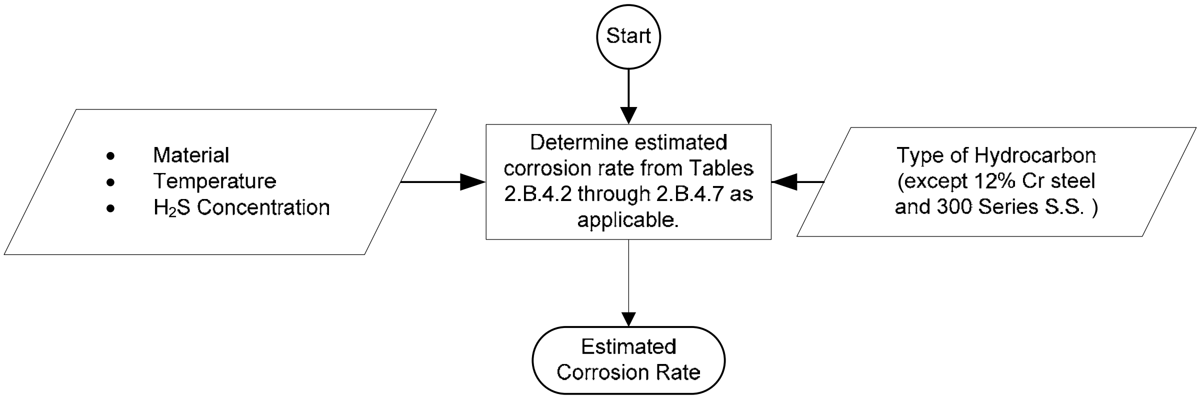

Figure 2.B.4.1—High Temperature H_2S/H_2 Corrosion—Determination of Corrosion Rate

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 [109]. Stagnant or low flow (<0.91 m/s or 3 ft/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 0.91 m/s (3 ft/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.

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Although the performance of many alloys in H_2SO_4service 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 that 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 [98], [109], [110], [111], and [112] in Section 2.2.

2.B.5.5 Tables

Table 2.B.5.1—H_2SO_4 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_2SO_4 present in this equipment/piping. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Maximum temperature (°C:°F)	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 (m/s: ft/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.

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Table 2.B.5.2—H_2SO_4 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

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Table 2.B.5.2—H_2SO_4 Corrosion—Estimated Corrosion Rate for Carbon Steel (mpy) (Continued)

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

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Table 2.B.5.2M—H_2SO_4 Corrosion—Estimated Corrosion Rate for Carbon Steel (mm/y)

Acid Conc (wt%)	Acid Temp (°C)	Acid Velocity (m/s)								
		0	1	2	3	4.5	6.5	8.5	11.5	12
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

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Table 2.B.5.2M—H_2SO_4 Corrosion—Estimated Corrosion Rate for Carbon Steel (mm/y) (Continued)

Acid Conc (wt%)	Acid Temp (°C)	Acid Velocity (m/s)								
		0	1	2	3	4.5	6.5	8.5	11.5	12
72.5	6	0.25	0.38	0.51	0.64	3.3	4.32	5.59	7.11	8.89
	15	0.38	0.76	1.27	2.54	12.45	16.51	20.57	25.37	25.37
	33	0.64	1.27	2.54	5.08	24.89	25.37	25.37	25.37	25.37
	50	1.27	2.54	6.35	20.32	25.37	25.37	25.37	25.37	25.37
67	6	0.51	0.76	1.02	1.52	7.11	9.4	11.68	15.24	18.8
	15	0.76	1.27	2.54	4.32	21.08	25.37	25.37	25.37	25.37
	33	1.27	2.54	4.57	7.62	25.37	25.37	25.37	25.37	25.37
	50	2.54	5.08	10.16	25.37	25.37	25.37	25.37	25.37	25.37
62	6	1.91	2.16	2.54	3.05	14.48	19.3	24.13	25.37	25.37
	15	3.05	4.32	6.35	10.16	25.37	25.37	25.37	25.37	25.37
	33	5.08	7.62	15.24	22.86	25.37	25.37	25.37	25.37	25.37
	50	12.7	19.05	25.37	25.37	25.37	25.37	25.37	25.37	25.37

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Table 2.B.5.3—H_2SO_4 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—H_2SO_4 Corrosion—Estimated Corrosion Rates for Type 304 SS (mm/y)

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

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Table 2.B.5.4—H_2SO_4 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

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Table2.B.5.4M—H_2SO_4 Corrosion—Estimated Corrosion Rates for Type 316 SS (mm/y)

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—H_2SO_4 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

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Table 2.B.5.5M—H_2SO_4 Corrosion—Estimated Corrosion Rates for Alloy 20 (mm/y)

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—H_2SO_4 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

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Table 2.B.5.6M—H_2SO_4 Corrosion—Estimated Corrosion Rates for Alloy C-276 (mm/y)

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—H_2SO_4 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—H_2SO_4 Corrosion—Estimated Corrosion Rates for Alloy B-2 (mm/y)

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.

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2.B.5.6 Figures

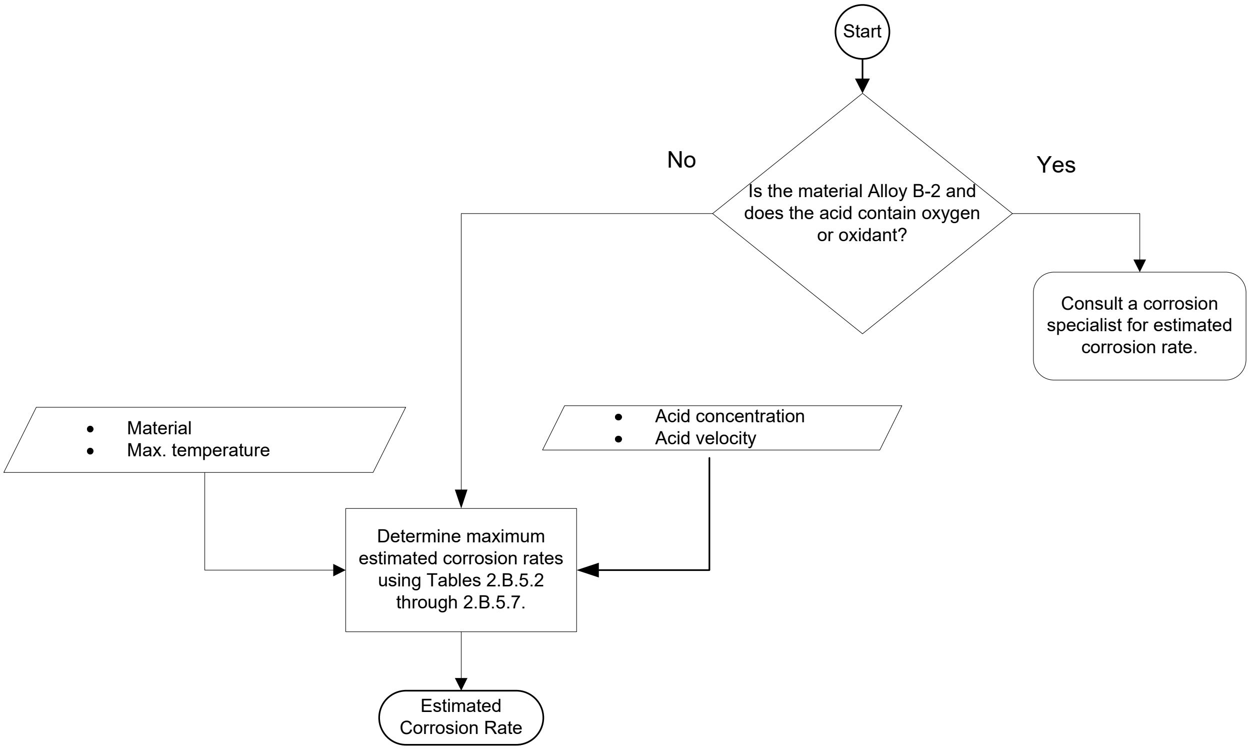

Figure 2.B.5.1—H_2SO_4 Corrosion—Determination of Corrosion Rate

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2.B.6 Hydrofluoric Acid Corrosion

2.B.6.1 Description of Damage

Concentrated hydrofluoric acid (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 AHF (200 ppm H_2O). 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 66 °C (150 °F). 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 66 °C (150 °F) to approximately 149 °C (300 °F), 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 sulfuric acid service. If precise data have 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 [20]. 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 [22].

Corrosion caused by HF results in general thinning except in the event of potential galvanic attack. The presence of HF may also result in hydrogen stress cracking and blistering. These degradation modes are considered in Part 2, Section 14.1.

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2.B.6.4 References

See References [74], [75], [113], [114], [115], and [116] in Section 2.2.

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 (°C:°F)	Determine the maximum temperature of the process stream.
Velocity (m/s:ft/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 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.

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

Temp. (°F)	Velocity (ft/s)	HF-in-Water Concentration (%)								
		1	2	5	6	63	64	80	81	
									Low Residual	High Residual
80	<10	2	150	150	800	800	5	5	2	6
	≥10	20	999	999	999	999	50	50	20	60
105	<10	10	500	500	999	999	30	30	5	15
	≥10	200	999	999	999	999	300	300	50	150
140	<10	10	500	500	999	999	30	30	10	30
	≥10	100	999	999	999	999	300	300	100	300
150	<10	100	999	999	999	999	500	500	20	60
	≥10	999	999	999	999	999	999	999	200	600
167.5	<10	100	999	999	999	999	500	500	50	150
	≥10	999	999	999	999	999	999	999	500	999
187.5	<10	100	999	999	999	999	500	500	70	210
	≥10	999	999	999	999	999	999	999	700	999
200	<10	500	999	999	999	999	999	999	100	300
	≥10	999	999	999	999	999	999	999	999	999

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

Temp. (°C)	Velocity (m/s)	HF-in-Water Concentration (%)								
		1	2	5	6	63	64	80	81	
									Low Residual	High Residual
27	<3.05	0.05	3.81	3.81	20.32	20.32	0.13	0.13	0.05	0.15
	≥3.05	0.51	25.37	25.37	25.37	25.37	1.27	1.27	0.51	1.52
41	<3.05	0.25	12.7	12.7	25.37	25.37	0.76	0.76	0.13	0.38
	≥3.05	5.08	25.37	25.37	25.37	25.37	7.62	7.62	1.27	3.81
60	<3.05	0.25	12.7	12.7	25.37	25.37	0.76	0.76	0.25	0.76
	≥3.05	2.54	25.37	25.37	25.37	25.37	7.62	7.62	2.54	7.62
66	<3.05	2.54	25.37	25.37	25.37	25.37	12.7	12.7	0.51	1.52
	≥3.05	25.37	25.37	25.37	25.37	25.37	25.37	25.37	5.08	15.24
75	<3.05	2.54	25.37	25.37	25.37	25.37	12.7	12.7	1.27	3.81
	≥3.05	25.37	25.37	25.37	25.37	25.37	25.37	25.37	12.7	25.37
86	<3.05	2.54	25.37	25.37	25.37	25.37	12.7	12.7	1.78	5.33
	≥3.05	25.37	25.37	25.37	25.37	25.37	25.37	25.37	17.78	25.37
93	<3.05	12.7	25.37	25.37	25.37	25.37	25.37	25.37	2.54	7.62
	≥3.05	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37

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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/y) 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

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2.B.6.6 Figures

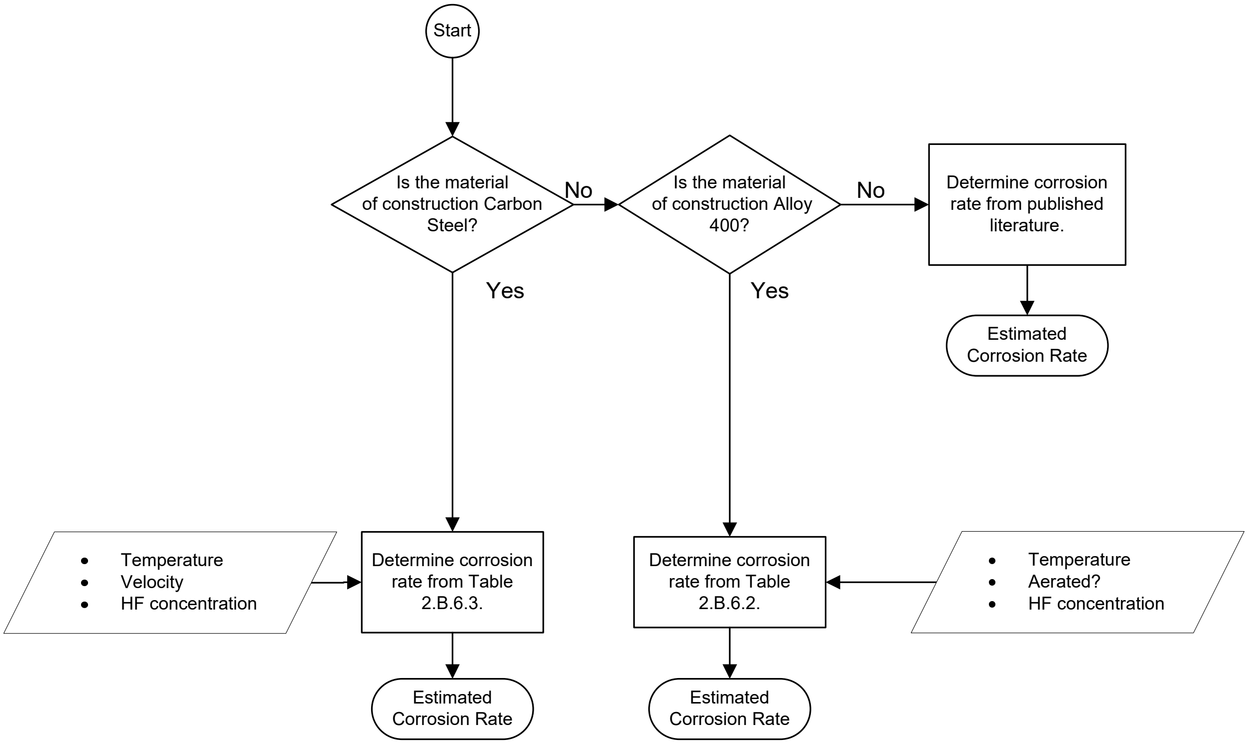

Figure 2.B.6.1—HF Corrosion—Determination of Corrosion Rate

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.

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2.B.7.4 References

See References [117], [118], [119], [120], and [121] in Section 2.2.

2.B.7.5 Tables

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

Basic Data	Comments
NH_4HS concentration (wt%)	Determine the NH_4HS 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_2S and NH_3 as follows. — If wt% H_2S < 2 × (wt% NH_3), wt% NH_4HS =1.5 × (wt% H_2S) — If wt% H_2S > 2 × (wt% NH_3), wt% NH_4HS =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_2S partial pressure, psia (kPa)	Determine the partial pressure of H_2S by multiplying the mole% of H_2S 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_4HS (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 pH_2S < 50 psia: Adjusted $CR = \max\left[\left\{\left(\frac{\text{Baseline } CR}{25}\right)\cdot(pH_2S-50)+\text{Baseline}\cdot CR\right\},0\right]$.

NOTE 2 For pH_2S ≥ 50 psia: Adjusted $CR = \max\left[\left\{\left(\frac{\text{Baseline } CR}{40}\right)\cdot(pH_2S-50)+\text{Baseline } CR\right\},0\right]$.

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

NH_4HS (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 pH_2S < 345 kPa: Adjusted $CR = \max\left[\left\{\left(\frac{\text{Baseline } CR}{173}\right)\cdot(pH_2S-345)+\text{Baseline } CR\right\},0\right]$.

NOTE 2 For pH_2S ≥ 345 kPa: Adjusted $CR = \max\left[\left\{\left(\frac{\text{Baseline } CR}{276}\right)\cdot(pH_2S-345)+\text{Baseline } CR\right\},0\right]$.

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2.B.7.6 Figures

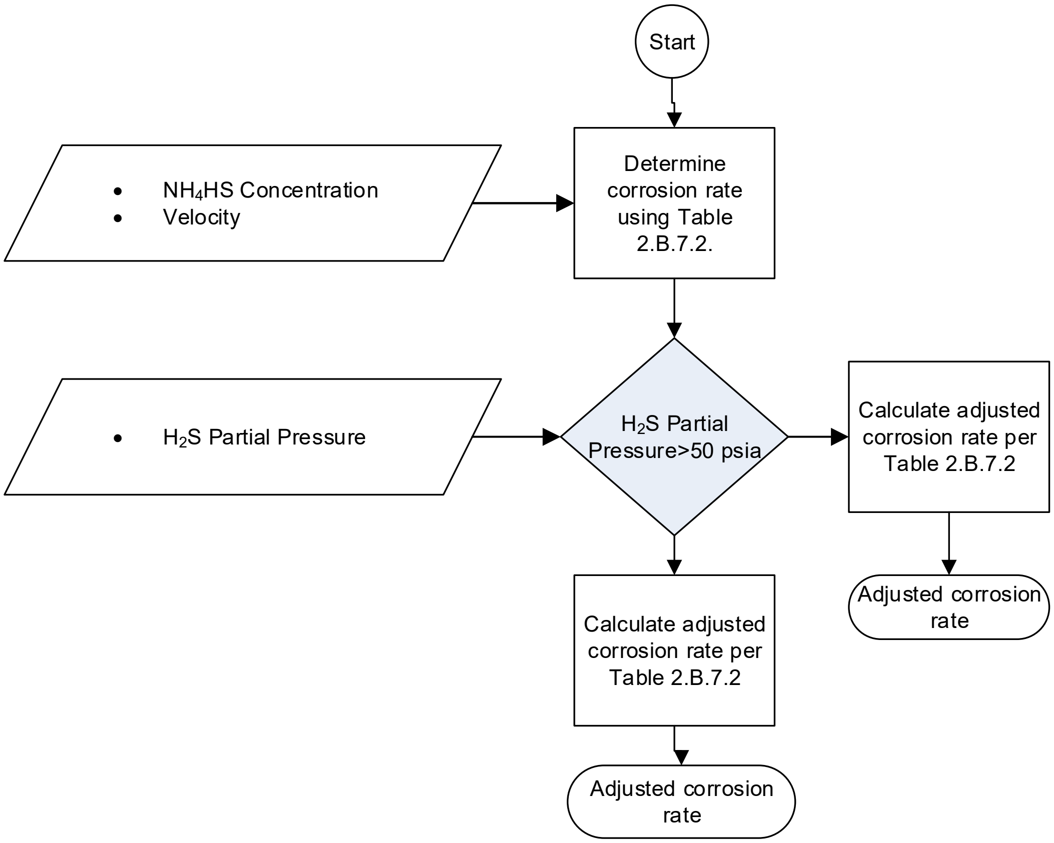

Figure 2.B.7.1—Alkaline Sour Water Corrosion—Determination of Corrosion Rate

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 (see Section 7). 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 H_2S, from plant streams. MEA and DEA will also remove CO_2, but MDEA is selective to H_2S and will remove little CO_2 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 H_2S and CO_2 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 H_2S-only systems, rich amine loadings up to 0.70 mole/mole have been satisfactory. In H_2S + CO_2 systems, rich loading is often limited to 0.35 to 0.45

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mole/mole. In MDEA units, and particularly those used for selective H_2S 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 stainless steels 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, reclaimer, 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 that 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 [38] (Appendix B—Considerations for Corrosion Control), [122], [123], [124], [125], [126], [127], [128], [129], [130], and [131] in Section 2.2.

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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 (°C :°F)	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 (m/s:ft/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

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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

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

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

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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

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

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

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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 ≤149 °C (300 °F)	
	mm/y	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

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2.B.8.6 Figures

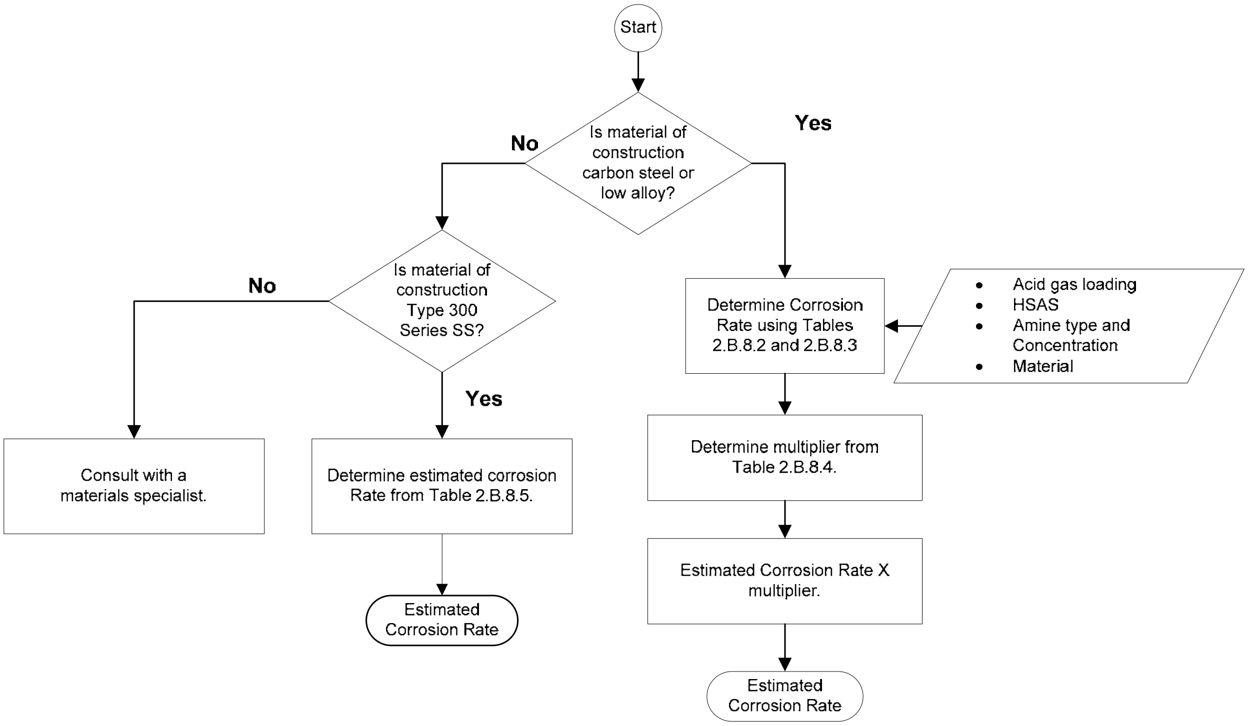

Figure 2.B.8.1—Amine Corrosion—Determination of Corrosion Rate

2.B.9 High Temperature Oxidation

2.B.9.1 Description of Damage

Corrosion due to high temperature oxidation occurs at temperatures above about 482 °C (900 °F) 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.

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2.B.9.4 Tables

Table 2.B.9.1—High Temperature Oxidation—Basic Data Required for Analysis

Basic Data	Comments
Material of construction	Determine the material of construction of this equipment/piping.
Maximum metal temperature (°C :°F)	Determine the maximum metal temperature. The tube metal temperature for furnace tubes is the controlling factor.

Table 2.B.9.2—High Temperature Oxidation—Estimated Corrosion Rate (mpy)

Material	Maximum Metal Temperature (°F)											
	925	975	1025	1075	1125	1175	1225	1275	1325	1375	1425	1475
CS	2	4	6	9	14	22	33	48	—	—	—	—
1 $^1/_4$ Cr	2	3	4	7	12	18	30	46	—	—	—	—
2 $^1/_4$ Cr	1	1	2	4	9	14	24	41	—	—	—	—
5 Cr	1	1	1	2	4	6	15	35	65	—	—	—
7 Cr	1	1	1	1	1	2	3	6	17	37	60	—
9 Cr	1	1	1	1	1	1	1	2	5	11	23	40
12 Cr	1	1	1	1	1	1	1	1	3	8	15	30
304 SS	1	1	1	1	1	1	1	1	1	2	3	4
309 SS	1	1	1	1	1	1	1	1	1	1	2	3
310 SS/HK	1	1	1	1	1	1	1	1	1	1	1	2
800 H/HP	1	1	1	1	1	1	1	1	1	1	1	2

Table 2.B.9.2M—High Temperature Oxidation—Estimated Corrosion Rate (mm/y)

Material	Maximum Metal Temperature (°C)											
	496	524	552	579	607	635	663	691	718	746	774	802
CS	0.05	0.1	0.15	0.23	0.36	0.56	0.84	1.22	—	—	—	—
1 $^1/_4$ Cr	0.05	0.08	0.1	0.18	0.3	0.46	0.76	1.17	—	—	—	—
2 $^1/_4$ Cr	0.03	0.03	0.05	0.1	0.23	0.36	0.61	1.04	—	—	—	—
5 Cr	0.03	0.03	0.03	0.05	0.1	0.15	0.38	0.89	1.65	—	—	—
7 Cr	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.15	0.43	0.94	1.52	—
9 Cr	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.13	0.28	0.58	1.02
12 Cr	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.08	0.2	0.38	0.76
304 SS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08	0.1
309 SS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.08
310 SS/HK	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05
800 H/HP	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.05

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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	—	—	—	—	—	—	—	—	—	—	—	—
5 Cr	—	—	—	—	—	—	—	—	—	—	—	—
7 Cr	—	—	—	—	—	—	—	—	—	—	—	—
9 Cr	60	—	—	—	—	—	—	—	—	—	—	—
12 Cr	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/y)

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	—	—	—	—	—	—	—	—	—	—	—	—
5 Cr	—	—	—	—	—	—	—	—	—	—	—	—
7 Cr	—	—	—	—	—	—	—	—	—	—	—	—
9 Cr	1.52	—	—	—	—	—	—	—	—	—	—	—
12 Cr	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

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2.B.9.5 Figures

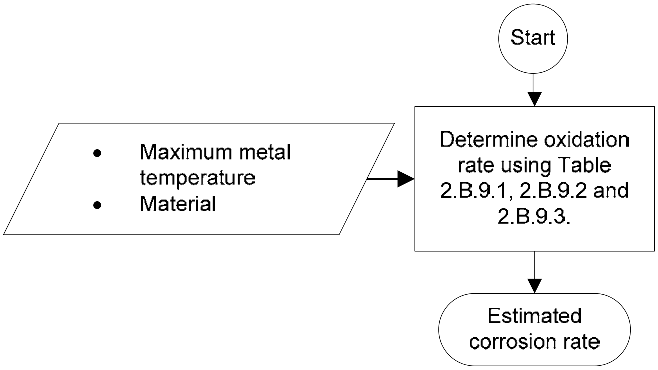

Figure 2.B.9.1—High Temperature Oxidation—Determination of Corrosion Rate

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 paragraph.

2.B.10.1.2 Scope and Limitations

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

a) Primary corrosive is H_2S. Assuming no significant amounts of ammonia, carbon dioxide, chlorides, or cyanides are present.

b) The corrosion mechanism is general corrosion, with some occurrence of pitting in the presence of oxygen.

c) This paragraph 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 CLSCC 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/y (2 mpy).

d) Cracking is not considered. Wet H_2S cracking mechanisms are addressed elsewhere in this document.

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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 1.83 m/s (6 ft/s). When velocities exceed 1.83 m/s (6 ft/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 have not been measured, a knowledgeable process specialist should be consulted.

2.B.10.3 Determination of Corrosion Rate

The steps required to determine the corrosion rate are 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).

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

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 dissolved oxygen. 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):

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

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

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

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

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

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

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

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)

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2.B.10.5 References

See References [132], [133], [134], [135], and [136] in Section 2.2.

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 max. 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, °C (°F)	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, m/s (ft/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/y)—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

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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

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2.B.10.7 Figures

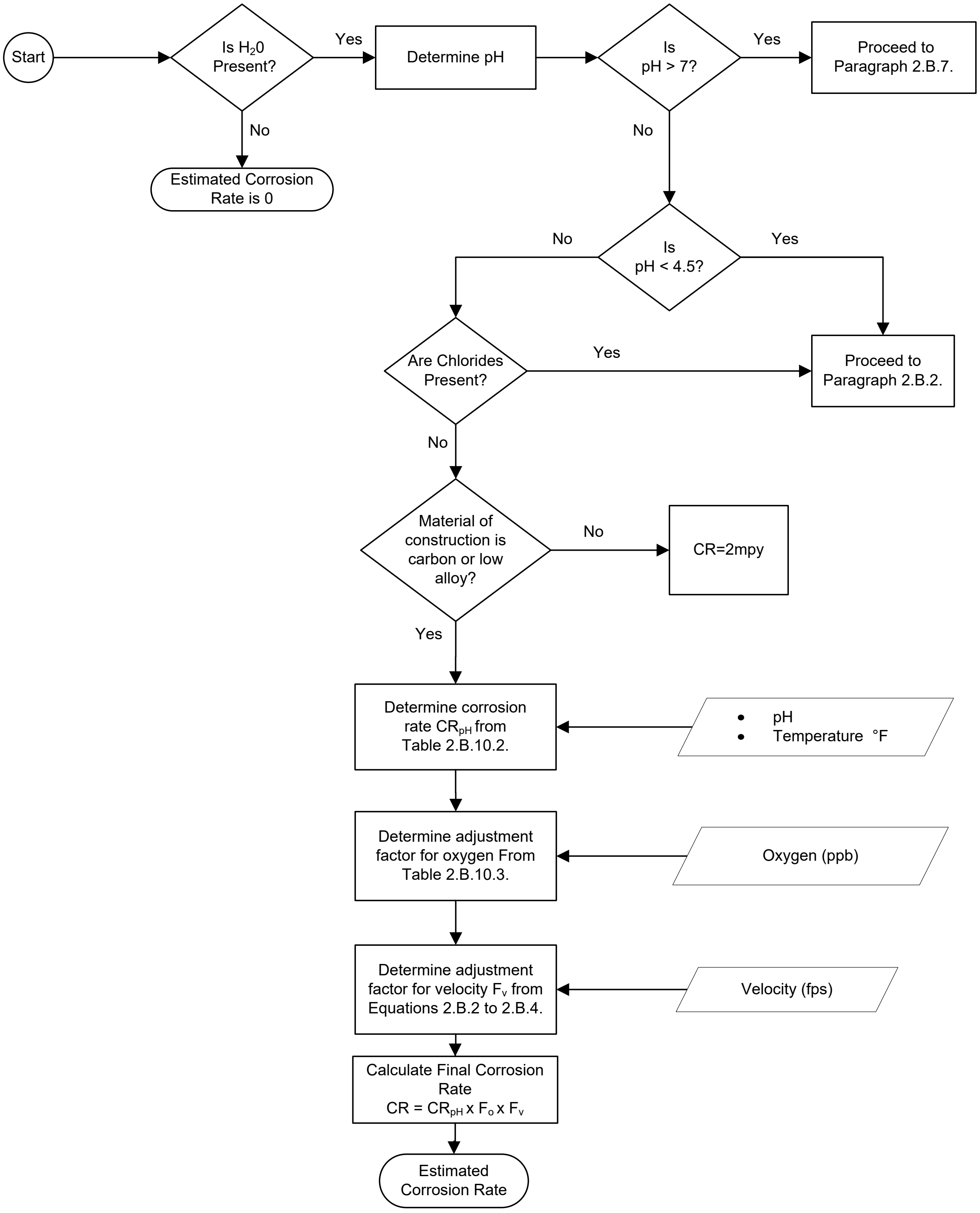

Figure 2.B.10.1—Acid Sour Water—Determination of Corrosion Rate

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2.B.11 Cooling Water Corrosion

2.B.11.1 Description of Damage

2.B.11.1.1 Overview

The objective for this paragraph is to describe a conservative approach for estimating corrosion rates of carbon steel components in cooling water systems. In fresh water 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 paragraph also describes qualitatively some of these considerations.

This paragraph 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 dissolved oxygen. In a general way, corrosion of iron and steel is proportional to the chloride content when dissolved oxygen 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

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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 non-oxidizing 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 fresh-water 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

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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 stainless steels 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 stainless steels 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.

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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 non-oxidizing.

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 60 °C (140 °F), then a scaling potential exists. However, note that 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 $Cl_2+H_2O \rightarrow HCLO+HCL$. 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.

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With fresh waters, corrosion of steel is governed by dissolved oxygen 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 dissolved oxygen through the deposit. At the metal surface under the deposit, oxygen is reduced cathodically. Cathodic reduction of dissolved oxygen 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 non-oxidizing 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 risk-based inspection model does not attempt to address every issue that must be considered. For the purposes of this model, the following assumptions have been made.

a) Low alloy steels are rarely used in cooling water systems and will not be addressed in the remainder of this paragraph. However, most of the content for carbon steel applies to low alloy steels.

b) 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.

c) 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).

d) 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.

e) An effective microbiological control program is in place, and corrosion driven by MIC is negligible, i.e. can be set to < 0.13 mm/y (5 mpy), pitting.

f) 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 paragraph.

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 paragraph 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

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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 dissolved oxygen, 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 [>60 °C (140 °F)], 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 computed 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.

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

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

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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 2.44 m/s (8 ft/s)].

The concept of RSIs 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).

$$LSI = pH_a - pH_s \tag{2.B.9}$$

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 Langelier index 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 Ca2+ 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 Langelier index 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.

$$RSI = 2 \cdot pH_s - pH_a \tag{2.B.10}$$

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.

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

All values of the Stability Index 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. Note that 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, the effect from scaling is assumed not protective against corrosion.

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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 dissolved oxygen.

2.B.11.3.1.3 Temperature Factor

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

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

This ΔT is used to determine the temperature correction factor, F_T, using Table 2.B.11.5. Note that 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 dissolved oxygen, which allows oxygen to escape. Therefore, at temperatures of 79 °C (175 °F) and greater, the corrosion rate decreases. However, in a closed system, the corrosion rate increases with temperature because of retention of small amounts of dissolved oxygen 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):

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

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

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

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

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

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

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

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, dissolved oxygen, pH, and velocity. However, the trend shown in Table 2.B.11.6 does comply with actual testing described in Reference [52] for velocities up to 2.13 m/s (7 ft/s). Note that for carbon steel in seawater, the velocity is even more a governing factor for the corrosion rate.

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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 paragraph 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 fresh water systems, and the corrosion rates are determined as a function of temperature, water flow velocity, dissolved oxygen, 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). Dissolved oxygen is typically present at normal saturated values of 6 to 8 ppm at 24 °C to 29 °C (75 °F to 85 °F). The pH of seawater is usually 7.7 to 8.3 in surface waters [44]. Seawater always contains SRB and a level of sulfate ion concentration (2 to 3,000 ppm) conductive 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 88 °C (190 °F). 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 seasquirts). 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.

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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 0.10 and 0.20 mm/y (4 and 8 mpy), 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 39.6 m/s (130 ft/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 in References [45], [50], and [51], Equations (2.B.19) and (2.B.20) may be used to compute 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):

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

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

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

Equations (2.B.19) and (2.B.20) were developed based on the data specified in Reference [50], assuming seawater temperature of about 21 °C (70 °F) and an oxygen concentration of 6 to 8 ppm.

With high flow rates, the corrosion rate increases up to around 12.2 m/s (40 ft/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 6.1 m/s (20 ft/s).

2.B.11.3.3 Groundwater

Groundwaters are not specifically addressed in this paragraph. 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.

Groundwaters 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 CO_2, 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 [<0.03 mm/y (1 mpy)] corrosion rate.

b) Medium [0.03 to 0.25 mm/y (1 to 10 mpy)].

c) High [0.25 to 1.27 mm/y (10 to 50 mpy)].

d) Very High [>1.27 mm/y (50 mpy)].

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

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2.B.11.4 Nomenclature

CR	is the corrosion rate, mm/yr (mpy)
CR_B	is the base corrosion rate, mm/yr (mpy)
$C_1 \rightarrow C_4$	are the pH_s calculation parameters
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 = 24 °C (75 °F)
T_{op}	is the corrosion operating temperature, °C (°F)
V_a	is the actual velocity, m/s (ft/s)
ΔT	is the temperature difference, °C (°F)

2.B.11.5 References

See References [137], [138], [139], [140], [141], [142], [143], [144], and [145] in Section 2.2.

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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, (°C:°F)	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 (incl. ammonia), phosphates, Cu, etc. that potentially effect under-deposit corrosion.
Ca (mg/L) as $CaCO_3$	Determine calcium hardness as calcium carbonate ($CaCO_3$).
Methyl orange 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 (m/s: ft/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 (m/s:ft/s)	Determine the maximum and minimum expected water velocities.

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Table 2.B.11.3—pH Calculation Parameters

<table>
<tr><th colspan="3">C_1 Factor</th><th colspan="2">C_3 Factor</th><th colspan="2">C_4 Factor</th></tr>
<tr><th colspan="2">Total Solids (mg/L)</th><th>C_1</th><th>Calcium Hardness (mg/L $CaCO_3$)</th><th>C_3</th><th>M.O. Alkalinity (mg/L $CaCO_3$)</th><th>C_4</th></tr>
<tr><td colspan="2">50 to 400</td><td>0.1</td><td>10.5</td><td>0.6</td><td>10.5</td><td>1.0</td></tr>
<tr><td colspan="2">>400 to 1000</td><td>0.2</td><td>12.5</td><td>0.7</td><td>12.5</td><td>1.1</td></tr>
<tr><th colspan="3" rowspan="2">C_2 Factor</th><td>15.5</td><td>0.8</td><td>15.5</td><td>1.2</td></tr>
<tr><td>20</td><td>0.9</td><td>20</td><td>1.3</td></tr>
<tr><th rowspan="2">Temperature (ºC)</th><th rowspan="2">Temperature (ºF)</th><th rowspan="2">C_2</th><td>25</td><td>1.0</td><td>25</td><td>1.4</td></tr>
<tr><td>31</td><td>1.1</td><td>31</td><td>1.5</td></tr>
<tr><td>1</td><td>33</td><td>2.6</td><td>39</td><td>1.2</td><td>40</td><td>1.6</td></tr>
<tr><td>4</td><td>39</td><td>2.5</td><td>49.5</td><td>1.3</td><td>50</td><td>1.7</td></tr>
<tr><td>8</td><td>46</td><td>2.4</td><td>62.5</td><td>1.4</td><td>62.5</td><td>1.8</td></tr>
<tr><td>12</td><td>53</td><td>2.3</td><td>78.5</td><td>1.5</td><td>79</td><td>1.9</td></tr>
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<tr><td>77</td><td>170</td><td>1.2</td><td>940</td><td>2.6</td><td>945</td><td>3.0</td></tr>
</table>

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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

NOTES

— RSI < 4—Heavy scale forming, non-aggressive.

— RSI 5 to 6—Slightly scale forming and mildly aggressive.

— RSI 6 to 6.5—Balanced or at $CaCO_3$ saturation.

— RSI 6.5 to 7—Non-scaling and slightly aggressive.

— 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/y)	
	RSI ≤ 1.8 and Velocity ≤ 2.4 m/s	RSI ≤ 1.8 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

NOTES

— RSI < 4—Heavy scale forming, non-aggressive.

— RSI 5 to 6—Slightly scale forming and mildly aggressive.

— RSI 6 to 6.5—Balanced or at $CaCO_3$ saturation.

— RSI 6.5 to 7—Non-scaling and slightly aggressive.

— RSI > 8—Under-saturated, very aggressive.

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

Operating Temperature (°F)		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
41	105	4.3	2.5
99	210	4.5	1.7

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

Flow Velocity		F_V—Flow Velocity Factor
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

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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

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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/y)
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

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2.B.11.7 Figures

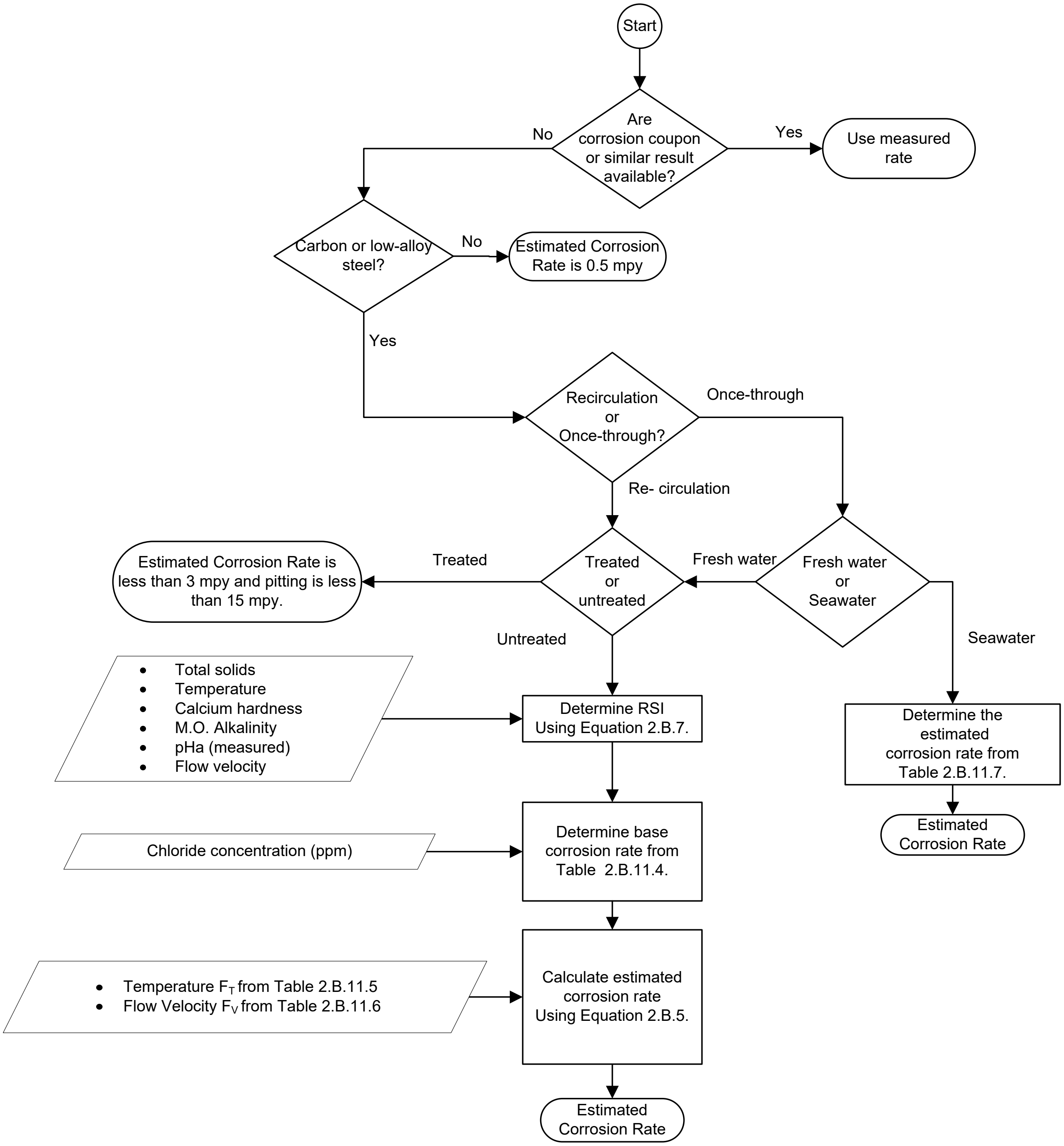

Figure 2.B.11.1—Cooling Water—Determination of Corrosion Rate

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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 paragraph 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 STP 741, 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 4-pin Werner technique as described in ASME 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.

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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 RP0169.

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 dissolved oxygen, 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 dissolved oxygen 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 reduce 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, dissolved oxygen 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

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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):

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

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 paragraphs.

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 0.13 mm/y (5 mpy) 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 0.13 and 0.25 mm/y (5 and 10 mpy), or as an average 0.178 mm/y (7 mpy), 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.

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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 3 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 RP0169 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.

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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:

$$F_{CE} = 1.5 \cdot 1.2 \cdot 3.0 \cdot 1.5 = 13.5 \qquad (2.B.22)$$

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

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2.B.12.6 References

See References [141], [145], [146], [147], [148], [149], [150], and [151] in Section 2.2.

2.B.12.7 Tables

Table 2.B.12.1—Soil-Side Corrosion—Basic Data Required for Analysis

Basic Data		Comments
Base corrosion rate, mm/yr (mpy)		The expected or observed corrosion rate for the buried structure, or a "similar" structure under "similar" service and conditions.
Equipment temperature, °C (°F)		Equipment temperature (operating temperature for piping and pipelines).
Soil resistivity, Ω-cm		Soil characteristics in the vicinity of the buried structure.
Cathodic protection (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/y	mpy
Sand	Low chlorides (inland, non-industrial)	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

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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 RP0169) 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 Liquid epoxy Asphalt enamel Asphalt mastic	1.0	1.1	1.5	1.1
Coal tar enamel	1.0	1.2	2.0	1.5
Extruded polyethylene 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 PP	1.0	1.2	2.0	1.2

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2.B.12.8 Figures

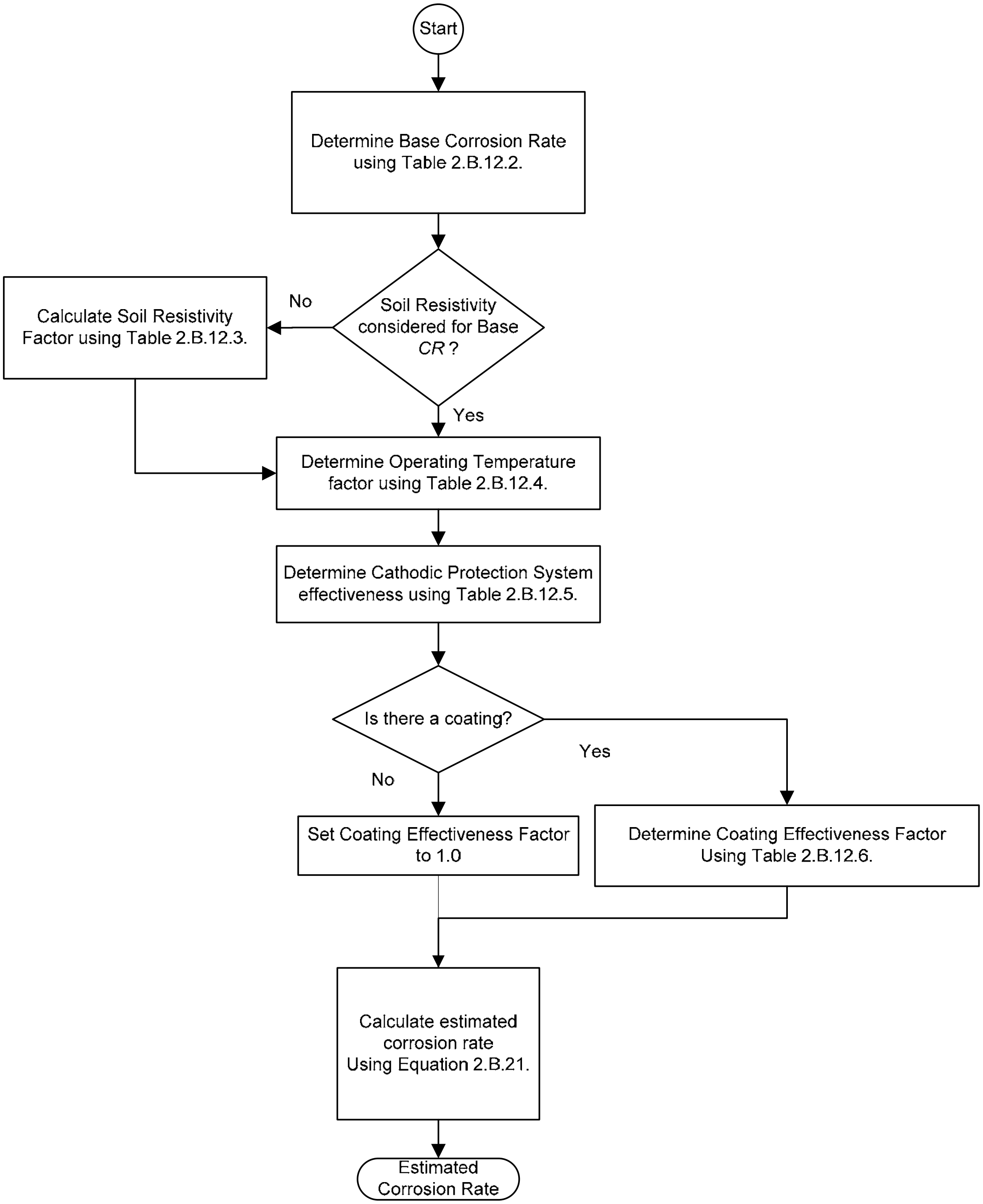

Figure 2.B.12.1—Soil-side Corrosion—Determination of Corrosion Rate

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2.B.13 CO_2 Corrosion

2.B.13.1 Description of Damage

Carbon dioxide is a weakly acidic gas. In streams with carbon dioxide and free water, the CO_2 dissolves in water producing carbonic acid (H_2CO_3). The carbonic acid then dissolves the steel producing iron carbonate and hydrogen ($Fe+H_2CO_3 \rightarrow FeCO_3+H_2$). Despite being a weak acid, carbonic acid can be extremely corrosive to carbon steel. CO_2 is commonly found in upstream sections before treatment. CO_2 corrosion requires the presence of free water in order to produce the Carbonic acid. The primary variables that influence CO_2 corrosion rates are the CO_2 concentration, operating pressure, operating temperature, application of inhibitors, flow rate, and presence of hydrocarbon fluids, and contaminants in the system.

Aqueous CO_2 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 $FeCO_3$ (and/or $Fe3O_4$), 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).

$$CR = CR_B \cdot \min\left[F_{glycol},\ F_{inhib}\right] \tag{2.B.23}$$

The calculation of the base corrosion rate, CR_B, is most complex; it depends on the temperature, the partial pressure of CO_2, the fluid flow velocity, and the pH of the fluid. The following paragraphs 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, 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 in the stream is greater than 100 %. When a mixture of water vapor and natural gas behaves approximately as ideal gases, the relative humidity in a gas is 100 % when the partial pressure of the water vapor is equal to the saturation pressure. This result in the simplified formula for the relative humidity,

$$RH = \left(\frac{x \cdot P}{P_{sat}(T)}\right)\left(\frac{1}{0.622 + x}\right) \tag{2.B.24}$$

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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 $P_{sat}(T)$ is the saturation pressure for water at temperature, T, which can be obtained from steam tables. The 0.622 is the ratio of the molecular weight of water (≈18) to the average molecular weight of air (≈29). Using Equation (2.B.24) and standard steam tables, an approximate equation for the dew point temperature T_d (°F) can be derived; see Equation (2.B.25):

$$\log_{10} T_d = 2.0866 + 0.2088 \cdot \log_{10}\left[\frac{\%w}{100}\right] + 0.2242 \cdot \log_{10}[P] \tag{2.B.25}$$

In Equation (2.B.25), P is the pressure in psia, and $\%w$ is the percent water by weight in the stream (lbm/100lbm), between 0 and 30.

2.B.13.3.3 Base Corrosion Rate

The base corrosion rate in mm/y is calculated from Equation (2.B.26).To obtain mpy, multiply the result in mm/y by 39.4.

$$CR_{base} = f(T, pH) \cdot f_{CO_2}^{\;0.62} \cdot \left(\frac{S}{19}\right)^{0.146 + 0.0324\, f_{CO_2}} \tag{2.B.26}$$

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 80 °C and 90 °C (176 °F and 194 °F.).

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 paragraphs.

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:

$$pH = 2.8686 + 0.7931 \cdot \log_{10}[T] - 0.57 \cdot \log_{10}\left[p_{CO_2}\right] \tag{2.B.27}$$

for Fe^{++} saturated water:

$$pH = 2.5907 + 0.8668 \cdot \log_{10}[T] - 0.49 \cdot \log_{10}\left[p_{CO_2}\right] \tag{2.B.28}$$

and for water with salinity slightly greater than seawater (salinity = 46 g/l):

$$pH = 2.7137 + 0.8002 \cdot \log_{10}[T] - 0.57 \cdot \log_{10}\left[p_{CO_2}\right] \tag{2.B.29}$$

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.

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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}.

$$\log_{10}\left[f_{CO_2}\right] = \log_{10}\left[p_{CO_2}\right] + \min\left[250,\, p_{CO_2}\right]\cdot\left(0.0031 - \frac{1.4}{T+273}\right) \tag{2.B.30}$$

$$\log_{10}\left[f_{CO_2}\right] = \log_{10}\left[p_{CO_2}\right] + \log_{10}\left[a\right] \tag{2.B.31}$$

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 that the fugacity coefficient, a, is the ratio between CO$_2$ fugacity and the partial pressure, or:

$$f_{CO_2} = p_{CO_2}\cdot a \tag{2.B.32}$$

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.

$$S = \frac{f\cdot\rho_m\cdot u_m^2}{2} \tag{2.B.33}$$

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):

$$f = 0.001375\left[1 + \left(20000\left(\frac{e}{D}\right) + \frac{10^6}{Re}\right)^{0.33}\right] \tag{2.B.34}$$

The term e/D is the relative roughness and Re is the Reynolds Number of the mixture given by Equation (2.B.35):

$$Re = \frac{D\rho_m u_m}{\mu_m} = \frac{\dot{m}D}{A\mu_m} \tag{2.B.35}$$

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.

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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, 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 CO_2 corrosion rate. M-506 accounts for this by simply reducing the corrosion rate by applying a factor of the form:

$$\log_{10}\left[F_{glycol}\right] = 1.6\cdot\left(\log\left[100 - G\right] - 2\right) \quad (2.B.36)$$

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 fugacity coefficient
A	is the pipe cross-sectional area, m^2 (ft^2)
CR	is the corrosion rate
CR_B	is the base corrosion rate
D	is the pipe diameter, m [ft]
e/D	is the relative roughness
f	is the fraction factor
f_{CO_2}	is the CO_2 fugacity, bar
$f(T, pH)$	is the temperature-pH function
F_{glycol}	is the corrosion rate correction factor for glycol
F_{inhib}	is the corrosion rate correction factor for the inhibitor
G	is the percent weight of glycol as a percent of water in the system
$\dot{m}$	is the calculated using the mass flux, kg/(m^2-s) [lb/(ft^2-s)]
P	is the pressure, psia

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p_{CO_2}	is the CO_2 partial pressure, bar (psi)
$P_{sat}(T)$	is the saturation pressure for water at temperature T, psia
$\%w$	is the percent water by weight in the stream
Re	is the Reynolds Number
RH	is the relative humidity
S	is the shear stress, Pa
T	is the temperature, °C (°F)
T_d	is dew point temperature, °C (°F)
u_m	is the mixture flow velocity, m/s
x	is the ratio of the mass of water to the mass of dry gas
ρ_m	is the mixture mass density, kg/m^3
μ_m	is the viscosity of the mixture, cP

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2.B.13.5 Tables

Table 2.B.13.1—CO_2 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 140 °C (284 °F) 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 4 MPa (580 psi) 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 non-ideal 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 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.

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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

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2.B.13.6 Figures

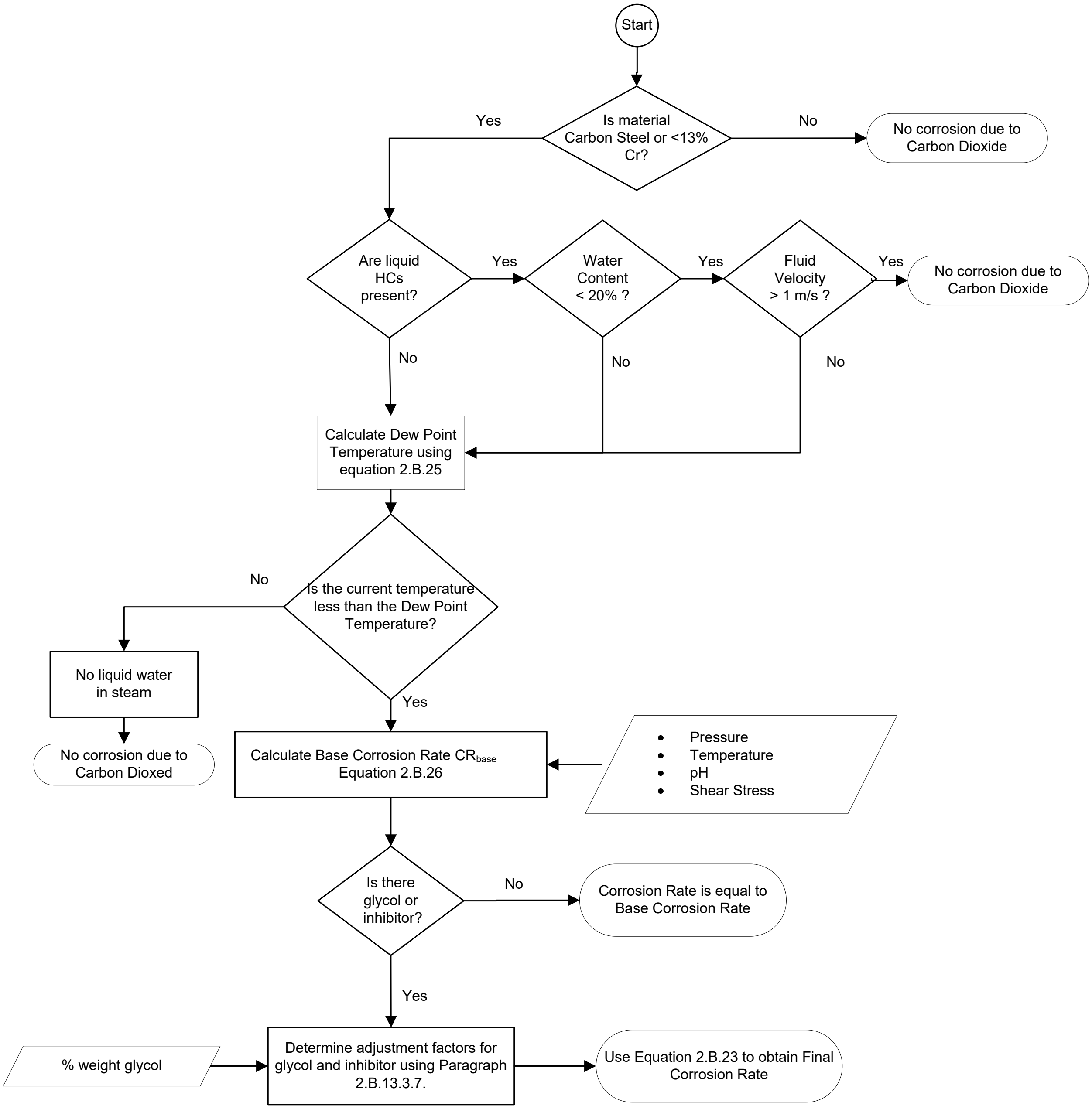

Figure 2.B.13.1—CO_2 Corrosion—Determination of Corrosion Rate

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2.B.14 Atmospheric 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 AST bottoms constructed of carbon steel. Product-side corrosion can result in general or localized thinning. Factors affecting product-side corrosion is the stored product corrosivity characteristics, operating temperature, steam coil practices, and the presence of water in the AST. Soil-side corrosion results in localized thinning. Factors affecting soil-side corrosion are soil type, pad type, water draining, CP, AST 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).

$$CR_S = CR_{SB} \cdot F_{SR} \cdot F_{PA} \cdot F_{TD} \cdot F_{CP} \cdot F_{TB} \cdot F_{ST} \tag{2.B.37}$$

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 0.13 mm/y (5 mpy). This base corrosion rate is the expected or observed corrosion rate for a typical AST 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 AST pad can affect the corrosion rate of the AST bottom. The resistivity of the AST pad material may be higher than the existing surrounding soil. However, corrosive soil beneath the high resistivity AST pad material may contaminate the AST 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 AST 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 that an adjustment factor of 1 is used for ASTs with RPBs, since RPBs effectively prevent the contamination of the AST pad material by the native soil.

b) Adjustment Factor for AST Pad, F_{PA}—The corrosion rate adjustment factor is given in Table 2.B.14.5. The type of pad or foundation that the AST rests upon will influence the corrosion rate. The adjustment factors are assigned in a similar manner to those for the native soil beneath the AST 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 AST can greatly increase corrosion. The adjustment is

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made so that storm water collecting around a AST 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 AST 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 AST.

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. Note that unless a High Level inspection can verify that the CP system is effective (verified by inspection in compliance with NACE RP0169 or equivalent), no credit is obtained for the CP system.

e) Adjust for AST 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 AST 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).

$$CR_P = CR_{PB} \cdot F_{PC} \cdot F_{PT} \cdot F_{SC} \cdot F_{WD} \tag{2.B.38}$$

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 0.05 mm/y (2 mpy). 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.

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2.B.14.3.3 Combined Atmospheric 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. Note that in order 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 AST 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 AST 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

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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 (mm/y: mpy)	If measured or estimated soil-side corrosion rate is available, it should be used and substituted for the base soil-side corrosion rate of 0.13 mm/y (5 mpy).
Soil condition (Ω-cm)	Soil resistivity of native soil underneath and around the AST or dike area. A common method of measuring soil resistivity is described in ASTM G57.
AST pad	The type of AST pad material (soil, sand, etc.) upon which the tank rests. In the case of an AST supported on a ring wall, it is the material used for filling inside the wall.
AST drainage	The effectiveness with which rainwater is drained away from the AST and prevented from collecting under the AST bottom.
CP	The existence of a CP system for the AST 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 (°C:°F)	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)	If measured or estimated soil-side corrosion rate is available, it should be used and substituted for the base soil-side corrosion rate of 0.05 mm/y (2 mpy).
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).
AST 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 AST.

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)
AST pad material	Continuous asphalt or concrete
AST drainage	Storm water does not collect around base of AST
CP	None or not functioning
Bottom type	Single bottom
Bulk fluid temperature	Below 24 °C (75 °F)

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Table 2.B.14.4—Soil-Side Soil Resistivity Adjustment Factor

Resistivity (ohm-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
AST with RPB		1.0

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Table 2.B.14.5—Soil-Side AST Pad Adjustment Factor

AST 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 AST Drainage Adjustment Factor

AST Drainage Type	Multiplying Factor—F_{TD}
One-third frequently underwater	3
Storm water collects at AST base	2
Storm water does not collect at AST 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

AST 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 < Temp ≤ 66	75 < Temp ≤ 150	1.1
66 < Temp ≤ 93	150 < Temp ≤ 200	1.3
93 < Temp ≤ 121	200 < Temp ≤ 250	1.4
>121	>250	1.0

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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 24 °C (75 °F)
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 < Temp ≤ 66	75 < Temp ≤ 150	1.1
66 < Temp ≤ 93	150 < Temp ≤ 200	1.3
93 < Temp ≤ 121	200 < Temp ≤ 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

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2.B.14.6 Figures

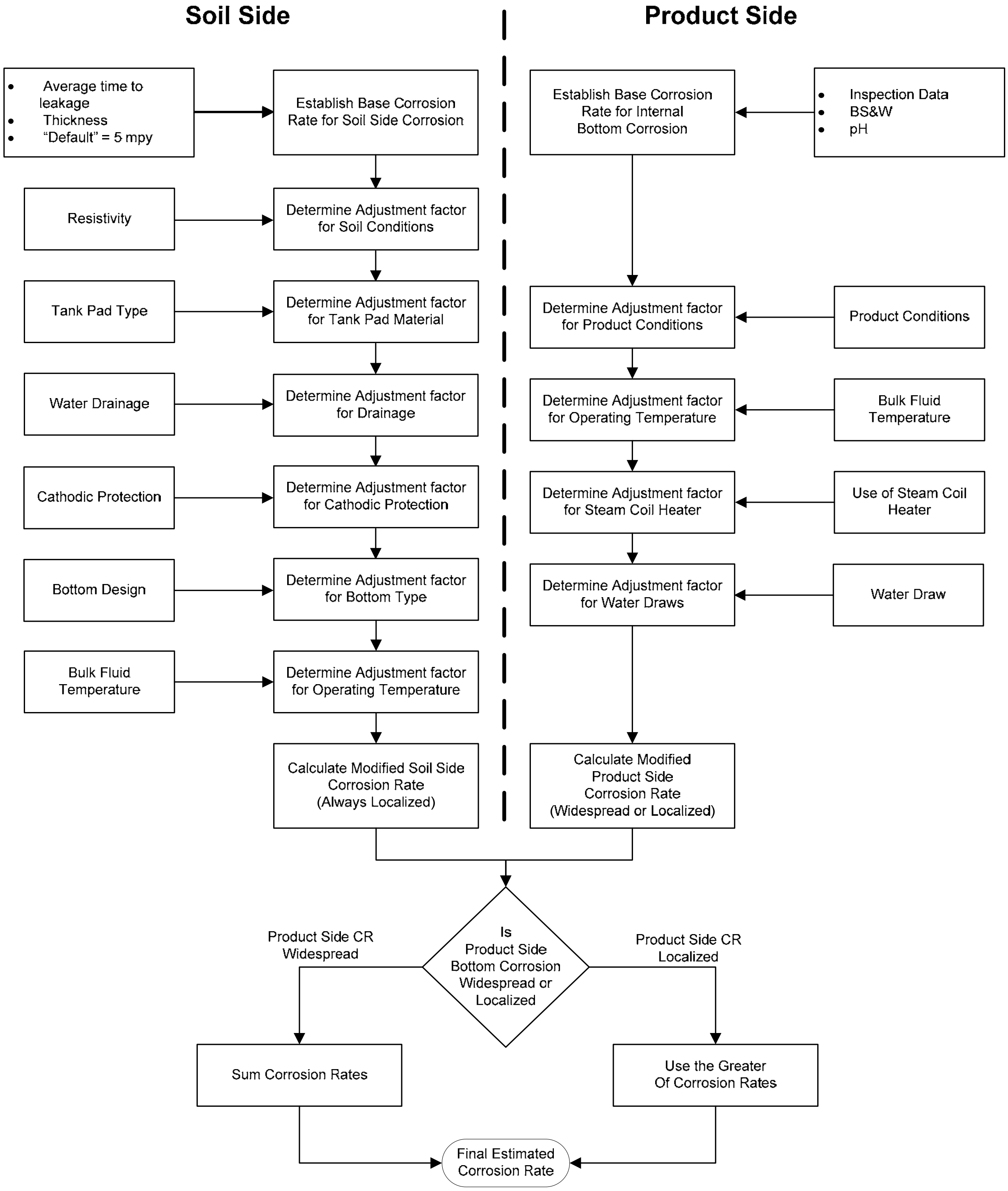

Figure 2.B.14.1—AST Bottom Corrosion—Determination of Soil-Side and Product-Side Corrosion Rates

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PART 2

ANNEX 2.C—LEVELS OF INSPECTION EFFECTIVENESS

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PART 2, ANNEX C CONTENTS

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Risk-Based Inspection Methodology
Part 2—Probability of Failure Methodology
Annex 2.C—Levels of Inspection Effectiveness

2.C.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.C.2 Inspection Effectiveness

2.C.2.1 The Value of Inspection

An estimate of the probability of failure 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 probability of failure, 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, ultrasonic, radiographic, 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.

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Determination of inspection effectiveness should consider, but not be limited to, the following:

a) equipment or component type;

b) active and credible damage mechanism(s);

c) susceptibility to and rate of damage;

d) NDE methods, coverage and frequency; and

e) accessibility to expected damaged areas.

API 580, Section 5.5 states:

> *"A complete RBI program provides a consistent methodology for assessing the optimum combination of methods and frequencies of inspection. Each available inspection method can be analyzed and its relative effectiveness in reducing failure probability can be estimated. Given this information and the cost of each procedure, an optimization program can be developed. The key to developing such a procedure is the ability to assess the risk associated with each item of equipment and then to determine the most appropriate inspection techniques for that piece of equipment."*

2.C.2.2 Inspection Effectiveness Categories

Levels of inspection effectiveness (LoIE) examples for specific equipment types (heat exchangers, pressure-relief valves, tanks, and buried components) are provided in Sections 2.C.3 through 2.C.7. The associated inspection effectiveness examples (i.e. NDE technique and coverage) for each damage mechanism are provided in Section 2.C.8 through 2.C.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.C.2.1 for a description of the inspection effectiveness categories.

IMPORTANT NOTE

The tables describing the levels of inspection effectiveness 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.

- Adapt and adopt similar tables for their specific use.
- Adapt user-specific knowledge and experience to add NDE techniques and areas of concern not currently in the tables.
- 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.

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2.C.2.3 Tables

Table 2.C.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.C.3 Pressure-relief Valves

Inspection programs vary in their effectiveness for determining failure rates. Examples of inspection effectiveness for PRDs are provided in Table 2.C.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 1, Section 7.2.4 for further discussion on the inclusion of inspection effectiveness ranking into the determination of POF for PRDs.

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2.C.3.1 Tables

Table 2.C.3.1—Inspection and Testing Effectiveness for Pressure-relief Devices

Inspection Effectiveness	Component Type	Description of Inspection
Highly Effective A	Pressure-relief device	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 reseat pressure have been documented on the test form. The inlet and outlet piping has been examined (e.g. visual or radiographic 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	Pressure-relief device	A bench test has been performed; however, the PRD was cleaned or steamed out prior to the bench test. Additionally, a visual inspection 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. visual or radiographic 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. visual or radiographic 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. visual or radiographic techniques techniques) for signs of excessive plugging or fouling [2].
Fairly Effective C	Pressure-relief device	A visual inspection 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. visual or radiographic 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	Pressure-relief device	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–user may decide to waive the inlet and outlet piping inspection requirement.

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2.C.4 Heat Exchanger Tube Bundles

2.C.4.1 Inspection Planning with Inspection History

2.C.4.1.1 Effect of Inspection on Probability of Failure

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 probability of failure rate curves as necessary.

An inspection provides the following two things.

a) 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 % AU curve (no inspection history) to a curve 20 % AU curve (Usually Effective Inspection); see Section 2.C.4.1.1 b) for a discussion of inspection effectiveness.

b) 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; see Part 1, Section 8.6.4 c).

2.C.4.1.2 Reduction in Uncertainty Due to Inspection Effectiveness

If the tube bundle has been inspected, the uncertainty is reduced and the probability of failure at any time changes. Table 2.C.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.C.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.C.4.1. The definitions for inspection effectiveness are provided in Table 2.C.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, ID and/or OD);

d) cracking (circumferential and/or longitudinal);

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e) fretting;

f) tube end damage (cracking and/or corrosion);

g) seal weld cracking/failure;

h) erosion/erosion-corrosion, etc.

Examples of various typical NDE methods for tube inspection include and are not limited to:

a) visual inspection;

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 visual and other types of inspection like PT, pit depth gauging, caliper measurements, etc.

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.C.4.1 is provided as a basic guideline for the owner–user created LoIE table(s), which is based on their experience and confidence in the results.

2.C.4.1.3 Tables

Table 2.C.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

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2.C.5 Atmospheric Storage Tank Components

2.C.5.1 Inspection Effectiveness for Atmospheric 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 ASTs 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 an AST 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 AST 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.C.5.1 through 2.C.5.3 outline inspection areas combined with examples of inspection effectiveness categories for AST components.

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2.C.5.2 Tables

Table 2.C.5.1—LoIE Example for AST Shell Course Internal Corrosion

Inspection Category	Inspection Effectiveness Category	Inspection [1]
A	Highly Effective	Both inspections shall be done: — intrusive inspection—good visual inspection 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 AST or similar service ASTs — 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 AST type or service
D	Poorly Effective	External spot UT based at suspect locations without benefit of any internal inspection information on AST type or service
E	Ineffective	Ineffective inspection technique/plan was utilized

NOTE 1 Inspection quality is high.

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Table 2.C.5.2—LoIE Example for AST Shell Course External Corrosion

Inspection Category	Inspection Effectiveness Category	Insulated Tank Inspection Example [1]	Non-Insulated Tank Inspection Example [1]
A	Highly Effective	— >95 % external visual inspection prior to removal of insulation — Remove >90 % of insulation at suspect locations **OR** >90 % pulse eddy current inspection — Visual inspection of the exposed surface area with follow-up by UT or pit gauge as required	>95 % visual inspection of the exposed surface area **AND** Follow-up by UT or pit gauge as required
B	Usually Effective	— >95 % external visual inspection prior to removal of insulation — Remove >50 % of insulation at suspect locations **OR** >50 % pulse eddy current inspection — Visual inspection of the exposed surface area with follow-up by UT or pit gauge as required	>50 % visual inspection of the exposed surface area **AND** Follow-up by UT or pit gauge as required
C	Fairly Effective	— >95 % external visual inspection prior to removal of insulation — Remove >30 % of insulation at suspect locations **OR** >30 % pulse eddy current inspection — Visual inspection of the exposed surface area with follow-up by UT or pit gauge as required	>25 % visual inspection of the exposed surface area **AND** Follow-up by UT or pit gauge as required
D	Poorly Effective	— >95 % external visual inspection prior to removal of insulation — Remove >10 % of insulation at suspect locations **OR** >10 % pulse eddy current inspection — Visual inspection of the exposed surface area with follow-up by UT or pit gauge as required	>10 % visual inspection 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 1 Inspection quality is high.

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Table 2.C.5.3—LoIE Example for Tank Bottoms

Inspection Category	Inspection Effectiveness Category	Soil Side [1]	Product Side [1]
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 1 Inspection quality is high.

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2.C.6 Non-metallic Linings

2.C.6.1 Inspection Effectiveness for Non-metallic Linings

Non-metallic lining assessment is important to any RBI analysis as an integral part of the ascribed equipment.

Although inspection effectiveness is not currently used in the calculation of the lining DF, LoIE Table 2.C.6.1 provides an example of inspection effectiveness categories for non-metallic linings.

2.C.6.2 Tables

Table 2.C.6.1—LoIE Example for Corrosion-resistant Non-metallic Liner

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2]	Non-intrusive Inspection Example [1,2]
A	Highly Effective	For the total surface area: 100 % visual inspection **AND** 100 % holiday test **AND** 100 % UT or magnetic tester for disbonding for bonded liners	No inspection techniques are yet available to meet the requirements for an "A" level inspection
B	Usually Effective	For the total surface area: >65 % visual inspection **AND** >65 % holiday test **AND** >65 % UT or magnetic tester for disbonding for bonded liners	For the total surface area: 100 % automated or manual ultrasonic scanning
C	Fairly Effective	For the total surface area: >35 % visual inspection **OR** >35 % holiday test **OR** >35 % UT or magnetic tester for disbonding for bonded liners	For the total surface area: >65 % automated or manual ultrasonic scanning
D	Poorly Effective	For the total surface area: >5 % visual inspection **OR** >5 % holiday test **OR** >5 % UT or magnetic tester for disbonding for bonded liners	For the total surface area: >35 % automated or manual ultrasonic scanning
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).

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2.C.7 Buried Components

2.C.7.1 Inspection Effectiveness for Buried Components

Similar to other equipment, components that are buried may use RBI to assign inspection intervals. LoIE Table 2.C.7.1 provides an example of inspection effectiveness categories for buried components.

2.C.7.2 Tables

Table 2.C.7.1—LoIE Example for Buried Components

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1]	Non-intrusive Inspection Example [1]
A	Highly Effective	100 % internal inspection via state-of-the-art pigging and in-line inspection technologies (UT, 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 visual inspection, and 100 % inspection with NDE technologies [2] — Sample soil and water resistivity and chemistry measurements along entire structure — Cathodic protection (CP) system maintained and managed by NACE certified personnel and complying with NACE SP0169 [14] 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 [14] includes stray current surveys on a regular basis — Sample soil and water resistivity and chemistry measurements along entire structure — DC 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.

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2.C.8 Inspection Effectiveness for Thinning

2.C.8.1 Use of the Inspection Effectiveness Tables

LoIE Table 2.C.8.1 and Table 2.C.8.2 are examples for levels of inspection effectiveness for thinning damage mechanisms.

2.C.8.2 Tables

Table 2.C.8.1—LoIE Example for General Thinning

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2,3,4]	Non-intrusive Inspection Example [1,2,3,4]
A	Highly Effective	For the total surface area: >50 % visual examination (partial internals removed) **AND** >50 % of the spot ultrasonic thickness measurements	For the total surface area: 100 % UT/RT of CMLs **OR** For selected areas: 10 % UT scanning **OR** 10 % profile radiography
B	Usually Effective	For the total surface area: >25 % visual examination **AND** >25 % of the spot ultrasonic thickness measurements	For the total surface area: >75 % spot UT **OR** >5 % UT scanning, automated or manual **OR** >5 % profile radiography of the selected area(s)
C	Fairly Effective	For the total surface area: >5 % visual examination **AND** >5 % of the spot ultrasonic thickness measurements	For the total surface area: >50 % spot UT or random UT scans (automated or manual) **OR** random profile radiography of the selected area(s)
D	Poorly Effective	For the total surface area: <5 % visual examination without thickness measurements	For the total surface area: >25 % spot UT
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 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.

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Table 2.C.8.2—LoIE Example for Local Thinning

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2,3,4]	Non-intrusive Inspection Example [1,2,3,4]
A	Highly Effective	For the total surface area: 100 % visual examination (with removal of internal packing, trays, etc.) **AND** 100 % follow-up at locally thinned areas	For the total suspect area: 100 % coverage of the CMLs using ultrasonic scanning or profile radiography
B	Usually Effective	For the total surface area: >75 % visual examination **AND** 100 % follow-up at locally thinned areas	For the total suspect area: >75 % coverage of the CMLs using ultrasonic scanning or profile radiography
C	Fairly Effective	For the total surface area: >50 % visual examination **AND** 100 % follow-up at locally thinned areas	For the total suspect area: >50 % coverage of the CMLs using ultrasonic scanning or profile radiography
D	Poorly Effective	For the total surface area: >20 % visual examination **AND** 100 % follow-up at locally thinned areas	For the total suspect area: >20 % coverage of the CMLs using ultrasonic scanning or profile radiography
E	Ineffective	Ineffective inspection technique/plan was utilized	Ineffective inspection technique/plan was utilized

NOTE 1 Inspection quality is high.

NOTE 2 Percentage coverage in non-intrusive 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.

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2.C.9 Inspection Effectiveness Tables for Stress Corrosion Cracking

2.C.9.1 Use of the Inspection Effectiveness Tables

LoIE Tables 2.C.9.1 through 2.C.9.9 are examples for levels of inspection effectiveness for SCC damage mechanisms.

2.C.9.2 Tables

Table 2.C.9.1—LoIE Example for Amine Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2]	Non-intrusive 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 % radiographic testing
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 % radiographic testing
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).

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Table 2.C.9.2—LoIE Example for ACSCC

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2]	Non-intrusive 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 % radiographic testing
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 % radiographic testing
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).

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Table 2.C.9.3—LoIE Example for Caustic Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2,3]	Non-intrusive 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 % radiographic testing
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 % radiographic testing
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.

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Table 2.C.9.4—LoIE Example for CLSCC

Inspection Category	**Inspection Effectiveness Category**	**Intrusive Inspection Example** [1,8,a]	**Non-intrusive Inspection Example** [1,8,a]
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 % radiographic testing
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 % radiographic testing
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 stress corrosion cracking.

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Table 2.C.9.5—LoIE Example for PTA Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2,3]	Non-intrusive 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 % radiographic testing
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 % radiographic testing.
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.

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Table 2.C.9.6—LoIE Example for SSC

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2]	Non-intrusive 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 % radiographic testing
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 % radiographic testing
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).

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Table 2.C.9.7—LoIE Example for HIC/SOHIC-H_2S Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2,3]	Non-intrusive Inspection Example [1,2,3]
A	Highly Effective	For the total surface area: — >95 % 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-ft^2 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-ft^2 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-ft^2 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-ft^2 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.

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Table 2.C.9.8—LoIE Example for HSC-HF Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2]	Non-intrusive 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 % radiographic testing
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 % radiographic testing
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).

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Table 2.C.9.9—LoIE Example for HIC/SOHIC-HF Cracking

Inspection Category	Inspection Effectiveness Category	Intrusive Inspection Example [1,2]	Non-intrusive Inspection Example [1,2]
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-ft^2 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 ft^2 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-ft^2 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-ft^2 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.

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2.C.10 Inspection Effectiveness For External Damage

2.C.10.1 Use of the Inspection Effectiveness Tables

LoIE Tables 2.C.10.1 through 2.C.10.4 are example for levels of inspection effectiveness for external damage mechanisms.

2.C.10.2 Tables

Table 2.C.10.1—LoIE Example for External Corrosion

Inspection Category	Inspection Effectiveness Category	Inspection [1]
A	Highly Effective	Visual inspection of >95 % of the exposed surface area with follow-up by UT, RT, or pit gauge as required
B	Usually Effective	Visual inspection of >60 % of the exposed surface area with follow-up by UT, RT, or pit gauge as required
C	Fairly Effective	Visual inspection of >30 % of the exposed surface area with follow-up by UT, RT, or pit gauge as required
D	Poorly Effective	Visual inspection 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 1 Inspection quality is high.

Table 2.C.10.2—LoIE Example for External CLSCC Cracking

Inspection Category	Inspection Effectiveness Category	Inspection [1,2]
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.

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Table 2.C.10.3—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 visual inspection prior to removal of insulation **AND** Remove 100 % of the insulation for damaged or suspected areas **AND** 100 % visual inspection 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 visual inspection **AND** 100 % profile or real-time radiography of damaged or suspect area **AND** Follow-up of corroded areas with 100 % visual inspection of the exposed surface with UT, RT, or pit gauge
B	Usually Effective	For the total surface area: 100 % external visual inspection prior to removal of insulation **AND** Remove >50 % of suspect areas **AND** Follow-up of corroded areas with 100 % visual inspection of the exposed surface area with UT, RT, or pit gauge	For the total surface area: 100 % external visual inspection **AND** Follow-up with profile or real-time radiography of >65 % of suspect areas **AND** Follow-up of corroded areas with 100 % visual inspection of the exposed surface with UT, RT, or pit gauge
C	Fairly Effective	For the total surface area: 100 % external visual inspection prior to removal of insulation **AND** Remove >25 % of suspect areas **AND** Follow-up of corroded areas with 100 % visual inspection of the exposed surface area with UT, RT, or pit gauge	For the total surface area: 100 % external visual inspection **AND** Follow-up with profile or real-time radiography of >35 % of suspect areas **AND** Follow-up of corroded areas with 100 % visual inspection of the exposed surface with UT, RT, or pit gauge
D	Poorly Effective	For the total surface area: 100 % external visual inspection 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 % visual inspection of the exposed surface area with UT, RT, or pit gauge	For the total surface area: 100 % external visual inspection **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 % visual inspection 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.

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Table 2.C.10.4—LoIE Example for CUI CLSCC

Inspection Category	**Inspection Effectiveness Category**	**Insulation Removed** [1]	**Insulation Not Removed** [1]
A	Highly Effective	For the suspected area: 100 % external visual inspection 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 visual inspection 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 visual inspection 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 visual inspection 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 1 Inspection quality is high.

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2.C.11 Inspection Effectiveness Tables for High Temperature Hydrogen Attack Damage

2.C.11.1 Use of the Inspection Effectiveness Tables

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–user's responsibility and accountability to develop an effective inspection program for assets potentially affected by HTHA and document their methodology, investigation, and results.

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API RP 581 PART 3

CONSEQUENCE OF FAILURE METHODOLOGY

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PART 3 CONTENTS

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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 three-volume set presenting the API 581 Risk-Based Inspection methodology. The other two Parts are Part 1—Inspection Planning Methodology and Part 2—Probability of Failure Methodology.

The COF methodology presented in Part 3 determines the COF that is used with the POF (Part 2) to provide a risk ranking and inspection plan (Part 1) for a component subject to process and environmental conditions typically found in the refining, petrochemical, and exploration and production industries. The consequence calculated using the procedures in Part 3 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 for the Level 2 COF are consistent with these approaches.

2 References

2.1 Normative

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.

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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 Part 3 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. A Level 2 COF methodology is provided in Section 5, which is intended to be more rigorous and can be applied to a wider range of hazardous fluids. A special COF methodology is provided for ASTs and is covered in Section 6.

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, vapor cloud explosions (VCEs)], combined with computer modeling to determine the magnitude of the consequence. Consequence areas can be determined based

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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 using computer modeling 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 releases are considered since they can still result in serious consequences. Consequence from chemical splashes and high-temperature steam burns are determined based on serious injuries to personnel. Physical explosions and BLEVE can also cause serious personnel injuries and component damage.

d) FC 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 readily can be 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, the results of which have been incorporated into lookup tables. The following assumptions are made in the Level 1 consequence analysis.

a) The fluid phase upon release can be a liquid or a gas, depending on the storage phase and the phase expected to occur upon release to the atmosphere. In general, no consideration is given to the cooling effects of flashing liquid, rainout, jet liquid entrainment, or two-phase releases.

b) Fluid properties for representative fluids containing mixtures are based on average values (e.g. MW, NBP, density, specific heats, AIT).

c) Probabilities of ignition, as well as the probabilities of other release events (VCE, pool fire, jet fire, etc.) have been pre-determined for each of the representative fluids as a function of temperature, fluid AIT, and release type. These probabilities are constants, that is, totally independent of the release rate.

d) The effects of BLEVEs are not included in the assessment.

e) The effects of pressurized nonflammable explosions, such as those possible when nonflammable pressurized gases (e.g. air or nitrogen) are released during a vessel rupture, are not included in the assessment.

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f) Meteorological conditions were assumed and used in the dispersion calculations that form the basis for the consequence analysis table lookup (see Annex 3.A).

g) Consequence areas do not consider the release of a toxic product during a combustion reaction (e.g. burning chlorinated hydrocarbons producing phosgene; hydrochloric acid producing chlorine gas; amines producing hydrogen cyanide; sulfur producing sulfur dioxide).

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 are 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 are 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, are 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 table lookups) do not represent the site data.

Like Level 1 COF, Level 2 consequence areas do not consider the release of a toxic product during a combustion reaction (e.g. burning chlorinated hydrocarbons producing phosgene; hydrochloric acid producing chlorine gas; amines producing hydrogen cyanide; sulfur producing sulfur dioxide).

3.5 COF Methodology for AST Bottoms and Shell Courses

The COF associated with ASTs is concerned primarily with the financial losses due to loss of containment and leakage through the AST bottom as well as leakage and/or rupture of an AST shell course. However, safety/area-based consequences can also be addressed for the shell courses following the Level 1 or Level 2 consequence analysis methods provided in Section 4 or Section 5. Detailed procedures for calculating the financial COF for both bottom plates and shell courses are provided in Section 6.

3.6 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 flowchart of the methodology is provided in Figure 3.1.

For both the Level 1 and Level 2 consequence analysis, detailed procedures for each of the 12 steps are provided. For the Level 2 consequence analysis, calculations for several of the steps are identical to the Level 1, and references are made to those sections. The special requirements and a step-by-step procedure for ASTs are provided in Section 6.1 through Section 6.6.

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3.7 Area- and Financial-based COF

The COF results are presented in terms of either area or financial loss. Financial-based COF is provided for all components, while area-based COF is provided for all components with the exception of AST bottoms, PRDs, and heat exchanger bundles (see Table 3.2).

3.8 Use of Atmospheric Dispersion Modeling

Calculation of the consequence areas 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.

3.9 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 FC.	4.12	

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Table 3.2—COF Calculation Type Based on Equipment and Component Type

Equipment/Component Type	Consequence Calculation Type	
	Area Based	**Financial Based**
Air cooler	Yes	Yes
Compressor	Yes	Yes
Heat exchanger (shell, channel)	Yes	Yes
Heat exchanger bundle	No	Yes
Pipe	Yes	Yes
PRD	No	Yes
Pressure vessel (drum, column filter, reactor)	Yes	Yes
Pump	Yes	Yes
Tank shell course	Yes	Yes
Tank bottom	No	Yes

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3.10 Figures

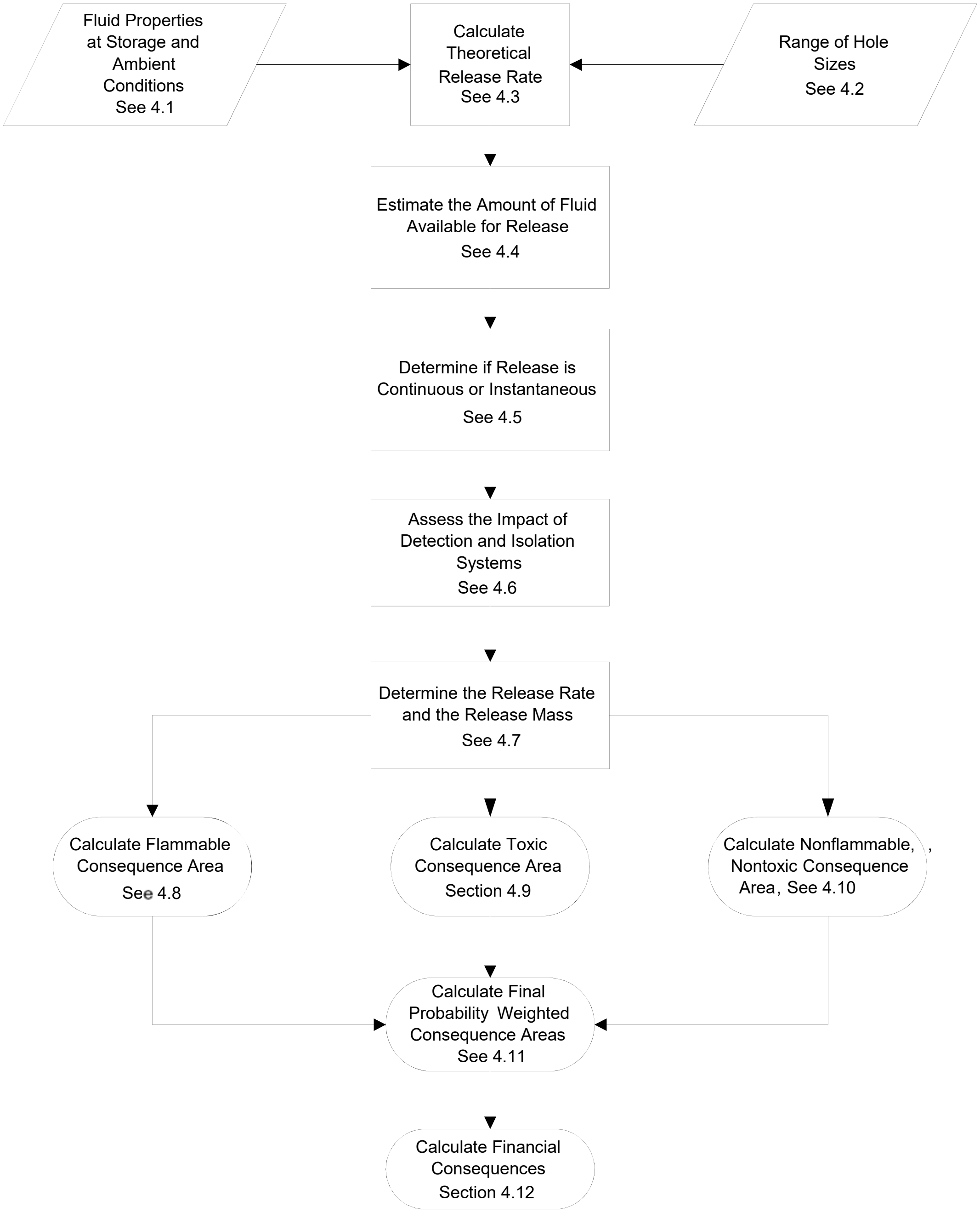

Figure 3.1—Level 1 COF Methodology

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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;

   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;

   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 material following the release to atmosphere, and either the MW or density is used in determining the release rate, depending on whether a liquid or gas, respectively, is released.

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 chosen whenever the fluid is nonflammable and nontoxic but would still present a hazard to personnel that may come in contact with the release. Acid/Caustic is modeled as a liquid spray; see Section 4.10.3.

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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).

$$k = \frac{C_p}{C_p - R} \tag{3.1}$$

The constant specific heat capacity, C_p, may be evaluated using the equations provided in Table 4.2.

4.1.5 Flammable Fluid Types

In the initial development of the Level 1 methodology, the results of the consequence analysis were correlated with equations and presented in lookup tables. As the consequence area results were reviewed, it became clear that adjustments had to be made to smooth out the results at the instantaneous to continuous release transition and as the operating temperature approached the autoignition for each fluid (see Section 4.8.5 and Section 4.8.6).

a) TYPE 0 Fluids—For the initial set of reference fluids, the consequence area equations were not smoothed and there remained step changes in the equations. Instead, adjustment factors and blending factors were applied to the consequence area equations. These initial fluids are designated here as TYPE 0 and can be found in Table 4.1.

b) TYPE 1 Fluids—Instantaneous to continuous blending was performed during development of subsequent reference fluids and the resulting consequence area equations accounted for the adjustments. As a result, instantaneous to continuous blending factors need not be 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 strongly dependent on the phase (i.e. gas, liquid, or two-phase) of the fluid after it is released into the environment. Most releases from pressurized units are 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/vapor. 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 should 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 vapor. 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 [kg/m^3 (lb/ft^3)], can be estimated from Table 4.2;

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- autoignition temperature, AIT [K (°R)], can be estimated from Table 4.2.

2) For a stored vapor:

- molecular weight, MW [kg/kg-mol (lb/lb-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;
- autoignition temperature, AIT [K (°R)], 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. Limiting the number of release hole sizes allows for an analysis that is manageable, yet still reflects the range of possible outcomes.

The release hole sizes shown in Table 4.4 are based on the component type and geometry as described in Annex 3.A. In addition, the release hole sizes are limited to a maximum diameter of 16 in. This diameter represents a practical maximum value for a release calculation because catastrophic failures of components generally do not involve disintegration of the equipment item.

4.2.2 Calculation of Release Hole Sizes

The following steps are repeated for each release hole size; typically four release hole sizes are evaluated.

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 generic failure frequency from this table or from Equation (3.2).

$$gff_{total} = \sum_{n=1}^{4} gff_n \tag{3.2}$$

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 correct release rate equation must be chosen, based on the phase of the material when it is inside the equipment item and its discharge regime (sonic or subsonic), as the material is released.

The initial phase of the hazardous material is the phase of the stored fluid prior to coming into contact with the atmosphere (i.e. flashing and aerosolization is not included at this point). For two-phase systems (condensers, phase separators, evaporators, reboilers, etc.), some judgment as to the handling of the model needs to be taken into account. In most cases, choosing liquid as the initial state inside the equipment is more conservative

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and may be preferred. One exception may be for two-phase piping systems. In this case, the upstream spill inventory should be considered so that if a majority of the upstream material can be released as vapor, then a vapor phase should be modeled. The results should be checked accordingly for conservatism. Items 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).

$$W_n = C_d \cdot K_{v,n} \cdot \rho_l \cdot \frac{A_n}{C_1}\sqrt{\frac{2 \cdot g_c \cdot (P_s - P_{atm})}{\rho_l}} \tag{3.3}$$

In Equation (3.3), the discharge coefficient, C_d, for fully turbulent liquid flow from sharp-edged orifices is in the range of $0.60 \le C_d \le 0.65$. 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.

$$K_{v,n} = \left(0.9935 + \frac{2.878}{Re_n^{0.5}} + \frac{342.75}{Re_n^{1.5}}\right)^{-1.0} \tag{3.4}$$

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 [nominally, 103.4 kPa (15 psig) or less]. Therefore, 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).

$$P_{trans} = P_{atm}\left(\frac{k+1}{2}\right)^{\frac{k}{k-1}} \tag{3.5}$$

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].

$$W_n = \frac{C_d}{C_2} \cdot A_n \cdot P_s \sqrt{\left(\frac{k \cdot MW \cdot g_c}{R \cdot T_s}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \tag{3.6}$$

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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].

$$W_n = \frac{C_d}{C_2} \cdot A_n \cdot P_s \sqrt{\left(\frac{MW \cdot g_c}{R \cdot T_s}\right)\left(\frac{2 \cdot k}{k-1}\right)\left(\frac{P_{atm}}{P_s}\right)^{\frac{2}{k}}\left(1-\left(\frac{P_{atm}}{P_s}\right)^{\frac{k-1}{k}}\right)} \tag{3.7}$$

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 $0.85 \le C_d \le 1.0$. A conservative value of $C_d = 0.90$ is recommended.

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.

$$A_n = \frac{\pi d_n^2}{4} \tag{3.8}$$

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's inventory is combined with inventory from other attached components that can 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 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 as presented here is used as an upper limit on the mass of fluid available for a release

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and does not indicate that this amount of fluid would be released in all leak scenarios. The inventory group mass can be calculated using Equation (3.9).

$$mass_{inv} = \sum_{i=1}^{N} mass_{comp,i} \tag{3.9}$$

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 additional mass is calculated assuming the same flow rate from the leaking component but is limited to a 203 mm (8 in.) release hole size. The additional mass can be calculated for each release hole size using Equation (3.10).

$$mass_{add,n} = 180 \cdot \min\left[W_n,\ W_{max8}\right] \tag{3.10}$$

In Equation (3.10), the maximum flow rate to be added to the release from the surrounding components, $W_{\max 8}$, [limited by a 203 mm (8 in.) diameter leak] can be calculated using Equations (3.3), (3.6), or (3.7), as applicable, with the hole area, A_n = 32,450 mm^2 (50.3 in.^{2}).

The maximum mass available for release is calculated using Equation (3.11).

$$mass_{avail,n} = \min\left[\left\{mass_{comp} + mass_{add,n}\right\},\ mass_{inv}\right] \tag{3.11}$$

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, $mass_{comp}$, 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, $mass_{comp,i}$.

d) STEP 4.4—Calculate the fluid mass in the inventory group, $mass_{inv}$, using Equation (3.9).

e) STEP 4.5—Calculate the flow rate from a 203 mm (8 in.) diameter hole, $W_{\max 8}$, using Equations (3.3), (3.6), or (3.7), as applicable, with $A_n = A_8 = 32{,}450$ mm^2 (50.3 in.^{2}). This is the maximum flow rate that can be added to the equipment fluid mass from the surrounding equipment in the inventory group.

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f) STEP 4.6—For each release hole size, calculate the added fluid mass, $mass_{add,n}$, 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_{max8} is from STEP 4.5.

g) STEP 4.7—For each release hole size, calculate the available mass 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 process for determining the appropriate type of release to model requires determining the time required to release 4,536 kg (10,000 lb) of fluid, t_n, through each of the release hole sizes. This has been determined to be the transition point between continuous and instantaneous release types. 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, calculate the time required to release 4,536 kg (10,000 lb) of fluid.

$$t_n = \frac{C_3}{W_n} \tag{3.12}$$

b) STEP 5.2—For each release hole size, determine if the release type is instantaneous or continuous using the following criteria.

   1) If the release hole size is 6.35 mm (0.25 in.) or less, then the release type is continuous.

   2) If $t_n \leq 180$ s and the release mass is greater than 4,536 kg (10,000 lb), then the release is instantaneous; otherwise, the release is continuous.

4.6 Estimate the Impact of Detection and Isolation Systems on Release Magnitude

4.6.1 Overview

Petrochemical processing plants typically have a variety of detection, isolation, and mitigation systems that are designed to reduce the effects of a release of hazardous materials. A simplified methodology for assessing the effectiveness of various types of detection, isolation, and mitigation systems is included in API 581. 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.

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Detection, isolation, and mitigation systems are assumed to affect the release in two ways, as follows.

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 extremely 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,

c) time to complete appropriate corrective actions.

Note that there is no total leak duration provided in Table 4.7 for the rupture case [largest release hole size, if greater than 102 mm (4 in.) 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.

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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 total leak durations 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 (3.13)].

$$rate_n = W_n\left(1 - fact_{di}\right) \tag{3.13}$$

4.7.2 Instantaneous Release Mass

For transient instantaneous puff releases, the release mass is required to perform the analysis. The available release mass as determined in Section 4.4.2 for each release hole size, $mass_{avail,n}$, is used as an upper bound for the release mass, $mass_n$, as shown in Equation (3.14).

$$mass_n = \min\left[\left\{rate_n \cdot ld_n\right\},\ \ mass_{avail,n}\right] \tag{3.14}$$

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 (3.15) can be used to calculate the actual duration of the release, ld_n.

$$ld_n = \min\left[\left\{\frac{mass_{avail,n}}{rate_n}\right\},\ \left\{60 \cdot ld_{max,n}\right\}\right] \tag{3.15}$$

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 (3.13), where the theoretical release rate, W_n, is from STEP 3.2. Note that 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 that the leak duration cannot exceed the maximum duration, $ld_{max,n}$, determined in STEP 6.5.

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c) STEP 7.3—For each release hole size, calculate the release mass, $mass_n$, using Equation (3.14) based on the release rate, $rate_n$, from STEP 3.2, the leak duration, ld_n, from STEP 7.2, and the available mass, $mass_{avail,n}$, 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 goes up significantly. (The probabilities of ignition and other event tree probabilities for the Level 1 COF are presented in Annex 3.A). As a result, there is an abrupt change in the Level 1 consequence results between a continuous release and an instantaneous release. An instantaneous release is defined as any release larger than 4,536 kg (10,000 lb) in 3 minutes, which is equivalent to a release rate of 25.2 kg/s (55.6 lb/s). A continuous release of 25.5 kg/s would have a much lower consequence than an instantaneous release at 25.2 kg/s of the same material. Therefore, the Level 1 COF includes a blending of the calculated results of the continuous and instantaneous releases (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 (3.16) 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.

$$CA_{f,n}^{CONT} = a\left(rate_n\right)^b \tag{3.16}$$

b) Instantaneous Release—For an instantaneous release, Equation (3.17) 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.

$$CA_{f,n}^{INST} = a\left(mass_n\right)^b \tag{3.17}$$

4.8.2.2 Development of Generic Equations

Equation (3.16) and Equation (3.17) were employed 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 4.2 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.

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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—34.5 kPa (5 psig);

   2) thermal radiation—37.8 kW/m^2 [12,000 Btu/(hr-ft^2)] (jet fire, pool fire, and fireball);

   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—20.7 kPa (3 psig);

   2) thermal radiation—12.6 kW/m^2 [4000 Btu/(hr-ft^2)] (jet fire, fireball, and pool fire);

   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, which, 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.

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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 4,536 kg (10,000 lb) by dividing the calculated consequence areas by the adjustment factor, $eneff_n$, given by Equation (3.18).

$$eneff_n = 4 \cdot \log_{10}\left[C_{4A} \cdot mass_n\right] - 15 \tag{3.18}$$

Note that the adjustment defined by Equation (3.18) 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 [4,536 kg (10,000 lb) released in less than 3 minutes, or a release rate of 25.2 kg/s (55.6 lb/s)] using Equation (3.19).

$$fact_n^{IC} = \min\left[\left\{\frac{rate_n}{C_5}\right\},\ 1.0\right] \tag{3.19}$$

For instantaneous equation constants that are not provided in Table 4.8 and Table 4.9 for the reference fluid, the blending factor is defined in Equation (3.20).

$$fact_n^{IC} = 0.0 \tag{3.20}$$

b) For Instantaneous Releases—Blending is not required for instantaneous releases [4,536 kg (10,000 lb) released in less than 3 minutes, or a release rate of 25.2 kg/s (55.6 lb/s)]. The blending factor, $fact_n^{IC}$, for an instantaneous release is defined in Equation (3.21).

$$fact_n^{IC} = 1.0 \tag{3.21}$$

The blended release area is calculated using Equation (3.22). Note that this area is proportionate to the proximity of the actual release rate, $rate_n$, is to the continuous/instantaneous transition rate of 25.2 kg/s (55.6 lb/s).

$$CA_n^{IC-blend} = CA_n^{INST} \cdot fact_n^{IC} + CA_n^{CONT}\left(1 - fact_n^{IC}\right) \tag{3.22}$$

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 (3.23).

$$CA^{AIT-blend} = CA^{AIL}\, fact^{AIT} + CA^{AINL}\left(1 - fact^{AIT}\right) \tag{3.23}$$

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The AIT blending factor, $fact^{AIT}$, is determined using the following equations.

$$fact^{AIT} = 0 \qquad for\ T_s + C_6 \le AIT \tag{3.24}$$

$$fact^{AIT} = \frac{\left(T_s - AIT + C_6\right)}{2 \cdot C_6} \qquad for\ T_s + C_6 > AIT > T_s - C_6 \tag{3.25}$$

$$fact^{AIT} = 1 \qquad for\ T_s - C_6 \ge AIT \tag{3.26}$$

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 (3.27).

$$CA_{f,cmd}^{flam} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA_{cmd,n}^{flam}}{gff_{total}} \right) \tag{3.27}$$

The equation for probability weighting of the personnel injury consequence areas is given by Equation (3.28).

$$CA_{f,inj}^{flam} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA_{inj,n}^{flam}}{gff_{total}} \right) \tag{3.28}$$

In Equation (3.27) and Equation (3.28), 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 (3.18).

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), $CA_{cmd,n}^{AINL-CONT}$.

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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.

$$a = a_{cmd}^{AINL-CONT} \tag{3.29}$$

$$b = b_{cmd}^{AINL-CONT} \tag{3.30}$$

2) Use Equation (3.31) to calculate the consequence area.

$$CA_{cmd,n}^{AINL-CONT} = a\left(rate_n\right)^b \cdot \left(1 - fact_{mit}\right) \tag{3.31}$$

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.

$$a = a_{cmd}^{AIL-CONT} \tag{3.32}$$

$$b = b_{cmd}^{AIL-CONT} \tag{3.33}$$

2) Use Equation (3.34) to calculate the consequence area.

$$CA_{cmd,n}^{AIL-CONT} = a\left(rate_n\right)^b \cdot \left(1 - fact_{mit}\right) \tag{3.34}$$

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.

$$a = a_{cmd}^{AINL-INST} \tag{3.35}$$

$$b = b_{cmd}^{AINL-INST} \tag{3.36}$$

2) Use Equation (3.37) for the consequence area.

$$CA_{cmd,n}^{AINL-INST} = a\left(mass_n\right)^b \cdot \left(\frac{1 - fact_{mit}}{eneff_n}\right) \tag{3.37}$$

g) STEP 8.7—For each release hole size, calculate the component damage consequence areas for Autoignition Likely, Instantaneous Release (AIL-INST), $CA_{cmd,n}^{AIL-INST}$.

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.

$$a = a_{cmd}^{AIL-INST} \tag{3.38}$$

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$$b = b_{cmd}^{AIL-INST} \tag{3.39}$$

2) Use Equation (3.40) to calculate the consequence area.

$$CA_{cmd,n}^{AIL-INST} = a\left(mass_n\right)^b \cdot \left(\frac{1-fact_{mit}}{eneff_n}\right) \tag{3.40}$$

h) STEP 8.8—For each release hole size, calculate the personnel injury consequence areas for Autoignition Not Likely, Continuous Release (AINL-CONT), $CA_{inj,n}^{AINL-CONT}$.

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.

$$a = a_{inj}^{AINL-CONT} \tag{3.41}$$

$$b = b_{inj}^{AINL-CONT} \tag{3.42}$$

2) Calculate the consequence area using Equation (3.43).

$$CA_{inj,n}^{AINL-CONT} = \left[a \cdot \left(rate_n^{AINL-CONT}\right)^b\right] \cdot \left(1-fact_{mit}\right) \tag{3.43}$$

i) STEP 8.9—For each release hole size, calculate the personnel injury consequence areas for Autoignition Likely, Continuous Release (AIL-CONT), $CA_{inj,n}^{AIL-CONT}$.

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.

$$a = a_{inj}^{AIL-CONT} \tag{3.44}$$

$$b = b_{inj}^{AIL-CONT} \tag{3.45}$$

2) Calculate the consequence area using Equation (3.46).

$$CA_{inj,n}^{AIL-CONT} = \left[a \cdot \left(rate_n^{AIL-CONT}\right)^b\right] \cdot \left(1-fact_{mit}\right) \tag{3.46}$$

j) STEP 8.10—For each release hole size, calculate the personnel injury consequence areas for Autoignition Not Likely, Instantaneous Release (AINL-INST), $CA_{inj,n}^{AINL-INST}$.

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.

$$a = a_{inj}^{AINL-INST} \tag{3.47}$$

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$$b = b_{inj}^{AINL-INST} \tag{3.48}$$

2) Calculate the consequence area using Equation (3.49).

$$CA_{inj,n}^{AINL-INST} = \left[a \cdot \left(mass_n^{AINL-INST} \right)^b \right] \cdot \left(\frac{1 - fact_{mit}}{eneff_n} \right) \tag{3.49}$$

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.

$$a = a_{inj}^{AIL-INST} \tag{3.50}$$

$$b = b_{inj}^{AIL-INST} \tag{3.51}$$

2) Calculate the consequence area using Equation (3.52).

$$CA_{inj,n}^{AIL-INST} = \left[a \cdot \left(mass_n^{AIL-INST} \right)^b \right] \cdot \left(\frac{1 - fact_{mit}}{eneff_n} \right) \tag{3.52}$$

l) STEP 8.12—For each release hole size, calculate the instantaneous/continuous blending factor, $fact_n^{IC}$, using Equations (3.19), (3.20), or (3.21), 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 (3.24), (3.25), or (3.26), as applicable.

n) STEP 8.14—For TYPE 0 fluids, calculate the continuous/instantaneous blended consequence areas for TYPE 0 fluid components using Equations (3.53) through (3.56) 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.

$$CA_{cmd,n}^{AIL} = CA_{cmd,n}^{AIL-INST} \cdot fact_n^{IC} + CA_{cmd,n}^{AIL-CONT} \cdot \left(1 - fact_n^{IC}\right) \tag{3.53}$$

$$CA_{inj,n}^{AIL} = CA_{inj,n}^{AIL-INST} \cdot fact_n^{IC} + CA_{inj,n}^{AIL-CONT} \cdot \left(1 - fact_n^{IC}\right) \tag{3.54}$$

$$CA_{cmd,n}^{AINL} = CA_{cmd,n}^{AINL-INST} \cdot fact_n^{IC} + CA_{cmd,n}^{AINL-CONT} \cdot \left(1 - fact_n^{IC}\right) \tag{3.55}$$

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$$CA^{AINL}_{inj,n} = CA^{AINL-INST}_{inj,n} \cdot fact^{IC}_{n} + CA^{AINL-CONT}_{inj,n} \cdot \left(1 - fact^{IC}_{n}\right) \tag{3.56}$$

o) STEP 8.15—Calculate the AIT blended consequence areas for all components using Equations (3.57) and (3.58) 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, $CA^{flam}_{cmd,n}$ and $CA^{flam}_{inj,n}$, for each release hole sizes selected in STEP 2.2.

$$CA^{flam}_{cmd,n} = CA^{AIL}_{cmd,n} \cdot fact^{AIT} + CA^{AINL}_{cmd,n} \cdot \left(1 - fact^{AIT}\right) \tag{3.57}$$

$$CA^{flam}_{inj,n} = CA^{AIL}_{inj,n} \cdot fact^{AIT} + CA^{AINL}_{inj,n} \cdot \left(1 - fact^{AIT}\right) \tag{3.58}$$

p) STEP 8.16—Determine the final consequence areas (probability weighted on release hole size) for component damage and personnel injury using Equation (3.59) and Equation (3.60) based on the consequence areas from STEP 8.15.

$$CA^{flam}_{f,cmd} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA^{flam}_{cmd,n}}{gff_{total}} \right) \tag{3.59}$$

$$CA^{flam}_{f,inj} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA^{flam}_{inj,n}}{gff_{total}} \right) \tag{3.60}$$

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, hydrogen fluoride (HF), ammonia, and chlorine pose only a toxic hazard. On the other hand, some toxic materials such as hydrogen sulfide (H_2S) 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 (H_2S), ammonia (NH_3), and chlorine (Cl)—is provided in Section 4.9.6 and Section 4.9.7.

4.9.3 Common Chemical Industry Toxic Materials

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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.

$$rate_n^{tox} = mfrac^{tox} \cdot W_n \tag{3.61}$$

$$mass_n^{tox} = mfrac^{tox} \cdot mass_n \tag{3.62}$$

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 that the magnitude reduction factor, $fact_{di}$, to account for detection and isolation systems is not applied to toxic releases as it is to flammable releases (see Section 4.6).

4.9.6 Estimation of Toxic Consequence Area for HF Acid and H_2S

a) The background for the development of the toxic consequence equations for HF acid and H_2S 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.

b) The toxic consequence areas for continuous releases of HF or H_2S as a function of the release rate may be calculated using Equation (3.63).

$$CA_{inj,n}^{tox-CONT} = C_8 \cdot 10^{\left(c \cdot \log_{10}\left[C_{4B} \cdot rate_n^{tox}\right] + d\right)}$$

$$CA_{inj,n}^{tox-CONT} = C_8 \cdot \left(\left[C_{4B} \cdot rate_n^{tox}\right] \wedge c \cdot 10 \wedge d\right) \tag{3.63}$$

Note that for continuous releases, the toxic release rate, $rate_n^{tox}$, 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 as a function of release duration. Interpolation between curves using the actual duration (defined in Section 4.9.10) is acceptable.

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c) The toxic consequence areas for instantaneous releases of HF or H_2S as a function of the release rate may be calculated using Equation (3.64).

$$CA_{inj,n}^{tox-INST} = C_8 \cdot 10^{\left(c \cdot \log_{10}\left[C_{4B} \cdot mass_n^{tox}\right]+d\right)}$$

$$CA_{inj,n}^{tox-INST} = C_8 \cdot \left(\left[C_{4B} \cdot mass_n^{tox}\right] \wedge c \cdot 10 \wedge d\right) \tag{3.64}$$

Note that for instantaneous releases, the toxic release mass, $mass_n^{tox}$, is used as the input to Equation (3.64). The constants, c and d to be used in Equation (3.64) 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 (3.65).

$$CA_{inj,n}^{tox-CONT} = e\left(rate_n^{tox}\right)^f \tag{3.65}$$

Note that for continuous releases, the toxic release rate, $rate_n^{tox}$, is used as the input to Equation (3.65). The constants e and f for Equation (3.65) are provided in Table 4.12 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 (3.66).

$$CA_{inj,n}^{tox-INST} = e\left(mass_n^{tox}\right)^f \tag{3.66}$$

Note that for instantaneous releases, the toxic release mass, $mass_n^{tox}$, is used as the input to Equation (3.66). The constants e and f for Equation (3.66) 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.

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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 (3.65) 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);

c) maximum leak duration, $ld_{max,n}$ listed in Table 4.7.

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$$ld_n^{tox} = \min\left(3600,\ \left\{\frac{mass_n}{W_n}\right\},\ \left\{60 \cdot ld_{max,n}\right\}\right) \tag{3.67}$$

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 multi-component 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 his or her 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 (3.68) is used to calculate the probability weighted toxic consequence area.

$$CA_{f,inj}^{tox} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA_{inj,n}^{tox}}{gff_{total}}\right) \tag{3.68}$$

4.9.15 Calculation of Toxic Consequence Areas

a) STEP 9.1—For each release hole size selected in STEP 2.2, calculate the effective duration of the toxic release using Equation (3.67).

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b) 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 that if there is more than one toxic component in the released fluid mixture, this procedure can be repeated for each toxic component.

c) 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 (3.61) and Equation (3.62).

d) STEP 9.4—For each release hole size, calculate the toxic consequence area for each of the release hole sizes.

  1) HF Acid and H2S—Calculate $CA_{inj,n}^{tox}$ using Equation (3.63) for a continuous release or Equation (3.64) 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 (3.65) for a continuous release or Equation (3.66) 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 (3.65) 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 (3.68).

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 100 °C (212 °F) 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 60 °C (140 °F). The approach used here is to assume that injury occurs above 60 °C (140 °F). 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 60 °C (140 °F).

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 (3.69).

$$CA_{inj,n}^{CONT} = C_9 \cdot rate_n \tag{3.69}$$

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For instantaneous release cases, four masses of steam were modeled: 4.5 kg, 45.4 kg, 454.0 kg, and 4,540 kg (10 lb, 100 lb, 1,000 lb, and 10,000 lb), and the relationship between release mass and consequence area to 20 % concentration was found to be in accordance with Equation (3.70).

$$CA_{inj,n}^{INST} = C_{10}\left(mass_n\right)^{0.6384} \tag{3.70}$$

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 (3.71).

$$fact_n^{IC} = \min\left[\left\{\frac{rate_n}{C_5}\right\},\ 1.0\right] \tag{3.71}$$

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 at the 180° semi-circular area covered by the liquid spray or rainout. Modeling was performed at three pressures; 103.4 kPa, 206.8 kPa, and 413.7 kPa (15 psig, 30 psig, and 60 psig) 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 (3.72) and Equation (3.73).

$$CA_{inj,n}^{CONT} = 0.2 \cdot C_8 \cdot g\left(C_4 \cdot rate_n\right)^h \tag{3.72}$$

$$CA_{inj,n}^{INST} = 0.0 \tag{3.73}$$

The constants g and h shown in Equation (3.72), are functions of pressure and can be calculated using Equations (3.74) and (3.75), respectively.

$$g = 2696.0 - 21.9 \cdot C_{11}\left(P_s - P_{atm}\right) + 1.474\left[C_{11}\left(P_s - P_{atm}\right)\right]^2 \tag{3.74}$$

$$h = 0.31 - 0.00032\left[C_{11}\left(P_s - P_{atm}\right) - 40\right]^2 \tag{3.75}$$

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 (3.76).

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$$CA_{inj,n}^{leak} = CA_{inj,n}^{INST} \cdot fact_n^{IC} + CA_{inj,n}^{CONT}\left(1 - fact_n^{IC}\right) \tag{3.76}$$

Note that there is no need to calculate a component damage area for nonflammable releases of steam or acid/caustic.

$$CA_{cmd,n}^{leak} = 0.0 \tag{3.77}$$

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 (3.78) is used to calculate the probability weighted nonflammable, nontoxic consequence area for steam, caustic, or acid releases.

$$CA_{f,inj}^{nfnt} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA_{inj,n}^{leak}}{gff_{total}} \right) \tag{3.78}$$

The term $CA_{inj,n}^{leak}$ in Equation (3.78) 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 (3.69) and $CA_{inj,n}^{INST}$ using Equation (3.70).

   2) For Acids or Caustics—Calculate $CA_{inj,n}^{CONT}$ for liquid releases using Equations (3.72), (3.74), and (3.75). Note that 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 (3.71). 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 (3.88) based on the consequence areas from STEP 10.1 and the blending factor, $fact_n^{IC}$, from STEP 10.2. Note that there is no need to calculate a component damage area for the Level 1 nonflammable releases (steam or acid/caustic):

$$CA_{cmd,n}^{leak} = 0.0 \tag{3.79}$$

d) STEP 10.4—Determine the final nonflammable, nontoxic consequence areas for personnel injury, CA_{inj}^{nfnt}, using Equation (3.80) based on consequence areas calculated for each release hole size in STEP 10.3. Note that 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:

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$$CA_{f,cmd}^{nfnt} = 0.0 \tag{3.80}$$

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;

c) nonflammable, nontoxic consequence; see Section 4.10.

4.11.2 Final Component Damage Consequence Area

The final component damage consequence area is:

$$CA_{f,cmd} = \max\left[CA_{f,cmd}^{flam},\ CA_{f,cmd}^{tox},\ CA_{f,cmd}^{nfnt}\right] \tag{3.81}$$

Note that 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}.

$$CA_{f,cmd} = CA_{f,cmd}^{flam} \tag{3.82}$$

4.11.3 Final Personnel Injury Consequence Area

The final personnel injury consequence area is:

$$CA_{inj} = \max\left[CA_{f,inj}^{flam},\ CA_{f,inj}^{tox},\ CA_{f,inj}^{nfnt}\right] \tag{3.83}$$

4.11.4 Final Consequence Area

The final consequence area is:

$$CA_{f} = \max\left[CA_{f,cmd},\ CA_{f,inj}\right] \tag{3.84}$$

4.11.5 Calculation of Final Consequence Area

a) STEP 11.1—Calculate the final component damage consequence area, $CA_{f,cmd}$, using Equation (3.82).

b) STEP 11.2—Calculate the final personnel injury consequence area, $CA_{f,inj}$, using Equation (3.83).

c) STEP 11.3—Calculate the final consequence area, CA_{f}, using Equation (3.84).

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4.12 Determine the FC

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:

a) cost of equipment repair and replacement;

b) cost of damage to surrounding equipment in affected areas;

c) costs associated with production losses and business interruption as a result of downtime to repair or replace damaged equipment;

d) costs due to potential injuries associated with a failure;

e) 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 FC of a loss of containment and subsequent release of hazardous materials can be determined by adding up the individual costs discussed above:

$$FC_f = FC_{f,cmd} + FC_{f,affa} + FC_{f,prod} + FC_{f,inj} + FC_{f,environ} \qquad (3.85)$$

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.

The 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 repair and replacement costs presented do not reflect actual installed cost.

The cost estimates shown in Table 4.15 are based on carbon steel prices. 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.

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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 (3.86). The probability weighting utilizes the generic frequencies of the release hole sizes provided in Part 2, Table 3.1.

$$FC_{f,cmd} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot holecost_n}{gff_{total}} \right) \cdot matcost \tag{3.86}$$

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 (3.57) in Equation (3.87).

$$FC_{f,affa} = CA_{f,cmd} \cdot equipcost \tag{3.87}$$

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 on-line 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 (3.88). The probability weighting uses the generic frequencies of the release hole sizes provided in Table 3.1 of Part 2.

$$Outage_{cmd} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot Outage_n}{gff_{total}} \right) \cdot Outage_{mult} \tag{3.88}$$

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.

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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 [36]. The downtime associated with repairing the surrounding equipment in the affected area is calculated using Equation (3.89).

$$Outage_{affa} = 10^{1.242+0.585\cdot\log_{10}\left[FC_{affa}\cdot(10)^{-6}\right]} \tag{3.89}$$

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.

$$FC_{f,prod} = \left(Outage_{cmd} + Outage_{affa}\right)\left(prodcost\right) \tag{3.90}$$

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. 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, etc.

The costs associated with personnel injury are calculated using Equation (3.91):

$$FC_{inj} = CA_{inj}\cdot popdens\cdot injcost$$

$$FC_{f,prod} = CA_{f,inj}\cdot popdens\cdot injcost \tag{3.91}$$

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

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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 $frac_{evap}$:

$$frac_{evap} = \begin{bmatrix} -7.1408 + 8.5827(10)^{-3} \cdot ((C_{12} \cdot NBP) + C_{41}) \\ -3.5594(10)^{-6} \cdot \left((C_{12} \cdot NBP) + C_{41}\right)^2 \\ + \dfrac{2331.1}{(C_{12} \cdot NBP) + C_{41}} - \dfrac{203545}{\left((C_{12} \cdot NBP) + C_{41}\right)^2} \end{bmatrix} \tag{3.92}$$

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 (3.93) 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.

$$vol_n^{env} = \frac{C_{13} \cdot mass_n \left(1 - frac_{evap}\right)}{\rho_l} \tag{3.93}$$

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 (3.94).

$$FC_{f,environ} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot vol_n^{env}}{gff_{total}} \right) \cdot envcost \tag{3.94}$$

4.12.7 Calculation of FC

a) STEP 12.1—Calculate the cost (consequence in \$) to repair the specific piece of equipment, $FC_{f,cmd}$, using Equation (3.86) 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 (3.87) 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 \$/m^2 (\$/ft^2).

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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 (3.88) 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 (3.89) 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 (3.90). 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 m^2 (personnel/ft^2). 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, $FC_{f,environ}$, 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 FC using Equation (3.85), which is the sum of the costs determined in STEPs 12.1 through 12.5.

4.13 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	is a constant provided for reference fluids for Level 1 consequence analysis
$a_{cmd}^{AIL-CONT}$	is a constant AIL continuous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$a_{inj}^{AIL-CONT}$	is a constant AIL continuous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$a_{cmd}^{AIL-INST}$	is a constant AIL instantaneous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$a_{inj}^{AIL-INST}$	is a constant AIL instantaneous release provided for reference fluids for Level 1 consequence analysis for personnel injury area

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$a_{cmd}^{AINL-CONT}$	is a constant for AINL continuous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$a_{inj}^{AINL-CONT}$	is a constant for AINL continuous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$a_{cmd}^{AINL-INST}$	is a constant for AINL instantaneous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$a_{inj}^{AINL-INST}$	is a constant for AINL instantaneous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
AIT	is the autoignition temperature of the released fluid, K (°R)
A_n	is the hole area associated with the n^{th} release hole size, mm^2 ($in.^2$)
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
$b_{inj}^{AIL-CONT}$	is a constant AIL continuous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$b_{cmd}^{AIL-INST}$	is a constant AIL instantaneous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$b_{inj}^{AIL-INST}$	is a constant AIL instantaneous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$b_{cmd}^{AINL-CONT}$	is a constant AINL continuous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$b_{inj}^{AINL-CONT}$	is a constant AINL continuous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
$b_{cmd}^{AINL-INST}$	is a constant AINL instantaneous release provided for reference fluids for Level 1 consequence analysis for equipment damage area
$b_{inj}^{AINL-INST}$	is a constant AINL instantaneous release provided for reference fluids for Level 1 consequence analysis for personnel injury area
c	is a gas release constant used in HF and H_2S releases for the COF 1 toxic area analysis
C_d	is the release hole coefficient of discharge, unitless
C_p	is the specific heat of the released fluid, J/kg-K (Btu/lb-°R)

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CA_f	is the final consequence area, m^2 (ft^2)
$CA_{inj,n}^{acid}$	is the personnel injury consequence area for caustic and acid leaks, associated with the n^{th} release hole size, m^2 (ft^2)
CA^{AIL}	is the flammable consequence area where autoignition is likely to occur, m^2 (ft^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, m^2 (ft^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, m^2 (ft^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, m^2 (ft^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, m^2 (ft^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, m^2 (ft^2)
CA^{AINL}	is the flammable consequence area where autoignition is not likely to occur, m^2 (ft^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, m^2 (ft^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, m^2 (ft^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, m^2 (ft^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, m^2 (ft^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, m^2 (ft^2)
$CA^{AIT-blend}$	is the AIT blended flammable consequence area, m^2 (ft^2)
$CA_{f,cmd}$	is the final component damage consequence area, m^2 (ft^2)

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$CA_{inj,n}^{CONT}$	is the personnel injury consequence area for continuous releases, associated with the *n*th release hole size, m^2 (ft^2)
$CA_{f,n}^{CONT}$	is the consequence area for a continuous release, m^2 (ft^2)
$CA_{f,cmd}^{flam}$	is the final probability weighted component damage flammable consequence area, m^2 (ft^2)
$CA_{cmd,n}^{flam}$	is the blended component damage flammable consequence area, associated with the *n*th release hole size, m^2 (ft^2)
$CA_{f,inj}^{flam}$	is the final probability weighted personnel injury flammable consequence area, m^2 (ft^2)
$CA_{f,inj,n}^{flam}$	is the blended personnel injury flammable consequence area, associated with the *n*th release hole size, m^2 (ft^2)
$CA_{n}^{IC-blend}$	is the continuous/instantaneous blended flammable consequence area, m^2 (ft^2)
$CA_{f,inj}$	is the final personnel injury consequence area, m^2 (ft^2)
$CA_{inj,n}^{INST}$	is the personnel injury consequence area for instantaneous releases, associated with the *n*th release hole size, m^2 (ft^2)
$CA_{f,n}^{INST}$	is the consequence area for an instantaneous release, m^2 (ft^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, m^2 (ft^2)
$CA_{f,max}$	is the final maximum consequence area, m^2 (ft^2)
$CA_{f,cmd}^{nfnt}$	is the component damage nonflammable, nontoxic consequence area, m^2 (ft^2)
$CA_{f,inj}^{nfnt}$	is the final probability weighted personnel injury consequence area for nonflammable, nontoxic releases such as steam or acids, m^2 (ft^2)
$CA_{inj,n}^{nfnt}$	is the personnel injury nonflammable, nontoxic consequence area, associated with the *n*th release hole size, m^2 (ft^2)
$CA_{inj,n}^{stm}$	is the personnel injury consequence area for steam leaks, associated with the *n*th release hole size, m^2 (ft^2)
$CA_{f,cmd}^{tox}$	is the final probability weighted component damage toxic consequence area, m^2 (ft^2)
$CA_{f,inj}^{tox}$	is the final probability weighted personnel injury toxic consequence area, m^2 (ft^2)

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$CA_{inj,n}^{tox-CONT}$	is the personnel injury toxic consequence area for a continuous release, associated with the n^{th} release hole size, m^2 (ft^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, m^2 (ft^2)
d	Is a gas release constant used in HF and H_2S releases for the Level 1 toxic consequence area analysis
d_n	is the diameter of the n^{th} release hole size, mm (in.)
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 4,536 kg (10,000 lb)
$envcost$	is the environmental cleanup costs, \$/bbl
$equipcost$	is the process unit replacement costs for component, $\$/m^2$ ($\$/ft^2$)
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 reduction factor, based on the detection and isolations 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
$fact_{mit}$	is the consequence area reduction factor, based on the mitigation systems present in the unit.
$frac_{evap}$	is the fraction of the released liquid pool that evaporates, needed to estimate the volume of material for environmental cleanup
FC	is the final financial consequence, \$
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, \$

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FC_{prod}	is the financial consequence of lost production on the unit, $
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 = $1.0\left(kg-m\right)/\left(N-s^2\right)\left[32.2\left(lb_m-ft\right)/\left(lb_f-s^2\right)\right]$
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	is the release fluid ideal gas specific heat capacity ratio, unitless
$K_{v,n}$	is the liquid flow viscosity correction factor, associated with the n^{th} release hole size, unitless
$ld_{max,n}$	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 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
$mass_{add,n}$	is the additional mass that can be added to the release as contributed from the surrounding equipment in the inventory group (limited by $W_{\max 8}$), associated with the n^{th} release hole size, kg (lb)
$mass_n^{AIL-INST}$	is the adjusted or mitigated discharge mass used in the AIL instantaneous consequence calculation associated with the n^{th} release hole size, kg (lb)
$mass_n^{AINL-INST}$	is the adjusted or mitigated discharge mass used in the AINL instantaneous consequence calculation associated with the n^{th} release hole size, kg (lb)
$mass_{avail,n}$	is the available mass for release for each of the release hole sizes selected, associated with the n^{th} release hole size, kg (lb)
$mass_{comp}$	is the inventory fluid mass for the component or piece of equipment being evaluated, kg (lb)

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$mass_{comp,i}$	is the inventory fluid mass for each of the i components or pieces or equipment that is included in the inventory group, kg (lb)
$mass_{inv}$	is the inventory group fluid mass, kg (lb)
$mass_n$	is the adjusted or mitigated discharge mass used in the consequence calculation associated with the *n*th release hole size, kg (lb)
$mass_n^{tox}$	is the release mass of toxic component used in the toxic consequence calculation associated with the *n*th release hole size, kg (lb)
$matcost$	is the material cost factor
$mfrac^{tox}$	is the mass fraction of toxic material in the released fluid mixture
MW	is the release fluid molecular weight, kg/kg-mol (lb/lb-mol)
NBP	is the normal boiling point, °C (°F)
$Outage_{affa}$	is the numbers of days of downtime required to repair damage to the surrounding equipment, days
$Outage_{cmd}$	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
$popdens$	is the population density of personnel or employees in the unit, personnel/m^2 (personnel/ft^2)
P_{atm}	is the atmospheric pressure, kPa (psia)
P_s	is the storage or normal operating pressure, kPa (psia)
P_{trans}	is the transition back pressure, kPa (psia). 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
$prodcost$	is the cost of lost production due to downtime to repair equipment, $/day
R	is the universal gas constant = 8.314 J/(kg-mol-K) [1545 ft-lb$_f$/(lb-mol-°R)]
Re_n	is the Reynolds Number for flow through the release, associated with the *n*th release hole size, unitless

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$rate_n$	is the adjusted or mitigated discharge rate used in the consequence calculation associated with the nth release hole size, kg/s (lb/s)
$rate_n^{AIL-CONT}$	is the adjusted or mitigated discharge rate used in the AIL continuous consequence calculation associated with the nth release hole size, kg/s (lb/s)
$rate_n^{AINL-CONT}$	is the adjusted or mitigated discharge rate used in the AINL continuous consequence calculation associated with the nth release hole size, kg/s (lb/s)
$rate_n^{tox}$	is the release mass rate of toxic component used in the consequence calculation, associated with the nth release hole size, kg/s (lb/s)
t_n	is the time to release 10,000 lb of fluid mass, calculated for each of the n release hole sizes selected, seconds
T_s	is the storage or normal operating temperature, K (°R)
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
$W_{\max 8}$	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, kg/s (lb/s)
W_n	is the theoretical release rate associated with the nth release hole size, kg/s (lb/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, kg/m^3 (lb/ft^3)
ρ_{atm}	is the atmospheric air density, kg/m^3 (lb/ft^3)
ρ_l	is the liquid density at storage or normal operating conditions, kg/m^3 (lb/ft^3)
ρ_v	is the vapor density, kg/m^3 (lb/ft^3)

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4.14 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, LNG, fuel gas
C_3-C_4	TYPE 0	Propane, butane, isobutane, 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_2S	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.

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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 *A*	Ideal Gas Constant *B*	Ideal Gas Constant *C*	Ideal Gas Constant *D*	Ideal Gas Constant *E*	
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 3	3.34E+04	2.68E+04	2.61e+03	8.90E+03	1.17E+03	N/A
Acid/Caustic	18	62.3	212	Liquid	Note 3	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
Ammonia	17.03	38.55	−28.2	Gas	—	—	—	—	—	—	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	4.34E+04	3.97E+04	4.17E+02	2.40E+04	N/A	1036
NO_2	90	58	275	Liquid	—	—	—	—	—	—	N/A
Phosgene	99	86	181	Liquid	—	—	—	—	—	—	N/A
TDI	174	76	484	Liquid	—	—	—	—	—	—	1148
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

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Fluid	MW	Liquid Density (lb/ft^3)	NBP (°F)	Ambient State	Ideal Gas Specific Heat Eq.	C_p					AIT (°F)
						Ideal Gas Constant A	Ideal Gas Constant B	Ideal Gas Constant C	Ideal Gas Constant D	Ideal Gas Constant E	

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).

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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 *A*	Ideal Gas Constant *B*	Ideal Gas Constant *C*	Ideal Gas Constant *D*	Ideal Gas Constant *E*	
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 3	3.34E+04	2.68E+04	2.61E+03	8.90E+03	1.17E+03	N/A
Acid/Caustic	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
Ammonia	17.03	0.769	−33.34	Gas	—	—	—	—	—	—	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_2S	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	4.34E+04	3.97E+04	4.17E+02	2.40E+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
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

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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 A	Ideal Gas Constant B	Ideal Gas Constant C	Ideal Gas Constant D	Ideal Gas Constant E	

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.

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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 *unless* 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 $^1/4$	$d_1 = 0.25$
2	Medium	>$^1/4$ 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	$d_4 = \min[D, 406]$

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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

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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 1 in. leaks 5 minutes for 4 in. leaks
A	B	30 minutes for $^1/_4$ in. leaks 20 minutes for 1 in. leaks 10 minutes for 4 in. leaks
A	C	40 minutes for $^1/_4$ in. leaks 30 minutes for 1 in. leaks 20 minutes for 4 in. leaks
B	A or B	40 minutes for $^1/_4$ in. leaks 30 minutes for 1 in. leaks 20 minutes for 4 in. leaks
B	C	1 hour for $^1/_4$ in. leaks 30 minutes for 1 in. leaks 20 minutes for 4 in. leaks
C	A, B, or C	1 hour for $^1/_4$ in. leaks 40 minutes for 1 in. leaks 20 minutes for 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 25 mm leaks 5 minutes for 102 mm leaks
A	B	30 minutes for 6.4 mm leaks 20 minutes for 25 mm leaks 10 minutes for 102 mm leaks
A	C	40 minutes for 6.4 mm leaks 30 minutes for 25 mm leaks 20 minutes for 102 mm leaks
B	A or B	40 minutes for 6.4 mm leaks 30 minutes for 25 mm leaks 20 minutes for 102 mm leaks
B	C	1 hour for 6.4 mm leaks 30 minutes for 25 mm leaks 20 minutes for 102 mm leaks
C	A, B, or C	1 hour for 6.4 mm leaks 40 minutes for 25 mm leaks 20 minutes for 102 mm leaks

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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	
		a	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*
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	TYPE 0																
Methanol	TYPE 1	0.026	0.909	1751	0.934					28.11	0.667	1.919	0.900				
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						

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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	
		a	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*
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	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_2S	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						

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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	
		a	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*	*a*	*b*
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	TYPE 0																
Methanol	TYPE 1	0.016	1.008	4484	0.902					37.71	0.688	6.255	0.871				
H_2	TYPE 0	165.0	0.933			1117	1.00			118.5	0.652			4193	0.621		
H_2S	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						

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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																
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_2S	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						

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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 Acid and H_2S

Continuous Releases Duration (minutes)	HF Acid		H_2S	
	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)	Ammonia		Chlorine	
	e	f	e	f
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

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Table 4.12M—Gas Release Toxic Consequence Equation Constants for Ammonia and Chlorine

Continuous Releases Duration (minutes)	**Ammonia**		**Chlorine**	
	e	f	e	f
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

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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	
		e	f	e	f
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

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Chemical	Release Duration (Minutes)	Gas Release Constants		Liquid Release Constants	
		e	f	e	f
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

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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

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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

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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	10	—	—	—	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.

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Table 4.15—Component Damage Costs

Equipment Type	Component Type	Damage Cost (2001 U.S. Dollars), $holecost$			
		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
	COURSES-10	5,000	12,000	20,000	40,000
Vessel/FinFan	KODRUM, DRUM	5,000	12,000	20,000	40,000
	FINFAN	1,000	2,000	20,000	60,000
	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

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Table 4.16—Material Cost Factors

Material	Cost Factor, $matcost$	Material	Cost Factor, $matcost$
Carbon Steel	1.0	90/10 Cu/Ni	6.8
1.25Cr-0.5Mo	1.3	Clad Alloy 600	7.0
2.25Cr-1Mo	1.7	CS “Teflon” 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
Polypropylene Lined (pp)	2.5	904L	8.8
9Cr-1Mo	2.6	Alloy 20	11
405 SS	2.8	Alloy 400	15
410 SS	2.8	Alloy 600	15
304 SS	3.2	Nickel	18
Clad 316 SS	3.3	Alloy 625	26
CS “Saran” Lined	3.4	Titanium	28
CS Rubber Lined	4.4	Alloy “C”	29
316 SS	4.8	Zirconium	34
CS Glass Lined	5.8	Alloy “B”	36
Clad Alloy 400	6.4	Tantalum	535

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Table 4.17—Estimated Equipment Outage

Equipment Type	Component Type	Estimated Outage in Days, $Outage_n$			
		Small	Medium	Large	Rupture
Compressor	COMPC, COMPR	NA	3	7	NA
Heat exchanger	HEXSS, HEXTS	2	3	3	10
	HEXTUBE	NA	NA	NA	NA
Pipe	PIPE-1, PIPE-2	0	NA	NA	1
	PIPE-4	0	1	NA	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	NA
Tank	TANKBOTTOM	5	NA	NA	50
	COURSE-1 through 10	2	3	3	14
Vessel/FinFan	KODRUM	2	3	3	10
	FINFAN	0	0	2	3
	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 NA—Not applicable means that these hole sizes are not used for these component types. Refer to Part 3, Annex 3.A, Section 3.A.3.2.

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Table 4.18—Fluid Leak Properties

Fluid	MW	Density (lb/ft^3)	NBP (°F)	Fraction Evaporated in 24 Hours (Note 1) $fract_{evap}$
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_2S	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 1 Estimated values.

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Table 4.18M—Fluid Leak Properties

Fluid	MW	Density (kg/m^3)	NBP (°C)	Fraction Evaporated in 24 Hours (Note 1) $fract_{evap}$
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_2S	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 1 Estimated values.

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4.15 Figures

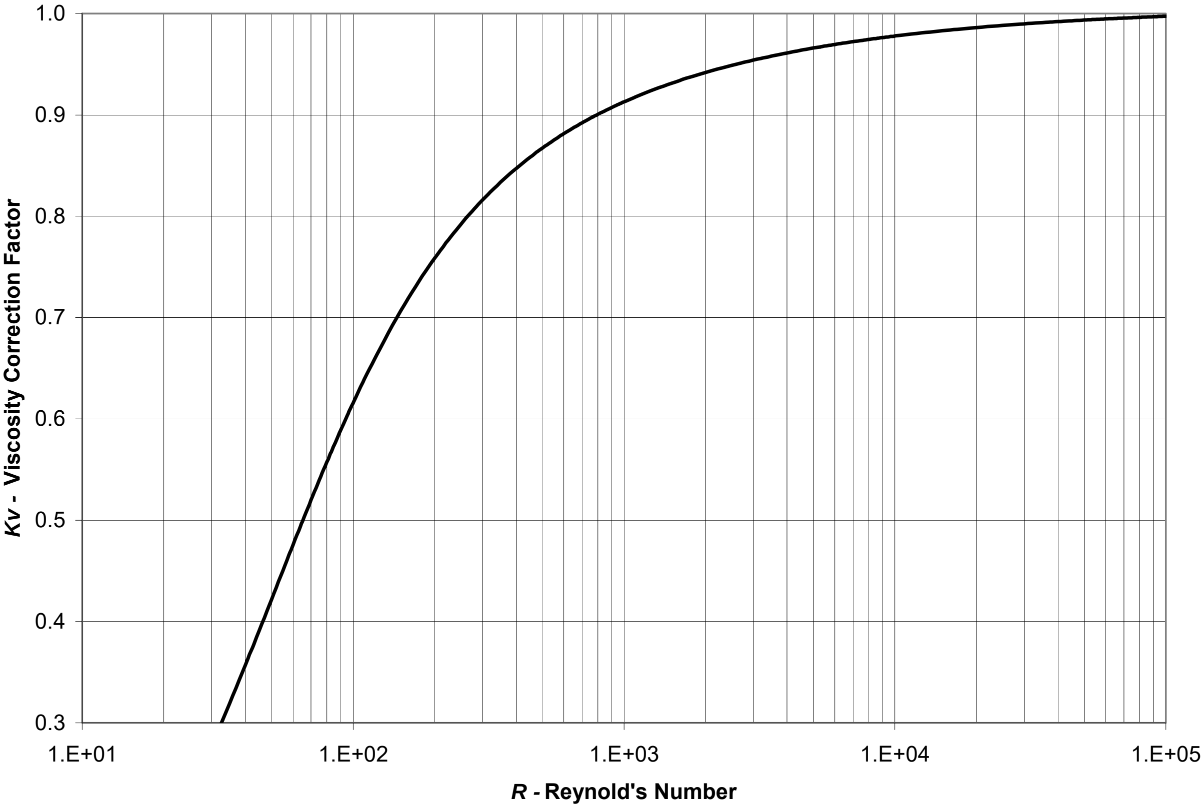

Figure 4.1—Liquid Flow Viscosity Correction Factor, K_v

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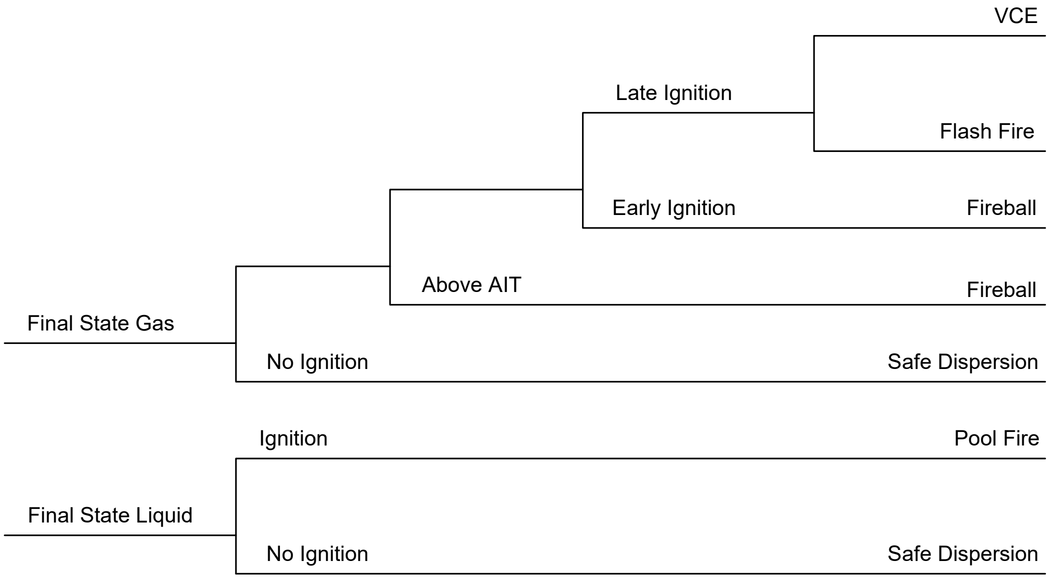
Instantaneous-Type Release



Continuous-Type Release

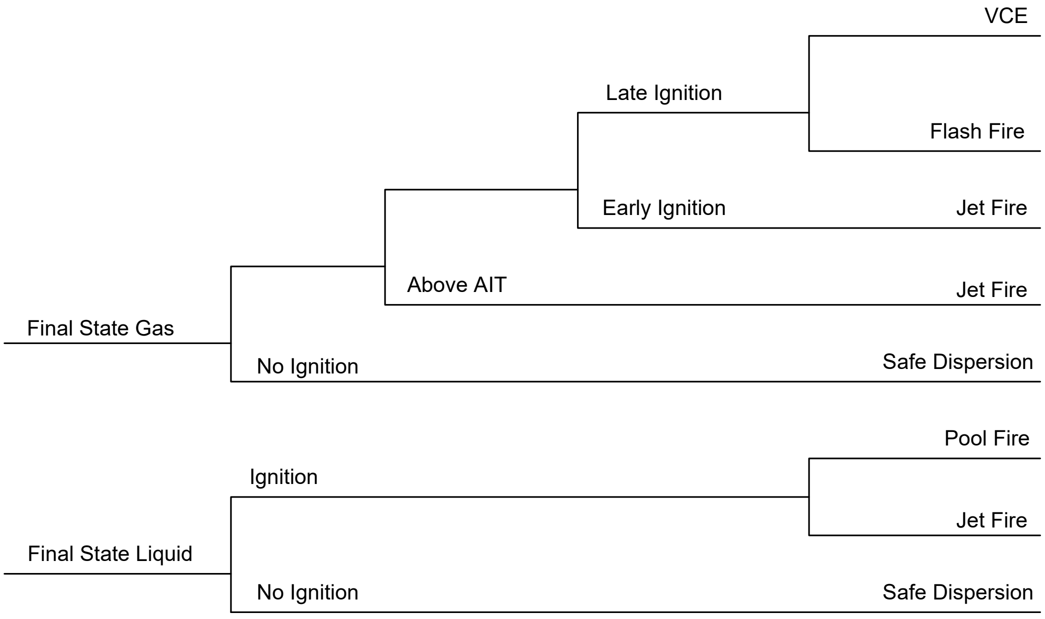


Figure 4.2—Level 1 COF Release Event Tree

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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 multi-component 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, $T_c \text{ and } P_c$.

k) AIT.

l) Saturation pressure, $Psat_s$, at storage temperature.

m) Flammability limits, LFL and upper flammability limit (UFL).

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n) Heat of combustion, HC_s.

o) Toxic limits (e.g. IDLH, ERPG, AELG, probits, etc.).

5.1.3 Required Properties at Flashed 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, Cp_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;

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.

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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 multi-component 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 that 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.

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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 that 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, $Psat_s$, must be determined.

$$\text{if } Psat_s \geq P_s \geq P_{atm} \Rightarrow \text{ release phase is vapor} \quad (3.95)$$

$$\text{if } P_s \geq Psat_s > P_{atm} \Rightarrow \text{ release phase is two-phase} \quad (3.96)$$

$$\text{if } P_s \geq P_{atm} > Psat_s \Rightarrow \text{ release phase is liquid} \quad (3.97)$$

5.3.3 Vapor Release Source

As shown in Equation (3.95), if the saturation pressure of the fluid at storage temperature, $Psat_s$, 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, $Psat_s$, 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.

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5.3.5 Liquid Release Source

Finally, as shown in Equation (3.97), if the saturation pressure of the fluid at the storage temperature, $Psat_s$, 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, $Psat_s$, 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.

   1) For liquid releases, use Equation (3.3).

   3) For vapor releases, use Equations (3.6) or (3.7), as applicable.

   4) 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.

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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].

$$frac_{ro} = 1 - 2 \cdot frac_{fsh} \qquad for \qquad frac_{fsh} < 0.5 \tag{3.98}$$

$$frac_{ro} = 0.0 \qquad for \qquad frac_{fsh} \geq 0.5 \tag{3.99}$$

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:

$$W_n^{pool} = rate_n \cdot frac_{ro} \tag{3.100}$$

$$W_n^{jet} = rate_n \left(1 - frac_{ro}\right) \tag{3.101}$$

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Note that the jet release rate may include entrained liquid. To calculate the mass fraction of liquid entrained in the jet, use Equation (3.102).

$$frac_{entl} = \frac{\left(frac_l \cdot frac_{fsh} \right)}{\left(1 - frac_{ro} \right)} \tag{3.102}$$

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].

$$erate_n = \pi^{1.5} \left[\frac{X_{surf} \cdot k_{surf} \cdot \left(T_g - T_b \right)}{C_{14} \cdot \Delta H_v \sqrt{\pi \cdot \alpha_{surf}}} \right] \left(2 \cdot g \cdot \dot{V}_{p,n} \right)^{0.5} t_{p,n} \tag{3.103}$$

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 Cremer and Warner Ltd. [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].

$$r_{p,n} = \sqrt{\frac{2}{3}} \left(\frac{8g \cdot \dot{V}_{p,n}}{\pi} \right)^{.25} t_{p,n}^{0.75} \tag{3.104}$$

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

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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].

$$erate_n = C_{15} \cdot \left(\frac{P_{b,g} \cdot MW}{RT_s} \right) u_w^{0.78} \cdot r_{p,n}^{1.89} \tag{3.105}$$

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, ft^2, at grade) where the air to fuel mixture is between the LFL and the upper flammability limit (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, LC-50, 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 that 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 that 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).

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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, Lee, 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, Lee, 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

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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:

$$rate_n^{flam} = rate_n \cdot mfrac^{flam} \tag{3.106}$$

The liquid and vapor portions of the flammable release rate are determined using Equation (3.107) and Equation (3.108).

$$rate_{l,n}^{flam} = rate_n^{flam} \cdot \left(1 - frac_{fsh}\right) \tag{3.107}$$

$$rate_{v,n}^{flam} = rate_n^{flam} \cdot frac_{fsh} \tag{3.108}$$

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 that when the flammable liquid or vapor release rate exceeds a rate that would indicate an instantaneous release [4,535.9 kg (10,000 lb) 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).

$$poi_{l,n}^{amb} = \exp\left(\begin{array}{l}\left[a + b\cdot\left(C_{12}\cdot T_{fp}\right) + c\cdot\left(C_{12}\cdot T_{fp}\right)^2 + d\cdot\left(C_{12}\cdot T_{fp}\right)^3\right] + \\ \left[e + f\cdot\left(C_{12}\cdot T_{fp}\right) + g\cdot\left(C_{12}\cdot T_{fp}\right)^2 + h\cdot\left(C_{12}\cdot T_{fp}\right)^3\right]\cdot\ln\left(C_{4B}\cdot rate_{l,n}^{flam}\right)\end{array}\right)$$

where,

a = -1.368924E-01

b = -7.598764E-03

c = 8.282163E-06

d = -6.124231E-09

e = 6.876128E-02

f = 1.193736E-04

g = 2.081034E-07

h = -4.057289E-11

(3.109)

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$$poi_{v,n}^{amb} = \exp\left(\begin{array}{l} \left[a + b \cdot \left(C_{12} \cdot T_{fp} \right) + c \cdot \left(C_{12} \cdot T_{fp} \right)^2 + d \cdot \left(C_{12} \cdot T_{fp} \right)^3 \right] + \\ \left[e + f \cdot \left(C_{12} \cdot T_{fp} \right) + g \cdot \left(C_{12} \cdot T_{fp} \right)^2 + h \cdot \left(C_{12} \cdot T_{fp} \right)^3 \right] \cdot \ln\left(C_{4B} \cdot rate_{v,n}^{flam} \right) \end{array} \right)$$

where,

a = -6.053124E-02

b = -9.958413E-03

c = 1.518603E-05

d = -1.386705E-08

e = 4.564953E-02

f = 7.912392E-04

g = -6.489157E-07

h = 7.159409E-10

(3.110)

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).

$$poi_l^{ait} = 1.0 \tag{3.111}$$

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.

$$poi_v^{ait} = \max\left[0.7, \quad 0.7 + 0.2\left(\frac{170.0 - MW}{170.0 - 2.0} \right) \right] \tag{3.112}$$

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.

$$poi_{l,n} = poi_{l,n}^{amb} + \left(poi_l^{ait} - poi_{l,n}^{amb} \right)\left(\frac{T_s - C_{16}}{AIT - C_{16}} \right) \tag{3.113}$$

$$poi_{v,n} = poi_{v,n}^{amb} + \left(poi_v^{ait} - poi_{v,n}^{amb} \right)\left(\frac{T_s - C_{16}}{AIT - C_{16}} \right) \tag{3.114}$$

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).

$$poi_{2,n} = poi_{v,n} \cdot frac_{fsh} + poi_{l,n} \cdot \left(1 - frac_{fsh} \right) \tag{3.115}$$

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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 $poii$. The probability of delayed ignition given ignition is $(1-poii)$.

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, $poii_{l,n}$, and a flammable vapor release, $poii_{v,n}$, can be estimated using Equation (3.116) and Equation (3.117). As an alternative, Cox, Lee, and Ang [15] provides a curve for the probability that an ignition will be an immediate vs a delayed ignition.

$$poii_{l,n} = poii_{l,n}^{amb} + \left(\frac{T_s - C_{16}}{AIT - C_{16}}\right)\cdot\left(poii^{ait} - poii_{l,n}^{amb}\right) \tag{3.116}$$

$$poii_{v,n} = poii_{v,n}^{amb} + \left(\frac{T_s - C_{16}}{AIT - C_{16}}\right)\cdot\left(poii^{ait} - poii_{v,n}^{amb}\right) \tag{3.117}$$

The probabilities of immediate ignition, given ignition at ambient conditions, $poii_{l,n}^{amb}$ and $poii_{v,n}^{amb}$, 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, $poii^{ait}$, 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:

$$poii_{2,n} = frac_{fsh}\cdot poii_{v,n} + \left(1 - frac_{fsh}\right)\cdot poii_{l,n} \tag{3.118}$$

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.

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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).

$$pvcedi_{2,n} = frac_{fsh} \cdot pvcedi_{v,n} + \left(1 - frac_{fsh}\right) \cdot pvcedi_{l,n} \tag{3.119}$$

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).

$$pffdi_{l,n} = 1 - pvcedi_{l,n} \tag{3.120}$$

$$pffdi_{v,n} = 1 - pvcedi_{v,n} \tag{3.121}$$

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).

$$pffdi_{2,n} = frac_{fsh} \cdot pffdi_{v,n} + \left(1 - frac_{fsh}\right) \cdot pffdi_{l,n} \tag{3.122}$$

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).

$$pfbii = 1.0 \quad for\ instantaneous\ vapor\ or\ two\text{-}phase\ releases \tag{3.123}$$

$$pfbii = 0.0 \quad for\ all\ other\ cases \tag{3.124}$$

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).

$$pvce_{v,n} = poi_{v,n} \cdot \left(1 - poii_{v,n}\right) \cdot \left(1 - pvcedi_{v,n}\right) \tag{3.125}$$

The probability of safe release of a leaking two-phase release is given by Equation (3.126).

$$psafe_{2,n} = \left(1 - poi_{2,n}\right) \tag{3.126}$$

The probability of a pool fire given a rupture of a vessel containing liquid per Figure 5.4 is given by Equation (3.127).

$$ppool_{l,n} = poi_{l,n} \cdot poii_{l,n} \tag{3.127}$$

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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:

$$\dot{m}_b = \frac{C_{17} \cdot HC_l}{Cp_l \left(T_b - T_{atm}\right) + \Delta H_v} \tag{3.128}$$

For boiling pools, such as cryogenic liquids or LPGs:

$$\dot{m}_b = \frac{C_{17} \cdot HC_l}{\Delta H_v} \tag{3.129}$$

Note that 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:

$$\dot{m}_b = \sum_{i=1}^{N} frac_{mole,i} \cdot \dot{m}_{b,i} \tag{3.130}$$

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:

$$Aburn_{pf,n} = \frac{W_n^{pool}}{\dot{m}_b} \tag{3.131}$$

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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 5 mm (0.0164 ft), in accordance with The Netherlands Organization for Applied Scientific Research (TNO Yellow Book), 1997 [18], recommendations.

$$Amax_{pf,n} = \frac{mass_{avail,n}}{C_{18} \cdot frac_{ro} \cdot \rho_l} \tag{3.132}$$

The pool fire area to be used in the consequence area calculation is then:

$$A_{pf,n} = \min\left[Aburn_{pf,n},\ Amax_{pf,n}\right] \tag{3.133}$$

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 ft^2 may be appropriate for all but the largest releases. From this area, the radius of the pool fire can be determined:

$$R_{pf,n} = \sqrt{\frac{A_{pf,n}}{\pi}} \tag{3.134}$$

5.8.2.4 Flame Length and Flame Tilt

The SFPE Fire Protection Handbook [20] provides a correlation from Thomas that can be used for calculating the flame length of a pool fire, L_{pf} .

$$L_{pf,n} = 110 \cdot R_{pf,n}\left[\frac{\dot{m}_b}{\rho_{atm}\sqrt{2 \cdot g \cdot R_{pf,n}}}\right]^{0.67} u_s^{-0.21} \tag{3.135}$$

The non-dimensional wind velocity, u_s , cannot be less than 1.0 and is dependent on the wind speed as follows:

$$u_{s,n} = \max\left[1.0\ ,\ u_w \cdot \left(\frac{\rho_v}{2 \cdot g \cdot \dot{m}_b \cdot R_{pf,n}}\right)^{0.333}\right] \tag{3.136}$$

The American Gas Association provides the following correlation for estimating the flame tilt:

$$\cos\theta_{pf,n} = \frac{1}{\sqrt{u_{s,n}}} \tag{3.137}$$

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:

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$$Qrad_n^{pool} = \frac{C_{14} \cdot \beta \cdot \dot{m}_b \cdot HC_l \cdot \pi \cdot R_{pf,n}^2}{2 \cdot \pi \cdot R_{pf,n} \cdot L_{pf,n} + \pi \cdot R_{pf,n}^2} \tag{3.138}$$

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:

$$Ith_n^{pool} = \tau_{atm,n} \cdot Qrad_n^{pool} \cdot Fcyl_n \tag{3.139}$$

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]:

$$\tau_{atm,n} = C_{19} \cdot \left(P_w \cdot xs_n\right)^{-0.09} \tag{3.140}$$

The water partial pressure expressed as a function of ambient temperature and relative humidity (RH) is given by Mudan and Croce [22] as follows:

$$P_w = C_{20}\left(RH\right)e^{\left[14.4114 - \left(\frac{C_{21}}{T_{atm}}\right)\right]} \tag{3.141}$$

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:

$$Fcyl_n = \sqrt{Fv_n^2 + Fh_n^2} \tag{3.142}$$

The vertical view factor can be calculated as follows:

$$Fv_n = \left(\begin{array}{l} \left(\dfrac{X\cos\theta_{pf,n}}{Y - X\sin\theta_{pf,n}}\right) \cdot \left(\dfrac{X^2 + \left(Y+1\right)^2 - 2Y\left(1 + \sin\theta_{pf,n}\right)}{\pi\sqrt{A'B'}}\right) \cdot \tan^{-1}\left[\dfrac{A'\left(Y-1\right)}{B'\left(Y+1\right)}\right] + \\ \left(\dfrac{\cos\theta_{pf,n}}{\pi\sqrt{C'}}\right) \cdot \left(\tan^{-1}\left[\dfrac{XY - \left(Y^2 - 1\right)\sin\theta_{pf,n}}{\sqrt{Y^2-1}\sqrt{C'}}\right] + \tan^{-1}\left[\dfrac{\sin\theta_{pf,n}\sqrt{Y^2-1}}{\sqrt{C'}}\right]\right) - \\ \left(\dfrac{X\cos\theta_{pf,n}}{\pi\left(Y - X\sin\theta_{pf,n}\right)}\right) \cdot \tan^{-1}\left[\sqrt{\dfrac{Y-1}{Y+1}}\right] \end{array} \right) \tag{3.143}$$

The horizontal view factor can be calculated as follows:

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$$Fh_n = \left(\begin{array}{l} \dfrac{1}{\pi}\tan^{-1}\left[\sqrt{\dfrac{Y+1}{Y-1}}\right] - \\ \left(\dfrac{X^2+(Y+1)^2-2\left(Y+1+XY\sin\theta_{pf,n}\right)}{\pi\sqrt{A'B'}}\right)\cdot\tan^{-1}\left[\sqrt{\dfrac{A'(Y-1)}{B'(Y+1)}}\right] + \\ \left(\dfrac{\sin\theta_{pf,n}}{\pi\sqrt{C'}}\right)\cdot\left(\tan^{-1}\left[\dfrac{XY-\left(Y^2-1\right)\sin\theta_{pf,n}}{\sqrt{Y^2-1}\sqrt{C'}}\right]+\tan^{-1}\left[\dfrac{\sin\theta_{pf,n}\sqrt{Y^2-1}}{\sqrt{C'}}\right]\right) \end{array} \right) \tag{3.144}$$

In Equation (3.143) and Equation (3.144), the following parameters are used.

$$X = \frac{L_{pf,n}}{R_{pf,n}} \tag{3.145}$$

$$Y = \frac{xs_n}{R_{pf,n}} \tag{3.146}$$

$$A' = X^2 + (Y+1)^2 - 2X(Y+1)\sin\theta_{pf,n} \tag{3.147}$$

$$B' = X^2 + (Y-1)^2 - 2X(Y-1)\sin\theta_{pf,n} \tag{3.148}$$

$$C' = 1 + \left(Y^2-1\right)\cos^2\theta_{pf,n} \tag{3.149}$$

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 12.6 kW/m^2 (4,000 Btu/hr-ft^2) is used for serious personnel injury. The maximum permissible radiation for component damage is 37.8 kW/m^2 (12,000 Btu/hr-ft^2).

Note that 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.

$$CA_{f,cmd,n}^{pool} = \pi \cdot \left(xs_{cmd,n}^{pool} + R_{pf,n}\right)^2 \tag{3.150}$$

$$CA_{f,inj,n}^{pool} = \pi \cdot \left(xs_{inj,n}^{pool} + R_{pf,n}\right)^2 \tag{3.151}$$

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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 12.6 kW/m^2 (4,000 Btu/hr-ft^2) for personnel and 37.8 kW/m^2 (12,000 Btu/hr-ft^2) 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:

$$Qrad_n^{jet} = C_{14} \cdot \beta \cdot W_n^{jet} \cdot HC_v \tag{3.152}$$

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:

$$Ith_n^{jet} = \tau_{atm,n} \cdot Qrad_n^{jet} \cdot Fp_n \tag{3.153}$$

If a point source model is used, then the radiation view factor between the source flame and the target can be approximated as follows:

$$Fp_n = \frac{1}{4\pi \cdot xs_n^2} \tag{3.154}$$

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 that 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.

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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, $xs_{cmd,n}^{jet}$ and $xs_{inj,n}^{jet}$, are determined, Equation (3.155) and Equation (3.156) are used to calculate the jet fire consequence areas.

$$CA_{f,cmd,n}^{jet} = \pi \cdot {xs_{cmd,n}^{jet}}^{2} \tag{3.155}$$

$$CA_{f,inj,n}^{jet} = \pi \cdot {xs_{inj,n}^{jet}}^{2} \tag{3.156}$$

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, $mass_{fb}$, is the fraction of the released mass that contains flammable material and can be determined using Equation (3.157).

$$mass_{fb} = mfrac^{flam} \cdot mass_{avail,n} \tag{3.157}$$

The maximum mass available for release, $mass_{avail,n}$, 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:

$$Dmax_{fb} = C_{22} \cdot mass_{fb}^{0.333} \tag{3.158}$$

The center height of the fireball is assumed to be:

$$H_{fb} = 0.75 \cdot Dmax_{fb} \tag{3.159}$$

The duration of the fireball is also a function of the flammable mass as follows:

$$t_{fb} = C_{23} \cdot mass_{fb}^{0.333} \qquad for \quad mass_{fb} \le 29,937\, kgs \;\; [66,000\, lbs] \tag{3.160}$$

$$t_{fb} = C_{24} \cdot mass_{fb}^{0.167} \qquad for \quad mass_{fb} > 29,937\, kgs \;\; [66,000\, lbs] \tag{3.161}$$

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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).

$$Qrad^{fball} = \frac{C_{14} \cdot \beta_{fb} \cdot mass_{fb} \cdot HC_l}{\pi \cdot Dmax_{fb}^2 \cdot t_{fb}} \tag{3.162}$$

The fraction of combustion power that is radiated from a fireball can be calculated from a correlation by [24]:

$$\beta_{fb} = C_{25} \cdot P_B^{\ 0.32} \tag{3.163}$$

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:

$$Ith^{fball} = \tau_{atm} \cdot Qrad^{fball} \cdot Fsph \tag{3.164}$$

For a fireball, the spherical model for the geometric view factor is used:

$$Fsph = \frac{\left(Dmax_{fb}\right)^2}{4C_{fb}^{\ 2}} \tag{3.165}$$

where

$$C_{fb} = \sqrt{\left(\frac{Dmax_{fb}}{2.0}\right)^2 + \left(\frac{xs^{fball}}{2.0}\right)^2} \tag{3.166}$$

Note that the atmospheric transmissivity and the geometric view factor are functions of the distance from the flame source to the target, xs^{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, xs_{cmd}^{fball} and xs_{inj}^{fball}, are determined, Equation (3.167) and Equation (3.168) are used to calculate the fireball consequence areas.

$$CA_{f,cmd}^{fball} = \pi \cdot \left(xs_{cmd}^{fball}\right)^2 \tag{3.167}$$

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$$CA_{f,inj}^{fball} = \pi \cdot \left(xs_{inj}^{fball} \right)^2 \tag{3.168}$$

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

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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 $0.03 \le \eta \le 0.19$ 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).

$$W_{TNT} = \frac{\eta \cdot mass_{vce} \cdot HC_s}{HC_{TNT}} \tag{3.169}$$

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 4648 J/kg (2000 Btu/lb).

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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 curved 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):

$$P_{SO,n} = C_{26} \cdot \left(\begin{array}{l} -0.059965896 + \dfrac{1.1288697}{\ln\left[\bar{R}_{HS,n}\right]} - \dfrac{7.9625216}{\left(\ln\left[\bar{R}_{HS,n}\right]\right)^2} + \\ \dfrac{25.106738}{\left(\ln\left[\bar{R}_{HS,n}\right]\right)^3} - \dfrac{30.396707}{\left(\ln\left[\bar{R}_{HS,n}\right]\right)^4} + \dfrac{19.399862}{\left(\ln\left[\bar{R}_{HS,n}\right]\right)^5} - \\ \dfrac{6.8853477}{\left(\ln\left[\bar{R}_{HS,n}\right]\right)^6} + \dfrac{1.2825511}{\left(\ln\left[\bar{R}_{HS,n}\right]\right)^7} - \dfrac{0.097705789}{\left(\ln\left[\bar{R}_{HS,n}\right]\right)^8} \end{array} \right) \qquad (3.170)$$

For use in Equation (3.171), the Hopkinson-scaled distance, $\bar{R}_{HS,n}$, presented above requires units of m/kg$^{1/3}$ and is calculated from the actual distance from the blast center as follows:

$$\bar{R}_{HS,n} = C_{27} \cdot \frac{xs_n^{vce}}{W_{TNT}^{1/3}} \qquad (3.171)$$

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].

$$Pr = -23.8 + 2.92 \cdot \ln\left[C_{28} \cdot P_{SO,n}\right] \qquad (3.172)$$

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 that 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.

$$CA_{f,cmd,n}^{vce} = \pi \cdot \left(xs_{cmd,n}^{vce}\right)^2 \qquad (3.173)$$

$$CA_{f,inj,n}^{vce} = \pi \cdot \left(xs_{inj,n}^{vce}\right)^2 \qquad (3.174)$$

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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.

$$CA_{f,cmd,n}^{flash} = 0.25 \cdot CA_{inj,n}^{flash} \tag{3.175}$$

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).

$$CA_{f,cmd,n}^{flam} = \begin{pmatrix} ppool_n \cdot CA_{f,cmd,n}^{pool} + pjet_n \cdot CA_{f,cmd,n}^{jet} + pfball_n \cdot CA_{f,cmd}^{fball} + \\ pvce_n \cdot CA_{f,cmd,n}^{vce} + pflash_n \cdot CA_{f,cmd,n}^{flash} \end{pmatrix} \tag{3.176}$$

$$CA_{f,inj,n}^{flam} = \begin{pmatrix} ppool_n \cdot CA_{f,inj,n}^{pool} + pjet_n \cdot CA_{f,inj,n}^{jet} + pfball_n \cdot CA_{f,inj}^{fball} + \\ pvce_n \cdot CA_{f,inj,n}^{vce} + pflash_n \cdot CA_{f,inj,n}^{flash} \end{pmatrix} \tag{3.177}$$

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).

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$$CA_{f,cmd}^{flam} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA_{f,cmd,n}^{flam}}{gff_{total}} \right) \tag{3.178}$$

The equation for probability weighting of the personnel injury consequence areas is given by Equation (3.179).

$$CA_{f,inj}^{flam} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA_{f,inj,n}^{flam}}{gff_{total}} \right) \tag{3.179}$$

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 that 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 that for the rupture case or some of the larger hole sizes a maximum value of 25.2 kg/s (55.6 lb/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 that for the rupture case and some of the larger hole sizes, a maximum value of 25.2 kg/s (55.6 lb/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.

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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, $poii_{l,n}^{amb}$ and $poii_{v,n}^{amb}$, 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, $poii_{l,n}$, and the vapor portion of the release, $poii_{v,n}$, using Equation (3.128) and Equation (3.129). Use a value for the probability of immediate ignition at the AIT, $poii^{ait}$ =1.0.

3) For two-phase releases, calculate the probability of immediate ignition given ignition, $poii_{2,n}$, 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, $pfbii$, 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.

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1) Probability of a pool fire given a release:

$$ppool_{v,n} = 0.0 \tag{3.180}$$

2) Probability of a jet fire given a release (continuous releases only):

$$pjet_{v,n} = poi_{v,n} \cdot poii_{v,n} \tag{3.181}$$

3) Probability of a VCE given a release:

$$pvce_{v,n} = poi_{v,n} \cdot \left(1 - poii_{v,n}\right) \cdot \left(1 - pvcedi_{v,n}\right) \tag{3.182}$$

4) Probability of a flash fire given a release (instantaneous releases only):

$$pflash_{v,n} = poi_{v,n} \cdot poii_{v,n} \tag{3.183}$$

5) Probability of a fireball:

$$pfball_{v,n} = 0.0 \tag{3.184}$$

6) Probability of safe dispersion given a release:

$$psafe_{v,n} = 1 - poi_{v,n} \tag{3.185}$$

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 that 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, $Qrad_n^{pool}$, using Equation (3.138).

7) A radiation limit of 37.8 kW/m^2 (12,000 Btu/hr-ft^2) is used for component damage consequence area. For personnel injury, 12.6 kW/m^2 (4,000 Btu/hr-ft^2) is used. These radiation limits are used to determine

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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, $Fcyl_n$, 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, Ith_n^{pool}, at the distance chosen using Equation (3.139) and compare it to the acceptable radiation limit [37.8 kW/m^2 (12,000 Btu/hr-ft^2) for component damage and 12.6 kW/m^2 (4,000 Btu/hr-ft^2) 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).

l) 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, $Qrad_n^{jet}$, using Equation (3.164). Use the jet release rate, W_n^{jet}, established in STEP 7.5.

2) A radiation limit of 37.8 kW/m^2 (12,000 Btu/hr-ft^2) is used for component damage consequence area. For personnel injury, 12.6 kW/m^2 (4,000 Btu/hr-ft^2) 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, Fp_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 [37.8 kW/m^2 (12,000 Btu/hr-ft^2) for component damage and 12.6 kW/m^2 (4,000 Btu/hr-ft^2) 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).

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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, $Dmax_{fb}$, 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, $Qrad^{fball}$, using Equation (3.162).

5) For the component damage consequence area, API 581 uses a radiation limit of 37.8 kW/m^2 (12,000 Btu/hr-ft^2). For personnel injury, 12.6 kW/m^2 (4,000 Btu/hr-ft^2) 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^{fball}.

   ii) Calculate the atmospheric transmissivity, τ_{atm}, and the spherical view factor, $Fsph$, using Equation (3.140) and Equation (3.165). Both of these parameters are functions of the distance from the fireball chosen above, xs^{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 [37.8 kW/m^2 (12,000 Btu/hr-ft^2) for component damage and 12.6 kW/m^2 (4,000 Btu/hr-ft^2) 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.

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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 that 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 34.5 kPa (5.0 psi). This overpressure limit is used to determine the safe distance, $xs^{vce}_{cmd,n}$, from the VCE using the following four-step iterative procedure.

   i) Guess at an acceptable component damage distance from the VCE, $xs^{vce}_{cmd,n}$.

   ii) Calculate the Hopkinson-scaled distance, $\overline{R}_{HS,n}$, using Equation (3.171). This parameter is a function of the distance from the VCE chosen above, $xs^{vce}_{cmd,n}$.

   iii) Calculate the side-on overpressure, $P_{SO,n}$, at the Hopkinson-scaled distance, $\overline{R}_{HS,n}$, using Equation (3.170).

   iv) Adjust the distance, $xs^{vce}_{cmd,n}$, 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, $CA^{vce}_{f,cmd,n}$, 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, $xs^{vce}_{inj,n}$, from the VCE using the following five-step iterative procedure.

   i) Guess at an acceptable personnel injury distance from the VCE, $xs^{vce}_{inj,n}$.

   ii) Calculate the Hopkinson-scaled distance, $\overline{R}_{HS,n}$, using Equation (3.171). This parameter is a function of the distance from the VCE chosen above, $xs^{vce}_{inj,n}$.

   iii) Calculate the side-on overpressure, $P_{SO,n}$, at the Hopkinson-scaled distance, $\overline{R}_{HS,n}$, using Equation (3.170).

   iv) Calculate the probit value, Pr, using Equation (3.172).

   v) Adjust the distance, $xs^{vce}_{cmd,n}$, accordingly, and repeat the above steps until the probit value is equal to 5.0.

5) Calculate the personal injury consequence area, $CA^{vce}_{f,inj,n}$, using Equation (3.174).

o) STEP 8.15—For each of the hole sizes, calculate the component damage consequence area, $CA^{flash}_{f,cmd,n}$, and the personnel injury consequence area, $CA^{flash}_{f,inj,n}$, 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

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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 non-fatal 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.

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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—LC_{50}

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 LC_{50} 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.

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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, $ld_{max,n}$ listed in Table 4.7.

$$ld_n^{tox} = \min\left[3600,\ \left\{\frac{mass_n}{W_n}\right\},\ \left\{60 \cdot ld_{max,n}\right\}\right] \tag{3.186}$$

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).

$$ptox_n = psafe_n \tag{3.187}$$

5.9.5 Consequences of Releases Containing Multiple Toxic Chemicals

Consequence results for releases of multi-component 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, $CA_{inj,n}^{tox}$.

$$CA_{f,inj,n}^{tox} = ptox_n \cdot CA_{f,n}^{cloud} \tag{3.188}$$

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).

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$$tox_{lim}^{mod} = \frac{tox_{lim}}{molfrac^{tox}} \tag{3.189}$$

For example, a hydrocarbon stream contains 5 mole% H_2S. H_2S 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:

$$tox_{lim}^{mod} = \frac{100 \text{ ppm}}{0.05} = 2000 \text{ ppm} \tag{3.190}$$

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).

$$CA_{f,inj}^{tox} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA_{f,inj,n}^{tox}}{gff_{total}} \right) \tag{3.191}$$

In Equation (3.191), the total GFF is as calculated in STEP 2.2.

5.9.8 Calculation of Toxic Consequence Areas

a) STEP 9.1—Determine the mole fraction of the release rate that contains a toxic component, $molefrac^{tox}$.

b) STEP 9.2—Calculate the release duration, ld_n^{tox} , using Equation (3.186).

c) 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.

d) STEP 9.4—Determine the modified toxic limit, tox_{lim}^{mod} , using Equation (3.189).

e) 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 that 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, $CA_{f,n}^{cloud}$.

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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, $CA_{f,inj,n}^{tox}$, using Equation (3.188).

i) STEP 9.9—Calculate the probability weighted or final toxic personnel injury consequence area, $CA_{f,inj}^{tox}$, 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.

$$W_{TNT} = C_{29} \cdot V_s \cdot \left(\frac{P_s - P_{atm}}{k-1} \right) \tag{3.192}$$

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).

$$CA_{f,cmd}^{pexp} = \pi \cdot \left(xs_{cmd}^{pexp} \right)^2 \quad \textit{for rupture case only} \tag{3.193}$$

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$$CA_{f,inj}^{pexp} = \pi \cdot \left(xs_{inj}^{pexp} \right)^2 \qquad \textit{for rupture case only} \tag{3.194}$$

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).

$$W_{TNT} = C_{30} \cdot n_v R T_s \cdot \ln\left[\frac{P_s}{P_{atm}} \right] \tag{3.195}$$

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).

$$CA_{f,cmd}^{bleve} = \pi \cdot \left(xs_{cmd}^{bleve} \right)^2 \qquad \textit{for rupture case only} \tag{3.196}$$

$$CA_{f,inj}^{bleve} = \pi \cdot \left(xs_{inj}^{bleve} \right)^2 \qquad \textit{for rupture case only} \tag{3.197}$$

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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).

$$CA^{nfnt}_{f,cmd,n} = pnfnt \cdot \max\left(CA^{pexp}_{f,cmd,n},\ CA^{bleve}_{f,cmd,n}\right) \tag{3.198}$$

$$CA^{nfnt}_{f,inj,n} = pnfnt \cdot \max\left(CA^{pexp}_{f,inj,n},\ CA^{bleve}_{f,inj,n}, CA^{leak}_{f,inj,n}\right) \tag{3.199}$$

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.

$$CA^{nfnt}_{f,cmd} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA^{nfnt}_{f,cmd,n}}{gff_{total}}\right) \tag{3.200}$$

$$CA^{nfnt}_{f,inj} = \left(\frac{\sum_{n=1}^{4} gff_n \cdot CA^{nfnt}_{f,inj,n}}{gff_{total}}\right) \tag{3.201}$$

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, $CA^{leak}_{f,inj,n}$, as is detailed in STEPs 10.1 through 10.3 of Section 4.10.6.

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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, xs_{cmd}^{pexp} , from the explosion using the following four-step iterative procedure.

   i) Guess at an acceptable component damage distance from the physical explosion, xs_{cmd}^{pexp} .

   ii) Calculate the Hopkinson-scaled distance, $\overline{R}_{HS}$, using Equation (3.171). This parameter is a function of the distance from the physical explosion chosen above, xs_{cmd}^{pexp} .

   iii) Calculate the side-on overpressure, P_{SO} , at the Hopkinson-scaled distance, $\overline{R}_{HS}$, using Equation (3.170).

   iv) Adjust the distance, xs_{cmd}^{pexp} , accordingly, and repeat the above steps until the side-on overpressure, P_{SO} , is equal to 34.5 kPa (5.0 psi).

4) Calculate the component damage consequence area, $CA_{f,cmd}^{pexp}$, 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, xs_{inj}^{pexp} , from the VCE using the following five-step iterative procedure.

   i) Guess at an acceptable personnel injury distance from the VCE, xs_{inj}^{pexp} .

   ii) Calculate the Hopkinson-scaled distance, $\overline{R}_{HS}$, using Equation (3.171). This parameter is a function of the distance from the VCE chosen above, xs_{inj}^{pexp} .

   iii) Calculate the side-on overpressure, P_{SO} , at the Hopkinson-scaled distance, $\overline{R}_{HS}$, Equation (3.170).

   iv) Calculate the probit value, Pr , using Equation (3.172).

   v) Adjust the distance, xs_{inj}^{pexp} , accordingly, and repeat the above steps until the probit value is equal to 5.0.

6) Calculate the personal injury consequence area, $CA_{f,inj}^{pexp}$, using Equation (3.174).

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c) STEP 10.3—For the rupture case, calculate the component damage consequence area, $CA_{f,cmd}^{bleve}$, and the personnel injury consequence area, $CA_{f,inj}^{bleve}$, 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, $\overline{R}_{HS}$, 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, $\overline{R}_{HS}$, 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 34.5 kPa (5.0 psi).

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, $\overline{R}_{HS}$, 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, $\overline{R}_{HS}$, 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).

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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.

$$CA_{f,cmd} = CA_{f,cmd}^{flam} + \max\left[psafe \cdot CA_{f,cmd}^{safe},\ CA_{f,cmd}^{nfnt} \right] \tag{3.202}$$

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.

$$CA_{f,inj} = CA_{f,inj}^{flam} + \max\left[psafe \cdot CA_{f,inj}^{safe},\ CA_{f,inj}^{tox},\ CA_{f,inj}^{nfnt} \right] \tag{3.203}$$

5.11.4 Final Consequence Area

The final consequence area is:

$$CA_f = \max\left[CA_{f,cmd},\ CA_{f,inj} \right] \tag{3.204}$$

5.11.5 Calculation for Final Consequence Area

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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 FC

5.12.1 General

The FC is determined accordance with the Level 1 consequence analysis; see Section 4.12.7.

5.12.2 Calculation of FC

The step-by-step procedure for estimating the impact of detection and isolation systems is in accordance with Section 4.12.2.

5.13 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.

$Aburn_{pf,n}$	is the pool fire area based on burning rate, associated with the nth release hole size, m^2 (ft^2)
AIT	is the autoignition temperature of the released fluid, K (°R)
$Amax_{pf,n}$	is the maximum pool fire area based on a pool depth of 5 mm (0.0164 ft), associated with the nth release hole size, m^2 (ft^2)
$A_{pf,n}$	is the pool fire surface area, associated with the nth release hole size, m^2 (ft^2)
BP_s	is the boiling point temperature of the stored fluid at normal operating conditions, K (°R)
CA_f	is the final consequence area, m^2 (ft^2)
$CA_{f,cmd}^{bleve}$	is the component damage consequence area for a BLEVE associated with the rupture case, m^2 (ft^2)
$CA_{f,inj}^{bleve}$	is the personnel injury consequence area for a BLEVE associated with the rupture case, m^2 (ft^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 nth release hole size, m^2 (ft^2)
$CA_{f,cmd}^{fball}$	is the component damage consequence area for a fireball associated with the rupture case, m^2 (ft^2)
$CA_{f,inj}^{fball}$	is the personnel injury consequence area for a fireball associated with the rupture case, m^2 (ft^2)

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$CA_{f,cmd}^{flam}$	is the final overall component damage flammable consequence area, m^2 (ft^2)
$CA_{f,cmd,n}^{flam}$	is the component damage flammable consequence area associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,inj}^{flam}$	is the final overall personnel injury flammable consequence area, m^2 (ft^2)
$CA_{f,inj,n}^{flam}$	is the personnel injury flammable consequence area associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,cmd,n}^{flash}$	is the component damage consequence area for a flash fire associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,inj,n}^{flash}$	is the personnel injury consequence area for a flash fire associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,cmd,n}^{jet}$	is the component damage consequence area for a jet fire associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,inj,n}^{jet}$	is the personnel injury consequence area for a jet fire associated with the n^{th} release hole size, m^2 (ft^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, m^2 (ft^2)
$CA_{f,cmd}^{nfnt}$	is the final probability weighted component damage consequence area for nonflammable, nontoxic releases, m^2 (ft^2)
$CA_{f,inj}^{nfnt}$	is the final probability weighted personnel injury consequence area for nonflammable, nontoxic releases, m^2 (ft^2)
$CA_{f,inj,n}^{nfnt}$	is the personnel injury nonflammable, nontoxic consequence area, associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,cmd}^{pexp}$	is the component damage consequence area for a physical explosion associated with the rupture case only, m^2 (ft^2)
$CA_{f,inj}^{pexp}$	is the personnel injury consequence area for a physical explosion associated with the rupture case only, m^2 (ft^2)
$CA_{f,cmd,n}^{pool}$	is the component damage consequence area for a pool fire associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,inj,n}^{pool}$	is the personnel injury consequence area for a pool fire associated with the n^{th} release hole size, m^2 (ft^2)

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$CA_{f,cmd,n}^{safe}$	is the component damage consequence area for a safe release associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,inj,n}^{safe}$	is the personnel injury consequence area for a safe release associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,inj}^{tox}$	is the final overall personnel injury toxic consequence area, m^2 (ft^2)
$CA_{f,inj,n}^{tox}$	is the personnel injury toxic consequence area associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,cmd,n}^{vce}$	is the component damage consequence area for a VCE associated with the n^{th} release hole size, m^2 (ft^2)
$CA_{f,inj,n}^{vce}$	is the personnel injury consequence area for a VCE associated with the n^{th} release hole size, m^2 (ft^2)
C_{fb}	is the distance from the center of the fireball to the target, m (ft)
Cp_l	is the specific heat of the pool liquid, J/kg-K (Btu/lb-°R)
$Dmax_{fb}$	is the maximum diameter of the fireball, m (ft)
$erate_n$	is the liquid pool mass evaporation rate associated with the n^{th} release hole size, kg/s (lb/s)
$fact_{di}$	is the release magnitude reduction factor, based on the detection and isolations systems present in the unit
$Fcyl_n$	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, m^{-2} (ft^{-2})
$frac_{fsh}$	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
$Fsph$	is the view factor for a spherical shape, unitless

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Fv_n	is the vertical radiation view factor for a cylindrical shape associated with the n^{th} release hole size, unitless
g	is the acceleration due to gravity on earth at sea level = 9.81 m/s^2 (32.2 ft/s^2)
g_c	is the gravitational constant = $1.0(kg-m)/(N-s^2)\left[32.2(lb_m-ft)/(lb_f-s^2)\right]$
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, m (ft)
HC_l	is the heat of combustion of the liquid fuel for the pool fire calculations, J/kg (Btu/lb)
HC_s	is the heat of combustion of the stored fluid or mixture, J/kg (Btu/lb)
HC_{TNT}	is the heat of combustion of TNT ≈ 2000, J/kg (Btu/lb)
HC_v	is the heat of combustion of the vapor fuel for the jet fire calculations, J/kg (Btu/lb)
Ith^{fball}	is the radiant heat flux received at a distant receiver location from a fireball associated with the rupture case, W/m^2 (Btu/hr-ft^2)
Ith_n^{jet}	is the radiant heat flux received at a distant receiver location from a jet fire associated with the n^{th} release hole size, W/m^2 (Btu/hr-ft^2)
Ith_n^{pool}	is the radiant heat flux received at a distant receiver location from a pool fire associated with the n^{th} release hole size, W/m^2 (Btu/hr-ft^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, W/m-K (Btu/hr-ft-^{o}R)
$ld_{max,n}$	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
$L_{pf,n}$	is the pool fire flame length, associated with the n^{th} release hole size, m (ft)
LFL	is the lower flammability limit for the fluid

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$\dot{m}_b$	is the burning flux rate of a pool fire, kg/m^2-s (lb/ft^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, kg/m^2-s (lb/ft^2-s)
$mass_{avail,n}$	is the available mass for release for each of the release hole sizes selected, associated with the n^{th} release hole size, kg (lb)
$mass_{fb}$	is the flammable mass of the stored liquid used in the fireball calculation, kg (lb)
$mass_{vce}$	is the mass of flammable material in the vapor cloud used in the VCE calculation, kg (lb)
$mfrac^{flam}$	is the flammable mass fraction of the released fluid mixture
$mfrac^{tox}$	is the toxic mass fraction of the released fluid mixture
$molfrac^{tox}$	is the toxic mole fraction of the released fluid mixture
MW	is the release fluid molecular weight, kg/kg-mol (lb/lb-mol)
n_v	is the moles that flash from liquid to vapor upon release to atmosphere, kg-mol (lb-mol)
$pfball_n$	is the probability of a fireball given a release associated with the n^{th} release hole size
$pfball_{v,n}$	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

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$pnfnt_n$	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^{ait}	is the maximum probability of ignition for a liquid release at or above the AIT
poi_v^{ait}	is the maximum probability of ignition for a vapor release at or above the AIT
$poi_{l,n}^{amb}$	is the probability of ignition given a liquid release at ambient temperature associated with the n^{th} release hole size
$poi_{v,n}^{amb}$	is the probability of ignition given a vapor release at ambient temperature associated with the n^{th} release hole size
$poi_{l,n}$	is the probability of ignition given a liquid release 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
$poi_{2,n}$	is the probability of ignition given a two-phase release associated with the n^{th} release hole size
$poii$	is the probability of immediate ignition given ignition
$poii^{ait}$	is the probability of immediate ignition given ignition if the fluid were to be released at or above its AIT , assumed = 1.0
$poii_{l,n}^{amb}$	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
$poii_{v,n}^{amb}$	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
$poii_{l,n}$	is the probability of immediate ignition given ignition of a liquid release associated with the n^{th} release hole size
$poii_{v,n}$	is the probability of immediate ignition given ignition of a vapor release associated with the n^{th} release hole size
$poii_{2,n}$	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
$ppool_n$	is the probability of a pool fire given a release associated with the n^{th} release hole size

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$ppool_{v,n}$	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
$pvce_n$	is the probability of a VCE 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
$pvce_{v,n}$	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
P_{atm}	is the atmospheric pressure, kPa (psia)
$P_{b,g}$	is the bubble point pressure of the released fluid at the ground temperature, kPa (psia)
P_B	is the component or equipment burst pressure, kPa (psia)
Pr	is the probit value, typically set at 5 (50 % probability)
P_s	is the storage or normal operating pressure, kPa (psia)
$P_{SO,n}$	is the side-on overpressure associated with the n^{th} release hole size, kPa (psia)
P_w	is the atmospheric water partial pressure, kPa (psia)
$Psat_s$	is the saturation pressure of the stored fluid at operating (storage) temperature, kPa (psia)
$Qrad^{fball}$	is the total energy flux radiated from a fireball, W/m^2 (Btu/hr-ft^2)

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$Qrad_n^{jet}$	is the total energy radiated from a jet fire associated with the n^{th} release hole size, W (Btu/hr)
$Qrad_n^{pool}$	is the total energy flux radiated from a pool fire associated with the n^{th} release hole size, W/m^2 (Btu/hr-ft^2)
$r_{p,n}$	is the pool radius, calculated for each of the n release hole sizes selected, m (ft)
R	is the universal gas constant = 8314 J/(kg-mol-K) [1545 ft-lb$_f$/(lb-mol-°R)]
$R_{pf,n}$	is the pool fire radius, calculated for each of the n release hole sizes selected, m (ft)
RH	is the atmospheric relative humidity, %
$rate_{l,n}^{flam}$	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, kg/s (lb/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, kg/s (lb/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, kg/s (lb/s)
$rate_n$	is the adjusted or mitigated discharge rate used in the consequence calculation associated with the n^{th} release hole size, kg/s (lb/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, kg/s (lb/s)
$\bar{R}_{HS,n}$	is the Hopkinson's scaled distance used in the blast calculations associated with the n^{th} release hole size, m/kg$^{1/3}$ (lb/ft$^{1/3}$)
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
T_{atm}	is the atmospheric temperature, K (°R)
T_b	is the bubble point temperature of released liquid, K (°R)
T_d	is the dew point temperature of released vapor, K (°R)

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T_f	is the flash temperature of the released fluid, K (°R)
T_{fp}	is the flash point of the released fluid, K (°R).
T_g	is the ground temperature, K (°R)
T_s	is the storage or normal operating temperature, K (°R)
$u_{s,n}$	is the non-dimensional wind speed associated with the n^{th} release hole size, unitless
u_w	is the wind speed measured at 6 ft off of grade, m/s (ft/s)
UFL	is the upper flammability limit for the fluid
$\dot{V}_{p,n}$	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, m^3 (ft^3)
W_n^{jet}	is the portion of the release rate that forms a jet associated with the n^{th} release hole size, kg/s (lb/s)
W_n	is the theoretical release rate associated with the n^{th} release hole size, kg/s (lb/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, kg/s (lb/s)
W_{TNT}	is the energy released in an explosion expressed as an equivalent mass of TNT, kg (lb)
xs_{cmd}^{bleve}	is the safe distance from a BLEVE for component damage associated with the rupture case, m (ft)
xs_{inj}^{bleve}	is the safe distance from a BLEVE for personnel injury associated with the rupture case, m (ft)
xs^{fball}	is the safe distance from the flame surface of a fireball, m (ft)
xs_{cmd}^{fball}	is the safe distance from a fireball for component damage associated with the rupture case, m (ft)
xs_{inj}^{fball}	is the safe distance from a fireball for personnel injury associated with the rupture case, m (ft)
$xs_{cmd,n}^{jet}$	is the safe distance from the jet fire flame surface for component damage associated with the n^{th} release hole size, m (ft)
$xs_{inj,n}^{jet}$	is the safe distance from the jet fire flame surface for personnel injury associated with the n^{th} release hole size, m (ft)

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xs_n^{jet}	is the safe distance from the jet fire flame surface associated with the n^{th} release hole size, m (ft)
xs_n	is the safe distance from the flame surface to the target location associated with the n^{th} release hole size, m (ft)
xs_{cmd}^{pexp}	is the safe distance from a physical explosion for component damage associated with the rupture case, m (ft)
xs_{inj}^{pexp}	is the safe distance from a physical explosion for personnel injury associated with the rupture case, m (ft)
$xs_{cmd,n}^{pool}$	is the safe distance from the pool fire flame surface for component damage associated with the n^{th} release hole size, m (ft)
$xs_{inj,n}^{pool}$	is the safe distance from the pool fire flame surface for personnel injury associated with the n^{th} release hole size, m (ft)
xs_n^{pool}	is the safe distance from the pool fire flame surface associated with the n^{th} release hole size, m (ft)
$xs_{cmd,n}^{vce}$	is the safe distance from the VCE for component damage associated with the n^{th} release hole size, m (ft)
$xs_{inj,n}^{vce}$	is the safe distance from the VCE for personnel injury associated with the n^{th} release hole size, m (ft)
xs_n^{vce}	is the safe distance from the VCE associated with the n^{th} release hole size, m (ft)
X_{surf}	is the surface roughness factor, unitless
α_{surf}	is the thermal diffusivity of the surface under the liquid pool, m^2/s (ft^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, J/kg (Btu/lb)
η	is the explosion yield factor, unitless
ρ_{atm}	is the atmospheric air density, kg/m^3 (lb/ft^3)
ρ_l	is the liquid density at storage or normal operating conditions, kg/m^3 (lb/ft^3)
ρ_v	is the vapor density at storage or normal operating conditions, kg/m^3 (lb/ft^3)

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$\theta_{pf,n}$	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

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5.14 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], [36], [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

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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 (Note 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 Cremer and Warner Ltd. [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 (Note 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 Cremer and Warner Ltd. [11].

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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 $poii_n^{amb}$	At AIT $poii^{ait}$	VCE, $pvcedi_{l,n}$ or $pvcedi_{v,n}$	Flash Fire, $pffdi_{l,n}$ 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

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5.15 Figures

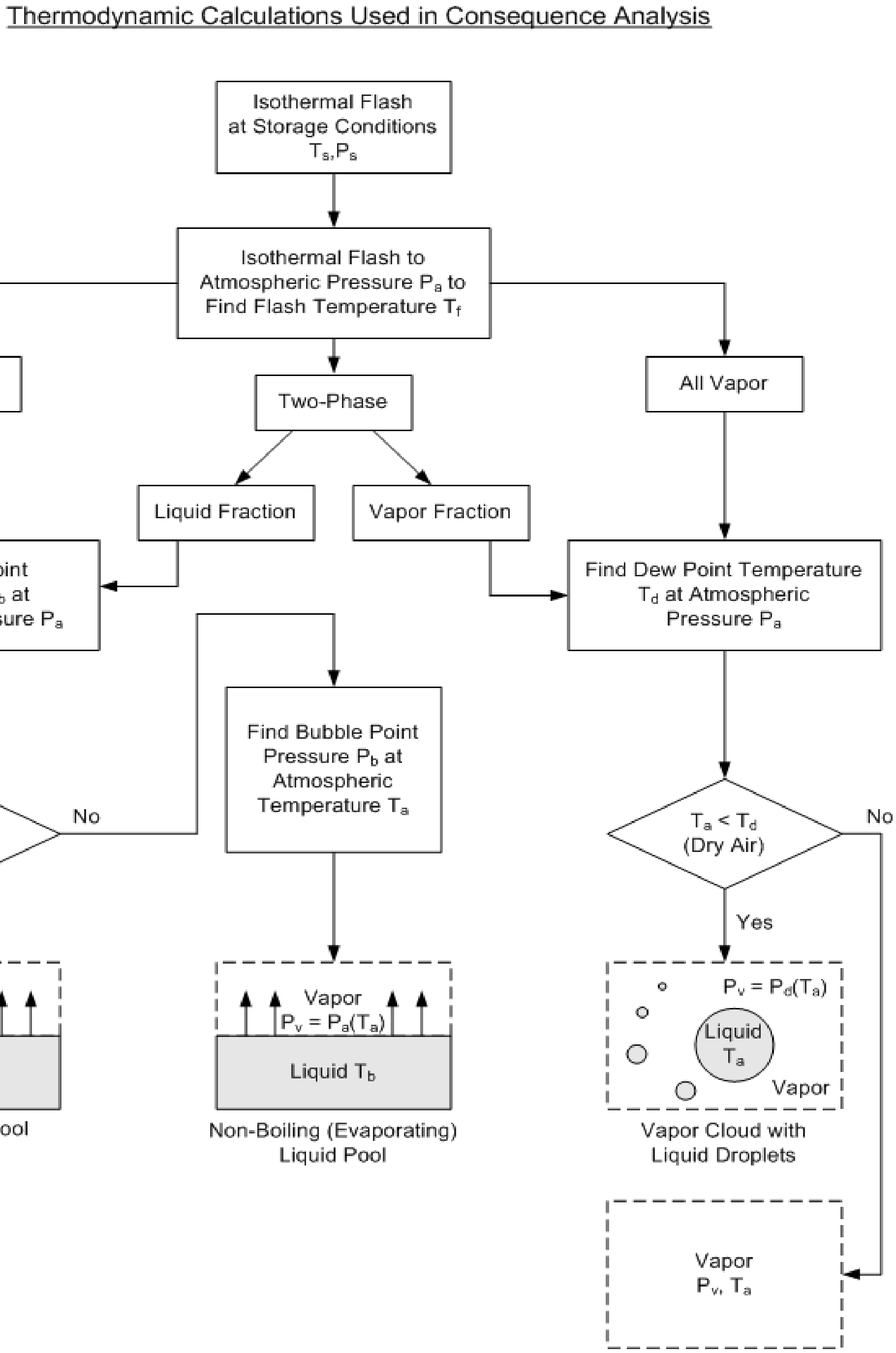

Figure 5.1—Source Term Modeling—Thermodynamic Modeling

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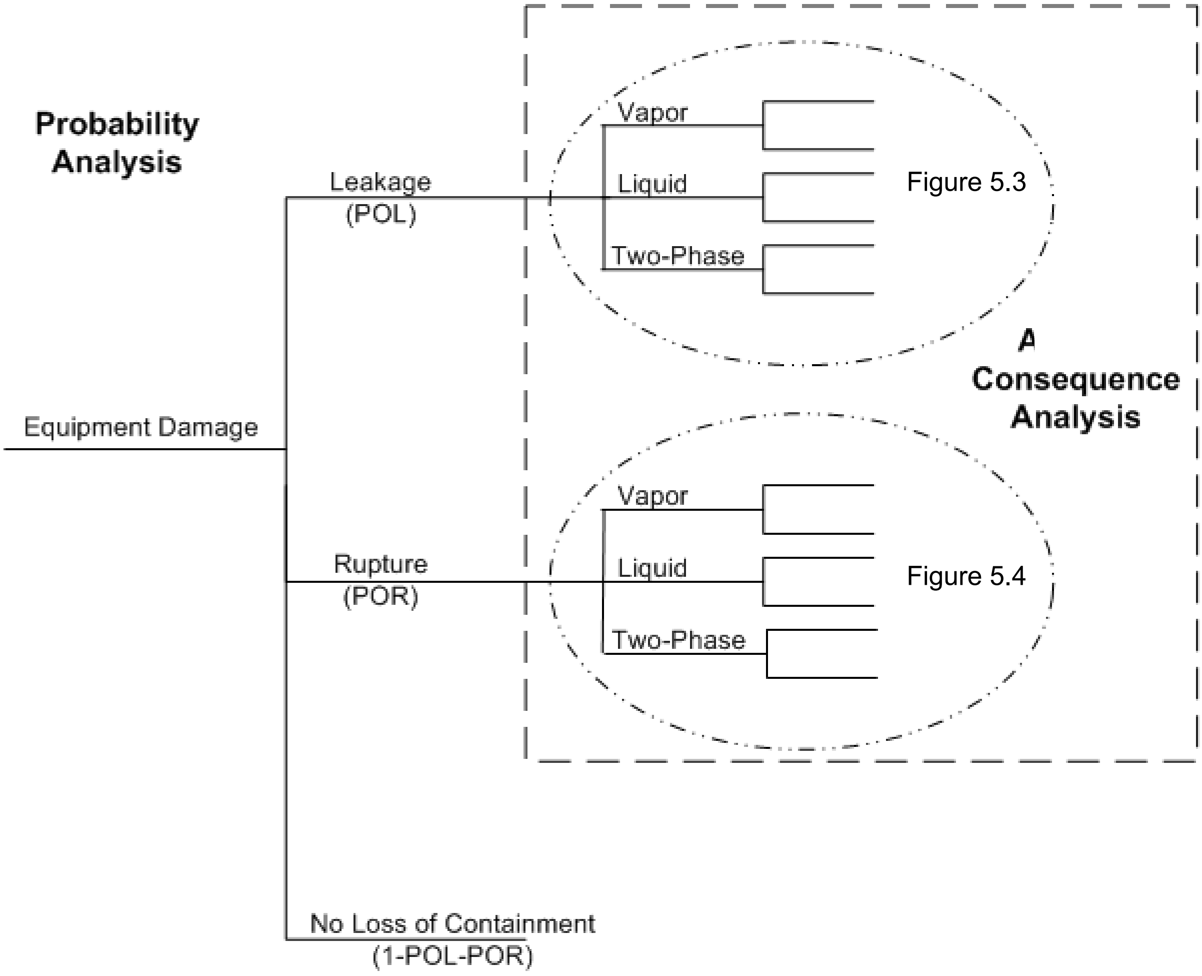

Figure 5.2—Overall Event Tree

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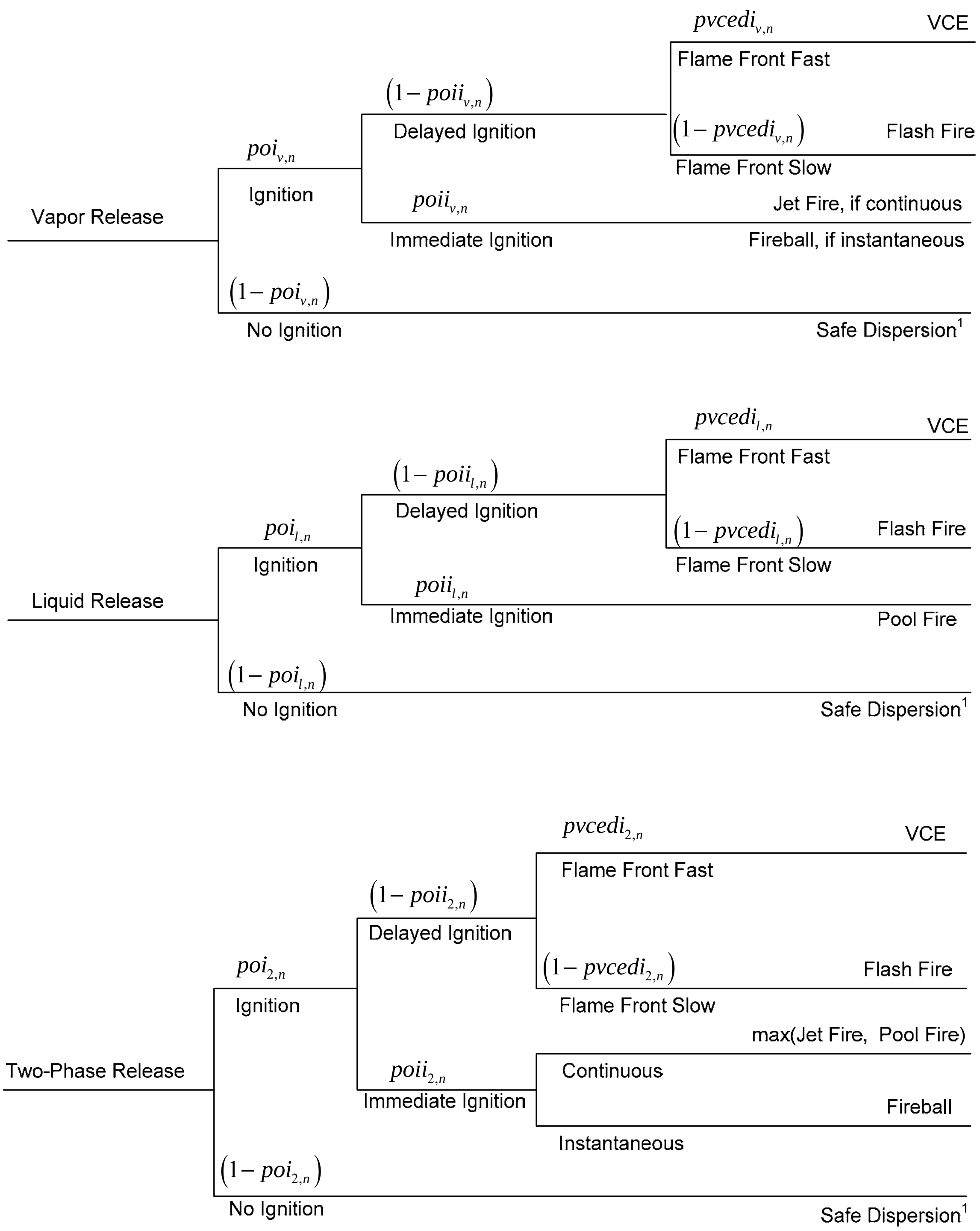

[1] If released fluid is toxic, or could result in steam burns or acid splashes, these consequences are considered before a safe dispersion.

Figure 5.3—Level 2 Consequence Analysis Event Tree for Leakage Case

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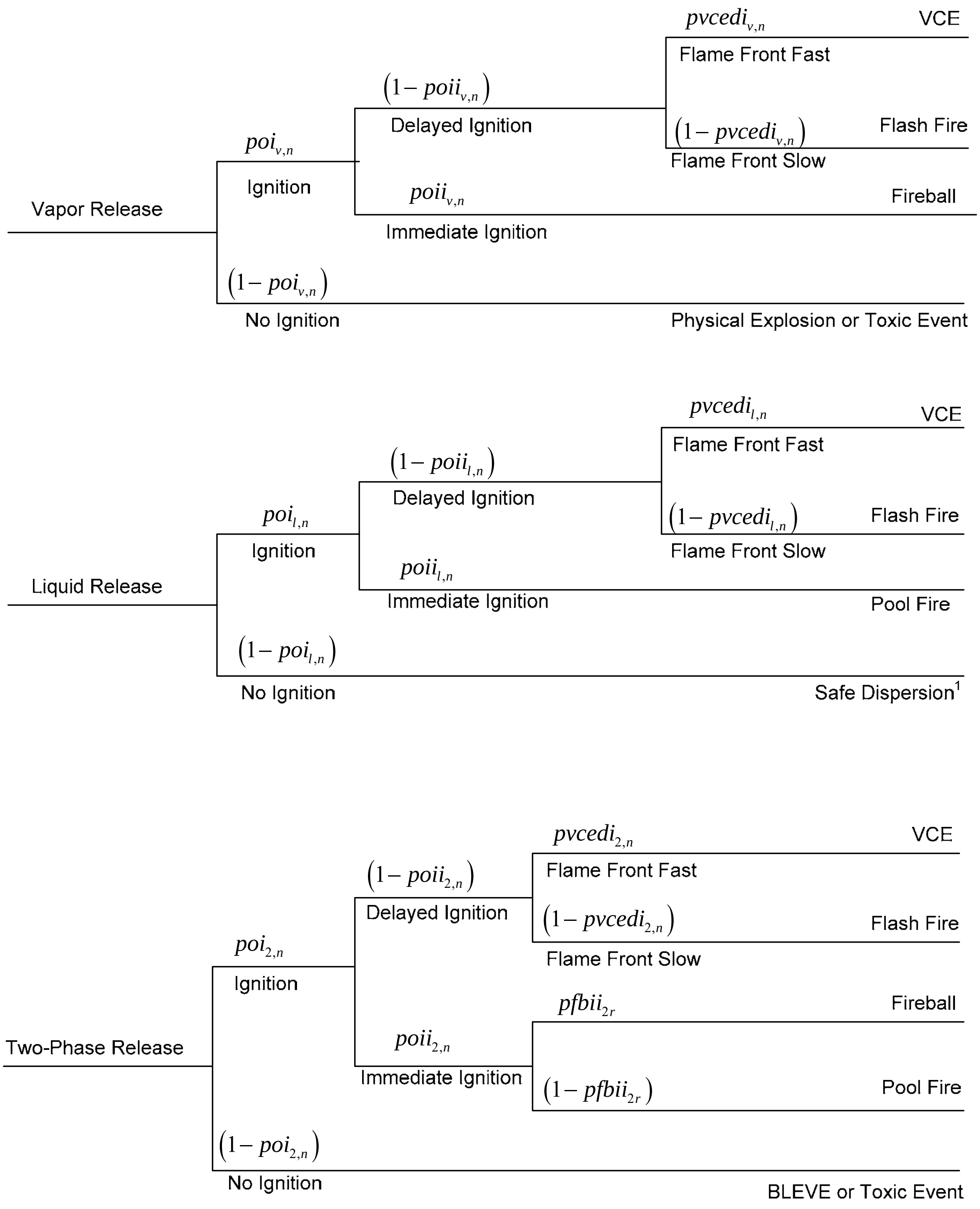

[1] If released fluid is toxic, or could result in steam burns or acid splashes, these consequences are considered before a safe dispersion.

Figure 5.4—Level 2 Consequence Analysis Event Tree for Rupture Case

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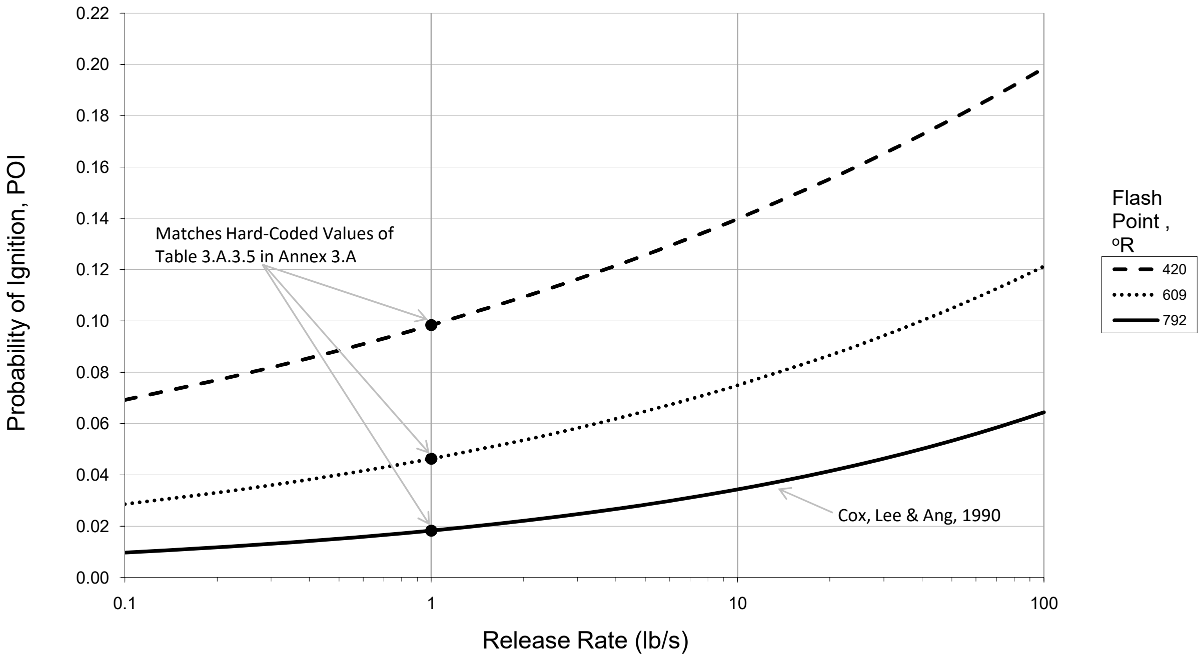

Figure 5.5—Probability of Ignition for Liquids (U.S. Customary Units)

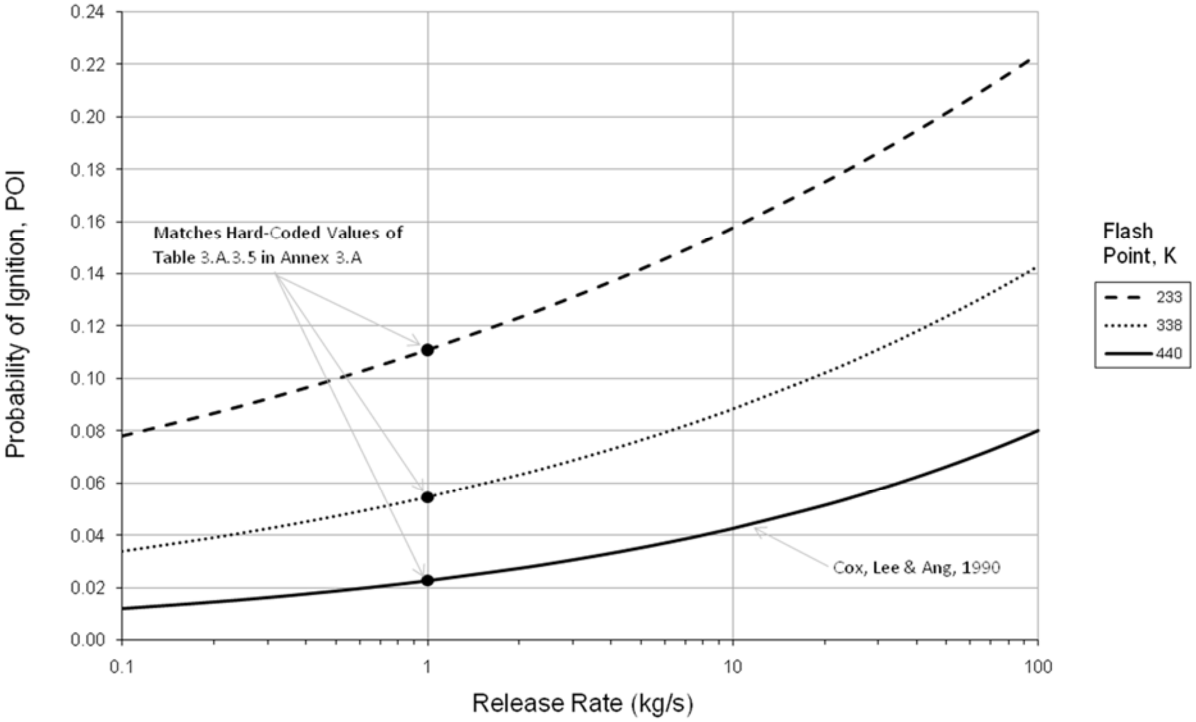

Figure 5.5M—Probability of Ignition for Liquids (Metric Units)

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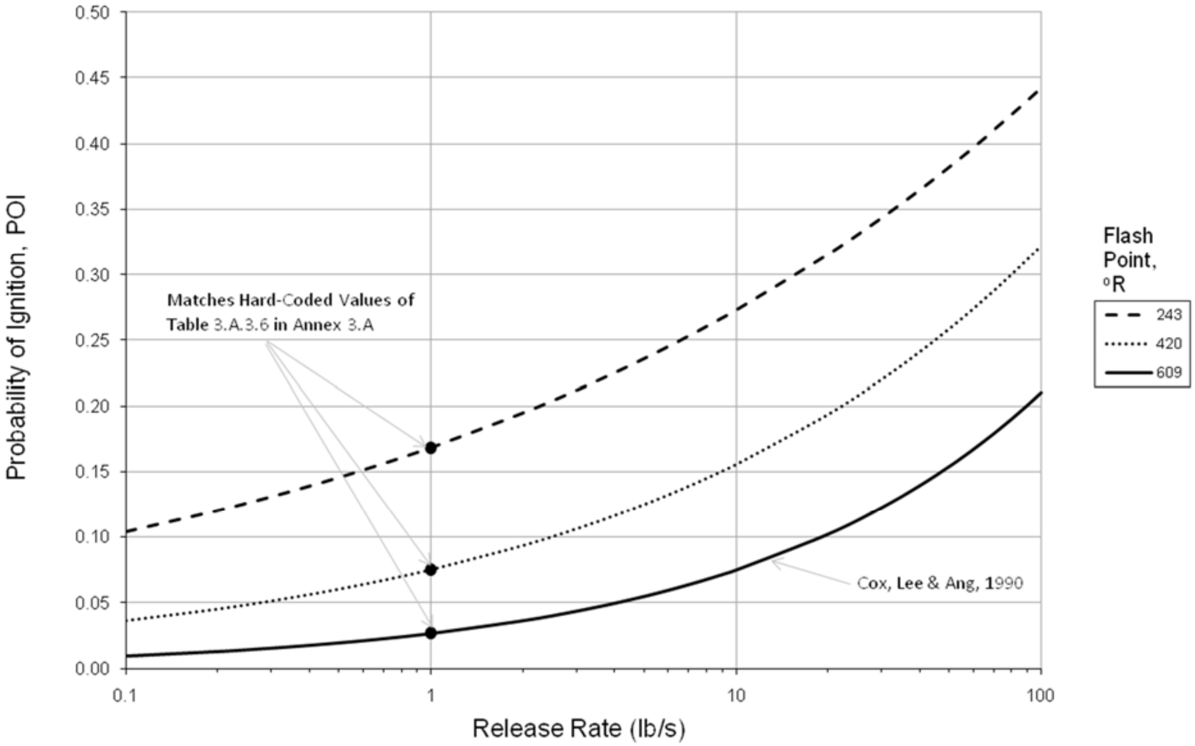

Figure 5.6—Probability of Ignition for Vapors (U.S. Customary Units)

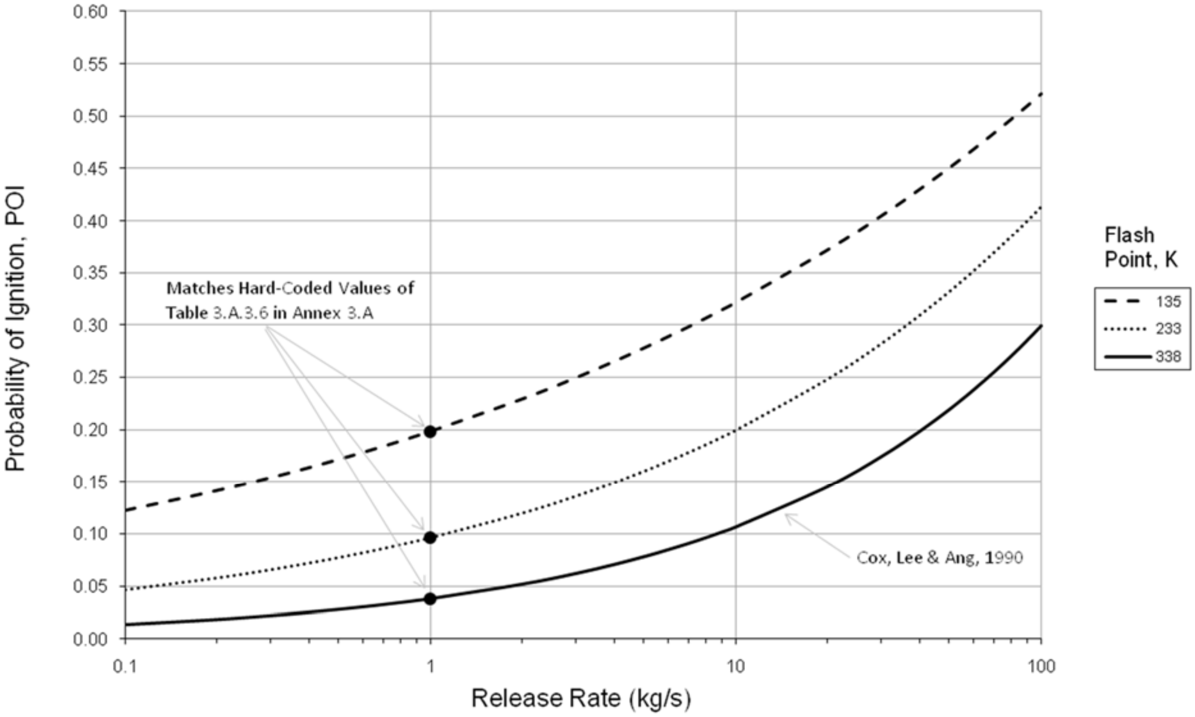

Figure 5.6M—Probability of Ignition for Vapors (Metric Units)

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6 COF—ASTs

6.1 Determine the Representative Fluid and Associated Properties

6.1.1 General

Section 6 provides two procedures for determining the COF for AST components, as follows.

a) AST Bottom component—Calculations are performed for financial COF only based on environmental consequences, component damage cost, and business interruption cost. AST consequence analysis for flammable and/or explosive or toxic are not provided in the methodology.

b) AST Shell components—Calculations are performed for both area- and financial-based methods.

6.1.2 Required Properties at Storage Conditions

If an area-based COF is to be determined for the AST shell, fluid properties should be determined for use in the Level 1 or 2 COF methodology. See Section 5.1.2 for detailed description of required properties at storage conditions.

If a financial COF is to be determined for the AST shell or bottom, the representative fluid will be picked from a close matching fluid from Table 6.1.

6.1.3 Required Properties at Flashed Conditions

If an area-based COF is to be determined for the AST shell, fluid properties should be determined for use in the Level 1 or 2 COF methodology. See Section 5.1.3 for detailed description of required properties at flashed conditions.

6.1.4 Hydraulic Conductivity

The amount of and rate of leakage from AST bottoms is dependent on the type of soil and its properties as well as whether or not the AST bottom has a RBP. A list of soil types and properties used in the AST consequence analysis routine is shown in Table 6.2.

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 6.2 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 (3.205).

$$k_{h,prod} = k_{h,water}\left(\frac{\rho_l}{\rho_w}\right)\left(\frac{\mu_w}{\mu_l}\right) \tag{3.205}$$

6.1.5 Fluid Seepage Velocity for AST Bottom

The seepage velocity of the fluid in the AST bottom or product through the soil is given by Equation (3.206), where k_h is the soil hydraulic conductivity and p_s is the soil porosity.

$$vel_{s,prod} = \frac{k_{h,prod}}{p_s} \tag{3.206}$$

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6.1.6 Calculation of Fluid Seepage Velocity for AST Bottom

b) STEP 1.1—If a Level 1 analysis is being performed, select a representative fluid from Table 6.1 to be used in the analysis.

c) STEP 1.2—Determine properties including density, ρ_l, and dynamic viscosity, μ_l, of the stored fluid. If a representative fluid is being used, these properties can be obtained in Table 6.1.

c) STEP 1.3—Calculate the hydraulic conductivity for water by averaging the upper and lower bound hydraulic conductivities provided in Table 6.2 for the soil type selected using Equation (3.207).

$$k_{h,water} = C_{31}\frac{\left(k_{h,water-lb} + k_{h,water-ub}\right)}{2} \tag{3.207}$$

d) STEP 1.4—Calculate the fluid hydraulic conductivity, $k_{h,prod}$, for the fluid stored in the AST using Equation (3.205) based on the density, ρ_l, and dynamic viscosity, μ_l, from STEP 1.2 and the hydraulic conductivity for water, $k_{h,water}$, from STEP 1.3.

e) STEP 1.5—Calculate the product seepage velocity, $vel_{s,prod}$, for the fluid stored in the AST using Equation (3.206) based on fluid hydraulic conductivity, $k_{h,prod}$, from STEP 1.4 and the soil porosity provided in Table 6.2.

6.2 Release Hole Size Selection

6.2.1 Overview

A discrete set of release events or release hole sizes similar to the approach outlined in the Level 1 consequence analysis are used.

6.2.2 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, from Table 6.3 for AST shell courses and from Table 6.4 for AST bottoms.

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 (3.208).

$$gff_{tot} = \sum_{n=1}^{4} gff_n \tag{3.208}$$

6.3 Release Rate Calculation

6.3.1 Overview

Release rate calculations are provided for a leak in a AST shell course and a leak in the AST bottom plate. For the leak in the shell course, the liquid head of the product is assumed to be constant in time, and the leak is to atmospheric pressure. For the leak in the AST bottom, the liquid head is assumed to be constant in time, and

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the leak is into the ground that is modeled as a continuous porous media approximated by soil properties typically used for AST foundations.

6.3.2 AST Shell Course

The discharge of a liquid through a sharp-edged orifice in an AST shell course with a liquid height above the orifices may be calculated using Equation (3.209).

$$W_n = C_{32} \cdot C_d \cdot A_n \sqrt{2 \cdot g \cdot LHT_{above,i}} \tag{3.209}$$

In Equation (3.209), the discharge coefficient, C_d, for fully turbulent liquid flow from sharp-edged orifices is in the range of $0.60 \le C_d \le 0.65$. A value of $C_d = 0.61$ is recommended.

6.3.3 AST Bottom

The product leakage flow rate through a small hole in the AST 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 [34]. The flow rate through a AST bottom into a porous media is calculated using the Bernoulli equation, Equation (3.210), or the Giroud equation, Equation (3.211), based on the hydraulic conductivity, $k_{h,prod}$, and release hole size, d_n.

$$W_n = C_{33} \cdot \pi \cdot d_n^2 \sqrt{2 \cdot g \cdot h_{liq}} \cdot n_{rh,n} \qquad for\ k_{h,prod} > C_{34} \cdot d_n^2 \tag{3.210}$$

$$W_n = C_{35} \cdot C_{qo} \cdot d_n^{0.2} \cdot h_{liq}^{0.9} \cdot k_{h,prod}^{0.74} \cdot n_{rh,n} \qquad for\ k_{h,prod} \le C_{37} \cdot \left[\frac{d_n^{1.8}}{C_{qo} \cdot h_{liq}^{0.4}} \right]^{\frac{1}{0.74}} \tag{3.211}$$

$$W_n = C_{38} \cdot 10^{\,2 \cdot \log(d_n) + 0.5 \cdot \log(h_{liq}) - 0.74 \cdot \left(\frac{C_{39} + 2 \cdot \log(d_n) - \log(k_{h,prod})}{m} \right)^m} \qquad for\ all\ other\ cases \tag{3.212}$$

$$Where\ m = C_{40} - 0.4324 \cdot \log(d_n) + 0.5405 \cdot \log(h_{liq})$$

In Equation (3.211), 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 AST bottom has a RBP, then the liquid height, h_{liq}, to be used in the flow rate calculations is set to 0.0762 m (0.25 ft). If the AST does not have a 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 AST diameter and is shown in Table 6.5.

6.3.4 Calculation of AST Shell Course Release Rate

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a) STEP 3.1—For each release hole size, determine the height of the liquid, h_{liq}, above the release hole size, d_n.

b) STEP 3.2—For each release hole size, determine the hole area, A_n, using Equation (3.213).

$$A_n = \frac{\pi d_n^2}{4} \tag{3.213}$$

c) STEP 3.3—Determine the liquid height above the i^{th} shell course, where h_{liq} is the maximum fill height in the tank and CHT is the height of each shell course.

$$LHT_{above,i} = \left[h_{liq} - (i-1) \cdot CHT \right] \tag{3.214}$$

d) STEP 3.3—For each release hole size, determine the flow rate, W_n, using Equation (3.209) based on h_{liq} from STEP 3.1 and A_n from STEP 3.2.

6.3.5 Calculation for AST Bottom Release Rate

a) STEP 3.1—For each release hole size, determine the number of release holes, $n_{rh,n}$, from Table 6.5.

b) STEP 3.2—Determine the hydraulic conductivity of the stored liquid, $k_{h,prod}$, from STEP 1.4.

c) STEP 3.3—For each release hole size, determine the flow rate, W_n, using Equation (3.210) or Equation (3.211), as applicable. The liquid height, h_{liq}, to use in this calculation is determined as follows.

   1) The AST has an RPB: $h_{liq} = 0.0762\ m\ [0.25\ ft]$.

   2) The AST does not have an RPB: $h_{liq} = Actual\ Product\ Height$.

6.4 Estimate the Inventory Volume and Mass Available for Release

6.4.1 Overview

The amount of inventory in the AST available for release depends on the component being evaluated. For AST bottoms, the available inventory is the entire contents of the AST. For the AST shell courses, the available inventory is a function of the location of the release hole and is calculated as the volume of fluid above the release hole.

6.4.2 Calculation of AST Shell Course Inventory Mass

The amount of fluid inventory used in the shell 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} shell course, where h_{liq} is the maximum fill height in the tank and CHT is the height of each shell course.

$$LHT_{above,i} = \left[h_{liq} - (i-1) \cdot CHT \right] \tag{3.215}$$

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b) STEP 4.2—Determine the volume above the course in question.

$$Lvol_{above,i} = \left(\frac{\pi D_{tank}^2}{4} \right) \cdot LHT_{above,i} \tag{3.216}$$

c) STEP 4.3—For each release hole size, determine the location of the hole on the AST shell. Based on this location, determine the available volume of the release. Note that the release hole should be assumed to be at the bottom of the course.

$$Lvol_{avail,n} = Lvol_{above,i} \tag{3.217}$$

d) STEP 4.4—Calculate the AST volume in barrels using Equation (3.216).

$$Bbl_{avail,n} = Lvol_{avail,n} \cdot C_{13} \tag{3.218}$$

e) STEP 4.5—Calculate the AST mass using ρ_l from Table 6.1 and using Equation (3.219).

$$mass_{avail,n} = Lvol_{avail,n} \cdot \rho_l \tag{3.219}$$

6.4.3 Calculation of AST Bottom Inventory Mass

The amount of fluid available for release through AST bottoms is the fluid level up to the AST design fill height or the operating fill height.

a) STEP 4.1—Calculate liquid volume in the AST in m^3 (ft^3) using Equation (3.220).

$$Lvol_{total} = \left(\frac{\pi D_{tank}^2}{4} \right) \cdot h_{liq} \tag{3.220}$$

b) STEP 4.2—Calculate the total AST volume in barrels using Equation (3.221).

$$Bbl_{total} = Lvol_{total} \cdot C_{13} \tag{3.221}$$

c) STEP 4.3—Calculate the AST mass using Equation (3.222).

$$mass_{total} = Lvol_{total} \cdot \rho_l \tag{3.222}$$

6.5 Determine the Type of Release

The type of release for the AST shell and the AST bottom is assumed to be continuous.

6.6 Estimate the Impact of Detection and Isolation Systems on Release Magnitude

Detection and isolation systems are not accounted for in the AST consequence analysis.

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6.7 Determine the Release Rate and Volume for the COF Analysis

6.7.1 Overview

The release for the AST shell is assumed to be continuous, and the release rate is calculated from Equation (3.223), where W_n is determined in Section 6.3.4 or Section 6.3.5, as applicable.

$$rate_n = W_n \tag{3.223}$$

The release rate and volume necessary for the COF are determined using a similar approach as Level 2 consequence analysis, with differences outlined in the procedure.

6.7.2 Calculation for AST Shell Course Release Volume

A step-by-step methodology for determining the release rate and volume is in accordance with the Level 2 consequence modeling (see Section 5) with differences noted as follows:

— the pool fire area should not exceed the area of the dike,

— the release volume should be calculated with the following steps.

a) STEP 7.1—For each release hole size, determine the release rate, $rate_n$, in bbl/day using Equation (3.223) where the release rate, W_n, is from STEP 3.3.

b) STEP 7.2—Determine the leak detection time, t_{ld}, as follows:

$$t_{ld} = 7\ days\ \ for\ d_n \le 3.17mm\ [0.125\ in]$$, or

$$t_{ld} = 1\ days\ \ for\ d_n > 3.17mm\ [0.125\ in]$$

c) STEP 7.3—For each release hole size, calculate the leak duration, ld_n, of the release using Equation (3.224) based on the release rate, $rate_n$, from STEP 7.1, the leak detection time, t_{ld}, from STEP 7.2, and the AST volume, $Bbl_{avail,n}$, from STEP 4.4.

$$ld_n = \min\left[\left\{\frac{Bbl_{avail,n}}{rate_n}\right\},\ 7\ days\right] \qquad for\ d_n \le 3.17mm\ [0.125\ in] \tag{3.224}$$

d) STEP 7.4—For each release hole size, calculate the release volume from leakage, Bbl_n^{leak}, using Equation (3.225) based on the release rate, $rate_n$, from STEP 7.1, the leak duration, ld_n, from STEP 7.3, and available volume, $Bbl_{avail,n}$, from STEP 4.4.

$$Bbl_n^{leak} = \min\left[\left\{rate_n \cdot ld_n\right\},\ Bbl_{avail,n}\right] \tag{3.225}$$

e) STEP 7.5—For each release hole size, calculate the release mass from leakage, $mass_n^{leak}$, using Equation (3.236) based on the available volume, Bbl_n^{leak}, from STEP 7.4.

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$$mass_n^{leak} = Bbl_n^{leak} \tag{3.226}$$

f) STEP 7.6—For each release hole size, calculate the release volume from a rupture, $Bbl_n^{rupture}$, using Equation (3.227) based on the available volume, $Bbl_{avail,n}$, from STEP 4.4.

$$Bbl_n^{rupture} = Bbl_{avail,n} \tag{3.227}$$

g) STEP 7.7—For each release hole size, calculate the mass from a rupture, $mass_n^{rupture}$, using Equation (3.228) based on the available volume, $Bbl_n^{rupture}$, from STEP 7.6.

$$mass_n^{rupture} = Bbl_n^{rupture} \tag{3.228}$$

6.7.3 Calculation of AST Bottom Release Volume

A step-by-step procedure for determining the release rate and volume is as follows.

a) STEP 7.1—For each release hole size, determine the release rate, $rate_n$, using Equation (3.223) where the release rate, W_n, is from STEP 3.5.

b) STEP 7.2—Determine the leak detection time, t_{ld}, as follows:

  1) $t_{ld} = 7\ days$ for a AST on a concrete or asphalt foundation, or

  2) $t_{ld} = 30\ days$ for a AST with a RPB, or

  3) $t_{ld} = 360\ days$ for a AST without a RPB.

c) STEP 7.3—For each release hole size, calculate the leak duration, ld_n, of the release using Equation (3.229) based on the release rate, $rate_n$, from STEP 7.1, the leak detection time, t_{ld}, from STEP 7.2, and the total volume, Bbl_{total}, from STEP 4.2.

$$ld_n = \min\left[\left\{\frac{Bbl_{total}}{rate_n}\right\},\ t_{ld}\right] \tag{3.229}$$

d) STEP 7.4—For each release hole size, calculate the release volume from leakage, Bbl_n^{leak}, using Equation (3.230) based on the release rate, $rate_n$, from STEP 7.1, the leak duration, ld_n, from STEP 7.3, and the total volume, Bbl_{total}, from STEP 4.2.

$$Bbl_n^{leak} = \min\left[\left\{rate_n \cdot ld_n\right\},\ Bbl_{total}\right] \tag{3.230}$$

e) STEP 7.5—For each release hole size, calculate the release volume from a rupture, $Bbl_n^{rupture}$, using Equation (3.231) based on the total volume, Bbl_{total}, from STEP 4.2.

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$$Bbl_n^{rupture} = Bbl_{total} \tag{3.231}$$

6.8 Determine Flammable and Explosive Consequences for AST Shell Courses

6.8.1 General

Flammable and explosive consequences for ASTs shell courses are determined using a similar approach as implemented for Level 1 and 2 consequence analysis.

6.8.2 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 Section 4.8 and Section 5.8.9.

6.9 Determine Toxic Consequences for AST Shell Courses

6.9.1 General

Toxic consequences for AST shell courses are determined using a similar approach as implemented for Level 1 and 2 consequence analysis.

6.9.2 Calculation of Toxic Consequences for AST Shell Courses

The step-by-step methodology for determining the toxic consequences are in accordance with the Level 1 and 2 consequence analysis; see Section 4.9 and Section 5.9.8.

6.10 Determine Nonflammable, Nontoxic Consequences

Nonflammable, nontoxic consequences are not determined for ASTs.

6.11 Determine Component Damage and Personnel Injury Consequences for AST Shell Courses

6.11.1 General

Flammable and explosive consequences for AST shell courses are determined using a similar approach as implemented for Level 2 consequence analyses.

6.11.2 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 2 consequence analysis; see Section 5.11.5.

6.12 Determine the FCs

6.12.1 Overview

The FC is determined in accordance with the Level 1 consequence analysis, with differences outlined in the procedure.

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6.12.2 Calculation of AST Shell Course FC

The step-by-step procedure for estimating the FC is in accordance with Section 4.12.7, except when calculating the environmental FC. The AST shell course FC can be calculated with the steps provided below.

— Component damage cost in accordance to Section 4.12.2.

— Damage cost to surrounding equipment in accordance with Section 4.12.3.

— Business interruption costs in accordance to Section 4.12.4.

— Potential Injury costs in accordance to Section 4.12.5.

The AST environmental FC can be calculated following the steps provided below.

a) STEP 12.1—Determine the following parameters.

   1) P_{lvdike}—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 12.2—Determine the environmental sensitivity used to establish C_{indike}, $C_{ss-onsite}$, $C_{ss-offsite}$, and C_{water} from Table 6.6.

c) STEP 12.3—Determine the probability weighted total barrels of fluid released by leakage, $Bbl_{released}$.

$$Bbl_{release}^{leak} = \frac{\sum_{n=1}^{3}\left(Bbl_n^{leak} \cdot gff_n\right)}{gff_{tot}} \tag{3.232}$$

d) STEP 12.4—Calculate the total barrels of fluid within the dike from leakage, Bbl_{indike}^{leak}, the total barrels of fluid in the on-site surface soil, $Bbl_{ss-onsite}^{leak}$, the total barrels of fluid in the off-site surface soil, $Bbl_{ss-offsite}^{leak}$, and the total barrels of fluid in that reach water, Bbl_{water}^{leak}, using Equation (3.233) through Equation (3.236), respectively.

$$Bbl_{indike}^{leak} = Bbl_{release}^{leak}\left(1 - \frac{P_{lvdike}}{100}\right) \tag{3.233}$$

$$Bbl_{ss-onsite}^{leak} = \frac{P_{onsite}}{100}\left(Bbl_{release}^{leak} - Bbl_{indike}^{leak}\right) \tag{3.234}$$

$$Bbl_{ss-offsite}^{leak} = \frac{P_{offsite}}{100}\left(Bbl_{release}^{leak} - Bbl_{indike}^{leak} - Bbl_{ss-onsite}^{leak}\right) \tag{3.235}$$

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$$Bbl^{leak}_{water} = Bbl^{leak}_{release} - \left(Bbl^{leak}_{indike} + Bbl^{leak}_{ss-onsite} + Bbl^{leak}_{ss-offsite} \right) \tag{3.236}$$

e) STEP 12.5—Calculate the financial environmental cost from leakage, $FC^{leakage}_{environ}$.

$$FC^{leak}_{environ} = Bbl^{leak}_{indike} \cdot C_{indike} + Bbl^{leak}_{ss-onsite} \cdot C_{ss-onite} + Bbl^{leak}_{ss-offsite} \cdot C_{ss-offite} + Bbl^{leak}_{water} \cdot C_{water} \tag{3.237}$$

f) STEP 12.6—Determine the total barrels of fluid released by a shell course rupture, $Bbl^{rupture}_{release}$.

$$Bbl^{rupture}_{release} = \frac{Bbl^{rupture}_{n} \cdot gff_4}{gff_{tot}} \tag{3.238}$$

g) STEP 12.7—Calculate the total barrels of fluid within the dike from a rupture, $Bbl^{rupture}_{indike}$, the total barrels of fluid in the on-site surface soil, $Bbl^{rupture}_{ss-onsite}$, the total barrels of fluid in the off-site surface soil, $Bbl^{rupture}_{ss-offsite}$, and the total barrels of fluid that reach water, Bbl^{leak}_{water}, using Equation (3.239) through Equation (3.242), respectively.

$$Bbl^{rupture}_{indike} = Bbl^{rupture}_{release} \left(1 - \frac{P_{lvdike}}{100} \right) \tag{3.239}$$

$$Bbl^{rupture}_{ss-onsite} = \frac{P_{onsite}}{100} \left(Bbl^{rupture}_{release} - Bbl^{rupture}_{indike} \right) \tag{3.240}$$

$$Bbl^{rupture}_{ss-offsite} = \frac{P_{offsite}}{100} \left(Bbl^{rupture}_{release} - Bbl^{rupture}_{indike} - Bbl^{rupture}_{ss-onsite} \right) \tag{3.241}$$

$$Bbl^{rupture}_{water} = Bbl^{rupture}_{release} - \left(Bbl^{rupture}_{indike} + Bbl^{rupture}_{ss-onsite} + Bbl^{rupture}_{ss-offsite} \right) \tag{3.242}$$

h) STEP 12.8—Calculate the financial environmental cost for a shell course rupture, $FC^{rupture}_{environ}$.

$$FC^{rupture}_{environ} = Bbl^{rupture}_{indike} \cdot C_{indike} + Bbl^{rupture}_{ss-onsite} \cdot C_{ss-onite} + Bbl^{rupture}_{ss-offsite} \cdot C_{ss-offite} + Bbl^{rupture}_{water} \cdot C_{water} \tag{3.243}$$

i) STEP 12.9—Calculate the total financial environmental cost from a leak and a rupture, $FC_{environ}$, where $FC^{leak}_{environ}$ is from STEP 12.5 and $FC^{rupture}_{environ}$ is from STEP 12.8.

$$FC_{environ} = FC^{leak}_{environ} + FC^{rupture}_{environ} \tag{3.244}$$

6.12.3 Calculation of AST Bottom FC

The step-by-step procedure for estimating the FC is in accordance with Section 4.12.7. The FCs for the AST bottom can be calculated with the steps provided below.

— Damage cost to surrounding equipment in accordance with Section 4.12.3 is not applicable for AST bottom component.

— Business interruption costs in accordance to Section 4.12.4.

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- Potential Injury costs in accordance to Section 4.12.5 is not applicable for AST bottom component.

The AST bottom environmental and equipment FCs can be calculated with the step provided below.

a) STEP 12.1—Determine the following parameters.

   1) P_{lvdike}—percentage of fluid leaving the dike.

   2) $P_{lvdike-onsite}$—percentage of fluid that leaves the dike area but remains on-site.

   3) $P_{lvdike-offsite}$—percentage of fluid that leaves the site area but does not enter nearby water.

b) STEP 12.2—Determine the environmental sensitivity to establish C_{indike}, $C_{ss-onsite}$, $C_{ss-offsite}$, C_{water}, $C_{subsoil}$, and $C_{groundwater}$ from Table 6.6.

c) STEP 12.3—Determine the seepage velocity of the product, vel_{s-prod}, using Equation (3.206).

d) STEP 12.4—Determine the total distance to the groundwater underneath the AST, s_{gw}, and the time to initiate leakage to the groundwater, t_{gl}.

$$t_{gl} = \frac{s_{gw}}{vel_{s,prod}} \tag{3.245}$$

e) STEP 12.5—For each release hole size, determine the volume of the product in the subsoil and groundwater where the leak detection time, t_{ld}, is determined in STEP 7.2.

$$Bbl^{leak}_{groundwater,n} = Bbl^{leak}_{n}\left(\frac{t_{ld}-t_{gl}}{t_{ld}}\right) \qquad for\ t_{gl} < t_{ld} \tag{3.246}$$

$$Bbl^{leak}_{groundwater,n} = 0 \qquad for\ t_{gl} \geq t_{ld} \tag{3.247}$$

$$Bbl^{leak}_{subsoil,n} = Bbl^{leak}_{n} - Bbl^{leak}_{groundwater,n} \tag{3.248}$$

f) STEP 12.6—For each release hole size, determine the environmental FC of a leak, $FC^{leak}_{environ}$.

$$FC^{leak}_{environ} = \frac{\sum_{n=1}^{3}\left(Bbl^{leak}_{groundwater,n}\cdot C_{groundwater} + Bbl^{leak}_{subsoil,n}\cdot C_{subsoil}\right) gff_n}{gff_{tot}} \tag{3.249}$$

g) STEP 12.7—Determine the total barrels of fluid released by a AST bottom rupture, $Bbl^{rupture}_{release}$.

$$Bbl^{rupture}_{release} = \frac{Bbl_{total}\cdot gff_4}{gff_{tot}} \tag{3.250}$$

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h) STEP 12.8—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 (3.239) through Equation (3.242), respectively.

i) STEP 12.9—Calculate the financial environmental cost for a AST bottom rupture, $FC_{environ}^{rupture}$, using Equation (3.243) where $Bbl_{indike}^{rupture}$, $Bbl_{ss-onsite}^{rupture}$, $Bbl_{ss-offsite}^{rupture}$, and Bbl_{water}^{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 (3.243), where $FC_{environ}^{leak}$ is from STEP 12.6 and $FC_{environ}^{rupture}$ is from STEP 12.8.

k) STEP 12.11—Calculate the component damage cost, FC_{cmd}, using Equation (3.251) with the release hole size damage costs from Table 4.15 and GFFs for the release hole sizes from STEP 2.3. The material cost factor, $matcost$, is obtained from Table 4.16.

$$FC_{cmd} = \left(\frac{\sum_{n=1}^{3} gff_n \cdot holecost_n + gff_4 \cdot holecost_4 \cdot \left(\frac{D_{tank}}{C_{36}} \right)^2}{gff_{total}} \right) \cdot matcost \tag{3.251}$$

The parameter, $\left(\frac{D_{tank}}{C_{36}} \right)^2$, is a cost adjustment factor for a AST bottom replacement. The cost factor included in Table 4.15 is normalized for an AST with a diameter of 30.5 m (100 ft), and this factor corrects the cost for other AST diameters.

6.13 Nomenclature

The following lists the nomenclature used in Section 6. The coefficients C_1 through C_{36} that 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, mm^2 (in.^{2})
$Bbl_{avail,n}$	is the available product volume for the n^{th} release hole size due to a leak, barrels
$Bbl_{groundwater}^{leak}$	is the total product volume in the groundwater due to a leak, barrels
$Bbl_{groundwater,n}^{leak}$	is the product volume for the n^{th} release hole size due to a leak in the groundwater, barrels
Bbl_{indike}^{leak}	is the total product volume in the dike due to a leak, barrels
Bbl_{n}^{leak}	is the product volume for the n^{th} release hole size due to a leak, barrels
$Bbl_{release}^{leak}$	is the total product volume released due to a leak, barrels

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$Bbl_{ssoffsite}^{leak}$	is the total product volume released on the surface located on-site due to a leak, barrels
$Bbl_{ssonsite}^{leak}$	is the total product volume released on the surface located off-site due to a leak, barrels
$Bbl_{subsoil}^{leak}$	is the total product volume in the subsoil due to a leak, barrels
$Bbl_{subsoil,n}^{leak}$	is the product volume for the *n*th release hole size due to a leak in the subsoil, barrels
Bbl_{water}^{leak}	is the total product volume in the water due to a leak, barrels
$Bbl_{n}^{rupture}$	is the product volume for the *n*th release hole size due to a rupture, barrels
$Bbl_{indike}^{rupture}$	is the product volume in the dike due to a rupture, barrels
$Bbl_{release}^{rupture}$	is the product volume in released due to a rupture, barrels
$Bbl_{ssoffsite}^{rupture}$	is the product volume on the surface located off-site due to a rupture, barrels
$Bbl_{ssonsite}^{rupture}$	is the product volume on the surface located on-site due to a rupture, barrels
$Bbl_{water}^{rupture}$	is the total product volume in the water due to a rupture, barrels
Bbl_{total}	is the product volume in the AST, barrels
C_d	is the discharge coefficient
$C_{groundwater}$	is the environmental cost for product in the groundwater, $/bbl
C_{indike}	is the environmental cost for product in the dike area, $/bbl
C_{qo}	is the adjustment factor for degree of contact with soil
$C_{ss-offsite}$	is the environmental cost for product on the surface located off-site, $/bbl
$C_{ss-onsite}$	is the environmental cost for product on the surface located on-site, $/bbl
$C_{subsoil}$	is the environmental cost for product in the subsoil, $/bbl
C_{water}	is the environmental cost for product in water, $/bbl
CHT	is the course height of the AST, m (ft)
d_n	is the diameter of the *n*th release hole, mm (in.)

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D_{tank}	is the AST diameter, m (ft)
FC_{cmd}	is the financial consequence of component damage, $
$FC_{environ}$	is the financial consequence of environmental cleanup, $
$FC_{environ}^{leak}$	is the financial consequence of environmental cleanup for leakage, $
FC_{prod}	is the financial consequence of lost production on the unit, $
$FC_{environ}^{rupture}$	is the financial consequence of environmental cleanup for leakage, $
FC_{total}	is the total financial consequence, $
g	is the acceleration due to gravity on earth at sea level = 9.81 m/s^2 (32.2 ft/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 AST, m (ft)
k_h	is the soil hydraulic conductivity, m/day (ft/day)
$k_{h,prod}$	is the soil hydraulic conductivity based on the AST product, m/day (ft/day)
$k_{h,water}$	is the soil hydraulic conductivity based on water, m/day (ft/day)
$k_{h,water-lb}$	is the lower bound soil hydraulic conductivity based on water, cm/s (in/s)
$k_{h,water-ub}$	is the upper bound soil hydraulic conductivity based on water, cm/s (in/s)
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
$LHT_{above,i}$	is the liquid height above the i^{th} AST shell course, m (ft)
$Lvol_{above,i}$	is the total liquid volume above the i^{th} AST shell course, m^3 (ft^3)
$Lvol_{above,n}$	is the total liquid volume for the n^{th} release hole size, m^3 (ft^3)
$Lvol_{avail,n}$	is the available liquid volume for the n^{th} release hole size, m^3 (ft^3)

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$Lvol_{total}$	is the total liquid volume in the AST, m^3 (ft^3)
$mass_{total}$	is the available mass for release
$matcost$	is the material cost factor
N_c	is the total number of AST shell courses
$n_{rh,n}$	is the number of release holes for each release hole size as a function of the AST diameter
n^{th}	is the representative holes sizes
$Outage_{affa}$	is the numbers of days of downtime required to repair damage to the surrounding equipment, days
$Outage_n$	is the number of downtime days to repair damage associated with the n^{th} release hole size, days
P_{lvdike}	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_{gw}	is the distance to the groundwater underneath the AST, m (ft)
t_{gl}	is the time required for the product to reach the groundwater through a leak in the AST bottom, day
t_{ld}	is the leak detection time, day
$vel_{s,prod}$	is the seepage velocity, m/day (ft/day)
W_n	is the discharge rate of the AST product through a hole in the shell course, bbl/day
μ_l	is the dynamic viscosity, (N-s)/m^2 [(lb_f-s)/ft^2]
μ_w	is the dynamic viscosity of water at storage or normal operating, (N-s)/m^2 [(lb_f-s)/ft^2]
ρ_l	is the liquid density at storage or normal operating conditions, kg/m^3 (lb/ft^3)

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ρ_w is the density of water at storage or normal operating conditions, kg/m^3 (lb/ft^3)

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6.14 Tables

Table 6.1—Fluids and Fluid Properties for AST 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 6.1M—Fluids and Fluid Properties for AST 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

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Table 6.2—Soil Types and Properties for AST Consequence Analysis

Soil Type	Hydraulic Conductivity for Water Lower Bound (in./s)	Hydraulic Conductivity for Water Upper Bound (in./s)	Soil Porosity
Coarse sand	3.94E-02	3.94E-03	0.33
Fine sand	3.94E-03	3.94E-04	0.33
Very fine sand	3.94E-04	3.94E-06	0.33
Silt	3.94E-06	3.94E-07	0.41
Sandy clay	3.94E-07	3.94E-08	0.45
Clay	3.94E-08	3.94E-09	0.50
Concrete-asphalt	3.94E-11	3.94E-12	0.3
Gravel	3.94E-01	3.94	0.40

Table 6.2M—Soil Types and Properties for AST Consequence Analysis

Soil Type	Hydraulic Conductivity for Water Lower Bound (cm/s)	Hydraulic Conductivity for Water Upper Bound (cm/s)	Soil Porosity
Coarse sand	1E-01	1E-02	0.33
Fine sand	1E-02	1E-03	0.33
Very fine sand	1E-03	1E-05	0.33
Silt	1E-05	1E-06	0.41
Sandy clay	1E-06	1E-07	0.45
Clay	1E-07	1E-08	0.50
Concrete-asphalt	1E-10	1E-11	0.3
Gravel	1E-00	1E-01	0.40

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Table 6.3—Release Hole Sizes and Areas—AST Shell Courses

Release Hole Number	Release Hole Size	Range of Hole Diameters (in.)	Release Hole Diameter (in.)
1	Small	0 to $^{1}/_{8}$	$d_1 = 0.125$
2	Medium	>$^{1}/_{8}$ to $^{1}/_{4}$	$d_2 = 0.25$
3	Large	>$^{1}/_{4}$ to 2	$d_3 = 2$
4	Rupture	>2	$d_4 = 12\left(\frac{D_{tank}}{4}\right)$

Table 6.3M—Release Hole Sizes and Areas—AST Shell 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	$d_4 = 1000\left(\frac{D_{tank}}{4}\right)$

Table 6.4—Release Hole Sizes and Areas—AST Bottoms

Release Hole Number	Release Hole Size	RPB?	Range of Hole Diameters (in.)	Release Hole Diameter (in.)
1	Small	Yes	0 to $^{1}/_{8}$	$d_1 = 0.125$
		No	0 to $^{1}/_{2}$	$d_1 = 0.50$
2	Medium	NA	0	$d_2 = 0$
		NA	0	
3	Large	NA	0	$d_3 = 0$
		NA	0	
4	Rupture	Yes	>$^{1}/_{8}$	$d_4 = 12\left(\frac{D_{tank}}{4}\right)$
		No	>$^{1}/_{2}$	

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Table 6.4M—Release Hole Sizes and Areas—AST 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	NA	0	$d_2 = 0$
		NA	0	
3	Large	NA	0	$d_3 = 0$
		NA	0	
4	Rupture	Yes	>3.175	$d_4 = 1000\left(\frac{D_{tank}}{4}\right)$

Table 6.5—Number of Release Holes As a Function of AST Diameter

AST Diameter [m (ft)]	Number of Release Holes with or Without a 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 AST 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.

$$n_{rh,1} = \max\left[\text{nint}\left[\left(\frac{D}{C_{36}}\right)^2\right],\ 1\right]$$

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Table 6.6—Cost Parameters Based on Environmental Sensitivity

Location (Note 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	$C_{ss-onsite}$—Environmental cost for product located in surface soil located on-site	50	50	50
3	$C_{ss-offsite}$ —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	1500	3000
5	$C_{groundwater}$ —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 6.1.

NOTE 2 The values shown above are estimates. The end user should decide if these values are appropriate for the specific application.

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6.15 Figures

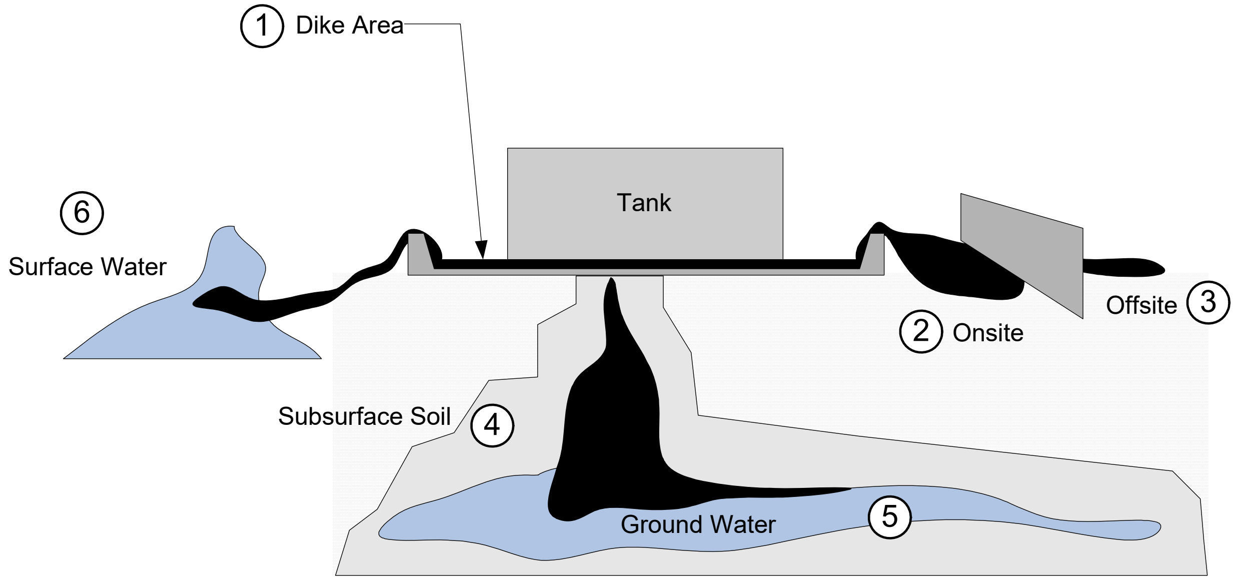

Figure 6.1—AST Consequence

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API RP 581 PART 3

ANNEX 3.A—BASIS FOR CONSEQUENCE METHODOLOGY

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PART 3, ANNEX A CONTENTS

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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 analysis.

This Annex provides background and supplemental information to the specific procedures for conducting the consequence analysis provided in Part 3.

3.A.2 References

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API, *A Survey of API Members' Aboveground Storage Tank Facilities*, 1994.

OFCM, Directory of Atmospheric Transport and Diffusion Consequence Assessment Models (FC-I3-1999), 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.

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 normal boiling point and the molecular weight, 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.

$$Property_{mix} = \sum x_i \cdot Property_i \qquad (3.A.1)$$

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It is important to note that the flammable consequence results are not highly sensitive to the exact material selected, provided the molecular weights are similar, because air dispersion properties and heats of combustion are similar for all hydrocarbons with similar molecular weights. 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, it is recommended that a Level 2 consequence analysis 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% C_3, 20 mol% C_4, 30 mol% C_5, 30 mol% C_6, and 10 mol% C_7 would have the following average key properties:

a) MW = 74.8;

b) AIT = 322.1 °C (629.8 °F) ;

c) NBP = 39.2 °C (102.6 °F);

d) density = 621.5 kg/m^3 (38.8 lb/ft^3).

The best selection from the materials in the representative fluids list of Table 3.A.3.1 would be C_5, since the property of first importance is the NBP, and C_5 has a NBP of 36 °C (97 °F), which is lower than the calculated NBP of our example mixture. It is non-conservative to select a representative fluid with a higher NBP than the fluid being considered, e.g. C_6-C_8 when modeling a fluid with a weighted NBP of 99 °C (210 °F).

3.A.3.1.2.3 Example with a Mixture

If a mixture contains inert materials such as CO_2 or water, the choice of representative fluid should 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% C_{20}, using C_{20} and the corresponding inventory of the hydrocarbon provides a conservative COF. A Level 2 consequence methodology may be used to more accurately 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 2 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.

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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 ($^1/_4$-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 $^1/_4$-in. and rupture release hole sizes, because the diameter is equal to a 1-in. release hole size. An NPS 4 pipe will have $^1/_4$-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 $^1/_4$-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.

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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 (note that 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;

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;

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.

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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 4,536 kg (10,000 lb) 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 4,536 kg (10,000 lb), 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 probability of failure 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,

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.

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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;

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.

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).

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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:

$$CA_f = x\left(rate\right)^y \qquad \textit{for a continuous release} \qquad (3.A.2)$$

$$CA_f = x\left(mass\right)^y \qquad \textit{for an instantaneous release} \qquad (3.A.3)$$

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:

$$CA_{f,comb} = \sum p_i CA_{f,i} \qquad (3.A.4)$$

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:

a) atmospheric temperature 21 °C (70 °F);

b) relative humidity 75 %;

c) wind speed 12.9 km/h (8 mph);

d) Stability Class D;

e) surface roughness parameter 30.5 mm (1.2 in.) for typical for processing plants.

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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 0.69 MPa (100 psig).

b) Initial temperatures representing a range from low-temperature [below autoignition, i.e. 20 °C (68 °F)] to high-temperature (near autoignition) conditions.

c) Range of release hole sizes from 6.35 mm to 406 mm (0.25 in. to 16 in.) diameter for continuous events.

d) Range of release masses from 45.4 kg to 453,592 kg (100 lb to 100,000 lb).

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:

$$Pr = A + B \cdot \ln\left[C^n t\right] \tag{3.A.5}$$

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).

$$A = \pi a b \tag{3.A.6}$$

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

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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

Hydrofluoric acid (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.

a) The mass fraction of HF is calculated if the released material contains HF as a component in a mixture.

b) The liquid release rate (or mass) of the HF component is used to calculate the toxic impact area.

c) 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).

$$CA_f = C_8 \cdot 10^{\left(c \cdot \log_{10}\left[C_4 \cdot rate\right] + d\right)} \tag{3.A.7}$$

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).

$$CA_f = C_8 \cdot 10^{\left(c \cdot \log_{10}\left[C_4 \cdot mass\right] + d\right)} \tag{3.A.8}$$

For instantaneous releases, the values of the constants c and d are provided for HF and H_2S in Part 3, Table 4.11.

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3.A.3.6.6 Development of Toxic Consequence Areas for H_2S

3.A.3.6.6.1 General

H_2S 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 H_2S to the atmosphere results in the quick formation of a toxic vapor cloud. For H_2S releases, the Level 1 consequence analysis uses the following guidelines to determine the release rate or mass of mixtures containing H_2S.

a) If the released material contains H_2S as a component in a mixture, the mass fraction of H_2S is obtained, and If the initial state of the material is a vapor, the mass fraction of H_2S is used to obtain the vapor discharge rate (or mass) of only H_2S; 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 H_2S is used to obtain the vapor flash rate (or mass) of only the H_2S; this rate (or mass) is used to determine the impact.

c) If the initial phase of a material being released is 1 wt% H_2S 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 C_{17}-C_{25} as the representative material.

    1) Calculate the liquid discharge rate for C_{17}-C_{25} 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 C_{17}-C_{25} using 100 % of the release rate,

        ii) the flammable effects of H_2S based on 1 % of the release rate.

    3) Calculate the toxic effects of H_2S, 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 H_2S 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 H_2S 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 H_2S 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 [24 °C (5 °F)], with liquid being released from a low pressure storage tank. The tank head was set at 3.05 m (10 ft).

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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).

$$CA_f = e\left(rate\right)^f \tag{3.A.9}$$

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, 100, 1,000, 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 ft^2 for ammonia are provided in Equation (3.A.10).

$$CA_f = 14.17\left(mass\right)^{0.9011} \tag{3.A.10}$$

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 ft^2 for chlorine could be correlated using Equation (3.A.11).

$$A = 14.97\left(mass\right)^{1.117} \tag{3.A.11}$$

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 ($AlCl_3$);

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b) carbon monoxide (CO);

c) hydrogen chloride (HCl);

d) nitric acid;

e) nitrogen dioxide (NO_2);

f) phosgene;

g) toluene diisocyanate (TDI);

h) ethylene glycol monoethyl ether (EE);

i) ethylene oxide (EO);

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 one-half of the cloud width (minor axis), taken at its largest point (within the 50 % probability of fatality dose level)
A	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
B	is a constant for the probit equation
c	is a constant for the specific consequence area equations for HF acid and H_2S
C	is the toxic concentration in the probit equation, ppm
CA_f	is the consequence area, m^2 (ft^2)

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$CA_{f,comb}$	is the combined/probability weighted consequence area, m^2 (ft^2)
$CA_{f,i}$	is the individual outcome consequence area for the i^{th} event outcome, m^2 (ft^2)
d	is a constant for the specific consequence area equations for HF acid and H_2S
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, kg (lb)
n	is the exponent in the probit equation
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
Pr	is the probit value, typically 5.0, which is defined as 50 % probability
$rate$	is the release rate, kg/s (lb/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

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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	Molecular Weight	Normal Boiling Point		Autoignition Temperature	
			°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, naptha, 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_2S	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

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Table 3.A.3.2—Assumptions Used When Calculating Liquid Inventories Within Equipment

Equipment Description	Component Type	Examples	Default Liquid Volume Percent
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	OH accumulators, feed drums, 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 (see Note 4), flare drums, air dryers (see Note 4)	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 % shell-side, 25 % tube-side
Fin fan air coolers	FINFAN	Total condensers, partial condensers, vapor coolers, and liquid coolers (see Note 5)	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 liquid volume 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 OH 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.

NOTE 5 For flue gas KO drums and air dryers, the LV% is typically negligible. Consideration should be given to reducing the 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.

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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_2S						
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_2S	0.9				0.9	
Styrene	1				1	

NOTE 1 Shaded areas represent outcomes that are not possible.

NOTE 2 Must be processed at least 27 °C (80 °F) above AIT.

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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_2S	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_2S	0.9		0.9			
Styrene	1		1			

NOTE 1 Shaded areas represent outcomes that are not possible.

NOTE 2 Must be processed at least 27 °C (80 °F) above AIT.

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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_2S						
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_2S	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 27 °C (80 °F) below AIT.

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Table 3.A.3.6—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						
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_2S						
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 Above 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_2S	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 27 °C (80 °F) above AIT.

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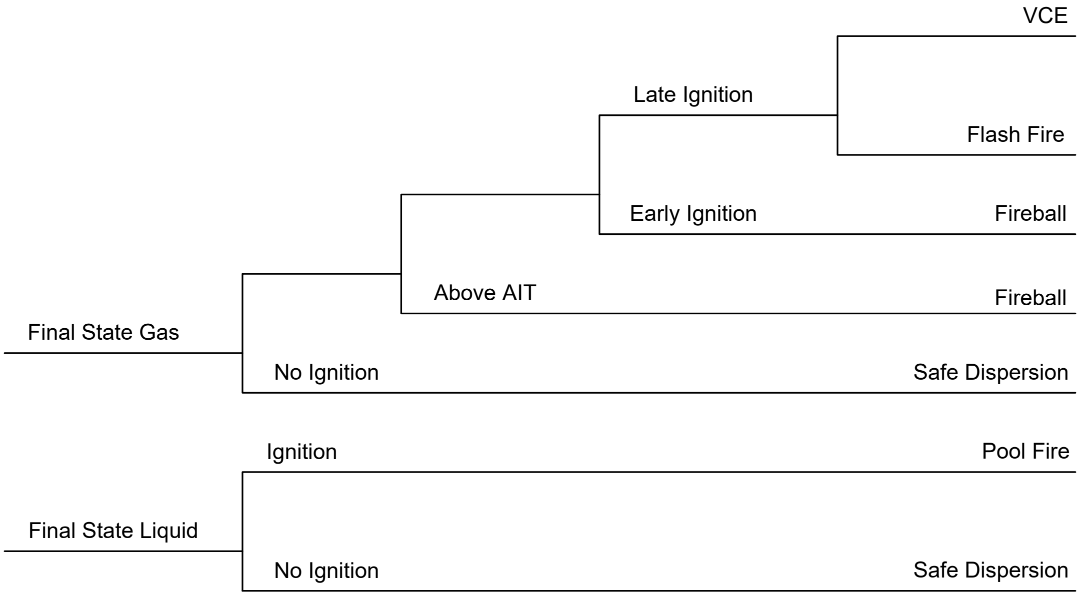
3.A.3.9 Figures

Instantaneous-Type Release



Continuous-Type Release

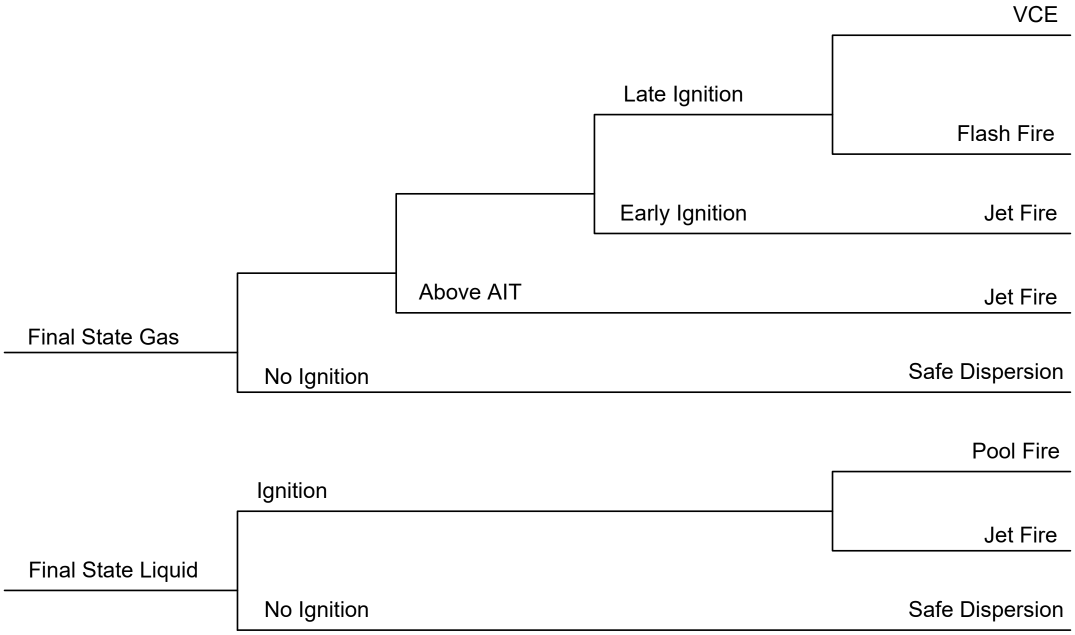


Figure 3.A.3.1—Level 1 Consequence Methodology Event Tree

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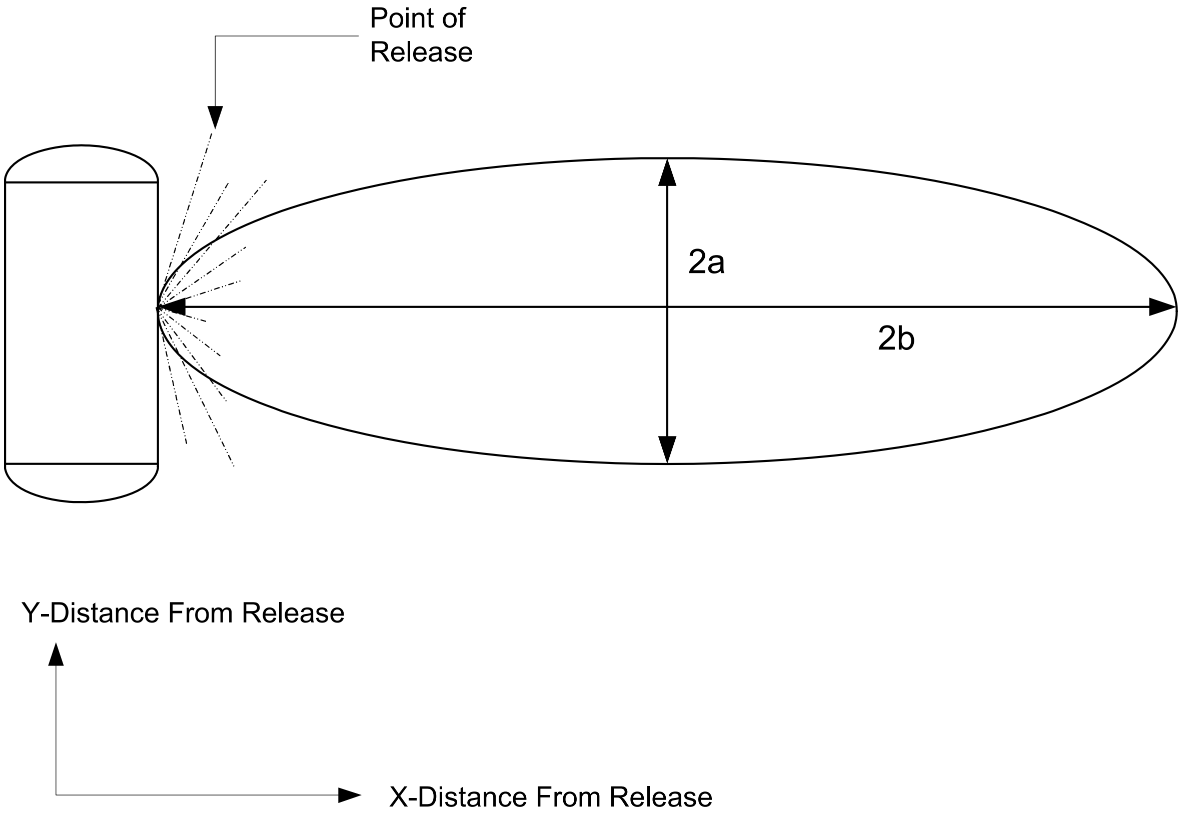

Figure 3.A.3.2—Approximated Cloud Shape for Toxic Plume from a Continuous Release

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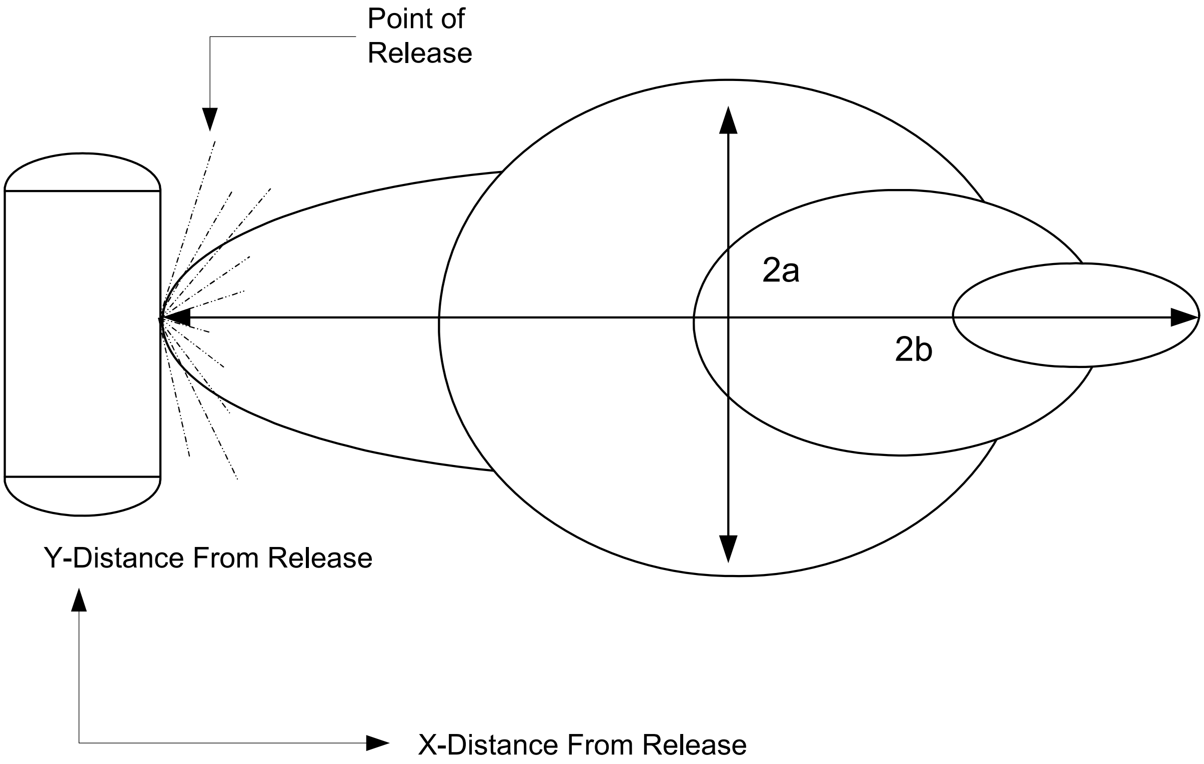

Figure 3.A.3.3—Approximated Cloud Shape for Toxic Puff from an Instantaneous Release

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3.A.4 Level 2 Consequence Methodology

3.A.4.1 General

The use of event trees and 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 molecular weights 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 Atmospheric Storage Tanks

3.A.5.1 Overview

The consequence model for atmospheric storage tanks (ASTs) is based on a modification of the Level 1 consequence analysis. Only a financial consequence analysis is provided for the AST bottom.

3.A.5.2 Representative Fluid and Associated Properties

A representative fluid that most closely matches the fluid contained in the AST system being evaluated is selected from the representative fluids shown in Part 3, Table 6.1. 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 3, Table 6.2.

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3.A.5.3 Generic Failure Frequencies and Release Holes Sizes

3.A.5.3.1 Atmospheric Storage Tank Bottom

The base failure frequency for the leak of an AST 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 7.2E-03 leaks per year was chosen as the base leak frequency for an AST bottom. Although the leak frequency data in Part 2, Table 3.1 indicate that ASTs 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 AST was accounted for elsewhere in the model since the percent of wall loss in the model is a function of the AST 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 AST with minimal corrosion would have a frequency modifier of less than 1, which lowers the leak frequency accordingly.

It should be noted that the damage factor (DF) for AST bottoms in Part 2 was originally developed based on a GFF of equal to 7.2E-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 7.2E-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 AST RAP project indicated that leak sizes of less than or equal to $^1/_2$ in. in diameter would adequately describe the vast majority of tank bottom leaks. An $^1/_8$ in. release hole size is used if a RPB is present and a $^1/_2$ in. hole size is used for AST bottoms without a RPB. A GFF of 7.2E-04 is assigned to this hole size in the consequence analysis. In addition, the number of release holes in an AST bottom is determined as a function of the AST bottom area; see Part 3, Table 6.3.

3.A.5.3.2 Shell 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 2E-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 4E-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 1E-07 per tank year.

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The total GFF for leakage events in AST shell courses is set at 1E-04. The generic failure frequencies 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 AST is not considered in the consequence methodology.

3.A.5.5 Determination of the Release Type (Instantaneous or Continuous)

The release type for the AST 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 AST bottom consequence methodology.

3.A.5.7 Determination of Toxic Consequences

Toxic consequences are not included in the AST bottom consequence methodology.

3.A.5.8 Determination of Environmental Consequences

Environmental consequences for AST 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 3, Figure 6.1.

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 0.30 m (1 ft) 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 0.61 m (2 ft) 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.

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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 0.61 m (2 ft) 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 AST bottom that rests on native clay soils will have minor subsurface impacts relative to the same AST 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 3, Table 6.6 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.					

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API RP 581 PART 3

ANNEX 3.B—SI AND US CUSTOMARY CONVERSION FACTORS

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PART 3, ANNEX B CONTENTS

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Risk-Based Inspection Methodology
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.

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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)	$31{,}623 \frac{mm^2}{m^2}$	$12 \frac{inch}{ft}$
C_2	(3.6), (3.7)	$1{,}000 \frac{mm^2}{m^2}$	1
C_3	(3.12)	$4{,}536\ kg$	$10{,}000\ lb$
C_{4A}	(3.18)	$2.205\ \frac{1}{kg}$	$1\ \frac{1}{lb}$
C_{4B}	(3.63), (3.64), (3.72), (3.109), (3.110)	$2.205\ \frac{sec}{kg}$	$1\ \frac{sec}{lb}$
C_5	(3.19), (3.71)	$25.2 \frac{kg}{sec}$	$55.6 \frac{lb}{sec}$
C_6	(3.25)	$55.6\ K$	$100\ {}^oR$
C_8	(3.63), (3.64), (3.72)	$0.0929\ m^2$	$1\ ft^2$
C_9	(3.69)	$0.123 \frac{m^2 \cdot sec}{kg}$	$0.6 \frac{ft^2 \cdot sec}{lb}$
C_{10}	(3.70)	$9.744 \frac{m^2}{kg^{0.06384}}$	$63.32 \frac{ft^2}{kg^{0.06384}}$
C_{11}	(3.74), (3.75)	$0.145 \frac{1}{kPa}$	$\frac{1}{psia}$
C_{12}	(3.92), (3.109), (3.110)	$1.8\ \frac{1}{K}$	$\frac{1}{{}^oR}$
C_{13}	(3.93), (3.218), (3.221)	$6.29 \frac{bbl}{m^3}$	$0.178\ \frac{bbl}{ft^3}$
C_{14}	(3.103), (3.138), (3.152), (3.162)	1	$3{,}600 \frac{sec}{hr}$
C_{15}	(3.105)	$4.685 \frac{m^{0.33}}{S^{0.22}}$	$1\ \frac{in^2}{ft^{1.67} S^{0.22}}$

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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_{16}	(3.113), (3.114), (3.116), (3.117)	$294.44\ K$	$530\ {}^oR$
C_{17}	(3.128), (3.129)	$0.001 \frac{kg}{m^2 \cdot sec}$	$2.048 \text{ x } 10^{-4} \frac{lb}{ft^2 \cdot sec}$
C_{18}	(3.132)	$0.0050\ m$	$0.0164\ ft$
C_{19}	(3.140)	$1.085\ (\text{kPa} \cdot m)^{0.092}$	$1.015\ (\text{psia} \cdot ft)^{0.092}$
C_{20}	(3.141)	1.013 kPa	0.147 psia
C_{21}	(3.141)	$5{,}328\ K$	$9{,}590\ {}^oR$
C_{22}	(3.158)	$5.8 \frac{m}{kg^{0.333}}$	$14.62 \frac{ft}{lb^{0.333}}$
C_{23}	(3.160)	$0.45 \frac{sec}{kg^{0.333}}$	$0.346 \frac{sec}{lb^{0.333}}$
C_{24}	(3.161)	$2.6 \frac{sec}{kg^{0.167}}$	$2.279 \frac{sec}{lb^{0.167}}$
C_{25}	(3.163)	$0.0296 \frac{1}{kPa^{0.32}}$	$0.0438 \frac{1}{psia^{0.32}}$
C_{26}	(3.170)	$100 \frac{kg}{J}$	$14.5 \frac{psi}{bar}$
C_{27}	(3.171)	1	0.3967
C_{28}	(3.172)	$1{,}000 \frac{1}{kPa}$	$6{,}895 \frac{1}{psia}$
C_{29}	(3.192)	$4.303 \text{ x } 10^{-4} \frac{sec^2}{m^2}$	$1.85 \text{ x } 10^{-4} \frac{lb_m}{psi \cdot ft^3}$
C_{30}	(3.195)	$2.150 \text{ x } 10^{-7} \frac{kg}{J}$	$6.43 \text{ x } 10^{-7} \frac{1}{ft}$
C_{31}	(3.207)	$864 \frac{sec \cdot m}{cm \cdot day}$	$7{,}200 \frac{sec \cdot ft}{inch \cdot day}$
C_{32}	(3.209)	$0.543 \frac{sec \cdot bbl}{day \cdot mm^2 \cdot m}$	$106.8 \frac{sec \cdot bbl}{day \cdot inch^2 \cdot ft}$

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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_{33}	(3.210)	$0.0815\dfrac{sec \cdot bbl}{day \cdot mm^2 \cdot m}$	$16.03\dfrac{sec \cdot bbl}{day \cdot inch^2 \cdot ft}$
C_{34}	(3.210)	$86.4\dfrac{m}{day \cdot mm^2}$	$1.829 \text{ x } 10^5\dfrac{ft}{day \cdot inch^2}$
C_{35}	(3.211)	$29.6195\dfrac{bbl}{day^{0.26} \cdot mm^{0.2} \cdot m^{1.64}}$	$8.0592\dfrac{bbl}{day^{0.26} \cdot inch^{0.2} \cdot ft^{1.64}}$
C_{36}	(3.151)	$30.5\ m$	$100\ ft$
C_{37}	(3.211)	$1.408 \text{ x } 10^{-8}\dfrac{m^{1.4}}{day \cdot mm^{1.8}}$	$6.995 \text{ x } 10^{-5}\dfrac{ft^{1.4}}{day \cdot inch^{1.8}}$
C_{38}	(3.212)	1.1341	403.95
C_{39}	(3.212)	3.9365	7.2622
C_{40}	(3.212)	5.9352	5.0489
C_{41}	(3.92)	32^oC	0^oF

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