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

API 570
THIRD EDITION, NOVEMBER 2009

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Downstream Segment

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It is the intent of API to keep this publication up to date. All piping system owners and operators are invited to report their experiences in the inspection and repair of piping systems whenever such experiences may suggest a need for revising or expanding the practices set forth in API 570.

This edition of API 570 supersedes all previous editions of API 570, *Piping Inspection Code: Inspection, Repair, Alteration, and Rating of In-service Piping Systems*. Each edition, revision, or addenda to this API Code may be used beginning with the date of issuance shown on the cover page for that edition, revision, or addenda. Each edition, revision, or addenda, to this API standard becomes effective six months after the date of issuance for equipment that is rerated, reconstructed, relocated, repaired, modified (altered), inspected, and tested per this standard. During the six-month time between the date of issuance of the edition, revision, or addenda and the effective date, the user shall specify to which edition, revision, or addenda, the equipment is to be, rerated, reconstructed, relocated, repaired, modified (altered), inspected and tested.

Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

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

1 Scope

1.1 General Application

1.1.1 Coverage

API 570 covers inspection, rating, repair, and alteration procedures for metallic and fiberglass reinforced plastic (FRP) piping systems and their associated pressure relieving devices that have been placed inservice.

1.1.2 Intent

The intent of this code is to specify the in-service inspection and condition-monitoring program that is needed to determine the integrity of piping. That program should provide reasonably accurate and timely assessments to determine if any changes in the condition of piping could possibly compromise continued safe operation. It is also the intent of this code that owner-users shall respond to any inspection results that require corrective actions to assure the continued safe operation of piping.

API 570 was developed for the petroleum refining and chemical process industries but may be used, where practical, for any piping system. It is intended for use by organizations that maintain or have access to an authorized inspection agency, a repair organization, and technically qualified piping engineers, inspectors, and examiners, all as defined in Section 3.

1.1.3 Limitations

API 570 shall not be used as a substitute for the original construction requirements governing a piping system before it is placed inservice; nor shall it be used in conflict with any prevailing regulatory requirements. If the requirements of this code are more stringent than the regulatory requirements, then the requirements of this code shall govern.

1.2 Specific Applications

The term non metallics has a broad definition but in this code refers to the fiber reinforced plastic groups encompassed by the generic acronyms FRP (fiberglass-reinforced plastic) and GRP (glass-reinforced plastic). The extruded, generally homogenous nonmetallics, such as high and low-density polyethylene are excluded. Refer to API 574 for guidance on degradation and inspection issues associated with FRP piping.

1.2.1 Included Fluid Services

Except as provided in 1.2.2, API 570 applies to piping systems for process fluids, hydrocarbons, and similar flammable or toxic fluid services, such as the following:

a) raw, intermediate, and finished petroleum products;

b) raw, intermediate, and finished chemical products;

c) catalyst lines;

d) hydrogen, natural gas, fuel gas, and flare systems;

e) sour water and hazardous waste streams above threshold limits, as defined by jurisdictional regulations;

f) hazardous chemicals above threshold limits, as defined by jurisdictional regulations;

g) cryogenic fluids such as: LN_2, LH_2, LOX, and liquid air;

h) high-pressure gases greater than 150 psig such as: GHe, GH_2, GOX, GN_2, and HPA.

1.2.2 Optional Piping Systems and Fluid Services

The fluid services and classes of piping systems listed below are optional with regard to the requirements of API 570.

a) Fluid services that are optional include the following:

   1) hazardous fluid services below threshold limits, as defined by jurisdictional regulations;

   2) water (including fire protection systems), steam, steam-condensate, boiler feed water, and Category D fluid services, as defined in ASME B31.3.

b) Other classes of piping systems that are optional are those that are exempted from the applicable process piping construction code.

1.3 Fitness-For-Service and Risk-Based Inspection (RBI)

This inspection code recognizes Fitness-For-Service concepts for evaluating in-service damage of pressure-containing components. API 579 provides detailed assessment procedures for specific types of damage that are referenced in this code. This inspection code recognizes RBI concepts for determining inspection intervals. API 580 provides guidelines for conducting a risk-based assessment.

2 Normative References

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

API Publication 510, *Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration*

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

API Recommended Practice 574, *Inspection Practices for Piping System Components*

API Recommended Practice 576, *Inspection of Pressure-relieving Devices*

API Recommended Practice 577, *Welding Inspection and Metallurgy*

API Recommended Practice 578, *Material Verification Program for New and Existing Piping Systems*

API Standard 579-1/ASME FFS-1, *Fitness-for-service*

API Recommended Practice 580, *Risk-based Inspection*

API Recommended Practice 581, *Risk-based Inspection Technology*

API Standard 598, *Valve Inspection and Testing*

API Recommended Practice 651, *Cathodic Protection of Aboveground Petroleum Storage Tanks*

API Recommended Practice 750, *Management of Process Hazards*

API Publication 2201, *Safe Hot Tapping Practices in the Petroleum and Petrochemical Industries*

ASME B16.34 [1], *Valves—Flanged, Threaded, and Welding End*

ASME B31.3, *Process Piping*

ASME B31G, *Manual for Determining the Remaining Strength of Corroded Pipelines*

ASME B31, *Code Case* 179/181

ASME *Boiler and Pressure Vessel Code* (*BPVC*), Section V, *Nondestructive Examination*

ASME *BPVC*, Section VIII, Divisions 1 and 2

ASME *BPVC*, Section IX, *Welding and Brazing Qualifications*

ASME PCC-1, *Guidelines for Pressure Boundary Bolted Flange Joint Assembly*

ASME PCC-2, *Repair of Pressure Equipment and Piping*

ASNT SNT-TC-1 [2], *A Personnel Qualification and Certification in Nondestructive Testing*

ASNT CP-189, *Standard for Qualification and Certification of Nondestructive Testing Personnel*

ASTM G57 [3], *Method for Field Measurement of Soil Resistivity Using the Wenner Four-Electrode Method*

MTI 129 [4], *A Practical Guide to Field Inspection of FRP Equipment and Piping*

NACE RP 0169 [5], *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*

NACE RP 0170, *Protection of Austenitic Stainless Steels and Other Austenitic Alloys from Polythionic Acid Stress Corrosion Cracking During Shutdown of Refinery Equipment*

NACE RP 0274, *High-voltage Electrical Inspection of Pipeline Coatings Prior to Installation*

NACE RP 0275, *Application of Organic Coatings to the External Surface of Steel Pipe for Underground Service*

NACE Pub 34101, *Refinery Injection and Process Mixing Points*

NFPA 704 [6], *Standard System for the Identification of the Hazards of Materials for Emergency Response*

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1 ASME International, 3 Park Avenue, New York, New York 10016-5990, www.asme.org.
2 American Society for Nondestructive Testing, 1711 Arlingate Lane, P.O. Box 28518, Columbus, Ohio 43228, www.asnt.org.
3 ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.
4 Materials Technology Institute, 1215 Fern Ridge Parkway, Suite 206, St. Louis, Missouri 63141-4405, www.mti-link.org.
5 NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.
6 National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169-7471, www.nfpa.org.

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1
alloy material
Any metallic material (including welding filler materials) that contains alloying elements, such as chromium, nickel, or molybdenum, which are intentionally added to enhance mechanical or physical properties and/or corrosion resistance. Alloys may be ferrous or non-ferrous based.

NOTE Carbon steels are not considered alloys, for purposes of this code.

3.1.2
alteration
A physical change in any component that has design implications affecting the pressure containing capability or flexibility of a piping system beyond the scope of its original design. The following are not considered alterations: comparable or duplicate replacements and the addition of small-bore attachments that do not require reinforcement or additional support.

3.1.3
applicable code
The code, code section, or other recognized and generally accepted engineering standard or practice to which the piping system was built or which is deemed by the owner or user or the piping engineer to be most appropriate for the situation, including but not limited to the latest edition of ASME B31.3.

3.1.4
ASME B31.3
A shortened form of ASME B31.3, *Process Piping*, published by the American Society of Mechanical Engineers.

3.1.5
authorization
Approval/agreement to perform a specific activity (e.g. repair) prior to the activity being performed.

3.1.6
authorized inspection agency
Defined as any of the following:

a) the inspection organization of the jurisdiction in which the piping system is used,

b) the inspection organization of an insurance company that is licensed or registered to write insurance for piping systems,

c) an owner or user of piping systems who maintains an inspection organization for activities relating only to his equipment and not for piping systems intended for sale or resale,

d) an independent inspection organization employed by or under contract to the owner or user of piping systems that are used only by the owner or user and not for sale or resale,

e) an independent inspection organization licensed or recognized by the jurisdiction in which the piping system is used and employed by or under contract to the owner or user.

3.1.7
authorized piping inspector
An employee of an authorized inspection agency who is qualified and certified to perform the functions specified in API 570. An NDE examiner is not required to be an authorized piping inspector. Whenever the term inspector is used in API 570, it refers to an authorized piping inspector.

3.1.8
auxiliary piping
Instrument and machinery piping, typically small-bore secondary process piping that can be isolated from primary piping systems. Examples include flush lines, seal oil lines, analyzer lines, balance lines, buffer gas lines, drains, and vents.

3.1.9
condition monitoring locations
CMLs
Designated areas on piping systems where periodic examinations are conducted.

NOTE Previously, CMLs were referred to as "thickness monitoring locations" (TMLs). CMLs may contain one or more examination points. CMLs can be a plane through a section of piping or a nozzle or an area where CMLs are located on a piping circuit.

3.1.10
construction code
The code or standard to which the piping system was originally built (i.e. ASME B31.3).

3.1.11
corrosion barrier
The corrosion allowance in FRP equipment typically composed of an inner surface and an interior layer which is specified as necessary to provide the best overall resistance to chemical attack.

3.1.12
corrosion rate
The rate of metal loss due to erosion, erosion/corrosion or the chemical reaction(s) with the environment, either internal and/or external.

3.1.13
corrosion specialist
A person acceptable to the owner/user who is knowledgeable and experienced in the specific process chemistries, corrosion degradation mechanisms, materials selection, corrosion mitigation methods, corrosion monitoring techniques, and their impact on piping systems.

3.1.14
critical check valves
Check valves in piping systems that have been identified as vital to process safety.

NOTE Critical check valves are those that need to operate reliably in order to avoid the potential for hazardous events or substantial consequences should a leak occur.

3.1.15
damage mechanism
Any type of deterioration encountered in the refining and chemical process industry that can result in flaws/defects that can affect the integrity of piping (e.g. corrosion, cracking, erosion, dents, and other mechanical, physical or chemical impacts). See API 571 for a comprehensive list and description of damage mechanisms.

3.1.16
deadlegs
Components of a piping system that normally have no significant flow. Some examples include blanked branches, lines with normally closed block valves, lines with one end blanked, pressurized dummy support legs, stagnant control valve bypass piping, spare pump piping, level bridles, relief valve inlet and outlet header piping, pump trim bypass lines, high-point vents, sample points, drains, bleeders, and instrument connections.

3.1.17
defect
An imperfection of a type or magnitude exceeding the acceptable criteria.

3.1.18
design pressure
The pressure at the most severe condition of coincident internal or external pressure and temperature (minimum or maximum) expected during service.

3.1.19
design temperature of a piping system component
The temperature at which, under the coincident pressure, the greatest thickness or highest component rating is required. It is the same as the design temperature defined in ASME B31.3 and other code sections and is subject to the same rules relating to allowances for variations of pressure or temperature or both. Quality control functions performed by examiners (or inspectors) as defined elsewhere in this document.

NOTE These functions would be typically those actions conducted by NDE personnel, welding or coating inspectors.

3.1.20
examination point
recording point
measurement point
test point
An area within a CML defined by a circle having a diameter not greater than 2 in. (50 mm) for a pipe diameter not exceeding 10 in. (250 mm), or not greater than 3 in. (75 mm) for larger lines and vessels. CMLs may contain multiple test points.

NOTE Test point is a term no longer in use as test refers to mechanical or physical tests (e.g. tensile tests or pressure tests).

3.1.21
examinations
Quality control functions performed by examiners (e.g. NDEs).

3.1.22
examiner
A person who assists the inspector by performing specific NDE on piping system components but does not evaluate the results of those examinations in accordance with API 570, unless specifically trained and authorized to do so by the owner or user.

3.1.23
external inspection
A visual inspection performed from the outside of a piping system to find conditions that could impact the piping systems' ability to maintain pressure integrity or conditions that compromise the integrity of the coating and insulation covering, the supporting structures and attachments (e.g. stanchions, pipe supports, ladders, platforms, shoes, hangers, instrument, and small branch connections).

3.1.24
Fitness-For-Service evaluation
A methodology whereby flaws and other deterioration/damage contained within piping systems are assessed in order to determine the structural integrity of the piping for continued service.

3.1.25
fitting
Piping component usually associated with a change in direction or diameter. Flanges are not considered fittings.

3.1.26
flammable materials
As used in this code, includes liquids, vapors, and gases, which will support combustion. Refer to NFPA 704 for guidance on classifying fluids in 6.3.4.

3.1.27
FRP specialist
A person acceptable to the owner/user who is knowledgeable and experienced in FRPs concerning the process chemistries, degradation mechanisms, materials selection, failure mechanisms, fabrication methods and their impact on piping systems.

3.1.28
general corrosion
Corrosion that is distributed more or less uniformly over the surface of the piping, as opposed to being localized in nature.

3.1.29
hold point
A point in the repair or alteration process beyond which work may not proceed until the required inspection has been performed and documented.

3.1.30
imperfections
Flaws or other discontinuities noted during inspection that may be subject to acceptance criteria during an engineering and inspection analysis.

3.1.31
indication
A response or evidence resulting from the application of a nondestructive evaluation technique.

3.1.32
industry-qualified UT shear wave examiner
A person who possesses an ultrasonic shear wave qualification from the API (e.g. API QUTE), or an equivalent qualification approved by the owner-user.

NOTE Rules for equivalency are defined on the API ICP website.

3.1.33
injection point
Injection points are locations where chemicals or process additives are introduced into a process stream. Corrosion inhibitors, neutralizers, process antifoulants, desalter demulsifiers, oxygen scavengers, caustic, and water washes are most often recognized as requiring special attention in designing the point of injection. Process additives, chemicals and water are injected into process streams in order to achieve specific process objectives.

NOTE Injection points do not include locations where two process streams join (mix points).

EXAMPLE Chlorinating agents in reformers, water injection in overhead systems, polysulfide injection in catalytic cracking wet gas, antifoam injections, inhibitors, and neutralizers.

3.1.34
in service
Piping systems placed in operation (installed).

NOTE 1 Does not include piping systems that are still under construction or in transport to the site prior to being placed in service or piping systems that have been retired.

NOTE 2 Piping systems that are not currently in operation due to an outage of the process, turnaround, or other maintenance activity are still considered to be "in service." Installed spare piping is also considered in service; whereas spare piping that is not installed is not considered in service.

3.1.35
in-service inspection
All inspection activities associated with piping after it has been initially placed in service, but before it has been retired.

3.1.36
inspection
The external, internal, or on-stream evaluation (or any combination of the three) of piping condition conducted by the authorized inspector or his/her designee.

NOTE NDE may be conducted by examiners at the discretion of the authorized piping inspector and become part of the inspection process, but the authorized piping inspector shall review and approve the results.

3.1.37
inspection code
Shortened title for this code (API 570).

3.1.38
inspection plan
A documented plan for detailing the scope, methods and timing of the inspection activities for piping systems, which may include recommended repair, and/or maintenance.

3.1.39
inspector
An authorized piping inspector.

3.1.40
integrity operating envelope
integrity operating window
Established limits for process variables that can affect the integrity of the piping system if the process operation deviates from the established limits for a predetermined amount of time.

3.1.41
internal inspection
An inspection performed of the inside of a piping system using visual and/or NDE techniques.

3.1.42
jurisdiction
A legally constituted government administration that may adopt rules relating to piping systems.

3.1.43
level bridle
A level gauge glass piping assembly attached to a vessel.

3.1.44
localized corrosion
Deterioration, e.g. corrosion that is confined to a limited area of the metal surface.

3.1.45
lockout/tagout
A safety procedure used to ensure that piping is properly isolated and cannot be energized or put back in service prior to the completion of inspection, maintenance or servicing work.

3.1.46
major repairs
Welding repairs that involve removal and replacement of large sections of piping systems.

3.1.47
management of change
MOC
A documented management system for review and approval of changes in process or piping systems prior to implementation of the change.

3.1.48
material verification program
A documented quality assurance procedure used to assess metallic alloy materials (including weldments and attachments where specified) to verify conformance with the selected or specified alloy material designated by the owner/user.

NOTE This program may include a description of methods for alloy material testing, physical component marking, and program recordkeeping.

3.1.49
maximum allowable working pressure
MAWP
The maximum internal pressure permitted in the piping system for continued operation at the most severe condition of coincident internal or external pressure and temperature (minimum or maximum) expected during service. It is the same as the design pressure, as defined in ASME B31.3 and other code sections, and is subject to the same rules relating to allowances for variations of pressure or temperature or both.

3.1.50
minimum design metal temperature
MDMT
The lowest temperature at which a significant pressure load (e.g. operating load, start-up loads, transient loads, etc.), can be applied to piping systems as defined in the applicable construction code.

EXAMPLE ASME B31.3, eigth edition, Paragraph 323.2 “Temperature Limitations.”

3.1.51
minimum required thickness
The thickness without corrosion allowance for each component of a piping system based on the appropriate design code calculations and code allowable stress that consider pressure, mechanical and structural loadings.

NOTE Alternately, required thickness can be reassessed using Fitness-For-Service analysis in accordance with API 579-1/ASME FFS-1.

3.1.52
mix points
Process mix points are points of joining of process streams of differing composition and/or temperature where additional design attention, operating limits, and/or process monitoring are utilized to avoid corrosion problems. Not all process mix points are problematic, however they need to be identified and evaluated for possible degradation mechanisms.

3.1.53
nonconformance
An item that is not in accordance with specified codes, standards or other requirements.

3.1.54
nonpressure boundary
Components and attachments of, or the portion of piping that does not contain the process pressure.

EXAMPLE Clips, shoes, repads, supports, wear plates, nonstiffening insulation support rings, etc.

3.1.55
off-site piping
Piping systems not included within the plot boundary limits of a process unit, such as, a hydrocracker, an ethylene cracker or a crude unit.

EXAMPLE Tank farm piping and other lower consequence piping outside the limits of the process unit.

3.1.56
on-site piping
Piping systems included within the plot limits of process units, such as, a hydrocracker, an ethylene cracker, or a crude unit.

3.1.57
on-stream
A condition where in-service piping systems have not been prepared for an internal inspection.

NOTE Piping systems that are on-stream can also be empty or may still have residual process fluids in them and not be currently part of the process system.

3.1.58
on-stream inspection
An inspection performed from the outside of piping systems while they are on-stream using NDE procedures to establish the suitability of the pressure boundary for continued operation.

3.1.59
overdue inspection
Piping inspections for in-service equipment that have not been performed by their due dates documented in the inspection schedule/plan.

3.1.60
overwater piping
Piping located where leakage (liquid or solids) would result in discharge into streams, rivers, bays, etc., resulting in a potential environmental incident.

3.1.61
owner/user
An owner or user of piping systems who exercises control over the operation, engineering, inspection, repair, alteration, pressure testing, and rating of the piping.

3.1.62
owner/user inspector
An authorized inspector employed by an owner/user who has qualified by written examination under the provisions of Section 4 and Annex A.

3.1.63
pipe
A pressure-tight cylinder used to convey a fluid or to transmit a fluid pressure and that is ordinarily designated "pipe" in applicable material specifications.

NOTE Materials designated as "tube" or "tubing" in the specifications are treated as pipe in this code when intended for pressure service.

3.1.64
piperack piping
Process piping that is supported by consecutive stanchions or sleepers (including straddle racks and extensions).

3.1.65
piping circuit
A section of piping that is exposed to a process environment of similar corrosivity or expected damage mechanisms and is of similar design conditions and construction material.

NOTE 1 Complex process units or piping systems are divided into piping circuits to manage the necessary inspections, calculations, and recordkeeping.

NOTE 2 When establishing the boundary of a particular piping circuit, the inspector may also size it to provide a practical package for recordkeeping and performing field inspection.

3.1.66
piping engineer
One or more persons or organizations acceptable to the owner or user who are knowledgeable and experienced in the engineering disciplines associated with evaluating mechanical and material characteristics affecting the integrity and reliability of piping components and systems. The piping engineer, by consulting with appropriate specialists, should be regarded as a composite of all entities necessary to properly address a technical requirement.

3.1.67
piping system
An assembly of interconnected piping circuits that are subject to the same set or sets of design conditions and is used to convey, distribute, mix, separate, discharge, meter, control, or snub fluid flows.

NOTE Piping systems also include pipe-supporting elements but do not include support structures, such as structural frames and foundations.

3.1.68
positive material identification
PMI
Any physical evaluation or test of a material to confirm that the material, which has been or will be placed into service, is consistent with the selected or specified alloy material designated by the owner/user.

NOTE These evaluations or tests can provide qualitative or quantitative information that is sufficient to verify the nominal alloy composition.

3.1.69
postweld heat treatment
PWHT
Treatment which consists of heating an entire weldment or piece of fabricated piping to an elevated temperature after completion of welding in order to relieve the detrimental effects of welding heat, such as reduce residual stresses, reduce hardness, and/or slightly modify properties See ASME B31.3 paragraph 331.

3.1.70
pressure boundary
The portion of the piping that contains the pressure retaining piping elements joined or assembled into pressure tight fluid-containing systems. Pressure boundary components include pipe, tubing, fittings, flanges, gaskets, bolting, valves, and other devices such as expansion joints and flexible joints.

NOTE Also see nonpressure boundary definition.

3.1.71
pressure design thickness
Minimum allowed pipe wall thickness needed to hold design pressure at the design temperature.

NOTE 1 Pressure design thickness is determined using the rating code formula, including needed reinforcement thickness.

NOTE 2 Pressure design thickness does not include thickness for structural loads, corrosion allowance, or mill tolerances.

3.1.72
primary process piping
Process piping in normal, active service that cannot be valved off or, if it were valved off, would significantly affect unit operability. Primary process piping normally includes most process piping greater than NPS 2, and typically does not include small bore or auxiliary process piping (see also secondary process piping).

3.1.73
procedures
A document that specifies or describes how an activity is to be performed on a piping system.

NOTE A procedure may include methods to be employed, equipment or materials to be used, qualifications of personnel involved, and sequence of work.

3.1.74
process piping
Hydrocarbon or chemical piping located at, or associated with a refinery or manufacturing facility. Process piping includes piperack, tank farm, and process unit piping, but excludes utility piping.

3.1.75
quality assurance
All planned, systematic, and preventative actions required to determine if materials, equipment, or services will meet specified requirements so that the piping will perform satisfactorily in service.

NOTE The contents of a quality assurance inspection manual for piping systems are outlined in 4.3.1.1.

3.1.76
quality control
Those physical activities that are conducted to check conformance with specifications in accordance with the quality assurance plan.

3.1.77
renewal
Activity that discards an existing component, fitting, or portion of a piping circuit and replaces it with new or existing spare materials of the same or better qualities as the original piping components.

3.1.78
repair
The work necessary to restore a piping system to a condition suitable for safe operation at the design conditions. If any of the restorative changes result in a change of design temperature or pressure, the requirements for re-rating also shall be satisfied. Any welding, cutting, or grinding operation on a pressure-containing piping component not specifically considered an alteration is considered a repair.

3.1.79
repair organization
Any of the following:

a) an owner or user of piping systems who repairs or alters his or her own equipment in accordance with API 570,

b) a contractor whose qualifications are acceptable to the owner or user of piping systems and who makes repairs or alterations in accordance with API 570,

c) one who is authorized by, acceptable to, or otherwise not prohibited by the jurisdiction and who makes repairs in accordance with API 570.

3.1.80
rating
Calculations to establish pressures and temperatures appropriate for a piping system, including design pressure/temperature, MAWP, structural minimums, required thicknesses, etc.

3.1.81
rerating
A change in the design temperature, design pressure or the MAWP of a piping system (sometimes called rating). A rerating may consist of an increase, a decrease, or a combination of both. Derating below original design conditions is a means to provide increased corrosion allowance.

3.1.82
risk-based inspection
RBI
A risk assessment and risk management process that is focused on inspection planning for piping systems for loss of containment in processing facilities, which considers both the probability of failure and consequence of failure due to material deterioration.

3.1.83
scanning
Inspection technique used to find the thinnest thickness measurement at a CML. See guidance contained in API 574.

3.1.84
secondary bonder
An individual who joins and overlays cured subassemblies of FRP piping.

3.1.85
secondary process piping
Process piping, often SBP downstream of block valves that can be closed without significantly affecting the process unit operability.

3.1.86
small-bore piping
SBP
Piping that is less than or equal to NPS 2.

3.1.87
soil-to-air interface
S/A
An area in which external corrosion may occur on partially buried pipe.

NOTE The zone of the corrosion will vary depending on factors such as moisture, oxygen content of the soil, and operating temperature. The zone generally is considered to be from 12 in. (305 mm) below to 6 in. (150 mm) above the soil surface. Pipe running parallel with the soil surface that contacts the soil is included.

3.1.88
spool
A section of piping encompassed by flanges or other connecting fittings such as unions.

3.1.89
structural minimum thickness
Minimum thickness without corrosion allowance, based on structural and other loadings.

3.1.90
temporary repairs
Repairs made to piping systems in order to restore sufficient integrity to continue safe operation until permanent repairs can be scheduled and accomplished within a time period acceptable to the inspector or piping engineer.

3.1.91
tank farm piping
Process piping inside tank farm dikes or directly associated with a tank farm.

3.2 Acronyms

CML	condition monitoring location
CUI	corrosion under insulation, including stress corrosion cracking under insulation
FRP	fiberglass reinforced plastic
LT	long term
MOC	management of change

MAWP	maximum allowable working pressure
MDR	manufacturer's data reports
MT	magnetic-particle technique
MTR	material test report
NDE	nondestructive examination
NPS	nominal pipe size (followed, when appropriate, by the specific size designation number without an inch symbol)
PQR	procedure qualification record
PT	liquid-penetrant technique
PWHT	post welding heat treatment
RBI	risk-based inspection
RT	radiographic examination (method) or radiography
RTP	reinforced thermoset plastic
SBP	small-bore piping
ST	short term
SMYS	specified minimum yield strength
UT	ultrasonic examination (method)
WPS	welding procedure specification

4 Owner/User Inspection Organization

4.1 General

An owner/user of piping systems shall exercise control of the piping system inspection program, inspection frequencies, and maintenance and is responsible for the function of an authorized inspection agency in accordance with the provisions of API 570. The owner/user inspection organization also shall control activities relating to the rating, repair, and alteration of its piping systems.

Integrity operating envelopes (windows) should be established for process parameters (both physical and chemical) that could impact equipment integrity if not properly controlled. Examples of the process parameters include temperatures, pressures, fluid velocities, pH, flow rates, chemical or water injection rates, levels of corrosive constituents, chemical composition, etc. Key process parameters for integrity operating envelopes should be identified and implemented, upper and lower limits established, as needed, and deviations from these limits should be brought to the attention of inspection/engineering personnel. Particular attention to monitoring integrity operating envelopes should also be provided during start-ups, shutdowns and significant process upsets.

4.2 Authorized Piping Inspector Qualification and Certification

Authorized piping inspectors shall have education and experience in accordance with Annex A of this inspection code. Authorized piping inspectors shall be certified in accordance with the provisions of Annex A. Whenever the term inspector is used in this code, it refers to an authorized piping inspector.

4.3 Responsibilities

4.3.1 Owner/User Organization

4.3.1.1 Systems and Procedures

An owner/user organization is responsible for developing, documenting, implementing, executing, and assessing piping inspection systems and inspection procedures that will meet the requirements of this inspection code. These systems and procedures will be contained in a quality assurance inspection/repair management system and shall include:

a) organization and reporting structure for inspection personnel;

b) documenting and maintaining inspection and quality assurance procedures;

c) documenting and reporting inspection and test results;

d) developing and documenting inspection plans;

e) developing and documenting risk-based assessments;

f) developing and documenting the appropriate inspection intervals;

g) corrective action for inspection and test results;

h) internal auditing for compliance with the quality assurance inspection manual;

i) review and approval of drawings, design calculations, and specifications for repairs, alterations, and reratings;

j) ensuring that all jurisdictional requirements for piping inspection, repairs, alterations, and rerating are continuously met;

k) reporting to the authorized piping inspector any process changes that could affect piping integrity;

l) training requirements for inspection personnel regarding inspection tools, techniques, and technical knowledge base;

m) controls necessary so that only qualified welders and procedures are used for all repairs and alterations;

n) controls necessary so that only qualified NDE personnel and procedures are utilized;

o) controls necessary so that only materials conforming to the applicable section of the ASME Code are utilized for repairs and alterations;

p) controls necessary so that all inspection measurement and test equipment are properly maintained and calibrated;

q) controls necessary so that the work of contract inspection or repair organizations meet the same inspection requirements as the owner/user organization;

r) internal auditing requirements for the quality control system for pressure-relieving devices.

4.3.1.2 MOC

The owner/user is also responsible for implementing an effective MOC process that will review and control changes to the process and to the hardware. An effective MOC process is vital to the success of any piping integrity management program in order that the inspection group will be able to anticipate changes in corrosion or other deterioration variables and alter the inspection plan to account for those changes. The MOC process shall include the appropriate materials/corrosion experience and expertise in order to effectively forecast what changes might affect piping integrity. The inspection group shall be involved in the approval process for changes that may affect piping integrity. Changes to the hardware and the process shall be included in the MOC process to ensure its effectiveness.

4.3.2 Piping Engineer

The piping engineer is responsible to the owner/user for activities involving design, engineering review, rating, analysis, or evaluation of piping systems covered by API 570.

4.3.3 Repair Organization

All repairs and alterations shall be performed by a repair organization. The repair organization shall be responsible to the owner/user and shall provide the materials, equipment, quality control, and workmanship necessary to maintain and repair the piping systems in accordance with the requirements of API 570.

4.3.4 Authorized Piping Inspector

When inspections, repairs, or alterations are being conducted on piping systems, an authorized piping inspector shall be responsible to the owner/user for determining that the requirements of API 570 on inspection, examination, quality assurance and testing are met. The inspector shall be directly involved in the inspection activities which in most cases will require field activities to ensure that procedures are followed. The inspector is also responsible for extending the scope of the inspection (with appropriate consultation with engineers/specialists), where justified depending upon the findings of the inspection. Where nonconformances are discovered, the inspector is responsible for notifying the owner-user in a timely manner and making appropriate repair or other mitigative recommendations.

The authorized piping inspector may be assisted in performing visual inspections by other properly trained and qualified individuals, who may or may not be certified piping inspectors (e.g. examiners and operating personnel). Personnel performing NDEs shall meet the qualifications identified in 4.3.5, but need not be authorized piping inspectors. However, all examination results shall be evaluated and accepted by the authorized piping inspector.

4.3.5 Examiners

4.3.5.1 The examiner shall perform the NDE in accordance with job requirements.

4.3.5.2 The examiner is not required to be certified in accordance with Annex A and does not need to be an employee of the owner/user. The examiner shall be trained and competent in the NDE procedures being used and may be required by the owner/user to prove competency by holding certifications in those procedures. Examples of other certifications that may be required include ASNT SNT-TC-1A [1], ASNT CP-189 [2], and AWS QC1 [3].

4.3.5.3 The examiner's employer shall maintain certification records of the examiners employed, including dates and results of personnel qualifications. These records shall be available to the inspector.

4.3.6 Other Personnel

Operating, maintenance, engineering or other personnel who have special knowledge or expertise related to particular piping systems shall be responsible for timely notification to the inspector or engineer of issues that may affect piping integrity such as the following:

a) any action that requires MOC;

b) operations outside defined integrity operating envelopes;

c) changes in source of feedstock and other process fluids;

d) piping failures, repair actions conducted and failure analysis reports;

e) cleaning and decontamination methods used or other maintenance procedures that could affect piping and equipment integrity;

f) reports of experiences that other plants have had with similar service piping and associated equipment failures;

g) any unusual conditions that may develop (e.g. noises, leaks, vibration, etc.).

5 Inspection, Examination, and Pressure Testing Practices

5.1 Inspection Plans

5.1.1 Development of an Inspection Plan

5.1.1.1 An inspection plan shall be established for all piping systems within the scope of this code. The inspection plan shall be developed by the inspector and/or engineer. A corrosion specialist should be consulted as needed to clarify potential damage mechanisms and specific locations where degradation may occur. A corrosion specialist should be consulted when developing the inspection plan for piping systems that operate at elevated temperatures [above 750 °F (400 °C)] and piping systems that operate below the ductile-to-brittle transition temperature.

5.1.1.2 The inspection plan is developed from the analysis of several sources of data. Piping systems shall be evaluated based on present or possible types of damage mechanisms. The methods and the extent of NDE shall be evaluated to assure they can adequately identify the damage mechanism and the severity of damage. Examinations shall be scheduled at intervals that consider the:

a) type of damage,

b) rate of damage progression,

c) tolerance of the equipment to the type of damage,

d) capability of the NDE method to identify the damage,

e) maximum intervals as defined in codes and standards, and

f) extent of examination.

Additionally, the use of RBI (see 5.2) is recommended when developing the required inspection plans, and to review recent operating history and MOC records that may impact inspection plans.

5.1.1.3 The inspection plan should be developed using the most appropriate sources of information including those references listed in Section 2. Inspection plans shall be reviewed and amended as needed when variables that may impact damage mechanisms and/or deterioration rates are identified. See API 574 for more information on the development of inspection plans.

5.1.2 Minimum Contents of an Inspection Plan

The inspection plan shall contain the inspection tasks and schedule required to monitor identified damage mechanisms and assure the pressure integrity of the piping systems. The plan should:

a) define the type(s) of inspection needed, e.g. internal, external, on-stream (nonintrusive);

b) identify the next inspection date for each inspection type;

c) describe the inspection methods and NDE techniques;

d) describe the extent and locations of inspection and NDE at CMLs;

e) describe the surface cleaning requirements needed for inspection and examinations for each type of inspection;

f) describe the requirements of any needed pressure test (e.g. type of test, test pressure, test temperature, and duration); and

g) describe any required repairs if known or previously planned before the upcoming inspection.

Generic inspection plans based on industry standards and practices may be used as a starting point in developing specific inspection plans. The inspection plan may or may not exist in a single document, however the contents of the plan should be readily accessible from inspection data systems.

5.1.3 Additional Contents of an Inspection Plan

Inspection plans may also contain other details to assist in understanding the rationale for the plan and in executing the plan. Some of these details may include:

a) describing the types of damage anticipated or experienced in the piping systems;

b) defining the location of the expected damage;

c) defining any special access, and preparation needed.

5.2 RBI

RBI can be used to determine inspection intervals and the type and extent of future inspection/examinations.

When the owner/user chooses to conduct an RBI assessment it shall include a systematic evaluation of both the probability and the associated consequence of failure, in accordance with API 580. API 581 [4] details an RBI methodology that has all of the key elements defined in API 580.

Identifying and evaluating potential damage mechanisms, current equipment condition and the effectiveness of the past inspections are important steps in assessing the probability of piping failure. Identifying and evaluating the process fluid(s), potential injuries, environmental damage, equipment damage and equipment downtime are important steps in assessing the consequence of piping failure. Identifying integrity operating envelopes for key process variables is an important adjunct to RBI (see 4.1).

5.2.1 Probability Assessment

The probability assessment shall be in accordance with API 580 and shall be based on all forms of damage that could reasonably be expected to affect equipment in any particular service. Examples of those damage mechanisms are shown in Table 1. Additionally, the effectiveness of the inspection practices, tools, and techniques used for finding the potential damage mechanisms shall be evaluated.

Other factors that should be considered in a probability assessment include:

a) appropriateness of the materials of construction;

b) equipment design conditions, relative to operating conditions;

c) appropriateness of the design codes and standards utilized;

d) effectiveness of corrosion monitoring programs;

e) the quality of maintenance and inspection quality assurance/quality control programs;

f) both the pressure retaining and structural requirements;

g) operating conditions both past and projected.

Piping failure data will be important information for this assessment when conducting a probability assessment.

5.2.2 Consequence Assessment

The consequence of a release is dependent on type and amount of process fluid contained in the equipment. The consequence assessment shall be in accordance with API 580 and shall consider the potential incidents that may occur as a result of fluid release, the size of a potential release, and the type of a potential release (includes explosion, fire, or toxic exposure.) The assessment should also determine the potential outcomes that may occur as a result of fluid release or equipment damage, which may include: health effects, environmental impact, additional equipment damage, and process downtime or slowdown.

5.2.3 Documentation

It is essential that all RBI assessments be thoroughly documented in accordance with API 580 clearly defining all the factors contributing to both the probability and consequence of a failure of the equipment.

After an RBI assessment is conducted, the results can be used to establish the equipment inspection plan and better define the following:

a) the most appropriate inspection and NDE methods, tools, and techniques;

b) the extent of NDE (e.g. percentage of equipment to examine);

c) the interval for internal (where applicable), external, and on-stream inspections;

d) the need for pressure testing after damage has occurred or after repairs/alterations have been completed;

e) the prevention and mitigation steps to reduce the probability and consequence of equipment failure. (e.g. repairs, process changes, inhibitors, etc.).

5.2.4 Frequency of RBI Assessments

When RBI assessments are used to set equipment inspection intervals, the assessment shall be updated after each equipment inspection as defined in API 580. The RBI assessment shall also be updated each time process or hardware changes are made or after any event occurs that could significantly affect damage rates or damage mechanisms. The maximum intervals between RBI assessments are outlined in 6.3.2, Table 2.

5.3 Preparation for Inspection

5.3.1 General

Safety precautions shall be included when preparing piping systems for inspection and maintenance activities to eliminate exposure to hazardous fluids, energy sources, and physical hazards. Regulations [e.g. those administered by the U.S. Occupational Safety and Health Administration (OSHA)] govern many aspects of piping systems inspection and shall be followed where applicable. In addition, the owner/user's safety procedures shall be reviewed and followed. See API 574 for more information on the safety aspects of piping inspection.

Procedures for segregating piping systems, installing blinds (blanks), and testing tightness should be an integral part of safety practices for flanged connections. Appropriate safety precautions shall be taken before any piping system is opened and before some types of external inspection are performed. In general, the section of piping to be opened should be isolated from all sources of harmful liquids, gases, or vapors and purged to remove all oil and toxic or flammable gases and vapors.

5.3.2 Inspection Equipment Preparation

All tools, equipment, and personal protective equipment used during piping work (i.e. inspection, NDE, pressure testing, repairs, and alterations) should be checked for damage and/or operability prior to use. NDE equipment and the repair organization's equipment are subject to the owner/user's safety requirements for electrical equipment. Other equipment that might be needed for the piping system access, such as planking, scaffolding, and portable ladders, should be checked for adequacy and safety before being used.

During preparation of piping systems for inspection, personal protective equipment shall be worn when required either by regulations, the owner/user, or the repair organization.

5.3.3 Communication

Before starting any piping system inspection and maintenance activities (NDE, pressure testing, repair, or alteration) personnel should obtain permission from operating personnel responsible for the piping to work in the vicinity.

When individuals are inside large piping systems, all persons working around the equipment should be informed that people are working inside the piping. Individuals working inside the piping should be informed when any work is going to be done on the exterior of the piping.

5.3.4 Piping Entry

Prior to entering large piping, the piping system shall be isolated from all sources of liquids, gases, vapors, radiation, electricity, mechanical and other sources of energy. The piping system should be drained, purged, cleaned, ventilated, gas tested and locked out/tagged out before it is entered.

Procedures to ensure continuous safe ventilation and precautions to ensure safe egress/emergency evacuation of personnel from the piping system should be clearly communicated to all those involved. Documentation of these precautions is required prior to any piping system entry.

Before entering piping systems, individuals shall obtain permission from the responsible operating personnel. Where required for confined space entry, personnel protective equipment shall be worn that will protect individuals from specific hazards that may exist in the piping system.

5.3.5 Records Review

Before performing any of the required inspections, inspectors shall familiarize themselves with prior history of the piping system for which they are responsible. In particular, they should review the piping system's prior inspection results, prior repairs, current inspection plan, and/or other similar service inspections. Additionally it is advisable to ascertain recent operating history that may affect the inspection plan. The types of damage and failure modes experienced by piping systems are provided in API 571 [5] and API 579-1/ASME FFS-1.

5.4 Inspection for Types and Locations of Damage Modes of Deterioration and Failure

5.4.1 Equipment Damage Types

5.4.1.1 Piping systems are susceptible to various types of damage by several damage mechanisms. Typical damage types and mechanisms are shown in Table 1.

Table 1—Some Typical Piping Damage Types and Mechanisms

Damage Type	Damage Mechanism
General and local metal loss	Sulfidation Oxidation Microbiologically influenced corrosion Organic acid corrosion Erosion/erosion-corrosion Galvanic corrosion CUI
Surface connected cracking	Fatigue Caustic stress corrosion cracking Sulfide stress cracking Chloride stress corrosion cracking Polythionic acid stress corrosion cracking Other forms of environmental cracking
Subsurface cracking	Hydrogen induced cracking
Microfissuring/microvoid formation	High temperature hydrogen attack Creep
Metallurgical changes	Graphitization Temper embrittlement
Blistering	Hydrogen blistering
Dimensional changes	Creep and stress rupture Thermal
Material properties changes	Brittle fracture
NOTE API 571 has a much more complete listing and description of damage mechanisms experienced in the refining and petrochemical industry.	

5.4.1.2 The presence or potential of damage in equipment is dependent upon its material of construction, design, construction, and operating conditions. The inspector should be familiar with these conditions and with the causes and characteristics of potential defects and damage mechanisms associated with the equipment being inspected.

5.4.1.3 Detailed information concerning common damage mechanisms (critical factors, appearance, and typical inspection and monitoring techniques) is found in API 571 [5] and other sources of information on damage mechanisms included in the bibliography. Additional recommended inspection practices for specific types of damage mechanisms are described in API 574 [7].

5.4.2 Areas of Deterioration for Piping Systems

Each owner/user shall provide specific attention to the need for inspection of piping systems that are susceptible to the following specific types and areas of deterioration:

a) injection points and mix points,

b) deadlegs,

c) CUI,

d) soil air interfaces,

e) service specific and localized corrosion,

f) erosion and corrosion/erosion,

g) environmental cracking,

h) corrosion beneath linings and deposits,

i) fatigue cracking,

j) creep cracking,

k) brittle fracture,

l) freeze damage,

m) contact point corrosion.

Refer to API 571 and API 574 for more detailed information about the above noted types and areas of deterioration.

5.5 General Types of Inspection and Surveillance

Different types of inspection and surveillance are appropriate depending on the circumstances and the piping system (see note). These include the following:

a) internal visual inspection,

b) on-stream inspection,

c) thickness measurement inspection,

d) external visual inspection,

e) CUI inspection,

f) vibrating piping inspection,

g) supplemental inspection,

h) injection point inspection.

NOTE See Section 6 for interval/frequency and extent of inspection. Imperfections identified during inspections and examinations should be characterized, sized, and evaluated per Section 7.

5.5.1 Internal Visual Inspection

Internal visual inspections are not normally performed on piping. When possible and practical, internal visual inspections may be scheduled for systems such as large-diameter transfer lines, ducts, catalyst lines, or other large-diameter piping systems. Such inspections are similar in nature to pressure vessel inspections and should be conducted with methods and procedures similar to those outlined in API 510 and API 574. Remote visual inspection techniques can be helpful when inspecting piping too small to enter.

An additional opportunity for internal inspection is provided when piping flanges are disconnected, allowing visual inspection of internal surfaces with or without the use of NDE. Removing a section of piping and splitting it along its centerline also permits access to internal surfaces where there is need for such inspection.

5.5.2 On-stream Inspection

The on-stream inspection may be required by the inspection plan. All on-stream inspections should be conducted by either an inspector or examiner. All on-stream inspection work performed by an examiner shall be authorized and approved by the inspector. When on-stream inspections of the pressure boundary are specified, they shall be designed to detect the damage mechanisms identified in the inspection plan.

The inspection may include several NDE techniques to check for various types of damage. Techniques used in on-stream inspections are chosen for their ability to identify particular damage mechanisms from the exterior and their capabilities to perform at the on-stream conditions of the piping system (e.g. metal temperatures). The external thickness measurement inspection described in 5.5.3 below may be a part of an on-stream inspection.

API 574 provides more information on piping system inspection and should be used when performing on-stream piping inspections.

5.5.3 Thickness Measurement Inspection

Thickness measurements are obtained to verify the thickness of piping components. This data is used to calculate the corrosion rates and remaining life of the piping system. Thickness measurements shall be obtained by the inspector or the examiner at the direction of the inspector. The owner/user shall ensure that all individuals conducting thickness measurements are trained and qualified in accordance with the applicable procedure used during the examination.

Normally thickness measurements are taken while the piping is on-stream. On-stream thickness monitoring is a good tool for monitoring corrosion and assessing potential damage due to process or operational changes.

The inspector should consult with a corrosion specialist when the short-term corrosion rate changes significantly from the previous identified rate to determine the cause. Appropriate responses to accelerated corrosion rates may include, additional thickness readings, UT scans in suspect areas, corrosion/process monitoring, revisions to the piping inspection plan and addressing nonconformances.

5.5.4 External Visual Inspection

An external visual inspection is performed to determine the condition of the outside of the piping, insulation system, painting, and coating systems, and associated hardware; and to check for signs of misalignment, vibration, and leakage. When corrosion product buildup is noted at pipe support contact areas, it may be necessary to lift the pipe off such supports for inspection. When lifting piping that is in operation, extra care should be exercised and consultation with an engineer may be necessary. In lieu of or supplementary to lifting the pipe, appropriate NDE methods (e.g. guided wave EMAT lamb-wave) may be used. External piping inspections may be made when the piping system is in-service. Refer to API 574 for information concerning conducting external inspections. External piping inspections may include CUI inspections per 5.5.6.

External inspections shall include surveys for the condition of piping hangers and supports. Instances of cracked or broken hangers, “bottoming out” of spring supports, support shoes displaced from support members, or other improper restraint conditions shall be reported and corrected. Vertical support dummy legs also shall be checked to confirm that they have not filled with water that is causing external corrosion of the pressure piping or internal corrosion of the support leg. Horizontal support dummy legs also shall be checked to determine that slight displacements from horizontal are not causing moisture traps against the external surface of active piping components.

Bellows expansion joints should be inspected visually for unusual deformations, misalignment, or displacements that may exceed design. Non standard piping components (e.g flex hoses) may have different degradation mechanisms. Specialist engineers or manufacturer data sources may need to be consulted in developing valid inspection plans for these components.

The inspector should examine the piping system for the presence of any field modifications or temporary repairs not previously recorded on the piping drawings and/or records. The inspector also should be alert to the presence of any components that may be unsuitable for long-term operation, such as improper flanges, temporary repairs (clamps), modifications (flexible hoses), or valves of improper specification. Threaded components and other flanged spool pieces that may be easily removed and reinstalled deserve particular attention because of their higher potential for installation of incorrect materials of construction.

The periodic external inspection called for in 6.4 should normally be conducted by the inspector, who also shall be responsible for recordkeeping and repair inspection. Qualified operating or maintenance personnel also may conduct external inspections, when acceptable to the inspector. In such cases, the persons conducting external piping inspections in accordance with API 570 shall be qualified through an appropriate amount of training.

In addition to these scheduled external inspections that are documented in inspection records, it is beneficial for personnel who frequent the area to report deterioration or changes to the inspector (see API 574 for examples of such deterioration).

5.5.5 External Inspection of Buried Equipment

Buried piping shall be inspected to determine its external surface condition. The external inspection interval shall be based on corrosion rate information obtained:

a) during maintenance activity on connecting piping of similar material;

b) from the periodic examination of similarly buried corrosion test coupons of like material;

c) from representative portions of the actual piping;

d) from buried piping in similar circumstances;

e) from permanently installed thickness monitoring devices;

f) from inspections conducted with remote visual equipment, if possible; or

g) from the results of cathodic protection surveys.

5.5.6 CUI Inspection

Inspection for CUI shall be considered for externally-insulated piping in areas or temperature ranges that are susceptible to CUI shown as indicated in API 574. CUI inspections may be conducted as part of the external inspection. If CUI damage is found during spot checks, the inspector should inspect other susceptible areas on the equipment.

Although external insulation may appear to be in good condition, CUI damage may still be occurring. CUI inspection may require removal of some or all insulation. If external coverings are in good condition and there is no reason to suspect damage behind them, it is not necessary to remove them for inspection of the equipment. CUI damage is often quite insidious in that it can occur in areas where it seems unlikely.

Considerations for insulation removal are not limited to but include:

a) history of CUI for the specific piping system or comparable piping systems;

b) visual condition of the external covering and insulation;

c) evidence of fluid leakage (e.g. stains or vapors);

d) whether the piping systems are in intermittent service;

e) condition/age of the external coating, if known;

f) evidence of areas with wet insulation;

g) the type of insulation used and whether that insulation is known to absorb and hold water.

5.5.7 Vibrating Piping and Line Movement Surveillance

Operating personnel should report vibrating or swaying piping to engineering or inspection personnel for assessment. Evidence of significant line movements that could have resulted from liquid hammer, liquid slugging in vapor lines, or abnormal thermal expansion should be reported. At locations where vibrating piping systems are restrained to resist dynamic pipe stresses (such as at shoes, anchors, guides, struts, dampeners, hangers), periodic MT or PT should be considered to check for the onset of fatigue cracking. Branch connections should receive special attention particularly unbraced small bore piping connected to vibrating pipe.

5.5.8 Supplemental Inspection

Other inspections may be scheduled as appropriate or necessary. Examples of such inspections include periodic use of radiography and/or thermography to check for fouling or internal plugging, thermography to check for hot spots in refractory lined systems, additional inspections after reported process unit upsets, verifying previously measured data for accuracy, inspection for environmental cracking, and any other piping specific damage mechanism. Acoustic emission, acoustic leak detection, and thermography can be used for remote leak detection and surveillance. Areas susceptible to localized erosion or erosion-corrosion should be inspected using visual inspection internally if possible or by using radiography. Scanning of the areas with UT is also a good technique and should be used if the line is larger than NPS 12.

5.5.9 Injection Point Inspection

Injection points are sometimes subject to accelerated or localized corrosion from normal or abnormal operating conditions. Those that are may be treated as separate inspection circuits, and these areas need to be inspected thoroughly on a regular schedule.

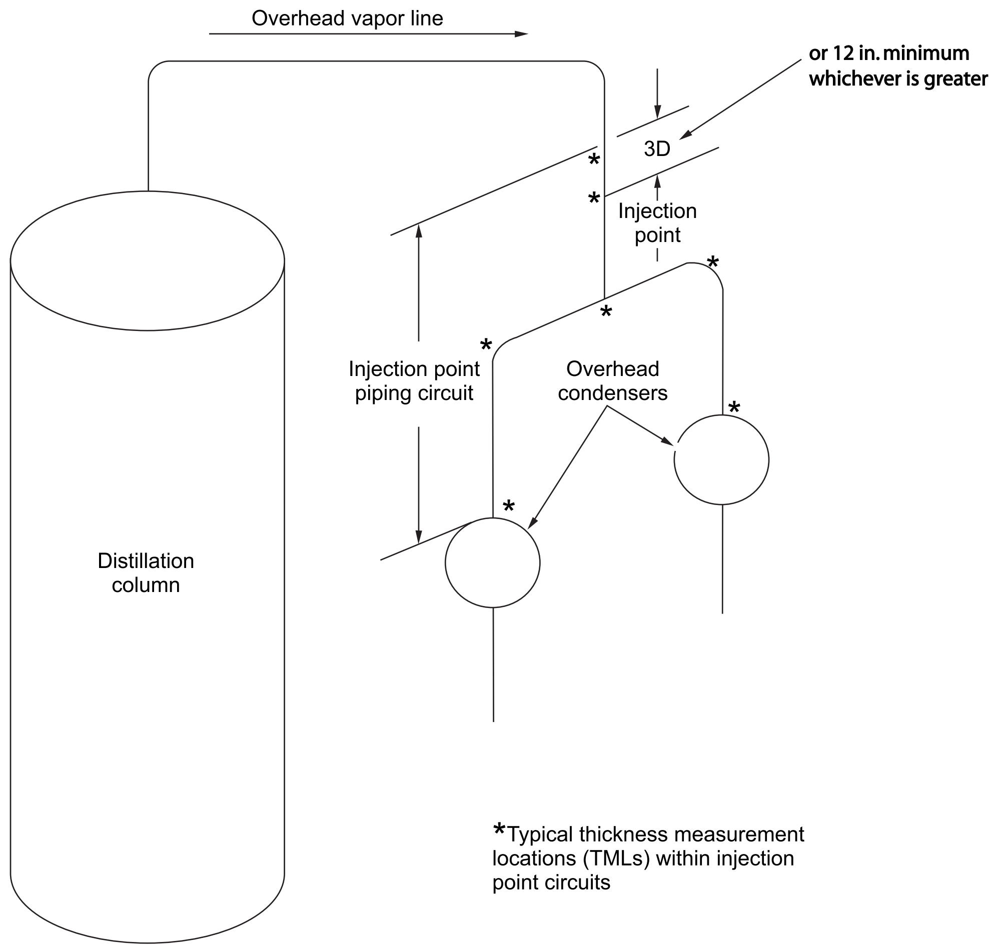

Figure 1—Typical Injection Point Piping Circuit

When designating an injection point circuit for the purposes of inspection, the recommended upstream limit of the injection point circuit is a minimum of 12 in. (300 mm) or three pipe diameters upstream of the injection point, whichever is greater. The recommended downstream limit of the injection point circuit is the second change in flow direction past the injection point, or 25 ft (7.6 m) beyond the first change in flow direction, whichever is less. In some cases, it may be more appropriate to extend this circuit to the next piece of pressure equipment, as shown in Figure 1.

The selection of thickness measurement locations (TMLs) within injection point circuits subject to localized corrosion should be in accordance with the following guidelines:

a) establish TMLs on appropriate fittings within the injection point circuit,

b) establish TMLs on the pipe wall at the location of expected pipe wall impingement of injected fluid,

c) establish TMLs at intermediate locations along the longer straight piping within the injection point circuit may be required,

d) establish TMLs at both the upstream and downstream limits of the injection point circuit.

The preferred methods of inspecting injection points are radiography and/or UT, as appropriate, to establish the minimum thickness at each TML. Close grid ultrasonic measurements or scanning may be used, as long as temperatures are appropriate.

For some applications, it is beneficial to remove piping spools to facilitate a visual inspection of the inside surface. However, thickness measurements will still be required to determine the remaining thickness.

During periodic scheduled inspections, more extensive inspection should be applied to an area beginning 12 in. (300 mm) upstream of the injection nozzle and continuing for at least ten pipe diameters downstream of the injection point. Additionally, measure and record the thickness at all TMLs within the injection point circuit.

5.6 CMLs

5.6.1 General

CMLs are specific areas along the piping circuit where inspections are to be made. The nature of the CML varies according to its location in the piping system. The selection of CMLs shall consider the potential for localized corrosion and service-specific corrosion as described in API 574 and API 571. Examples of different types of CMLs include locations for thickness measurement, locations for stress cracking examinations, locations for CUI and locations for high temperature hydrogen attack examinations.

5.6.2 CML Monitoring

Each piping system shall be monitored at CMLs. Piping circuits with high potential consequences of failure should occur and those subject to higher corrosion rates or localized corrosion will normally have more CMLs and be monitored more frequently. CMLs should be distributed appropriately throughout each piping circuit. CMLs may be eliminated or the number reduced under certain circumstances, such as olefin plant cold side piping, anhydrous ammonia piping, clean noncorrosive hydrocarbon product, or high-alloy piping for product purity. In circumstances where CMLs will be substantially reduced or eliminated, persons knowledgeable in corrosion should be consulted.

The minimum thickness at each CML can be located by ultrasonic scanning or radiography. Electromagnetic techniques also can be used to identify thin areas that may then be measured by UT or radiography. When accomplished with UT, scanning consists of taking several thickness measurements at the CML searching for localized thinning. The thinnest reading or an average of several measurement readings taken within the area of a examination point shall be recorded and used to calculate corrosion rates, remaining life, and the next inspection date in accordance with Section 7.

Where appropriate, thickness measurements should include measurements at each of the four quadrants on pipe and fittings, with special attention to the inside and outside radius of elbows and tees where corrosion/erosion could increase corrosion rates. As a minimum, the thinnest reading and its location shall be recorded. The rate of corrosion/damage shall be determined from successive measurements and the next inspection interval appropriately established. Corrosion rates, the remaining life and next inspection intervals should be calculated to determine the limiting component of each piping circuit.

CMLs should be established for areas with continuing CUI, corrosion at S/A interfaces, or other locations of potential localized corrosion as well as for general, uniform corrosion.

CMLs should be marked on inspection drawings and on the piping system to allow repetitive measurements at the same CMLs. This recording procedure provides data for more accurate corrosion rate determination. The rate of corrosion/damage shall be determined from successive measurements and the next inspection interval appropriately established based on the remaining life or RBI analysis.

5.6.3 CML Selection

In selecting or adjusting the number and locations of CMLs, the inspector should take into account the patterns of corrosion that would be expected and have been experienced in the process unit. A decision on the type, number and location of the CMLs should consider results from previous inspections, the patterns of corrosion and damage that are expected and the potential consequence of loss of containment. CMLs should be distributed appropriately over the piping system to provide adequate monitoring coverage of major components and nozzles. Thickness measurements at CMLs are intended to establish general and localized corrosion rates in different sections of the piping circuits. A minimal number of CMLs are acceptable when the established corrosion rate is low and the corrosion is not localized.

A number of corrosion processes common to refining and petrochemical units are relatively uniform in nature, resulting in a fairly constant rate of pipe wall reduction independent of location within the piping circuit, either axially or circumferentially. Examples of such corrosion phenomena include high-temperature sulfur corrosion and sour water corrosion (provided velocities are not so high as to cause local corrosion/erosion of elbows, tees, and other similar items). In these situations, the number of CMLs required to monitor a circuit will be fewer than those required to monitor circuits subject to more localized metal loss. In theory, a circuit subject to perfectly uniform corrosion could be adequately monitored with a single CML. In reality, corrosion is never truly uniform and in fact may be quite localized, so additional CMLs may be required. Inspectors must use their knowledge (and that of others) of the process unit to optimize the CML selection for each circuit, balancing the effort of collecting the data with the benefits provided by the data.

More CMLs should be selected for piping systems with any of the following characteristics:

a) higher potential for creating a safety or environmental emergency in the event of a leak;

b) higher expected or experienced corrosion rates;

c) higher potential for localized corrosion;

d) more complexity in terms of fittings, branches, deadlegs, injection points, and other similar items;

e) higher potential for CUI.

Fewer CMLs can be selected for piping systems with any of the following three characteristics:

a) low potential for creating a safety or environmental emergency in the event of a leak;

b) relatively noncorrosive piping systems;

c) long, straight-run piping systems.

CMLs can be eliminated for piping systems with any of the following characteristics:

a) extremely low potential for creating a safety or environmental emergency in the event of a leak;

b) noncorrosive systems, as demonstrated by history or similar service; and

c) systems not subject to changes that could cause corrosion as demonstrated by history and/or periodic reviews.

Every CML should have at least one or more examination points identified. Examples include:

— locations marked on un-insulated pipe using paint stencils, metal stencils, or stickers;

— holes cut in the insulation and plugged with covers;

— temporary insulation covers for fittings nozzles, etc.;

— isometrics or documents showing CMLs;

— radio frequency identification devices (RFID).

Careful identification of CMLs and examination points are necessary to enhance the accuracy and repeatability of the data.

Corrosion specialists should be consulted about the appropriate placement and number of CMLs for piping systems susceptible to localized corrosion or cracking, or in circumstances where CMLs will be substantially reduced or eliminated.

5.7 Condition Monitoring Methods

5.7.1 UT and RT

ASME *BPVC* Section V, Article 23, and Section SE–797 provide guidance for performing ultrasonic thickness measurements. Radiographic profile techniques are preferred for pipe diameters of NPS 1 and smaller. Ultrasonic thickness measurements taken on small bore pipe smaller (NPS 2 and below) may require specialized equipment (e.g. miniature transducers and/or curved shoes as well as diameter specific calibration blocks). Radiographic profile techniques may be used for locating areas to be measured, particularly in insulated systems or where nonuniform or localized corrosion is suspected. Where practical, UT can then be used to obtain the actual thickness of the areas to be recorded. Following ultrasonic readings at CMLs, proper repair of insulation and insulation weather coating is recommended to reduce the potential for CUI. Radiographic profile techniques, which do not require removing insulation, may be considered as an alternative. See API 574 for additional information on thickness monitoring methods for piping.

When corrosion in a piping system is nonuniform or the remaining thickness is approaching the minimum required thickness, additional thickness measuring may be required. Radiography or ultrasonic scanning are the preferred methods in such cases.

When ultrasonic measurements are taken above 150 °F (65 °C), instruments, couplants, and procedures should be used that will result in accurate measurements at the higher temperatures. If the procedure does not compensate for higher temperatures, measurements should be adjusted by the appropriate temperature correction factor.

Inspectors should be aware of possible sources of measurement inaccuracies and make every effort to eliminate their occurrence. As a general rule, each of the NDE techniques will have practical limits with respect to accuracy. Factors that can contribute to reduced accuracy of ultrasonic measurements include the following:

a) improper instrument calibration;

b) external coatings or scale;

c) significant surface roughness;

d) rocking of the probe (on the curved surface);

e) subsurface material flaws, such as laminations;

f) temperature effects [at temperatures above 150 °F (65 °C)];

g) improper resolution on the detector screens;

h) thicknesses of less than $^{1}/_{8}$ in. (3.2 mm) for typical digital thickness gauges;

i) improper coupling of probe to the surface (too much or too little couplant).

In addition, it must be kept in mind that the pattern of corrosion can be nonuniform. For corrosion rate determinations to be valid, it is important that measurements on the thinnest point be repeated as closely as possible to the same location. Alternatively, the minimum reading or an average of several readings at a examination point may be considered.

When piping systems are out of service, thickness measurements may be taken through openings using calipers. Calipers are useful in determining approximate thicknesses of castings, forgings, and valve bodies, as well as pit depth approximations from CUI on pipe.

Pit depth measuring devices also may be used to determine the depth of localized metal loss.

5.7.2 Other NDE Techniques for Piping Systems

In addition to thickness monitoring, other examination techniques may be appropriate to identify or monitor for other specific types of damage mechanisms. In selecting the technique(s) to use during piping inspection, the possible types of damage for each piping circuit should be taken into consideration. The inspector should consult with a corrosion specialist or an engineer to help define the type of damage, the NDE technique and extent of examination. API 571 [5] also contains some general guidance on inspection techniques that are appropriate for different damage mechanisms. Examples of NDE techniques that may be of use include the following.

a) Magnetic particle examination for cracks and other linear discontinuities that extend to the surface of the material in ferromagnetic materials. ASME *BPVC*, Section V, Article 7 [8], provides guidance on performing MT examination.

b) Liquid penetrant examination for disclosing cracks, porosity, or pin holes that extend to the surface of the material and for outlining other surface imperfections, especially in nonmagnetic materials. ASME *BPVC*, Section V, Article 6 [8], provides guidance on performing PT examination.

c) RT for detecting internal imperfections such as porosity, weld slag inclusions, cracks, and thickness of components. ASME *BPVC*, Section V [8], Article 2, provides guidance on performing RT.

d) Ultrasonic flaw detection for detecting internal and surface breaking cracks and other elongated discontinuities. ASME *BPVC*, Section V, Article 4, Article 5, and Article 23 [8], provide guidance on performing UT.

e) Alternating current flux leakage examination technique for detecting surface-breaking cracks and elongated discontinuities.

f) Eddy current examination for detecting localized metal loss, cracks, and elongated discontinuities. ASME *BPVC*, Section V, Article 8 [8], provides guidance on performing eddy current examination.

g) Field metallographic replication for identifying metallurgical changes.

h) Acoustic emission examination for detecting structurally significant defects. ASME *BPVC*, Section V, Article 11 and Article 12 [8], provides guidance on performing acoustic emission examination.

i) Thermography for determining temperature of components.

j) Leak testing for detecting through-thickness defects. ASME *BPVC* Section V, Article 10 [8], provides guidance on performing leak testing.

k) Long range UT for the detection of metal loss.

5.7.3 Surface Preparation for NDE

Adequate surface preparation is important for proper visual examination and for the satisfactory application of most examination methods, such as those mentioned above. The type of surface preparation required depends on the individual circumstances and NDE technique, but surface preparations such as wire brushing, blasting, chipping, grinding, or a combination of these preparations may be required.

Advice from NDE specialists may be needed in order to select and apply the proper surface preparation for each individual NDE technique.

5.7.4 UT Shear Wave Examiners

The owner/user shall specify industry-qualified UT shear wave examiners when the owner/user requires the following:

a) detection of interior surface (ID) breaking flaws when inspecting from the external surface (OD); or

b) detection, characterization, and/or through-wall sizing of defects.

Application examples for the use of industry-qualified UT shear wave examiners include detecting and sizing planer flaws from the external surface and collecting data for Fitness-For-Service evaluations.

5.8 Pressure Testing of Piping Systems—General

Pressure tests are not normally conducted as part of a routine inspection (see 8.2.6 for pressure testing requirements for repairs, alterations, and re-rating). Exceptions to this include requirements of the U.S. Coast Guard for over water piping and requirements of local jurisdictions, after welded alterations or when specified by the inspector or piping engineer. When they are conducted, pressure tests shall be performed in accordance with the requirements of ASME B31.3. Additional considerations for pressure testing are provided in API 574, API 579-1/ASME FFS-1 and ASME PCC-2. Lower pressure tests, which are used only for tightness of piping systems, may be conducted at pressures designated by the owner/user.

Pressure tests are typically performed on an entire piping circuit. However, where practical, pressure tests of individual components/sections can be performed in lieu of entire circuit (e.g. a replacement section of piping). An engineer should be consulted when a pressure test of piping components/sections is to be performed (including use of isolation devices) to ensure it is suitable for the intended purpose.

When a pressure test is required, it shall be conducted after any heat treatment.

Before applying a hydrostatic test, the supporting structures and foundation design should be reviewed by an engineer to ensure that they are suitable for the hydrostatic load.

NOTE The owner/user is cautioned to avoid exceeding 90 % of the SMYS for the material at test temperature and especially for equipment used in elevated temperature service.

5.8.1 Test Fluid

The test fluid should be water unless there is the possibility of damage due to freezing or other adverse effects of water on the piping system or the process or unless the test water will become contaminated and its disposal will present environmental problems. In either case, another suitable nontoxic liquid may be used. If the liquid is flammable, its flash point shall be at least 120 °F (49 °C) or greater, and consideration shall be given to the effect of the test environment on the test fluid.

Piping fabricated of or having components of 300 series stainless steel should be hydrotested with a solution made up of potable water (see note), de-ionized/de-mineralized water or steam condensate having a total chloride concentration (not free chlorine concentration) of less than 50 ppm.

NOTE Potable water in this context follows U.S. practice, with 250 parts per million maximum chloride, sanitized with chlorine or ozone.

For sensitized austenitic stainless steel piping subject to polythionic stress corrosion cracking, consideration should be given to using an alkaline-water solution for pressure testing (see NACE RP 0170).

If a pressure test is to be maintained for a period of time and the test fluid in the system is subject to thermal expansion, precautions shall be taken to avoid pressure build up beyond that specified.

After testing is completed, the piping should be thoroughly drained (all high-point vents should be open during draining), air blown, or otherwise dried. If potable water is not available or if immediate draining and drying is not possible, water having a very low chloride level, higher pH (>10), and inhibitor addition may be considered to reduce the risk of pitting and microbiologically induced corrosion.

5.8.2 Pneumatic Pressure Tests

A pneumatic (or hydropneumatic) pressure test may be used when it is impracticable to hydrostatically test due to temperature, structural, or process limitations. However, the potential risks to personnel and property of pneumatic testing shall be considered when carrying out such a test. As a minimum, the inspection precautions contained in ASME B31.3 shall be applied in any pneumatic testing.

5.8.3 Test Temperature and Brittle Fracture Considerations

At ambient temperatures, carbon, low-alloy, and other steels, including high alloy steels embrittled by service exposure, may be susceptible to brittle failure. A number of failures have been attributed to brittle fracture of steels that were exposed to temperatures below their transition temperature and to pressures greater than 25 % of the required hydrostatic test pressure or 8 ksi of stress, whichever is less. Most brittle fractures, however, have occurred on the first application of a high stress level (the first hydrotest or overload). The potential for a brittle failure shall be evaluated by an engineer prior to hydrostatic testing or especially prior to pneumatic testing because of the higher potential energy involved. Special attention should be given when testing low-alloy steels, especially $2^1/_4$Cr-1Mo, because they may be prone to temper embrittlement.

To minimize the risk of brittle fracture during a pressure test, the metal temperature should be maintained at least 30 °F (17 °C) above the MDMT for piping that is more than 2 in. (5 cm) thick, and 10 °F (6 °C) above the MDMT for piping that have a thickness of 2 in. (5 cm) or less. The test temperature need not exceed 120 °F (50 °C) unless there is information on the brittle characteristics of the piping construction material indicating a higher test temperature is needed.

5.8.4 Precautions and Procedures

During a pressure test, where the test pressure will exceed the set pressure of the pressure relieve valve on a piping system, the pressure relief valve or valves should be removed or blanked for the duration of the test. As an alternative, each valve disk shall be held down by a suitably designed test clamp. The application of an additional load to the valve spring by turning the adjusting screw is prohibited. Other appurtenances that are incapable of withstanding the test pressure, such as gage glasses, pressure gages, expansion joints, and rupture disks, should be removed or blanked. Lines containing expansion joints that cannot be removed or isolated may be tested at a reduced pressure in accordance with the principles of ASME B31.3. If block valves are used to isolate a piping system for a pressure test, caution should be used to not exceed the permissible seat pressure as described in ASME B16.34 or applicable valve manufacturer data.

Upon completion of the pressure test, pressure relief devices of the proper settings and other appurtenances removed or made inoperable during the pressure test shall be reinstalled or reactivated.

Before applying a pressure test, appropriate precautions and procedures should be taken into account to assure the safety of personnel involved with the pressure test. A close visual inspection of piping components should not be performed until the equipment pressure is at or below the MAWP. This review is especially important for in-service piping.

5.8.5 Pressure Testing Alternatives

Appropriate NDE shall be specified and conducted when a pressure test is not performed after a major repair or alteration. Substituting NDE procedures for a pressure test after an alteration is allowed only after the engineer and inspector have approved the substitution.

For cases where UT is substituted for radiographic inspection, the owner/user shall specify industry-qualified UT shear wave examiners or the application of ASME B31 *Code Case* 179/181, as applicable, for closure welds that have not been pressure tested and for welding repairs identified by the engineer or inspector.

5.9 Material Verification and Traceability

During repairs or alterations to alloy material piping systems, where the alloy material is required to maintain pressure containment, the inspector shall verify that the installation of new materials is consistent with the selected or specified construction materials. This material verification program should be consistent with API 578. Using risk assessment procedures, the owner/user can make this assessment by 100 % verification, PMI testing in certain critical situations, or by sampling a percentage of the materials. PMI testing can be accomplished by the inspector or the examiner with the use of suitable methods as described in API 578.

If a piping system component should fail because an incorrect material was inadvertently substituted for the proper piping material, the inspector shall consider the need for further verification of existing piping materials. The extent of further verification will depend upon circumstances such as the consequences of failure and the probability of further material errors.

The owner/user shall assess the need for and extent of application of a material verification program consistent with API 578 addressing inadvertent material substitution in existing alloy piping systems. A material verification program consistent with API 578 may include procedures for prioritization and risk ranking of piping circuits. That assessment may lead to retroactive PMI testing, as described in API 578, to confirm that the installed materials are consistent with the intended service. Components identified during this verification that do not meet acceptance criteria of the PMI testing program (such as in API 578, Section 6) would be targeted for replacement. The owner/user and authorized piping inspector, in consultation with a corrosion specialist, shall establish a schedule for replacement of those components. The authorized inspector shall use periodic NDE, as necessary, on the identified components until the replacement.

5.10 Inspection of Valves

Normally, thickness measurements are not routinely taken on valves in piping circuits. The body of a valve is normally thicker than other piping components for design reasons. However, when valves are dismantled for servicing and repair, the shop personnel should visually examine the valve components for any unusual corrosion patterns or thinning and, when noted, report that information to the inspector. Bodies of valves that are exposed to significant temperature cycling (for example, catalytic reforming unit regeneration and steam cleaning) should be examined periodically for thermal fatigue cracking.

If gate valves are known to be or are suspected of being exposed to severe or unusual corrosion-erosion, thickness readings should be conducted on the body between the seats, since this is an area of high turbulence and high stress.

Control valves or other throttling valves, particularly in high-pressure drop-and-slurry services, can be susceptible to localized corrosion/erosion of the body downstream of the orifice. If such metal loss is suspected, the valve should be removed from the line for internal inspection. The inside of the downstream mating flange and piping also should be inspected for local metal loss.

When valve body and/or closure pressure tests are performed after servicing, they should be conducted in accordance with API 598.

Critical check valves should be visually and internally inspected to ensure that they will stop flow reversals. An example of a critical check valve may be the check valve located on the outlet of a multistage, high head hydroprocessing charge pump. Failure of such a check valve to operate correctly could result in overpressuring the piping during a flow reversal. The normal visual inspection method should include the following items.

a) Checking to insure that the flapper is free to move, as required, without looseness beyond tolerance due to wear.

b) The flapper stop should not have wear beyond tolerance. This will minimize the likelihood that the flapper will move past the top dead central position and remain in an open position when the check valve is mounted in a vertical position.

c) The flapper nut should be secured to the flapper bolt to avoid backing off in service.

Leak checks of critical check valves are normally not required, but may be considered for special circumstances.

5.11 In-service Inspection of Welds

Inspection for piping weld quality is normally accomplished as a part of the requirements for new construction, repairs, or alterations. However, welds are often inspected for corrosion as part of a radiographic profile inspection or as part of internal inspection. When preferential weld corrosion is noted, additional welds in the same circuit or system should be examined for corrosion. API 577 [12] provides additional guidance on weld inspection.

Due to the different capabilities and characteristics of various NDE methods to find flaws, using an NDE method that is different from the one employed during original fabrication may reveal pre-existing flaws that were not caused by in-service exposure (e.g. applying UT and MT for in-service inspection when only RT was applied during fabrication). For this reason, it is often a good practice to specify the types of NDE during original fabrication that the owner-user plans to apply during in-service inspections.

On occasion, radiographic profile examinations of welds that have been in-service may reveal a flaw in the weld. If crack-like imperfections are detected while the piping system is in operation, further inspection with weld quality radiography and/or UT should be used to assess the magnitude of the imperfection. Additionally, the inspector should make an effort to determine whether the crack-like imperfections are from original weld fabrication or may be from an environmental cracking mechanism.

Crack-like flaws and environmental cracking shall be assessed by an engineer in accordance with API 579-1/ASME FFS-1 and/or corrosion specialist. Preferential weld corrosion shall be assessed by the inspector. Issues to consider when assessing the quality of existing welds include the following:

a) original fabrication inspection method and acceptance criteria;

b) extent, magnitude, and orientation of imperfections;

c) length of time in service;

d) operating versus design conditions;

e) presence of secondary piping stresses (residual and thermal);

f) potential for fatigue loads (mechanical and thermal);

g) primary or secondary piping system;

h) potential for impact or transient loads;

i) potential for environmental cracking;

j) repair and heat treatment history;

k) weld hardness.

For in-service piping weldments, it may not be appropriate to use the original construction code radiography acceptance criteria for weld quality in ASME B31.3. The B31.3 acceptance criteria are intended to apply to new construction on a sampling of welds, not just the welds examined, in order to assess the probable quality of all welds (or welders) in the system. Some welds may exist that will not meet these criteria but will still perform satisfactorily in-service after being hydrostatically tested. This is especially true on small branch connections that are normally not examined during new construction.

The owner/user shall specify industry-qualified UT shear wave examiners when the owner/user requires either of the following items.

a) Detection of interior surface (ID) breaking planar flaws when inspecting from the external surface (OD).

b) Where detection, characterization, and/or through-wall sizing is required of planar defects. Application examples for the use of such industry-qualified UT shear wave examiners include obtaining flaw dimensions for Fitness-For-Service assessment and monitoring of known flaws.

5.12 Inspection of Flanged Joints

Flanged joints should be examined for evidence of leakage, such as stains, deposits, or drips. Process leaks onto flange fasteners and valve bonnet fasteners may result in corrosion or environmental cracking. This examination should include those flanges enclosed with flange or splash-and-spray guards. Flanged joints that have been clamped and pumped with sealant should be checked for leakage at the bolts. Fasteners subjected to such leakage may corrode or crack (e.g. caustic cracking). If repumping is contemplated, affected fasteners should be renewed first.

Accessible flange faces should be examined for distortion and to determine the condition of gasket-seating surfaces. If flanges are significantly bent or distorted, their markings and thicknesses should be checked against engineering requirements before taking corrective action.

Flange fasteners should be examined visually for corrosion and thread engagement. Fasteners should be fully engaged. Any fastener failing to do so is considered acceptably engaged if the lack of complete engagement is not more than one thread.

The markings on a representative sample of newly installed fasteners and gaskets should be examined to determine whether they meet the material specification. The markings are identified in the applicable ASME and ASTM standards. Questionable fasteners should be verified or renewed.

Additional guidance on the inspection of flanged joints can be found in ASME PCC-1 [13].

5.13 Inspection Organization Audits

Each owner/user organization should be audited periodically to determine if the authorized inspection agency is meeting the requirements of this inspection code. The audit team should consist of people experienced and competent in the application of this code. The audit team should typically be from another owner/user plant site or from a third party organization experienced and competent in refining and/or petrochemical process plant inspection programs or a combination of third party and other owner/user sites.

The audit team at a minimum shall determine that:

a) the requirements and principles of this inspection code are being met;

b) all owner-user responsibilities are being properly discharged;

c) documented inspection plans are in place for covered piping systems;

d) intervals and extent of inspections are adequate for covered piping systems;

e) all general types of inspections and surveillance are being adequately applied;

f) inspection data analysis, evaluation, and recording are adequate;

g) all repairs, reratings and alterations comply with this code.

The owner/user shall receive a report of the audit team's findings. When nonconformances are found the owner/user authorized inspection agency shall take the necessary corrective actions. Each organization needs to establish a system for tracking and completion of audit findings. The resolution of the audit findings should be made available to the audit team for review. This information should also be reviewed during subsequent audits.

6 Interval/Frequency and Extent of Inspection

6.1 General

To ensure equipment integrity, all piping systems and pressure-relieving devices shall be inspected at the intervals/ frequencies provided in this section. Scheduled inspections shall be conducted on or before their due date or be considered overdue for inspection. Inspections that have been risk assessed, in accordance with API 580, and found to have acceptable risk for an extension of the due date are not considered overdue until the end of the documented extension period. See 7.10 for more information and requirements on overdue inspections, inspection deferrals, and inspection interval revisions.

The appropriate inspection shall provide the information necessary to determine that all of the essential sections or components of the equipment are safe to operate until the next scheduled inspection. The risks associated with operational shutdown and start-up and the possibility of increased corrosion due to exposure of equipment surfaces to air and moisture during shutdown should be evaluated when an internal inspection is being planned.

This code is based upon monitoring a representative sampling of inspection locations on selected piping with specific intent to reveal a reasonably accurate assessment of the condition of the piping.

6.2 Inspection During Installation and Service Changes

6.2.1 Piping Installation

Piping shall be inspected in accordance with code of construction requirements at the time of installation. The purpose of installation inspection is to verify that the piping is clean and safe for operation, and to initiate plant inspection records for the piping systems. The minimum installation inspection should include the following items:

a) verifying that piping is installed correctly, supports are adequate and secured, exterior attachments such as supports, shoes, hangers are secured, insulation is properly installed, flanged and other mechanical connections are properly assembled and the piping is clean and dry;

b) verifying the pressure-relieving devices satisfy design requirements (correct device and correct set pressure) and are properly installed.

This installation inspection should document base-line thickness measurements to be used as initial thickness readings for corrosion rate calculations in lieu of nominal and minimum thickness data in specifications, and design datasheets/drawings. This will also facilitate the creation of an accurate corrosion rate calculation after the first in-service thickness measurements are recorded.

6.2.2 Piping Service Change

If the service conditions of the piping system are changed, i.e. will exceed the current operating envelope (e.g. process contents, maximum operating pressure, and the maximum and minimum operating temperature), inspection intervals shall be established for the new service conditions.

If both the ownership and the location of the piping are changed, the piping shall be inspected before it is reused. Also, the allowable service conditions and the inspection interval shall be established for the new service.

6.3 Piping Inspection Planning

6.3.1 General

The frequency and extent of inspection on piping circuits whether above or below ground depend on the forms of degradation that can affect the piping and consequence of a piping failure. The various forms of degradation that can affect process piping circuits are described in Table 1 and API 571 in more detail. A simplified classification of piping based on the consequence of failure is defined in 6.3.4. As described in 5.1, inspection strategy based on probability and consequence of failure is referred to as RBI.

The simplified piping classification scheme in 6.3.4 is based on the consequence of a failure. The classification is used to establish frequency and extent of inspection. The owner/user may devise a more extensive classification scheme that more accurately assesses consequence for certain piping circuits. The consequence assessment would consider the potential for explosion, fire, toxicity, environmental impact, and other potential effects associated with a failure.

After an effective assessment is conducted, the results can be used to establish a piping circuit inspection strategy and define the following:

a) the appropriate inspection methods, scope, tools and techniques to be utilized based on the expected forms of degradation;

b) the appropriate inspection frequency;

c) the need for pressure testing after damage has been incurred or after repairs or modifications have been completed; and

d) the prevention and mitigation actions that could reduce the probability and consequence of a piping failure.

6.3.2 RBI for Inspection Planning

An RBI assessment may be used to increase or decrease the inspection limits described in Table 2. Similarly, the extent of inspection may be increased or decreased beyond the targets in Table 3, by an RBI assessment. When used to increase inspection interval limits or the extent of inspection, RBI assessments shall be conducted at intervals not to exceed the respective limits in Table 2, or more often if warranted by process, equipment, or consequence changes. These RBI assessments shall be reviewed and approved by a piping engineer and authorized piping inspector at intervals not to exceed the respective limits in Table 2, or more often if warranted by process, equipment, or consequence changes.

6.3.3 Inspection Intervals

If RBI is not being used, the interval between piping inspections shall be established and maintained using the following criteria:

a) corrosion rate and remaining life calculations;

b) piping service classification (see 6.3.4);

c) applicable jurisdictional requirements;

d) judgment of the inspector, the piping engineer, the piping engineer supervisor, or a materials specialist, based on operating conditions, previous inspection history, current inspection results, and conditions that may warrant supplemental inspections covered in 5.5.6.

The owner/user or the inspector shall establish inspection intervals for thickness measurements and external visual inspections and, where applicable, for internal and supplemental inspections.

Thickness measurements should be scheduled at intervals that do not exceed the lesser of one half the remaining life determined from corrosion rates indicated in 7.1.1.1 or the maximum intervals recommended in Table 2. Shorter intervals may be appropriate under certain circumstances. Prior to using Table 2, corrosion rates shall be calculated in accordance with 7.1.1.1.

Table 2 contains recommended maximum inspection intervals for Classes 1, 2 and 3 of piping services described in 6.3.4, as well as recommended intervals for injection points and S/A interfaces. Maximum intervals for Class 4 piping are left to the determination of the owner/user depending upon reliability and business needs.

The inspection interval shall be reviewed and adjusted as necessary after each inspection or significant change in operating conditions. General corrosion, localized corrosion, pitting, environmental cracking, and other applicable forms of deterioration mentioned in Section 5 shall be considered when establishing the various inspection intervals.

6.3.4 Piping Service Classes

6.3.4.1 General

All process piping systems shall be categorized into different piping classes. Such a classification system allows extra inspection efforts to be focused on piping systems that may have the highest potential consequences if failure or loss of containment should occur. In general, the higher classified systems require more extensive inspection at shorter intervals in order to affirm their integrity for continued safe operation. Classifications should be based on potential safety and environmental effects should a leak occur.

Owner/users shall maintain a record of process piping fluids handled, including their classifications. API 750 and NFPA 704 provide information that may be helpful in classifying piping systems according to the potential hazards of the process fluids they contain.

The four classes listed below in 6.3.4.2 through 6.3.4.5 are recommended.

6.3.4.2 Class 1

Services with the highest potential of resulting in an immediate emergency if a leak were to occur are in Class 1. Such an emergency may be safety or environmental in nature. Examples of Class 1 piping include, but are not necessarily limited to those containing the following.

a) Flammable services that can autorefrigerate and lead to brittle fracture.

b) Pressurized services that can rapidly vaporize during release, creating vapors that can collect and form an explosive mixture, such as C2, C3, and C4 streams. Fluids that can rapidly vaporize are those with atmospheric boiling temperatures below 50 °F (10 °C) or where the atmospheric boiling point is below the operating temperature (typically a concern with high-temperature services).

c) Hydrogen sulfide (greater than 3 % weight) in a gaseous stream.

d) Anhydrous hydrogen chloride.

e) Hydrofluoric acid.

f) Piping over or adjacent to water and piping over public throughways (refer to Department of Transportation and U.S. Coast Guard regulations for inspection of over water piping).

g) Flammable services operating above their auto-ignition temperature.

6.3.4.3 Class 2

Services not included in other classes are in Class 2. This classification includes the majority of unit process piping and selected off-site piping. Typical examples of these services include but are not necessarily limited to those containing the following:

a) on-site hydrocarbons that will slowly vaporize during release such as those operating below the flash point,

b) hydrogen, fuel gas, and natural gas,

c) on-site strong acids and caustics.

6.3.4.4 Class 3

Services that are flammable but do not significantly vaporize when they leak and are not located in high-activity areas are in Class 3. Services that are potentially harmful to human tissue but are located in remote areas may be included in this class. Examples of Class 3 service include but are not necessarily limited to those containing the following:

a) on-site hydrocarbons that will not significantly vaporize during release such as those operating below the flash point;

b) distillate and product lines to and from storage and loading;

c) tank farm piping;

d) off-site acids and caustics.

6.3.4.5 Class 4

Services that are essentially nonflammable and nontoxic are in Class 4, as are most utility services. Inspection of Class 4 piping is optional and usually based on reliability needs and business impacts as opposed to safety or environmental impact. Examples of Class 4 service include, but are not necessarily limited to those containing the following:

a) steam and steam condensate;

b) air;

c) nitrogen;

d) water, including boiler feed water, stripped sour water;

e) lube oil, seal oil;

f) ASME B31.3, Category D services;

g) plumbing and sewers.

6.4 Extent of Visual External and CUI Inspections

External visual inspections, including inspections for CUI, should be conducted at maximum intervals listed in Table 2 to evaluate items such as those in API 574. Alternatively, external visual inspection intervals can be established by using a valid RBI assessment conducted in accordance with API 580. This external visual inspection for potential CUI is also to assess insulation condition and shall be conducted on all piping systems susceptible to CUI listed in API 574. The results of the visual inspection should be documented to facilitate follow-up inspections.

Following the external visual inspection of susceptible systems, additional examination is required for the inspection of CUI. The extent and type of the additional CUI inspection are listed in Table 3. Damaged insulation at higher elevations may result in CUI in lower areas remote from the damage. NDE inspection for CUI should also be conducted as listed in Table 3 at suspect locations meeting the temperature criteria listed in API 574. RT or insulation removal and visual inspection is normally required for this inspection at damaged or suspect locations. Other NDE assessment methods may be used where applicable. If the inspection of the damaged or suspect areas has located significant CUI, additional areas should be inspected and, where warranted, up to 100 percent of the circuit should be inspected.

The extent of the CUI program described in Table 3 should be considered as target levels for piping systems and locations with no CUI inspection experience. It is recognized that several factors may affect the likelihood of CUI to include:

a) local climatic conditions,

b) insulation design and maintenance,

c) coating quality,

d) service conditions.

Facilities with CUI inspection experience may increase or reduce the CUI inspection targets of Table 3. An exact accounting of the CUI inspection targets is not required. The owner/user may confirm inspection targets with operational history or other documentation.

Piping systems that are known to have a remaining life of over 10 years or that are adequately protected against external corrosion need not be included for the NDE inspection recommended in Table 3. However, the condition of the insulating system or the outer jacketing, such as a cold-box shell, should be observed periodically by operating or other personnel. If deterioration is noted, it should be reported to the inspector. The following are examples of these systems:

a) piping systems insulated effectively to preclude the entrance of moisture,

b) jacketed cryogenic piping systems,

c) piping systems installed in a cold box in which the atmosphere is purged with an inert gas,

d) piping systems in which the temperature being maintained is sufficiently low or sufficiently high to preclude the presence of water.

The external visual inspection on bare piping is to assess the condition of paint and coating systems, to check for external corrosion, and to check for other forms of deterioration.

6.5 Extent of Thickness Measurement Inspection

To satisfy inspection interval requirements, each thickness measurement inspection should obtain thickness readings on a representative sampling of CMLs on each circuit (see 5.6). This representative sampling should include data for all the various types of components and orientations (horizontal and vertical) found in each circuit. This sampling also shall include CMLs with the earliest renewal date as of the previous inspection. The more CMLs measured for each circuit, the more accurately the next inspection date will be projected. Therefore, scheduled inspection of circuits should obtain as many measurements as necessary.

The extent of inspection for injection points is covered in API 574.

6.6 Extent of Small-bore, Auxiliary Piping, and Threaded-connections Inspections

6.6.1 SBP Inspection

SBP that is primary process piping should be inspected in accordance with all the requirements of this document.

SBP that is secondary process piping has different minimum requirements depending upon service classification. Class 1 secondary SBP shall be inspected to the same requirements as primary process piping. Inspection of Class 2 and Class 3 secondary SBP is optional. SBP deadlegs (such as level bridles) in Class 2 and Class 3 systems should be inspected where corrosion has been experienced or is anticipated.

Deadlegs with CMLs should be tracked in a separate piping circuit from the mainline piping. These deadlegs or low points are typically identified and documented in the inspection record by the inspector. Deadlegs may be combined into one circuit if their anticipated corrosion rates are similar. Inspections should include profile radiography on small diameter deadlegs, such as vents and drains, and UT or RT on larger diameter deadlegs.

6.6.2 Auxiliary Piping Inspection

Inspection of auxiliary SBP associated with instruments and machinery is optional and the need for which would typically be determined by risk assessment. Criteria to consider in determining whether auxiliary SBP will need some form of inspection include the following:

a) classification,

b) potential for environmental or fatigue cracking,

c) potential for corrosion based on experience with adjacent primary systems,

d) potential for CUI.

6.6.3 Threaded-connections Inspection

Inspection of threaded connections will be according to the requirements listed above for small-bore and auxiliary piping. When selecting CMLs on threaded connections, include only those that can be radiographed during scheduled inspections.

Threaded connections associated with machinery and subject to fatigue damage should be periodically assessed and considered for possible renewal with a thicker wall or upgrading to welded components. The schedule for such renewal will depend on several issues, including the following:

a) classification of piping,

b) magnitude and frequency of vibration,

c) amount of unsupported weight,

d) current piping wall thickness,

e) whether or not the system can be maintained on-stream,

f) corrosion rate,

g) intermittent service.

6.7 Inspection and Maintenance of Pressure-relieving Devices (PRDs)

6.7.1 General

PRDs shall be tested and repaired by a repair organization experienced in relief valve maintenance. PRDs should be inspected, tested, and maintained in accordance with API 576 [19].

6.7.2 Quality Assurance Process for PRDs

Each equipment repair organization shall have a fully documented quality assurance system. As a minimum, the following shall be included in the quality assurance manual:

a) title page;

b) revision log;

Table 2—Recommended Maximum Inspection Intervals

Type of Circuit	Thickness Measurements	Visual External
Class 1	Five years	Five years
Class 2	10 years	Five years
Class 3	10 years	10years
Class 4	Optional	Optional
Injection points [a]	Three years	By class
S/A [b]	—	By class

NOTE Thickness measurements apply to systems for which CMLs have been established in accordance with 5.6.

[a] Inspection intervals for potentially corrosive injection/mix points can also be established by a valid RBI analysis in accordance with API 580.

[b] See API RP 574 for more information on S/A interfaces.

Table 3—Recommended Extent of CUI Inspection Following Visual Inspection

Pipe Class	Approximate Amount of Follow-up Examination with NDE or Insulation Removal at Areas with Damaged Insulation	Approximate Amount of CUI Inspection by NDE at Suspect Areas on Piping Systems within Susceptible Temperature Ranges as indicated in API 574
1	75 %	50 %
2	50 %	33 %
3	25 %	10 %
4	Optional	Optional

c) contents page;

d) statement of authority and responsibility;

e) organizational chart;

f) scope of work;

g) drawings and specification controls;

h) requirements for material and part control;

i) repair and inspection program;

j) requirements for welding, NDE, and heat treatment;

k) requirements for valve testing, setting, leak testing, and sealing;

l) general example of the valve repair nameplate;

m) requirements for calibrating measurement and test gauges;

n) requirements for updating and controlling copies of the quality control manual;

o) sample forms;

p) training and qualifications required for repair personnel;

q) requirements for handling of nonconformances.

Each repair organization shall also have a fully documented training program that shall ensure that repair personnel are qualified within the scope of the repairs.

6.7.3 PRD Testing and Inspection Intervals

6.7.3.1 General

Pressure-relieving devices shall be tested and inspected at intervals that are frequent enough to verify that the valves perform reliably in the particular service conditions. Other pressure-relieving devices (e.g. rupture disks and vacuum-breaker valves) shall be inspected at intervals based on service conditions. The inspection interval for all pressure-relieving devices is determined by either the inspector, engineer, or other qualified individual per the owner/user's quality assurance system.

6.7.3.2 Unless documented experience and/or an RBI assessment indicates that a longer interval is acceptable, test and inspection intervals for pressure-relieving devices in typical process services should not exceed:

a) five years for typical process services, and

b) 10 years for clean (nonfouling) and noncorrosive services.

When a pressure-relieving device is found to be heavily fouled or stuck, the inspection and testing interval shall be reduced unless a review shows that the device will perform reliably at the current interval. The review should determine the cause of the fouling or the reasons for the pressure-relieving device not operating properly.

7 Inspection Data Evaluation, Analysis, and Recording

7.1 Corrosion Rate Determination

7.1.1 Remaining Life Calculations

The remaining life of the piping system shall be calculated from the following formula:

$$\text{Remaining life (years)} = \frac{t_{actual} - t_{required}}{\text{corrosion rate [inches (mm) per year]}} \tag{1}$$

where

t_{actual} is the actual thickness, in inches (millimeters), measured at the time of inspection for a given location or component as specified in 5.6.

t_{required} is the required thickness, in inches (millimeters), at the same location or component as the tactual measurement computed by the design formulas (e.g. pressure and structural) before corrosion allowance and manufacturer's tolerance are added.

The LT corrosion rate of piping circuits shall be calculated from the following formula:

$$\text{Corrosioon rate (LT)} = \frac{t_{initial} - t_{actual}}{\text{time (years) between } t_{initial} \text{ and } t_{actual}} \tag{2}$$

The ST corrosion rate of piping circuits shall be calculated from the following formula:

$$\text{Corrosioon rate (ST)} = \frac{t_{previous} - t_{actual}}{\text{time (years) between } t_{previous} \text{ and } t_{actual}}$$

where

t_{initial} is the thickness, in inches (millimeters), at the same location as tactual measured at initial installation or at the commencement of a new corrosion rate environment;

t_{previous} is the thickness, in inches (millimeters), at the same location as tactual measured during one or more previous inspections.

The preceding formulas may be applied in a statistical approach to assess corrosion rates and remaining life calculations for the piping system. Care shall be taken to ensure that the statistical treatment of data results reflects the actual condition of the various pipe components. Statistical analysis employing point measurements is not applicable to piping systems with significant localized unpredictable corrosion mechanisms.

LT and ST corrosion rates should be compared to see which results in the shortest remaining life as part of the data assessment. The authorized inspector, in consultation with a corrosion specialist, shall select the corrosion rate that best reflects the current process (see 6.3.3 for inspection interval determination).

7.1.2 Newly Installed Piping Systems or Changes in Service

For new piping systems and piping systems for which service conditions are being changed, one of the following methods shall be employed to determine the probable rate of corrosion from which the remaining wall thickness at the time of the next inspection can be estimated.

a) A corrosion rate for a piping circuit may be calculated from data collected by the owner/user on piping systems of similar material in comparable service and comparable operating conditions.

b) If data for the same or similar service are not available, a corrosion rate for a piping circuit may be estimated from the owner/user's experience or from published data on piping systems in comparable service.

c) If the probable corrosion rate cannot be determined by either method listed in Item a) or Item b), the initial thickness measurement determinations shall be made after no more than three months of service by using nondestructive thickness measurements of the piping system. Corrosion monitoring devices, such as corrosion coupons or corrosion probes, may be useful in establishing the timing of these thickness measurements. Subsequent measurements shall be made after appropriate intervals until the corrosion rate is established.

7.1.3 Existing Piping Systems

Corrosion rates shall be calculated on either a short-term or a LT basis.

If calculations indicate that an inaccurate rate of corrosion has been assumed, the rate to be used for the next period shall be adjusted to agree with the actual rate found.

7.2 MAWP Determination

The MAWP for the continued use of piping systems shall be established using the applicable code. Computations may be made for known materials if all the following essential details are known to comply with the principles of the applicable code:

a) upper and/or lower temperature limits for specific materials,

b) quality of materials and workmanship,

c) inspection requirements,

d) reinforcement of openings,

e) any cyclical service requirements.

For unknown materials, computations may be made assuming the lowest grade material and joint efficiency in the applicable code. When the MAWP is recalculated, the wall thickness used in these computations shall be the actual thickness as determined by inspection minus twice the estimated corrosion loss before the date of the next inspection (see 6.3.3). Allowance shall be made for the other loadings in accordance with the applicable code. The applicable code allowances for pressure and temperature variations from the MAWP are permitted provided all of the associated code criteria are satisfied.

Table 4 contains two examples of calculations of MAWP illustrating the use of the corrosion half-life concept.

7.3 Required Thickness Determination

The required thickness of a pipe shall be the greater of the pressure design thickness or the structural minimum thickness. For services with high risk, the piping engineer should consider increasing the required thickness to provide for unanticipated or unknown loadings, or undiscovered metal loss. See API 574 for information on design and structural minimum thicknesses.

7.4 Assessment of Inspection Findings

Pressure containing components found to have degradation that could affect their load carrying capability [pressure loads and other applicable loads (e.g. weight, wind, etc., per API 579-1/ASME FFS-1)] shall be evaluated for continued service. Fitness-For-Service techniques, such as those documented in API 579-1/ASME FFS-1, Second Edition, may be used for this evaluation. The Fitness-For-Service techniques used shall be applicable to the specific degradation observed. The following techniques may be used as applicable.

a) To evaluate metal loss in excess of the corrosion allowance, a Fitness-For-Service assessment may be performed in accordance with one of the following sections of API 579-1/ASME FFS-1. This assessment requires the use of a future corrosion allowance, which shall be established, based on 7.1.

   1) Assessment of General Metal Loss—API 579-1/ASME FFS-1, Section 4.

   2) Assessment of Local Metal Loss—API 579-1/ASME FFS-1, Section 5.

   3) Assessment of Pitting Corrosion—API 579-1/ASME FFS-1, Section 6.

b) To evaluate blisters and laminations, a Fitness-For-Service assessment should be performed in accordance with API 579-1/ASME FFS-1, Section 7. In some cases, this evaluation will require the use of a future corrosion allowance, which shall be established, based on 7.1.

c) To evaluate weld misalignment and shell distortions, a Fitness-For-Service assessment should be performed in accordance with API 579-1/ASME FFS-1, Section 8.

d) To evaluate crack-like flaws, a Fitness-For-Service assessment should be performed in accordance with API 579-1/ASME FFS-1, Section 9.

e) To evaluate the effects of fire damage, a Fitness-For-Service assessment should be performed in accordance with API 579-1/ASME FFS-1, Section 11.

7.5 Piping Stress Analysis

Piping shall be supported and guided so that:

a) its weight is carried safely,

b) it has sufficient flexibility for thermal expansion or contraction, and

c) it does not vibrate excessively.

Piping flexibility is of increasing concern the larger the diameter of the piping and the greater the difference between ambient and operating temperature conditions.

Piping stress analysis to assess system flexibility and support adequacy is not normally performed as part of a piping inspection. However, many existing piping systems were analyzed as part of their original design or as part of a re-rating or modification, and the results of these analyses can be useful in developing inspection plans. When unexpected movement of a piping system is observed, such as during an external visual inspection (see 5.4.3), the inspector should discuss these observations with the piping engineer and evaluate the need for conducting a piping stress analysis.

Table 4—Two Examples of the Calculation of MAWP Illustrating the Use of the Corrosion Half-life Concept

Example 1	
Design pressure/temperature	500 psig/400 °F (3447 kPA/204 °C)
Pipe description	NPS 16, standard weight, A 106-B
Outside diameter of pipe, D	16 in. (406 mm)
Allowable stress	20,000 psi (137,900 kPa)
Longitudinal weld efficiency, E	1.0
Thickness determined from inspection	0.32 in. (8.13 mm)
Observed corrosion rate (see 7.1.1)	0.01 in./year (0.254 mm/year)
Next planned inspection	5 years
Estimated corrosion loss by date of next inspection	= 5 × 0.01 = 0.05 in. (5 × 0.254 = 1.27mm)
MAWP In U.S. Customary (USC) units	= $2SEt/D$ = 550 psig
In SI units	= 3747 kPa
Conclusion: OK	
Example 2	
Next planned inspection	7 years
Estimated corrosion loss by date of next inspection	= 7 × 0.01 = 0.07 in. (7 × 0.254 = 1.78mm)
MAWP In USC units	= $2SEt/D$ = 450 psig
In SI units	= 3104 kPa
Conclusion: Must reduce inspection interval or determine that normal operating pressure will not exceed this new MAWP during the seventh year, or renew the piping before the seventh year.	
NOTE 1 psig = pounds per square inch gauge; psi = pounds per square inch.	
NOTE 2 The formula for MAWP is from ASME B31.3, Equation 3b, where t = corroded thickness.	

See API 574 for more information on pressure design, minimum required and structural minimum thicknesses, including formulas, example problems and default tables of suggested minimums.

Piping stress analysis can identify the most highly stressed components in a piping system and predict the thermal movement of the system when it is placed in operation. This information can be used to concentrate inspection efforts at the locations most prone to fatigue damage from thermal expansion (heat-up and cooldown) cycles and/or creep damage in high-temperature piping. Comparing predicted thermal movements with observed movements can help identify the occurrence of unexpected operating conditions and deterioration of guides and supports. Consultation with the piping engineer may be necessary to explain observed deviations from the analysis predictions, particularly for complicated systems involving multiple supports and guides between end points.

Piping stress analysis also can be employed to help solve observed piping vibration problems. The natural frequencies in which a piping system will vibrate can be predicted by analysis. The effects of additional guiding can be evaluated to assess its ability to control vibration by increasing the system's natural frequencies beyond the frequency of exciting forces, such as machine rotational speed. It is important to determine that guides added to control vibration do not adversely restrict thermal expansion.

7.6 Reporting and Records for Piping System Inspection

7.6.1 Permanent and Progressive Records

Piping system owners and users shall maintain permanent and progressive records of their piping systems and pressure-relieving devices. Permanent records will be maintained throughout the service life of each piping system. As a part of these records, progressive inspection and maintenance records will be regularly updated to include new information pertinent to the operation, inspection, and maintenance history of the piping system. See also API 574 for more information of piping system records.

7.6.2 Types of Piping Records

Piping system and pressure-relieving device records shall contain four types of information pertinent to mechanical integrity as follows.

a) Fabrication, Construction and Design Information to the Extent Available—For example, MDRs, MTRs, weld maps, WPS/PQR, design specification data, piping design calculations, NDE records, heat treat records, pressure-relieving device sizing calculations and construction drawings.

b) Inspection History—For example, inspection reports, and data for each type of inspection conducted (e.g. internal, external, thickness measurements), and inspection recommendations for repair. Inspection reports shall document the date of each inspection and/or examination, the date of the next scheduled inspection, the name (or initials) of the person who performed the inspection and/or examination, the serial number or other identifier of the equipment inspected, a description of the inspection and/or examination performed, and the results of the inspection and/or examination. Piping RBI records should be in accordance with API 580.

c) Repair, Alteration, and Re-rating Information—For example:

   1) repair and alteration forms if prepared;

   2) reports indicating that piping systems still in-service with either identified deficiencies, temporary repairs or recommendations for repair, are suitable for continued service until repairs can be completed; and

   3) rerating documentation (including rerating calculations and new design conditions.

d) Fitness-For-Service Assessment Documentation Requirements are Described in API 579-1/ASME FFS-1—Specific documentation requirements for the type of flaw being assessed are provided in the appropriate part of API 579-1/ASME FFS-1.

7.6.3 Operating and Maintenance Records

Site operating and maintenance records, such as operating conditions, including process upsets that may affect mechanical integrity, changes in service, mechanical damage from maintenance should also be available to the inspector.

7.6.4 Computer Records

The use of a computer-based system for storing, calculating, and analyzing data should be considered in view of the volume of data that will be generated as part of a piping inspection program. Computer programs are particularly useful for the following:

a) storing and analyzing the actual thickness readings;

b) calculating short and long-term corrosion rates, retirement dates, MAWP, and reinspection intervals on a recording-point by recording-point basis;

c) highlighting areas of high corrosion rates, piping circuits overdue for inspection, piping close to retirement thickness, and other information.

7.6.5 Piping Circuit Records

The following information should be recorded for each piping circuit on which CMLs are located:

a) material of construction/piping specification;

b) operating and design pressures and temperatures;

c) ANSI flange rating;

d) process fluids;

e) whether the circuit is a deadleg, injection point, intermittent service, or other special circuit;

f) the corrosion rate and remaining service life of, at least, the limiting examination point on the circuit;

g) maximum interval for external inspection;

h) maximum interval for thickness measurement inspection;

i) any unusual or localized corrosion mode that would require specialized inspection techniques;

j) particular circuit features that might subject it to rapid corrosion increases in the event of a process upset or loss of injection fluid flow.

7.6.6 Inspection Isometric Drawings (ISOs)

The primary purpose of inspection ISOs is to identify the location of CMLs and to identify the location of any recommended maintenance. Inspection ISOs are recommended and should contain the following:

a) all significant components of the piping circuits (e.g. all valves, elbows, tees, branches, etc.);

b) all secondary piping for Class 1 (or high consequence RBI) piping circuits;

c) secondary piping up to the block valve that is normally used for Class 2 (or appropriate RBI consequence) unit pipe;

d) all CMLs with appropriate information to locate the CMLs;

e) adequate orientation and scale to provide legible detail;

f) piping—circuit numbers and changes;

g) continuation drawing numbers;

h) identification of temporary repairs.

Inspection ISOs are recommended for all unit piping and all Class 1 (or high consequence RBI) pipe rack piping on which CMLs have been identified for thickness measurement. Alternate methods for pipe rack piping which adequately describes the system without ISOs may be used.

Inspection ISOs are recommended for Class 2 (or appropriate RBI consequence) rack piping with CMLs, except that grid type drawings may be used if all other details are shown. The use of local details or local isometrics is acceptable to show the location of CMLs on grid drawings.

Inspection ISOs do not need to be drawn to scale or show dimensions unless necessary to locate CMLs.

7.7 Inspection Recommendations for Repair or Replacement

A list of repair or replacement recommendations (includes recommendations for nonconformances) that impact piping integrity is required and shall be kept current. The recommendation tracking system shall include:

a) recommended corrective action or repair and date,

b) priority or target date for recommended action,

c) piping system identifier (e.g. piping system or circuit number) that the recommendation affects.

A management system is required for tracking and reviewing outstanding recommendations on a periodic basis.

7.8 Inspection Records for External Inspections

Results of external piping system inspections shall be documented. A narrative or checklist format is recommended when documenting inspection results. The location of CUI inspections, either by insulation removal or NDE, should be identified. The location may be identified by establishing a CML on the appropriate inspection ISO or with marked-up construction ISOs and narrative reports.

7.9 Piping Failure and Leak Reports

Leaks and failures in piping that occur as a result of corrosion, cracking or mechanical damage shall be reported and recorded to the owner-user. As with other piping failures, leaks and failures in piping systems shall be investigated to identify and correct the cause of failure. Temporary repairs to piping systems shall be documented in the inspection records.

7.10 Inspection Deferral or Interval Revision

Any piping circuit not inspected within the established interval is considered overdue for inspection, unless an acceptable alternative inspection plan is established by a deferral process or the inspection interval is revised with appropriate analysis.

A deferral is appropriate when the piping circuit's current interval is still considered to be correct given the available data but an extension of the inspection date based on a documented risk analysis process is acceptable to the inspector. Deferrals are one-time, temporary extensions of piping inspection due dates and shall not be considered inspection interval revisions.

An inspection interval revision is appropriate when review of the piping condition and history indicates that the current inspection interval was set too conservatively or liberally. Basic requirements for interval revisions are:

a) the piping history and condition shall be reviewed by the inspector;

b) interval revisions shall be documented by the inspector and should include the technical basis supporting the interval revision;

c) the inspector shall approve an interval revision or deferral.

NOTE If there are potentially any unusual types of degradation involved in the inspection of the piping systems, the inspector is advised to seek the guidance of the piping engineer or corrosion specialist before interval changes are approved.

8 Repairs, Alterations, and Rerating of Piping Systems

8.1 Repairs and Alterations

8.1.1 General

The principles of ASME B31.3 or the code to which the piping system was built shall be followed to the extent practical for in-service repairs. ASME B31.3 is written for design and construction of piping systems. However, most of the technical requirements on design, welding, examination, and materials also can be applied in the inspection, re-rating, repair, and alteration of operating piping systems. When ASME B31.3 cannot be followed because of its new construction coverage (such as revised or new material specifications, inspection requirements, certain heat treatments, and pressure tests), the piping engineer or inspector shall be guided by API 570 in lieu of strict conformity to ASME B31.3. As an example of intent, the phrase "principles of ASME B31.3" has been employed in API 570, rather than "in accordance with ASME B31.3."

The principles and practices of API RP 577 shall also be followed for all welded repairs and modifications.

8.1.2 Authorization

All repair and alteration work shall be done by a repair organization as defined in Section 3 and shall be authorized by the inspector prior to its commencement. Authorization for alteration work to a piping system may not be given without prior consultation with, and approval by, the piping engineer. The inspector will designate any inspection hold points required during the repair or alteration sequence. The inspector may give prior general authorization for limited or routine repairs and procedures, provided the inspector is satisfied with the competency of the repair organization.

8.1.3 Approval

All proposed methods of design, execution, materials, welding procedures, examination, and testing shall be approved by the inspector or by the piping engineer, as appropriate. Owner/user approval of on-stream welding is required.

Welding repairs of cracks that occurred in-service should not be attempted without prior consultation with the piping engineer in order to identify and correct the cause of the cracking. Examples are cracks suspected of being caused by vibration, thermal cycling, thermal expansion problems, and environmental cracking.

The inspector shall approve all repair and alteration work at designated hold points and after the repairs and alterations have been satisfactorily completed in accordance with the requirements of API 570.

8.1.4 Welding Repairs (Including On-stream)

8.1.4.1 Temporary Repairs

For temporary repairs, including on-stream, a full encirclement welded split sleeve or box-type enclosure designed by the piping engineer may be applied over the damaged or corroded area. See ASME PCC-2 for more information on temporary repairs to piping systems. Longitudinal cracks shall not be repaired in this manner unless the piping engineer has determined that cracks would not be expected to propagate from under the sleeve. In some cases, the piping engineer will need to consult with a fracture analyst. The design of temporary enclosures and repairs shall be approved by the piping engineer.

If the repair area is localized (for example, pitting or pinholes) and the SMYS of the pipe is not more than 40,000 psi (275,800 kPa), and a Fitness-For-Service analysis shows it is acceptable, a temporary repair may be made by fillet welding a properly designed split coupling or plate patch over the pitted or locally thinned area (see 8.2.3 for design considerations and Annex C for an example). The material for the repair shall match the base metal unless approved by the piping engineer. A fillet-welded patch shall not be installed on top of an existing fillet-welded patch. When installing a fillet-welded patch adjacent to an existing fillet-welded patch, the minimum distance between the toe of the fillet weld shall not be less than:

$$\sqrt{Dt}$$

where

D is the inside diameter in inches (millimeters);

t is the minimum required thickness of the fillet-welded patch in inches (millimeters).

For minor leaks, properly designed enclosures may be welded over the leak while the piping system is in-service, provided the inspector is satisfied that adequate thickness remains in the vicinity of the weld and the piping component can withstand welding without the likelihood of further material damage, such as from caustic service.

Temporary repairs should be removed and replaced with a suitable permanent repair at the next available maintenance opportunity. Temporary repairs may remain in place for a longer period of time only if approved and documented by the piping engineer.

8.1.4.2 Permanent Repairs

Repairs to defects found in piping components may be made by preparing a welding groove that completely removes the defect and then filling the groove with weld metal deposited in accordance with 8.2.

Corroded areas may be restored with weld metal deposited in accordance with 8.2. Surface irregularities and contamination shall be removed before welding. Appropriate NDE methods shall be applied after completion of the weld.

If it is feasible to take the piping system out of service, the defective area may be removed by cutting out a cylindrical section and replacing it with a piping component that meets the applicable code.

Insert patches (flush patches) may be used to repair damaged or corroded areas if the following requirements are met:

a) full-penetration groove welds are provided;

b) for Class 1 and Class 2 piping systems, the welds shall be 100 % radiographed or ultrasonically tested using NDE procedures that are approved by the inspector;

c) patches may be any shape but shall have rounded corners [1 in. (25 mm) minimum radius].

See ASME PCC-2 for more information on welded repairs to piping systems.

8.1.5 Nonwelding Repairs (On-stream)

Temporary repairs of locally thinned sections or circumferential linear defects may be made on-stream by installing a properly designed and applied enclosure (e.g. bolted clamp, nonmetallic composite wrap, metallic and epoxy wraps, or other non-welded applied temporary repair). The design shall include control of axial thrust loads if the piping component being enclosed is (or may become) insufficient to control pressure thrust. The effect of enclosing (crushing) forces on the component also shall be considered. See ASME PCC-2 for more information on nonmetallic composite wrap repair methods.

During turnarounds or other appropriate opportunities, temporary leak sealing and leak dissipating devices, including valves, shall be removed and appropriate actions taken to restore the original integrity of the piping system. The inspector and/or piping engineer shall be involved in determining repair methods and procedures. Temporary leak sealing and leak dissipating devices may remain in place for a longer period of time only if approved and documented by the piping engineer.

Procedures that include leak sealing fluids (“pumping”) for process piping should be reviewed for acceptance by the inspector or piping engineer. The review should take into consideration the compatibility of the sealant with the leaking material; the pumping pressure on the clamp (especially when re-pumping) and any resulting crushing forces; and; the risk of sealant affecting downstream flow meters, relief valves, or machinery; the risk of subsequent leakage at bolt threads causing corrosion or stress corrosion cracking of bolts; and the number of times the seal area is repumped.

See ASME PCC-2 for more information on temporary non-welded repairs for piping systems.

8.2 Welding and Hot Tapping

8.2.1 General

All repair and alteration welding shall be done in accordance with the principles of ASME B31.3 or the code to which the piping system was built.

Any welding conducted on piping components in operation shall be done in accordance with API 2201. The inspector shall use as a minimum the "Suggested Hot Tap Checklist" contained in API 2201 for hot tapping performed on piping components. See API 577 for further guidance on hot tapping and welding in-service.

8.2.2 Procedures, Qualifications, and Records

The repair organization shall use welders and welding procedures qualified in accordance with ASME B31.3 or the code to which the piping was built. See API 577 for guidance on welding procedures and qualifications.

The repair organization shall maintain records of welding procedures and welder performance qualifications. These records shall be available to the inspector prior to the start of welding.

8.2.3 Preheating and PWHT

8.2.3.1 General

Refer to API 577 for guidance on preheating and PWHT.

8.2.3.2 Preheating

Preheat temperature used in making welding repairs shall be in accordance with the applicable code and qualified welding procedure. Exceptions for temporary repairs shall be approved by the piping engineer.

Preheating to not less than 300 °F (150 °C) may be considered as an alternative to PWHT for alterations or repairs of piping systems initially PWHT as a code requirement (see note). This applies to piping constructed of the P-1 steels listed in ASME B31.3. P-3 steels, with the exception of Mn-Mo steels, also may receive the 300 °F (150 °C) minimum preheat alternative when the piping system operating temperature is high enough to provide reasonable toughness and when there is no identifiable hazard associated with pressure testing, shutdown, and startup. The inspector should determine that the minimum preheat temperature is measured and maintained. After welding, the joint should immediately be covered with insulation to slow the cooling rate.

NOTE Preheating may not be considered as an alternative to environmental cracking prevention.

Piping systems constructed of other steels initially requiring PWHT normally are postweld heat treated if alterations or repairs involving pressure retaining welding are performed. The use of the preheat alternative requires consultation with the piping engineer who should consider the potential for environmental cracking and whether the welding procedure will provide adequate toughness. Examples of situations where this alternative could be considered include seal welds, weld metal buildup of thin areas, and welding support clips.

8.2.3.3 PWHT

PWHT of piping system repairs or alterations should be made using the applicable requirements of ASME B31.3 or the code to which the piping was built. See 8.2.2.2 for an alternative preheat procedure for some PWHT requirements. Exceptions for temporary repairs shall be approved by the piping engineer.

Local PWHT may be substituted for 360° banding on local repairs on all materials, provided the following precautions and requirements are applied.

a) The application is reviewed, and a procedure is developed by the piping engineer.

b) In evaluating the suitability of a procedure, consideration shall be given to applicable factors, such as base metal thickness, thermal gradients, material properties, changes resulting from PWHT, the need for full-penetration welds, and surface and volumetric examinations after PWHT. Additionally, the overall and local strains and distortions resulting from the heating of a local restrained area of the piping wall shall be considered in developing and evaluating PWHT procedures.

c) A preheat of 300 °F (150 °C), or higher as specified by specific welding procedures, is maintained while welding.

d) The required PWHT temperature shall be maintained for a distance of not less than two times the base metal thickness measured from the weld. The PWHT temperature shall be monitored by a suitable number of thermocouples (a minimum of two) based on the size and shape of the area being heat treated.

e) Controlled heat also shall be applied to any branch connection or other attachment within the PWHT area.

f) The PWHT is performed for code compliance and not for environmental cracking resistance.

8.2.4 Design

Butt joints shall be full-penetration groove welds.

Piping components shall be replaced when repair is likely to be inadequate. New connections and replacements shall be designed and fabricated according to the principles of the applicable code. The design of temporary enclosures and repairs shall be approved by the piping engineer.

New connections may be installed on piping systems provided the design, location, and method of attachment conform to the principles of the applicable code.

Fillet-welded patches require special design considerations, especially relating to weld-joint efficiency and crevice corrosion. Fillet-welded patches shall be designed by the piping engineer. A patch may be applied to the external surfaces of piping, provided it is in accordance with 8.1.3 and meets either of the following requirements:

a) the proposed patch provides design strength equivalent to a reinforced opening designed according to the applicable code;

b) the proposed patch is designed to absorb the membrane strain of the part in a manner that is in accordance with the principles of the applicable code, if the following criteria are met:

   1) the allowable membrane stress is not exceeded in the piping part or the patch,

   2) the strain in the patch does not result in fillet weld stresses exceeding allowable stresses for such welds,

   3) an overlay patch shall have rounded corners (see Annex C).

Different components in the same piping system or circuit may have different design temperatures. In establishing the design temperature, consideration shall be given to process fluid temperatures, ambient temperatures, heating and cooling media temperatures, and insulation.

8.2.5 Materials

The materials used in making repairs or alterations shall be of known weldable quality, shall conform to the applicable code, and shall be compatible with the original material. For material verification requirements, see 5.8.

8.2.6 NDE

Acceptance of a welded repair or alteration shall include NDE in accordance with the applicable code and the owner/user's specification, unless otherwise specified in API 570. The principles and practices of API 577 shall also be followed. When surface and volumetric examinations are required, they shall be in accordance with ASME *BPVC* Section V (or equivalent).

8.2.7 Pressure Testing

After welding is completed, a pressure test in accordance with 5.8 shall be performed if practical and deemed necessary by the inspector. Pressure tests are normally required after alterations and major repairs. See ASME PCC-2 for more information on conducting pressure tests. When a pressure test is not necessary or practical, NDE shall be utilized in lieu of a pressure test. Substituting appropriate NDE procedures for a pressure test after an alteration, re-rating, or repair may be done only after consultation with the inspector and the piping engineer. For existing insulated lines that are being pressure tested after repairs, re-rating, or alterations, it is not necessary to strip insulation on all existing welds. Pressure tests with longer hold times and observations of pressure gauges can be substituted for insulation stripping when the risks associated with leak under the insulation are acceptable.

When it is not practical to perform a pressure test of a final closure weld that joins a new or replacement section of piping to an existing system, all of the following requirements shall be satisfied.

a) The new or replacement piping is pressure tested and examined in accordance with the applicable code governing the design of the piping system, or if not practical, welds are examined with appropriate NDE, as specified by the authorized piping inspector.

b) The closure weld is a full-penetration butt-weld between any pipe or standard piping component of equal diameter and thickness, axially aligned (not miter cut), and of equivalent materials. Acceptable alternatives are:

   1) slip-on flanges for design cases up to Class 150 and 500 °F (260 °C); and

   2) socket welded flanges or socket welded unions for sizes NPS 2 or less and design cases up to Class 150 and 500 °F (260 °C).

   A spacer designed for socket welding or some other means shall be used to establish a minimum $^{1}/_{16}$ in. (1.6 mm) gap. Socket welds shall be per ASME B31.3 and shall be a minimum of two passes.

c) Any final closure butt-weld shall be of 100 % RT; or angle-beam ultrasonic flaw detection may be used, provided the appropriate acceptance criteria have been established.

d) MT or PT shall be performed on the root pass and the completed weld for butt-welds and on the completed weld for fillet-welds.

The owner/user shall specify industry-qualified UT shear wave examiners for closure welds that have not been pressure tested and for weld repairs identified by the piping engineer or authorized piping inspector.

8.3 Re-rating

Re-rating piping systems by changing the temperature rating or the MAWP may be done only after all of the following requirements have been met.

a) Calculations are performed by the piping engineer or the inspector.

b) All re-ratings shall be established in accordance with the requirements of the code to which the piping system was built or by computation using the appropriate methods in the latest edition of the applicable code.

c) Current inspection records verify that the piping system is satisfactory for the proposed service conditions and that the appropriate corrosion allowance is provided.

d) Rerated piping systems shall be leak tested in accordance with the code to which the piping system was built or the latest edition of the applicable code for the new service conditions, unless documented records indicate a previous leak test was performed at greater than or equal to the test pressure for the new condition. An increase in the rating temperature that does not affect allowable tensile stress does not require a leak test.

e) The piping system is checked to affirm that the required pressure relieving devices are present, are set at the appropriate pressure, and have the appropriate capacity at set pressure.

f) The piping system re-rating is acceptable to the inspector or piping engineer.

g) All piping components in the system (such as valves, flanges, bolts, gaskets, packing, and expansion joints) are adequate for the new combination of pressure and temperature.

h) Piping flexibility is adequate for design temperature changes.

i) Appropriate engineering records are updated.

j) A decrease in minimum operating temperature is justified by impact test results, if required by the applicable code.

9 Inspection of Buried Piping

9.1 General

Inspection of buried process piping (not regulated by the U.S. Department of Transportation) is different from other process piping inspection because significant external deterioration can be caused by corrosive soil conditions and the inspection can be hindered by the inaccessibility of the affected areas of the piping. Important, non-mandatory references for underground piping inspection are API 574 and the following NACE documents: RP0169, RP0274, and RP 0275; and API 651.

9.2 Types and Methods of Inspection

9.2.1 Above-grade Visual Surveillance

Indications of leaks in buried piping may include a change in the surface contour of the ground, discoloration of the soil, softening of paving asphalt, pool formation, bubbling water puddles, or noticeable odor. Surveying the route of buried piping is one method of identifying problem areas.

9.2.2 Close-interval Potential Survey

The close-interval potential survey performed at ground level over the buried pipe can be used to locate active corrosion points on the pipe's surface.

Corrosion cells can form on both bare and coated pipe where the bare steel contacts the soil. Since the potential at the area of corrosion will be measurably different from an adjacent area on the pipe, the location of the corrosion activity can be determined by this survey technique.

9.2.3 Pipe Coating Holiday Survey

The pipe coating holiday survey can be used to locate coating defects on buried coated pipes, and it can be used on newly constructed pipe systems to ensure that the coating is intact and holiday-free. More often it is used to evaluate coating serviceability for buried piping that has been in-service for an extended period of time.

From survey data, the coating effectiveness and rate of coating deterioration can be determined. This information is used both for predicting corrosion activity in a specific area and for forecasting replacement of the coating for corrosion control.

9.2.4 Soil Resistivity

Corrosion of bare or poorly coated piping is often caused by a mixture of different soils in contact with the pipe surface. The corrosiveness of the soils can be determined by a measurement of the soil resistivity. Lower levels of resistivity are relatively more corrosive than higher levels, especially in areas where the pipe is exposed to significant changes in soil resistivity.

Measurements of soil resistivity should be performed using the Wenner Four-Pin Method in accordance with ASTM G57. In cases of parallel pipes or in areas of intersecting pipelines, it may be necessary to use the Single-Pin Method to accurately measure the soil resistivity. For measuring resistivity of soil samples from auger holes or excavations, a soil box serves as a convenient means for obtaining accurate results.

The depth of the piping shall be considered in selecting the method to be used and the location of samples. The testing and evaluation of results should be performed by personnel trained and experienced in soil resistivity testing.

9.2.5 Cathodic Protection Monitoring

Cathodically protected buried piping should be monitored regularly to assure adequate levels of protection. Monitoring should include periodic measurement and analysis of pipe-to-soil potentials by personnel trained and experienced in cathodic protection system operation. More frequent monitoring of critical cathodic protection components, such as impressed current rectifiers, is required to ensure reliable system operation.

Refer to NACE RP0169 and Section 11 of API 651 for guidance applicable to inspecting and maintaining cathodic protection systems for buried piping.

9.2.6 Inspection Methods

A number of direct examination techniques methods are available that may be applied to buried piping and a more extensive guide to these can be found in API 574. Some methods can indicate the external or wall condition of the piping, whereas other methods indicate only the internal condition. Examples are as follows.

a) In-line inspection (ILI) tools commonly referred to as “smart” or “intelligent pigging”. This method involves the insertion and travel of a device (pig) through the piping either while it is in-service or after it has been removed from service. A wide array of devices are available employing different methods of inspection utilizing magnetic flux leakage (MFL, UT, optical, laser and electromagnetic techniques). The line to be evaluated should be free from restrictions that would cause the device to stick within the line. The degree and number of bends in a line may restrict the application of some technologies. The line should also have facilities for launching and recovering the pigs or have an access that allows the addition of temporary launching/receiving capabilities.

b) Video Cameras—Television cameras are available that can be inserted into the piping. These cameras may provide visual inspection information on the internal condition of the line.

c) Excavation—In many cases, the only available inspection method that can be performed is unearthing the piping in order to visually inspect the external condition of the piping and to evaluate its thickness and internal condition using the methods discussed in 5.5.5. Care should be exercised in removing soil from above and around the piping to prevent damaging the line or line coating. The last few inches (millimeters) of soil should be removed manually to avoid this possibility. If the excavation is sufficiently deep, the sides of the trench should be properly shored to prevent their collapse, in accordance with OSHA regulations, where applicable. If the coating or wrapping is deteriorated or damaged, it should be removed in that area to inspect the condition of the underlying metal.

d) Externally applied screening techniques.

An array of technologies are now available that can be externally applied to the pipe at a location and screen select areas from that position. These techniques may require some excavation but considerable less than a full access described earlier. Typical of these techniques is LR UT often referred to as guided wave UT. These technologies allow 15 ft or longer distances to be screened from one installation and provide a screening assessment of the pipe. Distance travelled and the degree of detection/accuracy is a function of the applied technology and pipe conditions including degree of corrosions, external and internal coatings and soil conditions.

Other technologies employing ultrasound may be used to screen several feet from one location and are useful for assessing damage in locations such as soil to air interfaces.

9.3 Frequency and Extent of Inspection

9.3.1 Above-grade Visual Surveillance

The owner/user should, at approximately six month intervals survey the surface conditions on and adjacent to each pipeline path (see 9.2.1).

9.3.2 Pipe-to-soil Potential Survey

A close-interval potential survey on a cathodically protected line may be used to verify that the buried piping has a protective potential throughout its length. For poorly coated pipes where cathodic protection potentials are inconsistent, the survey may be conducted at five-year intervals for verification of continuous corrosion control.

For piping with no cathodic protection or in areas where leaks have occurred due to external corrosion, a pipe-to-soil potential survey may be conducted along the pipe route. The pipe should be excavated at sites where active corrosion cells have been located to determine the extent of corrosion damage. A continuous potential profile or a close-interval survey may be required to locate active corrosion cells.

9.3.3 Pipe Coating Holiday Survey

The frequency of pipe coating holiday surveys is usually based on indications that other forms of corrosion control are ineffective. For example, on a coated pipe where there is gradual loss of cathodic protection potentials or an external corrosion leak occurs at a coating defect, a pipe coating holiday survey may be used to evaluate the coating.

9.3.4 Soil Corrosivity

For piping buried in lengths greater than 100 ft (30 m) and not cathodically protected, evaluations of soil corrosivity should be performed at five-year intervals. Soil resistivity measurements may be used for relative classification of the soil corrosivity (see 9.1.4). Additional factors that may warrant consideration are changes in soil chemistry and analyses of the polarization resistance of the soil and piping interface.

9.3.5 Cathodic Protection

If the piping is cathodically protected, the system should be monitored at intervals in accordance with Section 10 of NACE RP0169 or API 651.

9.3.6 External and Internal Inspection Intervals

If internal corrosion of buried piping is expected as a result of inspection on the above-grade portion of the line, inspection intervals and methods for the buried portion should be adjusted accordingly. The inspector should be aware of and consider the possibility of accelerated internal corrosion in deadlegs.

The external condition of buried piping that is not cathodically protected should be determined by either pigging, which can measure wall thickness, or by excavating according to the frequency given in Table 5. Significant external corrosion detected by pigging or by other means may require excavation and evaluation even if the piping is cathodically protected.

Piping inspected periodically by excavation shall be inspected in lengths of 6 ft to 8 ft (2.0 m to 2.5 m) at one or more locations judged to be most susceptible to corrosion. Excavated piping should be inspected full circumference for the type and extent of corrosion (pitting or general) and the condition of the coating.

If inspection reveals damaged coating or corroded piping, additional piping shall be excavated until the extent of the condition is identified. If the average wall thickness is at or below retirement thickness, it shall be repaired or replaced.

If the piping is contained inside a casing pipe, the condition of the casing should be inspected to determine if water and/or soil has entered the casing. The inspector should verify the following:

a) both ends of the casing extend beyond the ground line,

b) the ends of the casing are sealed if the casing is not self-draining, and

c) the pressure-carrying pipe is properly coated and wrapped.

9.3.7 Leak Testing Intervals

An alternative or supplement to inspection is leak testing with liquid at a pressure at least 10 % greater than maximum operating pressure at intervals one-half the length of those shown in Table 5 for piping not cathodically protected and at the same intervals as shown in Table 5 for cathodically protected piping. The leak test should be maintained for a period of 8 hours. Four hours after the initial pressurization of the piping system, the pressure should be noted and, if necessary, the line repressurized to original test pressure and isolated from the pressure source. If, during the remainder of the test period, the pressure decreases more than 5 %, the piping should be visually inspected externally and/or inspected internally to find the leak and assess the extent of corrosion. Sonic measurements may be helpful in locating leaks during leak testing.

Buried piping also may be surveyed for integrity by using temperature-corrected volumetric or pressure test methods. Other alternative leak test methods involve acoustic emission examination and the addition of a tracer fluid to the pressurized line (such as helium or sulfur hexafloride). If the tracer is added to the service fluid, the owner/user shall confirm suitability for process and product.

Table 5—Frequency of Inspection for Buried Piping Without Effective Cathodic Protection

Soil Resistivity (ohm-cm)	Inspection Interval (years)
<2,000	five
2000 to 10,000	10
>10,000	15

9.4 Repairs to Buried Piping Systems

9.4.1 Repairs to Coatings

Any coating removed for inspection shall be renewed and inspected appropriately. For coating repairs, the inspector should be assured that the coating meets the following criteria:

a) it has sufficient adhesion to the pipe to prevent underfilm migration of moisture,

b) it is sufficiently ductile to resist cracking,

c) it is free of voids and gaps in the coating (holidays),

d) it has sufficient strength to resist damage due to handling and soil stress,

e) it can support any supplemental cathodic protection.

In addition, coating repairs may be tested using a high voltage holiday detector. The detector voltage shall be adjusted to the appropriate value for the coating material and thickness. Any holidays found shall be repaired and retested.

9.4.2 Clamp Repairs

If piping leaks are clamped and reburied, the location of the clamp shall be logged in the inspection record and may be surface marked. Both the marker and the record shall note the date of installation and the location of the clamp. All clamps shall be considered temporary. The piping should be permanently repaired at the first opportunity.

9.4.3 Welded Repairs

Welded repairs shall be made in accordance in 8.2.

9.5 Records

Record systems for buried piping should be maintained in accordance with 7.6. In addition, a record of the location and date of installation of temporary clamps shall be maintained.

Annex A
(informative)

Inspector Certification

A.1 Examination

A written examination to certify inspectors within the scope of API 570 shall be based on the current API 570 inspector certification body of knowledge as published by API.

A.2 Certification

An API 570 authorized piping inspector certification will be issued when an applicant has successfully passed the API 570 certification exam and satisfies the criteria for experience and education. Education and experience, when combined, shall be equal to at least one of the following:

a) a Bachelor of Science degree in engineering or technology, plus one year of experience in supervision of inspection activities or performance of inspection activities as described in API 570;

b) a two-year degree or certificate in engineering or technology, plus two years of experience in the design, construction, repair, inspection, or operation of piping systems, of which one year must be in supervision of inspection activities or performance of inspection activities as described in API 570;

c) a high school diploma or equivalent, plus three years of experience in the design, construction, repair, inspection, or operation of piping systems, of which one year must be in supervision of inspection activities or performance of inspection activities as described in API 570;

d) a minimum of five years of experience in the design, construction, repair, inspection, or operation of piping systems, of which one year must be in supervision of inspection activities or performance of inspection activities as described in API 570.

A.3 Recertification

A.3.1 Recertification is required three years from the date of issuance of the API 570 authorized piping inspector certificate. Recertification by written examination will be required for authorized piping inspectors who have not been actively engaged as authorized piping inspectors within the most recent three-year certification period and for authorized piping inspectors who have not previously passed the exam. Exams will be in accordance with all provisions contained in API 570.

A.3.2 "Actively engaged as an authorized piping inspector" shall be defined as a minimum of 20 % of time spent performing inspection activities or supervision of inspection activities, or engineering support of inspection activities, as described in the API 570, over the most recent three year certification period.

NOTE Inspection activities common to other API inspection documents (NDE, record-keeping, review, of welding documents, etc.) may be considered here.

A.3.3 Once every other recertification period (every six years), inspectors actively engaged as an authorized piping inspector shall demonstrate knowledge of revisions to API 570 that were instituted during the previous six years. This requirement shall be effective six years from the inspector's initial certification date. Inspectors who have not been actively engaged as an authorized piping inspector within the most recent three-year certification period shall recertify as required in A.3.1.

Annex B
(informative)

Requests for Interpretations

B.1 Introduction

API will consider written requests for interpretations of API 570. API staff will make such interpretations in writing after consultation, if necessary, with the appropriate committee officers and the committee membership. The API committee responsible for maintaining API 570 meets regularly to consider written requests for interpretations and revisions, and to develop new criteria as dictated by technological development. The committee's activities in this regard are limited strictly to interpretations of the latest edition of API 570 or to the consideration of revisions to API 570 based on the new data or technology.

As a matter of policy, API does not approve, certify, rate, or endorse any item, construction, proprietary device, or activity; and accordingly, inquiries requiring such consideration will be returned. Moreover, API does not act as a consultant on specific engineering problems or on the general understanding or application of the rules. If, based on the inquiry information submitted, it is the opinion of the committee that the inquirer should seek engineering or technical assistance, the inquiry will be returned with the recommendation that such assistance be obtained.

All inquiries that do not provide the information needed for full understanding will be returned.

B.2 Inquiry Format

Inquiries shall be limited strictly to requests for interpretation of the latest edition of API 570 or to the consideration of revisions to API 570 based on new data or technology. Inquiries shall be submitted in the following format:

a) Scope—The inquiry shall involve a single subject or closely related subjects. An inquiry letter concerning unrelated subjects will be returned.

b) Background—The inquiry letter shall state the purpose of the inquiry, which shall be either to obtain an interpretation of API 570 or to propose consideration of a revision to API 570. The letter shall provide concisely the information needed for complete understanding of the inquiry (with sketches, as necessary) and include references to the applicable edition, revision, paragraphs, figures, and tables.

c) Inquiry—The inquiry shall be stated in a condensed and precise question format, omitting superfluous background information and, where appropriate, composed in such a way that "yes" or "no" (perhaps with provisos) would be a suitable reply. This inquiry statement should be technically and editorially correct. The inquirer shall state what he or she believes API 570 requires. If in the opinion of the inquirer a revision to API 570 is needed, the inquirer shall provide recommended wording.

Submit the request for interpretation to the API Request for Interpretation website at: http://apiti.api.org.

B.3 Request for Interpretation Responses

Responses to previous request for interpretation can be found on the API website at http://mycommittees.api.org/standards/reqint/default.aspx.

Annex C
(informative)

Examples of Repairs

C.1 Repairs

Manual welding utilizing the gas metal-arc or shielded metal-arc processes may be used.

When the temperature is below 50 °F (10 °C), low-hydrogen electrodes, AWS E-XX16 or E-XX18, shall be used when welding materials conforming to ASTM A-53, Grades A and B; A-106, Grades A and B; A-333; A-334; API 5L; and other similar material. These electrodes should also be used on lower grades of material when the temperature of the material is below 32 °F (0 °C). The piping engineer should be consulted for cases involving different materials.

When AWS E-XX16 or E-XX18 electrodes are used on weld numbers 2 and 3 (see Figure C.1 below), the beads shall be deposited by starting at the bottom of the assembly and welding upward. The diameter of these electrodes should not exceed $^{5}/_{32}$ in. (4.0 mm). Electrodes larger that $^{5}/_{32}$ in. (4.0 mm) may be used on weld number 1 (see Figure C.1), but the diameter should not exceed $^{3}/_{16}$ in. (4.8 mm).

The longitudinal welds (number 1, Figure C.1) on the reinforcing sleeve shall be fitted with a suitable tape or mild steel backing strip (see note) to avoid fusing the weld to the side wall of the pipe.

NOTE If the original pipe along weld number 1 has been checked thoroughly by ultrasonic methods and it is of sufficient thickness for welding, a backing strip is not necessary.

All repair and welding procedures for on-stream lines shall conform to API 2201.

C.2 Small Repair Patches

The diameter of electrodes should not exceed $^{5}/_{32}$ in. (4.0 mm). When the temperature of the base material is below 32 °F (0 °C), low-hydrogen electrodes shall be used. Weaving of weld beads deposited with low-hydrogen electrodes should be avoided.

All repair and welding procedures for on-stream lines shall conform to API 2201.

Examples of small repair patches are shown below in Figure C.2.

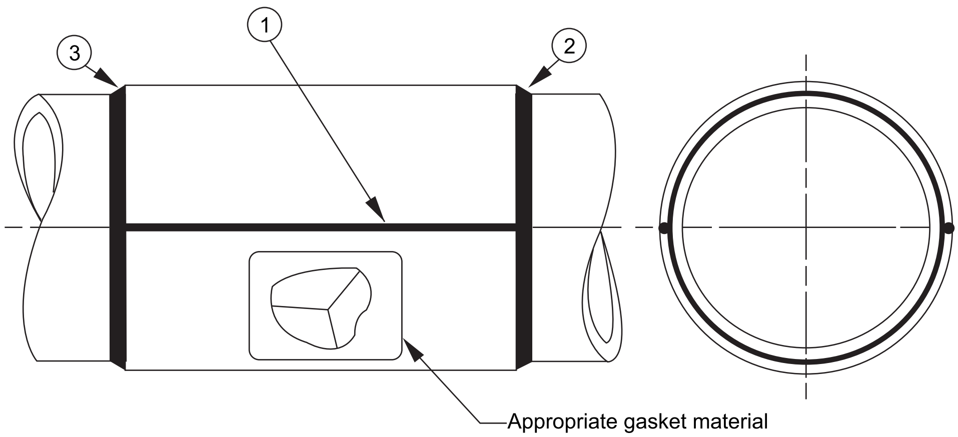

Figure C.1—Encirclement Repair Sleeve

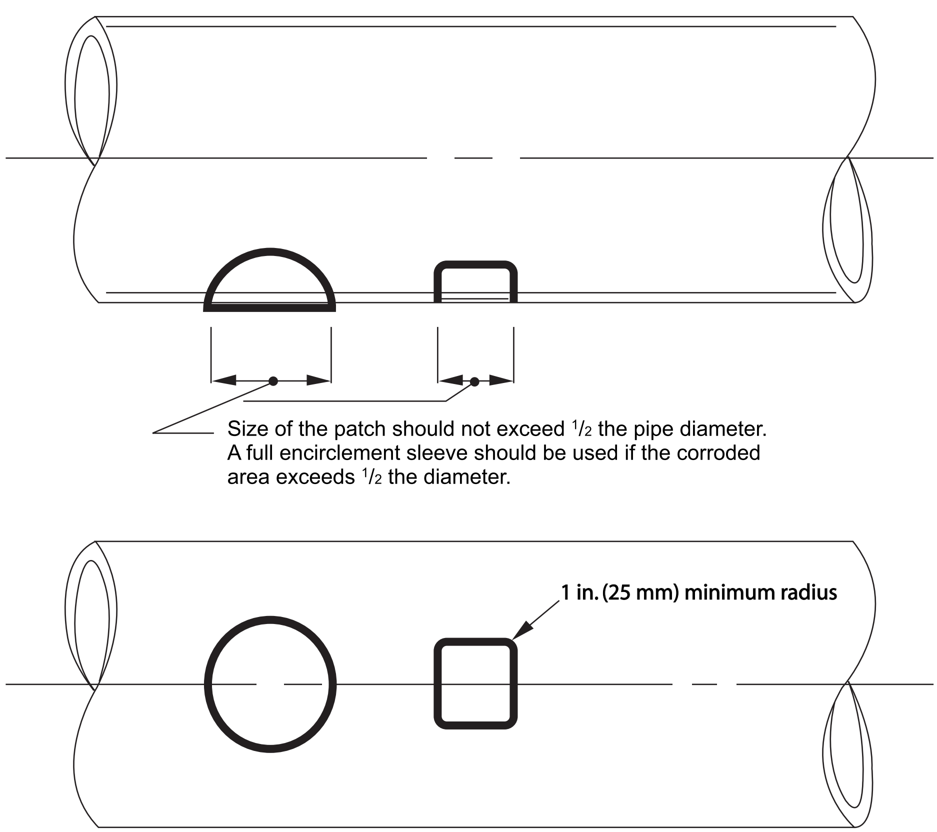

Figure C.2—Small Repair Patches

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