



Inspection
Academy

Welcome to API 510

Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair,
and Alteration

API 510 TENTH EDITION, MAY 2014

ADDENDUM 1, MAY 2017

ADDENDUM 2, MARCH 2018





Welcome

Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration

ONLINE INTERACTIVE COURSE

API 510

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Inspection Engineer

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API 510

TENTH EDITION, MAY 2014

ADDENDUM 1, MAY 2017

ADDENDUM 2, MARCH 2018

AGENDA

API 510 – Online Course



In-service Inspection, Rating, Repair, and Alteration

API 510
TENTH EDITION, MAY 2014
ADDENDUM 1, MAY 2017
ADDENDUM 2, MARCH 2018

Day 1

CH (1,2,3,4)

Time
7: 10 PM

API 510

In-service Inspection, Rating, Repair, and Alteration

API 510
TENTH EDITION, MAY 2014
ADDENDUM 1, MAY 2017
ADDENDUM 2, MARCH 2018

Day 2

CH (5)

Time
7: 10 PM

API 510

In-service Inspection, Rating, Repair, and Alteration

API 510
TENTH EDITION, MAY 2014
ADDENDUM 1, MAY 2017
ADDENDUM 2, MARCH 2018

Day 3

CH (6,7)

Time
7: 10 PM

API 510

In-service Inspection, Rating, Repair, and Alteration

API 510
TENTH EDITION, MAY 2014
ADDENDUM 1, MAY 2017
ADDENDUM 2, MARCH 2018

Day 4

CH (8,9)

Available Color :
7: 10 PM

API 510

Equipment in the Refining Industry

API RECOMMENDED PRACTICE 571
SECOND EDITION, APRIL 2011

Day 5

API 571, API 576 API 572

Time
7: 10 PM

APIs

BODY OF KNOWLEDGE

5

API 570



ASME

API



10 – 15 %
(15 – 20) Q

(4 – 6) Q

(4 – 6) Q

(2 – 4) Q

7 – 8 %
10 – 12 Q

4 % Max.
6 Q

70 – 75 %
CH 5 (20 – 25) Q
CH 8 (20 – 25) Q
CH 6,7 (20 – 25) Q
CH 1,3,4 (15) Q

BOK

Effective Sheet

Total No. of Q. 170

- 25 Q (Pre-Test)
- 4 Q (Matching)

110 Closed

2 hours + 45 minutes

60 Open

3 hours + 45 minutes

Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration

API 510
TENTH EDITION, MAY 2014

ADDENDUM 1, MAY 2017
ADDENDUM 2, MARCH 2018





API 510 Sections

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Inspection Data Evaluation, Analysis, and Recording

Repairs, Alterations, and Rerating of Pressure Vessels and PRD



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Alternative Rules for E&P Pressure Vessels

ANNEX A,B,C,D,E



SCOPE





CH 1

SCOPE

CONTENT



1.1

General Application

- Coverage
- Intent
- Imitations

1.2

Specific Applications

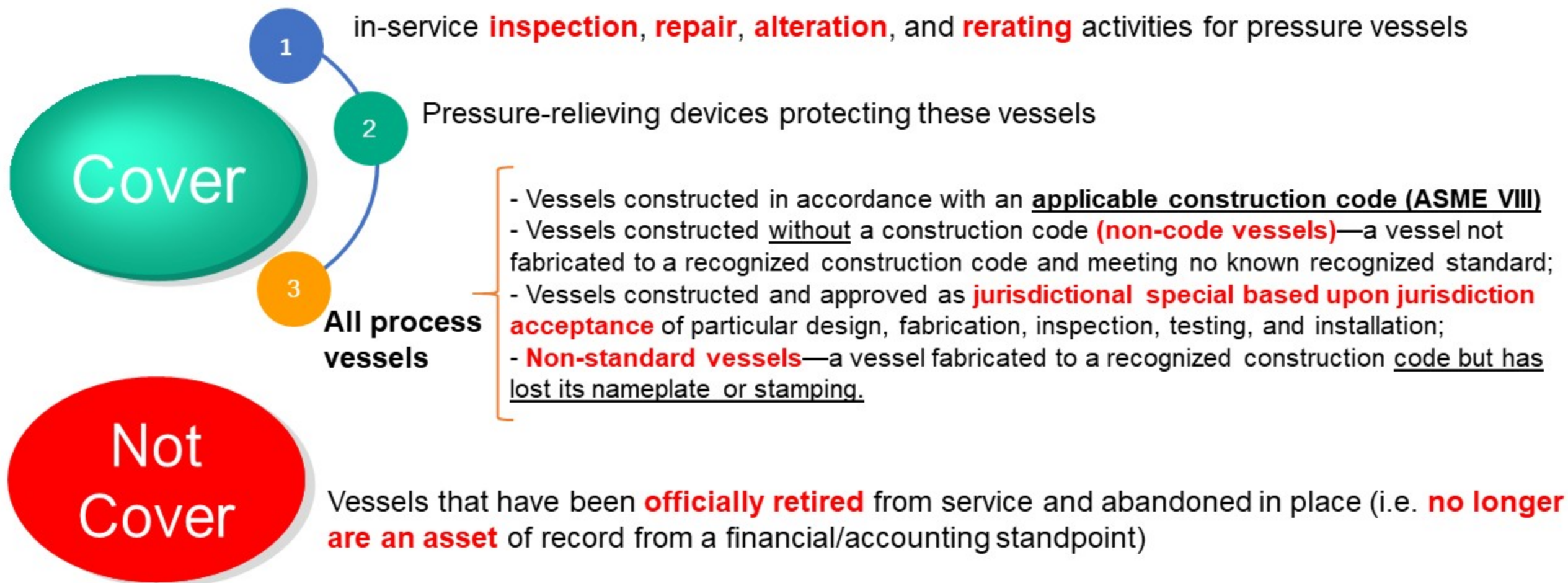
- Exploration and Production (E&P) Vessels
- Excluded and Optional Services

1.3

Recognized Technical Concepts FFS & RBI

1.1 GENERAL APPLICATION

1.1.1 Coverage



CODE EXEMPTIONS

Annex A (Low Risk) or very high Risk



The following classes of containers and pressure vessels are excluded from the specific requirements of this inspection code, unless specified by the owner/user.

Pressure vessels that do **not exceed the following volumes and pressures:**

- 1) 5 ft³ (**0.141 m³**) in volume and 250 lbf/in.² (1723.1 KPa = **17.2 bar**) design pressure,
- 2) 3 ft³ (**0.08 m³**) in volume and 350 lbf/in.² (2410 Kpa = **24 bar**) design pressure,
- 3) 1 1/2 ft³ (**0.042 m³**) in volume and 600 lbf/in.² (4136.9 Kpa = **41.3 bar**) design pressure.

All classes of containers listed for **exemption from the scope of ASME Code, Section VIII, Division 1** are as follows. (10 Points)

Pressure vessels on movable structures covered **by jurisdictional regulations:**





Volume tanks for trucks, ships, and barges



Pressure vessels installed in oceangoing ships, barges, and floating craft.



Air receivers associated with braking systems of mobile equipment



Fired Process Tubular Heaters

CODE EXEMPTIONS



All classes of containers listed for exemption from the scope of ASME VIII, Div. 1 are as follows.

Fired process tubular heaters.

Pressure containers that are **integral parts or components of rotating mechanical devices** where the primary design considerations are derived from the functional requirements of the device.

Any structure whose primary **function is transporting fluids** from one location to another within a system of which it is an integral part (i.e. piping systems).

Piping components and the pressure-containing parts of these components are generally recognized as piping components or accessories.

A vessel for **containing water** under pressure & **vessels containing air**, when the following **limitations are not exceeded:**

- i) a design pressure of 300 lbf/in.² (2067.7 KPa = **20 bar**),
- ii) a design temperature of 210 °F (**99 °C**).

CODE EXEMPTIONS



All classes of containers listed for exemption from the scope of ASME VIII, Div. 1 are as follows.

A hot water supply storage tank when the following limitations are **not exceeded**:

- i) a heat input of 200,000 Btu/hr (211×10^8 J/hr),
- ii) a water temperature of 210 °F (99 °C),
- iii) a nominal water-containing capacity of 120 gal (455 L).

BTU (British Thermal Units) is a unit of measurement that measures the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit

Vessels with an internal or external design pressure that **cannot exceed 15 psig (103.4 KPa)**.

Vessels with an **inside diameter, width, height**, or cross-section diagonal not exceeding **6 in. (15 cm)** but with **no limitation on their length or pressure**.

Pressure vessels for human occupancy.



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ASME PVHO-1-2019
(Revision of ASME PVHO-1-2016)

**Safety Standard for
Pressure Vessels for
Human Occupancy**

AN AMERICAN NATIONAL STANDARD



COVERAGE



- If for some reason an item that has been placed in service cannot follow the construction code because of its new construction orientation, the requirements for design, material, fabrication, and inspection shall conform to API 510 rather than to the construction code.
- If in-service vessels are covered by requirements in the construction code and API 510 or if there is a **conflict between the two codes, the requirements of API 510 shall take precedence.**

1.1 GENERAL APPLICATION

1.1.2 Intent



Specify the in-service inspection and condition-monitoring program and provide reasonably accurate and timely assessments

(1) The on-going integrity of Pressure Vessel and PRVs
& (2) Continued Safe Operation

Repair guidance

Owner/users shall respond to any inspection results that require corrective actions

1.1 GENERAL APPLICATION

1.1.3 Limitation



Adoption and use of this inspection code does not permit its use in conflict with any prevailing regulatory requirements.

However, if the requirements of this code are more stringent than the requirements of the regulation, then the requirements of this code shall govern.

1.2 SPECIFIC APPLICATIONS



Exploration and Production (E&P) Vessels



UNITED STATES COAST GUARD
U.S. DEPARTMENT OF HOMELAND SECURITY



U.S. Department of Transportation

BOEM
BUREAU OF OCEAN ENERGY MANAGEMENT

All pressure vessels used for E&P service [e.g. drilling, producing, gathering, transporting] may be inspected **under the alternative rules set forth in Section 9.**

Except for Section 6 (Interval/Frequency and Extent of Inspection)

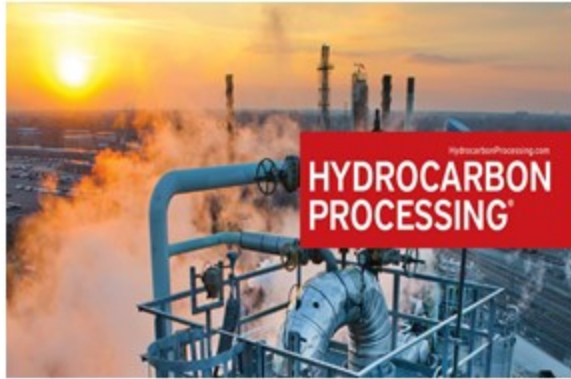
, all of the sections in this inspection code are applicable to pressure vessels in E&P service.

The alternative rules in Section 9 are intended for services that may be regulated under safety, spill, emission, or transportation controls **by:**

- **The U.S. Coast Guard;**
- The Office of Hazardous Materials Transportation of the U.S. Department of Transportation (DOT)
- Other units of DOT; the Bureau of Ocean Energy Management, Regulation, and Enforcement, formerly the Minerals Management Service of the U.S. Department of the Interior; state and local oil and gas agencies; or any other regulatory commission.

1.2 SPECIFIC APPLICATIONS

Excluded and Optional Services



Vessels excluded from the specific requirements of this inspection code are listed in **Annex A.**

Each owner/ user **has the option of including any excluded pressure vessel** in their inspection program as outlined in this code.

Some vessels exempted in accordance with the criteria in ASME Code, Section VIII, Division 1 **should be considered** for inclusion **based on risk** (probability and consequence of failure) as determined by the owner/user.

1.3 FFS & RBI

Recognized Technical Concepts



API 579-
1/ASME
FFS-1

Quantitative engineering evaluations that are performed to demonstrate the structural integrity of an in-service component that may contain a flaw or damage by using methodologies specifically prepared for pressurized equipment which containing flaws that have been identified by inspection (can continue to operate safely for some period of time..?)

RBI
API 580

- **Planning tools** for establishing **inspection intervals** based on RBI study by using risk analysis (both POF and COF) to develop an **effective inspection plan**.
- API 581 provides a method of conducting RBI in accordance with the principles in API 580.



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NORMATIVE REFERENCES



NORMATIVE REFERENCES

APIs editions



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

API Recommended Practice 572, *Inspection of Pressure Vessels*

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 Alloy 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 Methodology*

API Recommended Practice 582, *Welding Guidelines for the Chemical, Oil, and Gas Industries*

API Recommended Practice 583, *Corrosion Under Insulation and Fireproofing*

API Recommended Practice 584, *Integrity Operating Windows*

API Recommended Practice 585, *Pressure Equipment Integrity Incident Investigations*

API Recommended Practice 939-C, *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*

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

API Recommended Practice 2201, *Safe Hot Tapping Practices for the Petroleum and Petrochemical Industries*

NORMATIVE REFERENCES

ASME & other editions



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

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

ASME Boiler and Pressure Vessel Code, Section II: Materials

ASME Boiler and Pressure Vessel Code, Section V: Nondestructive Examination

ASME Boiler and Pressure Vessel Code, Section VIII: Rules for Construction of Pressure Vessels; Division 1

ASME Boiler and Pressure Vessel Code, Section VIII: Rules for Construction of Pressure Vessels; Division 2: Alternative Rules

ASME Boiler and Pressure Vessel Code, Section IX: Welding and Brazing Qualifications

ASNT CP-189 ², *Standard for Qualification and Certification of Nondestructive Testing Personnel*

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

NACE MR0103 ³, *Materials Resistant to Sulfide Stress Cracking in Corrosive Petroleum Refining Environments*

NACE SP0170, *Protection of Austenitic Stainless Steels and Other Austenitic Alloys from Polythionic Acid Stress Corrosion Cracking During Shutdown of Refinery Equipment*

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

National Board NB-23 ⁴, *National Board Inspection Code*

OSHA 29 CFR Part 1910 ⁵, *Occupational Safety and Health Standards*

WRC Bulletin 412 ⁶, *Challenges and Solutions in Repair Welding for Power and Processing Plants*



3



TERMS, DEFINITIONS, ACRONYMS, AND ABBREVIATIONS





CH 3

TERMS, DEFINITIONS, ACRONYMS, AND ABBREVIATIONS

CONTENT



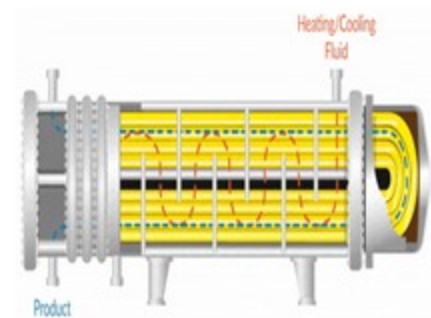
3.1

Terms and Definitions

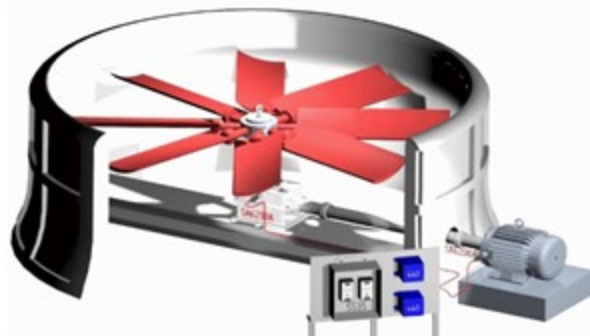
3.2

Acronyms and Abbreviations

3.1 TERMS AND DEFINITIONS



API 660, 572



API 661

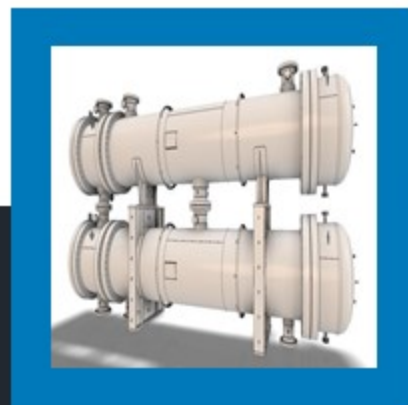
Pressure Vessel



API 573

API 572

API 510,572



Heat Exchangers



Air Coolers



Unfired Steam Generators
(boilers)



Tower & Column



Pressure Vessel

A container designed to withstand internal or external pressure. This pressure may be imposed by an external source, by the application of heat from a direct or indirect source, or by any combination thereof. **This definition includes** heat exchangers, air coolers, columns, towers, unfired steam generators (boilers), and other vapor generating vessels that use heat from the operation of a processing system or other indirect heat source.

3.1 TERMS AND DEFINITIONS

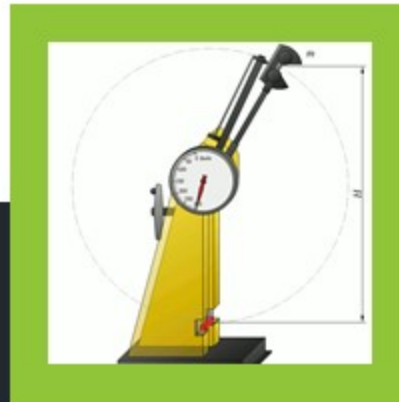
Testing



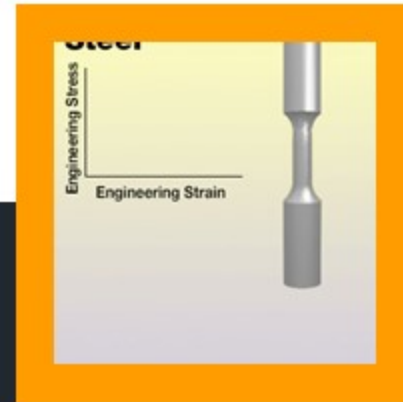
Hydrostatic Test or



Hardness Test



Notch Toughness Test



Tensile Testing

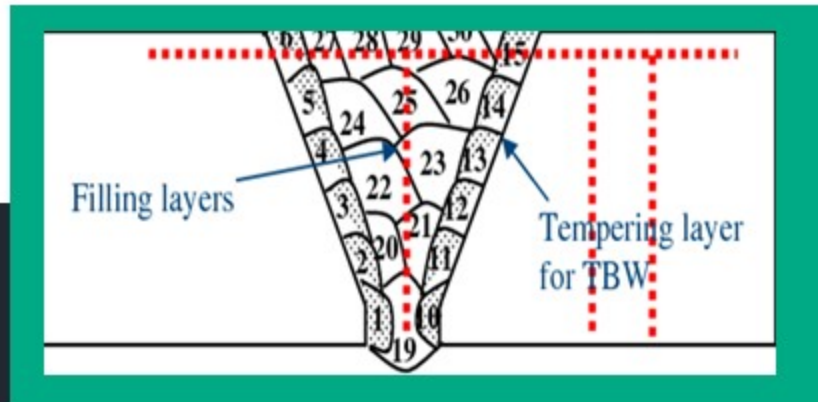


pneumatic Test

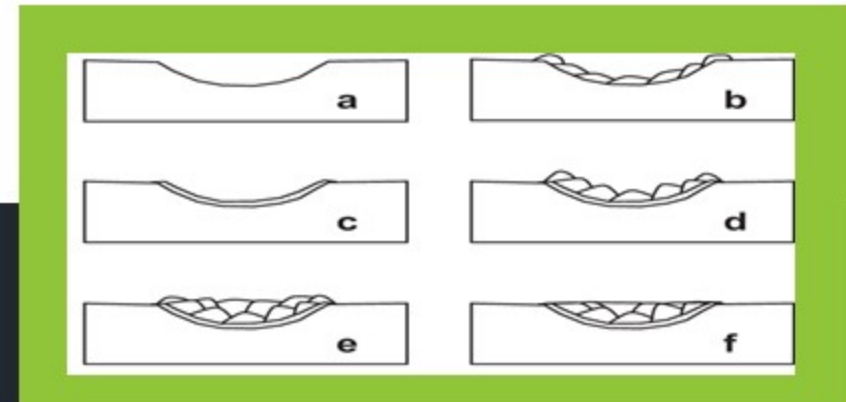
Within this document, testing generally refers to either pressure testing, whether performed hydrostatically, pneumatically, or a combination hydrostatic/pneumatic, or mechanical testing to determine such data as material hardness, strength, and notch toughness. Testing, however, does not refer to NDE using techniques such as (PT), (MT), (UT), (RT), etc.

3.1 TERMS AND DEFINITIONS

Controlled-Deposition Welding (CDW)



Temper bead



Half Temper bead

Any welding technique used to obtain **controlled grain refinement and tempering** of the underlying heat-affected zone in the base metal.

3.1 TERMS AND DEFINITIONS

Personals



Pressure Vessel Engineer

A person acceptable to the owner/user who is knowledgeable and experienced in the engineering disciplines associated with evaluating mechanical and material characteristics that affect the integrity and reliability of pressure vessels.



Authorized Pressure Vessel Inspector

An employee of an authorized inspection agency who is qualified and certified to perform inspections under this inspection code, including Annex B. Whenever the term “inspector” is used in API 510, it refers to an authorized pressure vessel inspector.



Corrosion Specialist

A person, acceptable to the owner/user, who has knowledge and experience in corrosion damage mechanisms, metallurgy, materials selection, and corrosion monitoring techniques.



Examiner

A person who assists the inspector by performing specific NDE on pressure vessel components and evaluates to the applicable acceptance criteria but does not evaluate the results of those examinations in accordance with API 510, unless specifically trained and authorized to do so by the owner/user.

TERMS AND DEFINITIONS FOR

CORROSION

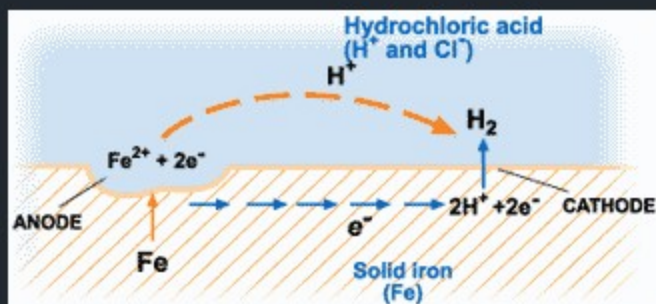


plate lining

Metal plates that are welded to the inside of the pressure vessel wall for the purpose of protecting the vessel construction material from interaction with process fluids. Normally, plates are of a more corrosion resistant or erosion resistant alloy than the vessel wall and provide additional corrosion/erosion resistance.



Pitting

Pitting can be highly localized (including a single pit) or wide spread on a metal surface.



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.

Localized Corrosion

Corrosion that is largely confined to a limited or isolated area of the metal surface of a pressure vessel.



Corrosion Allowance

Additional material thickness available to allow for metal loss during the service life of the vessel component.

CUI

Refers to all forms of CUI including stress corrosion cracking and corrosion under fireproofing.



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 vessels (e.g. corrosion, cracking, erosion, dents, and other mechanical, physical, or chemical impacts)

General Corrosion

Corrosion that is distributed more or less uniformly over the surface of the metal



Environmental Cracking

Amine SCC
Carbonate SCC
Caustic SCC

3.1 TERMS AND DEFINITIONS

Organization



Authorized Inspection Agency

- inspection organization of **the jurisdiction**
- organization of an **insurance**
- **owner or user** inspection organization for activities relating **only to his equipment**
- **independent inspection** organization employed by or **under contract to the owner/user**
- independent inspection organization **licensed or recognized by the jurisdiction**

Owner/User

The organization that **exercises control over** the operation, engineering, inspection, repair, alteration, pressure testing, and rating of the Pressure Vessel..



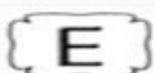
Jurisdiction

A legally constituted governmental administration that may adopt rules relating to pressure vessels.

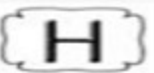
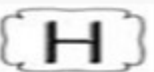
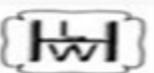
Repair Organization

1. an owner or user of pressure vessels and/or relief valves who repairs his or her own equipment in accordance with this code;
2. a repair contractor whose qualifications are acceptable to the pressure vessel owner or user;
3. an individual or organization that is authorized by the legal jurisdiction to repair pressure vessels or service relief devices.
4. the holder of a valid R-stamp issued by the National Board for repair of pressure vessels;
5. the holder of a valid VR-stamp issued by the National Board for repair and servicing of relief valves;
6. the holder of a valid ASME Certificate of Authorization that authorizes the use of an appropriate ASME Code symbol stamp;
7. the holder of another recognized code of construction certificate that authorizes the use of an appropriate construction code symbol stamp;

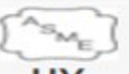
Power Boilers - Section I

		Power Boilers
		Power Boiler Assemblies
		Electric Boilers
		Miniature Boilers
		Pressure Piping
		Power Boiler Safety Valves**

Heating Boilers - Section IV

		Cast Iron Heating Boilers*
		Heating Boilers, other
		Lined Potable Water Heaters
		Heating Boilers Safety Valves**

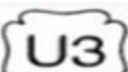
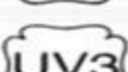
Pressure Vessels - Section VIII Division 1

		Pressure Vessels
		Miniature Vessels*
		Pressure Vessels Safety Valves**
		Pressure Vessels Rupture Discs**

Pressure Vessels - Section VIII Division 2

		Alternative Rules for Pressure Vessels
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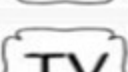
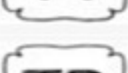
Pressure Vessels - Section VIII Division 3

		High Pressure Vessels
		Safety Valves for High Pressure Vessels**

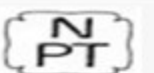
Reinforced Plastic Vessels - Section X

		Fiber-Reinforced Plastic Pressure Vessels
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Transport Tanks - Section XII

		Transport Tanks
		Transport Tanks Safety Valves
		Transport Tanks Pressure Relief Devices**

Nuclear Stamps

		Nuclear Components
		Nuclear Partialis
		Nuclear Installation and Shop Assembly
		Nuclear Safety and Safety Relief Valves
		Storage and Transport Containment of Nuclear Fuel

Nuclear Certificates of Accreditation

	NS	Nuclear Supports
	QSC	Material Organization

National Board Inspection Code

	R	Repair and Alteration
	VR	Repair of Safety Valves

3.1 TERMS AND DEFINITIONS

System and Management

Quality Assurance

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

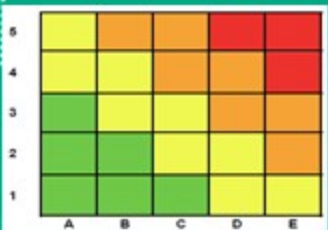


Deferral

An approved and documented postponement of an inspection, test, or examination

Risk-Based Inspection

A risk assessment and risk management process that is focused on **inspection planning for equipment** for loss of containment in processing facilities, which considers both the probability of failure and consequence of failure due to materials of construction deterioration.



integrity operating window

Established limits for process variables (parameters) that can affect the integrity of the equipment if the process operation deviates from the established limits for a predetermined amount of time

Management of Change

A documented management system for review and approval of changes (both physical and process) to pressure vessel prior to implementation of the change.



Quality Control (QC)

Those **physical activities** that are conducted to check conformance with specifications in accordance with the QA plan.

3.1 TERMS AND DEFINITIONS

Change

Repair

The work necessary **to restore vessel 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 work shall be considered an alteration and **the requirements for re-rating also shall be satisfied**.

Any welding, cutting, or grinding operation on pressure-containing component **not specifically considered an alteration is considered a repair**.

Temporary Repairs

Repairs made to pressure vessels to restore **sufficient integrity** to continue safe operation until permanent repairs are conducted

Rerating

A change in either the design temperature rating, the MDMT or the MAWP rating of a vessel. The design temperature and MAWP of a vessel may be increased or decreased because of a rerating. **Derating** below original design conditions is a permissible way to provide for additional corrosion allowance.

Alteration

A physical change in any component that has design implications that affect the pressure-containing capability of a pressure vessel beyond the scope described in existing data reports. The following should not be considered alterations:

- any comparable or duplicate replacement,
- addition of any reinforced nozzle less than or equal to the size of existing reinforced nozzles,
- addition of nozzles not requiring reinforcement.

Major Repairs

Any work not considered an alteration that removes and replaces a major part of the pressure boundary other than a nozzle (e.g. replacing part of the shell or replacing a vessel head).

If any of the restorative work results in a change to the design temperature, minimum allowable temperature (MAT), or maximum allowable working pressure (MAWP), the work shall be considered an alteration and the requirements for rerating shall be satisfied.

T (Design) = 200 °C

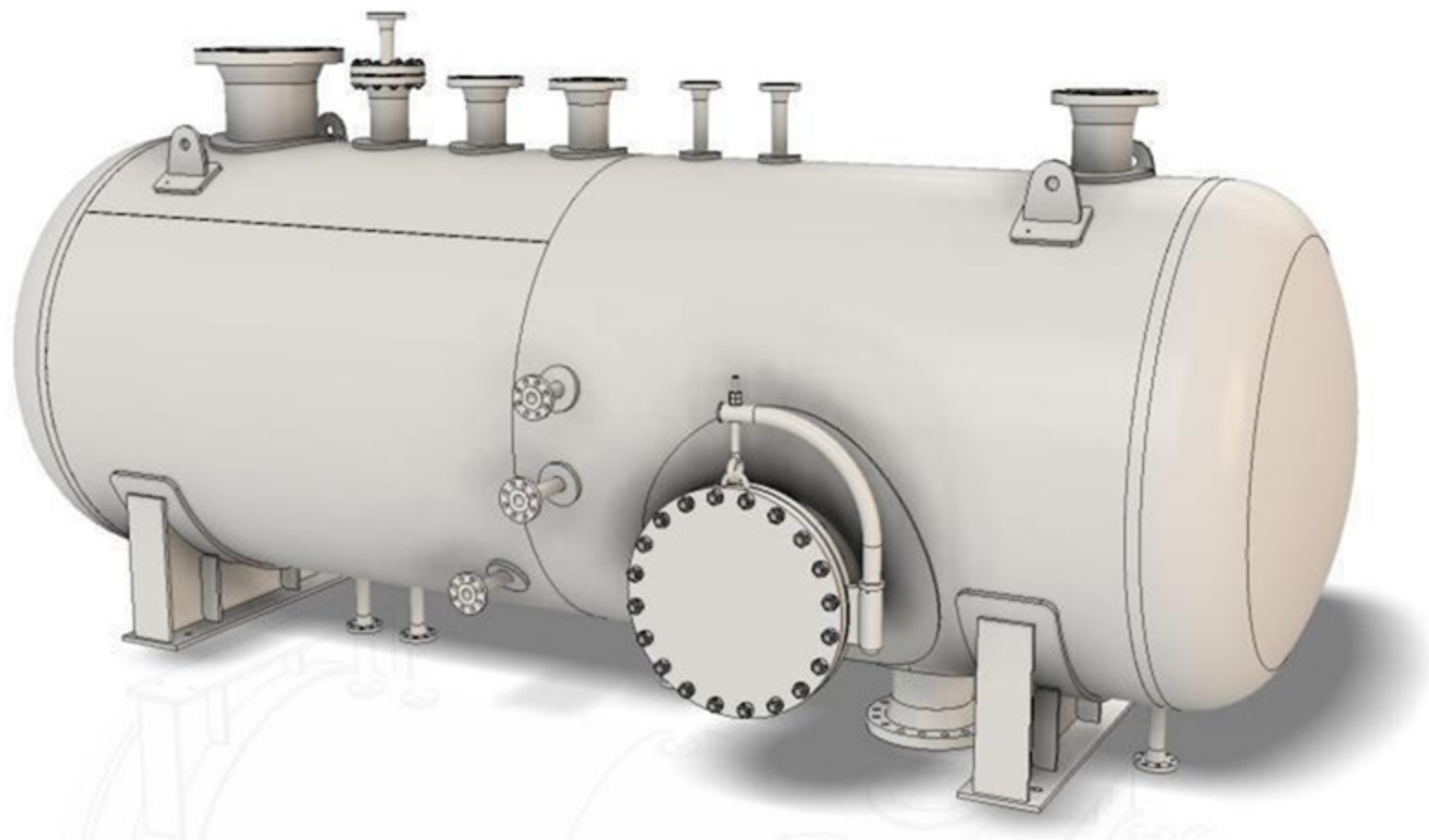
P (Design) = 20 Bar

Shell Thich. = 10 mm

T (Operate) = 120 °C

P (Operate) = 13 Bar

C.A = 3 mm



3.1 TERMS AND DEFINITIONS

General



Minimum Required Thickness

The minimum thickness **without corrosion allowance** for each element of a pressure vessel based on the appropriate design code calculations and code allowable stress that consider pressure, **mechanical, and structural loadings**.

Alternately, required thickness can be reassessed and revised using FFS analysis in accordance with API 579-1/ASME FFS-1.

Applicable Construction Code

The **code, code section, or other recognized and generally accepted engineering standard** or practice to which the vessel was built or that is accepted by the owner/user or the engineer to be most appropriate for the situation.

Non-pressure Boundary

Components of the vessel that do not contain the process pressure (e.g. trays, tray rings, distribution piping, baffles, Non-stiffening insulation support rings, clips, davits, etc.).

Pressure Boundary

That portion of the pressure vessel that contains the pressure retaining elements joined or assembled into a pressure tight, fluid-containing vessel (e.g. typically the shell, heads, and nozzles but excluding items such as supports, skirts, clips, etc. that do not retain pressure).

Scanning NDE

Examination methods designed to find the thinnest spot or all defects in a specified area of a pressure vessel such as profile RT of nozzles, scanning UT techniques, and/or other suitable (NDE) techniques that will reveal the scope and extent of localized corrosion or other deterioration.

3.1 TERMS AND DEFINITIONS

Temperature and Pressure

(1)

MINIMUM DESIGN METAL TEMPERATURE/MINIMUM ALLOWABLE TEMPERATURE

(2)

DESIGN TEMPERATURE

(3)

MAXIMUM ALLOWABLE WORKING PRESSURE

(4)

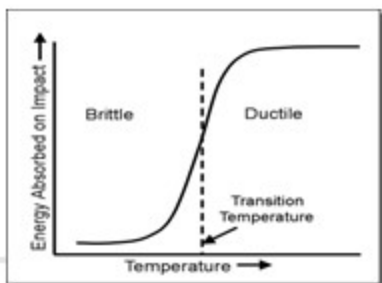
TRANSITION TEMPERATURE

The maximum gauge P permitted at the top of vessel in its operating position for a designated T. This P is based on calculations using the minimum thickness for all critical vessel elements, (exclusive of thickness designated for corrosion) and adjusted for applicable static head pressure and non-pressure loads (e.g. wind, earthquake, etc.). The MAWP may refer to either the original design or a rerated MAWP obtained through a FFS assessment.

The temperature at which a material fracture mode changes from ductile to brittle

The temperature used for the design of the pressure vessel per the applicable construction code.

The lowest permissible metal temperature for a given material at a specified thickness based on its resistance to brittle fracture



3.1 TERMS AND DEFINITIONS

Inspection



Inspection

The external, internal, or on-stream evaluation (or any combination of the three) of the condition of a vessel conducted by the authorized inspector or his/her designee in accordance with this code.

In-service Inspection

All inspection activities associated with a pressure vessel once it has been placed in service but before it is permanently retired from service.

Internal Inspection

An inspection performed from the inside of a pressure vessel using visual and/or NDE techniques.

External Inspection

A visual inspection performed from the outside of a pressure vessel to find conditions that could impact the vessel's ability to maintain pressure integrity or conditions that compromise the integrity of the supporting structures (e.g. ladders, platforms, supports). The external inspection may be done either while the vessel is operating or while the vessel is out-of-service and can be conducted at the same time as an on-stream inspection.

On-stream Inspection

An inspection performed from the outside of a pressure vessel while it is on-stream using NDE procedures to establish the suitability of the pressure boundary for continued operation.

3.1 TERMS AND DEFINITIONS

Inspection



Overdue Inspection

Inspections for in-service vessels that are still in operation that have not been performed by their due dates documented in the inspection plan, which have not been deferred by a documented deferral process

inspection plan

A strategy defining how and when a pressure vessel or pressure-relieving device will be inspected, repaired, and/or maintained

Hold Point

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

Due Date

The date established by the owner-user and in accordance with this code, whereby an inspection, test, examination, or inspection recommendation or is to be completed. The date may be established by rule-based inspection methodologies (e.g. fixed intervals, retirement half-life interval), RBI, fitness-for-service analysis results, owner-user inspection agency practices/procedures/guidelines .. etc

Overdue Inspection Recommendations

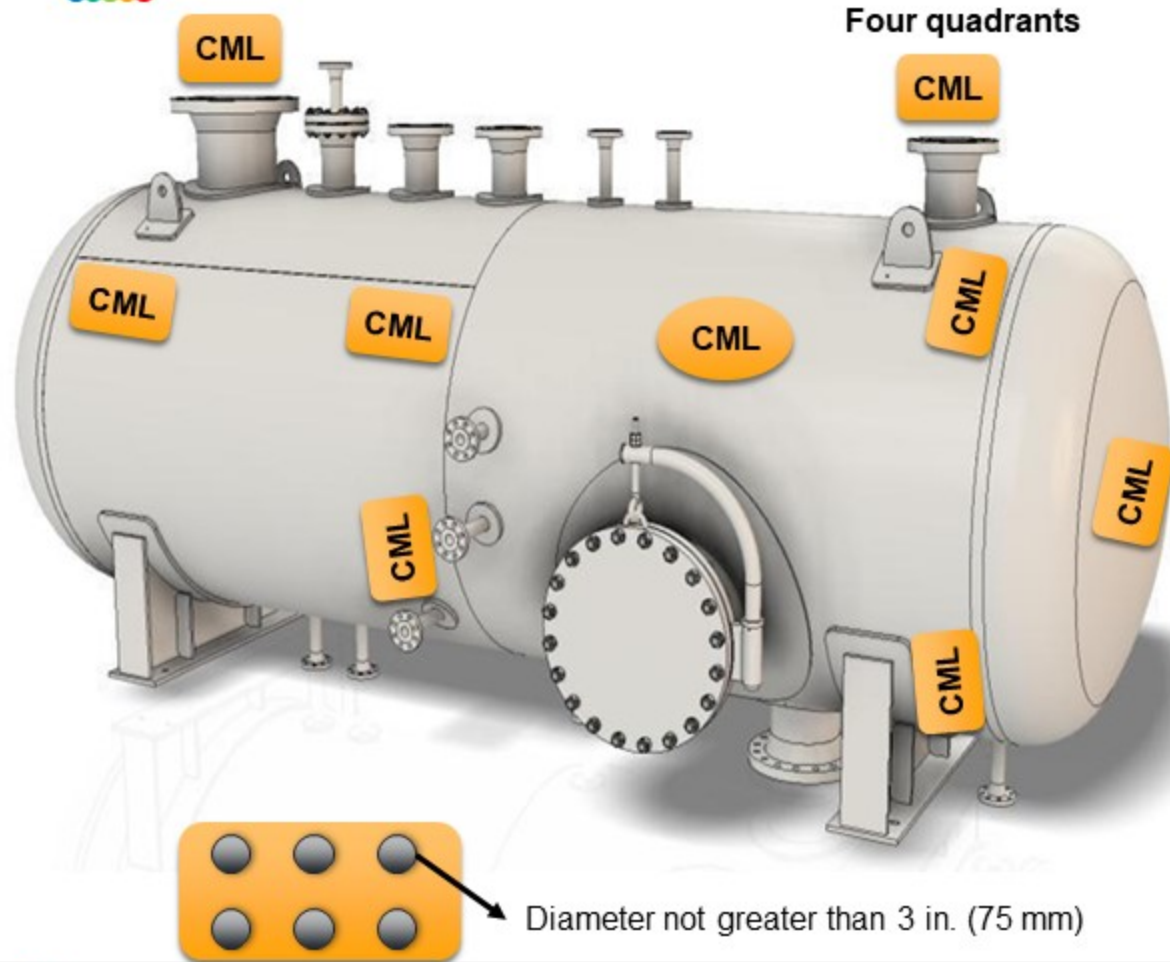
Recommendations for repair or other mechanical integrity purposes for vessels that are still in operation that have not been completed by their documented due dates, which have not been deferred by a documented deferral process.

3.1 TERMS AND DEFINITIONS

Inspection



Four quadrants



Diameter not greater than 3 in. (75 mm)

Condition Monitoring Locations (CMLs)

45

- **Designated areas** on vessels where periodic external examinations are conducted in order to directly assess the condition of the vessel.
- CMLs may contain one or more examination points and utilize multiple inspection techniques that are based on the predicted damage mechanism to give the highest probability of detection.
- CMLs can be a single small area on a pressure vessel (e.g. a 2-in. diameter spot or plane through a section of a nozzle where recording points exist in all four quadrants of the plane).

Examination Point (Recording Point, Measurement Point)

- An area within a CML defined by a circle having a diameter not greater than 3 in. (75 mm) for pressure vessels.
- CMLs may contain multiple examination points, for example, a vessel nozzle may be a CML and have multiple examination points (e.g. an examination point in all four quadrants of the CML on the nozzle).

3.1 TERMS AND DEFINITIONS

Findings



A response or evidence resulting from the application of a NDE that may be nonrelevant or could be flaws or defects upon further analysis.

Flaws or other discontinuities noted during inspection or examination that **may or may** not exceed the applicable acceptance criteria.

An imperfection whose type or size exceeds the applicable acceptance criteria and is therefore rejectable.

3.1 TERMS AND DEFINITIONS

Service



In Service

Designates a pressure vessel that has been placed in operation as opposed to new construction prior to being placed in service or retired vessels. A pressure vessel not in operation because of a process outage is still considered an in-service pressure vessel.

- Does not include pressure vessels that are still under construction or in transport to the site prior to being placed in service or pressure vessels that have been retired from service. It does include **pressure vessels that are temporarily out of service but still in place** in an operating site. A stage in the service life of a vessel between installation and being removed from service.

On-Stream

A condition where a pressure vessel has not been prepared for an internal inspection

Cyclic Service

Refers to service conditions that may produce **fatigue damage** due to cyclic loading from pressure, thermal, and mechanical loads that are not induced by pressure. Other cyclic loads associated with vibration may arise from such sources as impact, turbulent flow vortices, resonance in compressors, and wind, or any combination thereof



3.1 TERMS AND DEFINITIONS

Service



Same or Similar Service

A designation where **two or more pressure vessels** are installed in parallel, comparable, or identical service and their process and environmental conditions have been consistent over a period of years based on the inspection criteria being assessed such that the damage mechanisms and rates of damage are comparable.

- EXAMPLE 1 Parallel service: A process or part of a process connected in parallel having **comparable configuration** with analogous and readily recognized similarities.
- EXAMPLE 2 Identical service: A designation where there is agreement that the configuration, process and operating regime, metallurgy, and environmental conditions are **all the same**, such that expected degradation characteristics are expected to be the same.



3.1 TERMS AND DEFINITIONS

General



Temper Embrittlement

The reduction in toughness due to a **metallurgical change** that can occur in some low alloy steels (e.g. 2 1/4Cr-1Mo) as a result of long-term exposure in the temperature range of about 650 °F to 1100 °F (345 °C to 595 °C).

Tightness Test

A pressure test that is conducted on pressure vessels after maintenance or repair activities to indicate that the equipment is **leak free** and is conducted at a test pressure **determined by the owner/user that is not higher than the MAWP.**

Manufacturer's Data Report

A document that contains **data and information from the manufacturer** of the pressure vessel that certifies that the materials of construction contained in the vessel meet certain material property requirements, tolerances, etc. and are in accordance with specified standards.

Strip Lining

Strips of metal plates that are welded to the inside of the vessel wall for the purpose of protecting the vessel construction material from interaction with process fluids. Normally the strips are of a more corrosion resistant or erosion resistant alloy than the vessel wall and provide additional corrosion/erosion resistance. This is similar to plate lining except narrower strips are used instead of larger plates.

PWHT

A work process which consists of heating an entire weldment or section of fabricated piping to an elevated temperature after completion of welding in order to **relieve the detrimental effects of welding heat, such as reducing residual stresses, reducing hardness, and/or slightly modifying properties**

Procedures

A document that specifies or describes how an activity is to be performed. It may include methods to be employed, equipment or materials to be used, qualifications of personnel involved, and sequence of work.



4



OWNER/USER INSPECTION ORGANIZATION





CH 4

OWNER/USER INSPECTION ORGANIZATION

CONTENT



4.1

4.1 Owner/User Organization Responsibilities

Owner/User Systems and Procedures
Management of Change (MOC)
Integrity Operating Windows (IOWs)

4.2,3,
4,5,6

Engineer
Repair Organization
Inspector
Examiners
Other Personnel

4.7

Inspection Organization
Audits



4.1 GENERAL

An owner/user of Pressure Vessel

- **shall** exercise control of the vessel and pressure relief device inspection program, inspection frequencies, and maintenance
- **responsible** for the function of an authorized inspection agency in accordance with the provisions of API 510.
- **The owner/user inspection organization also shall control activities relating to the rating, repair, and alteration of its pressure vessels and relief devices.**

OWNER/USER INSPECTION ORGANIZATION

Owner



Systems and Procedures



MOC



Integrity Operating
Windows (IOWs)

OWNER/USER
ORGANIZATION

RESPONSIBILITIES



Systems and Procedures

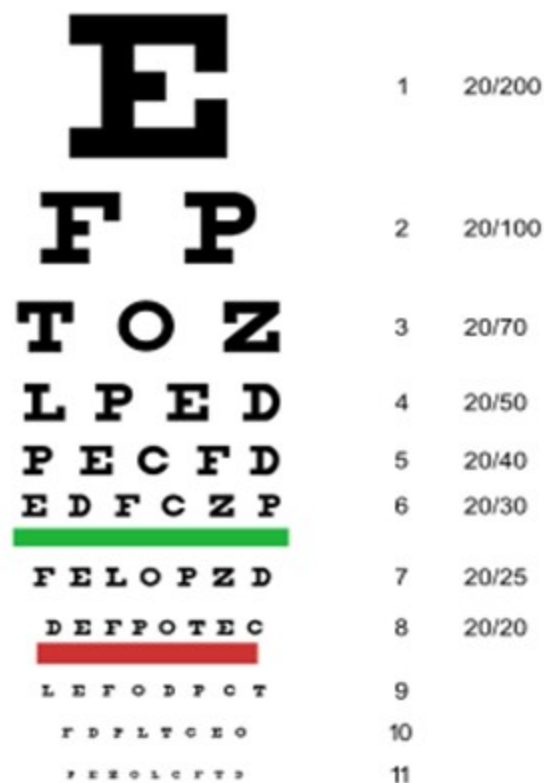
An owner/user organization is responsible for developing, documenting, implementing, executing, and assessing pressure vessel/pressure-relieving device and inspection procedures that will meet the requirements of this inspection Code. **These systems and procedures** will be contained in a **QA inspection/repair management system and shall include:**

- a) Organization and reporting structure for inspection personnel.
- b) Documenting of inspection and QA procedures.
- c) Documenting and reporting inspection and test results.
- d) Developing and documenting inspection plans.
- e) Developing and documenting risk-based assessments applied to inspection activities.
- f) Establishing and documenting the appropriate inspection intervals.
- g) Corrective action for inspection and test results.
- h) Internal auditing for compliance with the QA inspection manual.
- i) Review and approval of drawings, design calculations, engineering assessments, and specifications for repairs, alterations, and reratings.
- j) Ensuring that all jurisdictional requirements for pressure vessel inspection, repairs, alterations, and rerating are continuously met.
- k) Reporting to the inspector any process changes or other conditions that could affect pressure vessel 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 all repairs and alterations are performed in accordance with this inspection code and applicable specifications.
- o) Controls necessary so that only qualified NDE personnel and procedures are utilized.
- p) Controls necessary so that only materials conforming to the applicable construction code are utilized for repairs and alterations.
- q) Controls necessary so that all inspection measurement, NDE, and testing equipment are properly maintained and calibrated.
- r) Controls necessary so that the work of contract inspection or repair organizations meets the same inspection requirements as the owner/user organization.
- s) Internal auditing requirements for the QC system for pressure-relieving devices.
- t) Controls necessary to ensure that inspectors have the visual acuity necessary to perform their assigned inspection tasks.

Management shall have an appropriate requirement and work process to ensure that inspectors have an annual vision test to ensure that they are capable of reading standard J-1 letters on standard Jaeger test type charts for near vision.

The Jaeger chart

The Jaeger chart is an eye chart used in testing near vision acuity. It is a card on which paragraphs of text are printed, with the text sizes increasing from 0.37 mm to 2.5 mm. This card is to be held by a patient at a fixed distance from the eye dependent on the J size being read. The smallest print that the patient can read determines their visual acuity.



OWNER/USER INSPECTION ORGANIZATION

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MOC



THE OWNER/ USER

Responsible for implementing an **effective** MOC process that will review and control changes to the process and to the hardware

With effective MOC, Inspection group will able to:

- Solve issues concerning the suitability of the pressure equipment design and current condition for the proposed changes
- anticipate changes in corrosion or other types of damage
- Update the inspection plan and records to account for those changes

MOC members

- Inspection, Materials/corrosion experience and mechanical engineering experience and expertise
- **The inspection group shall be involved in** the approval process for changes that may pressure vessel integrity

Change Effectiveness

Changes to the hardware and the process shall be included in the MOC process to ensure its effectiveness.

OWNER/USER INSPECTION ORGANIZATION

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IOWs (API 584)



Owner/
User

should implement and maintain an effective program for creating, establishing, and monitoring IOW.

Why..?

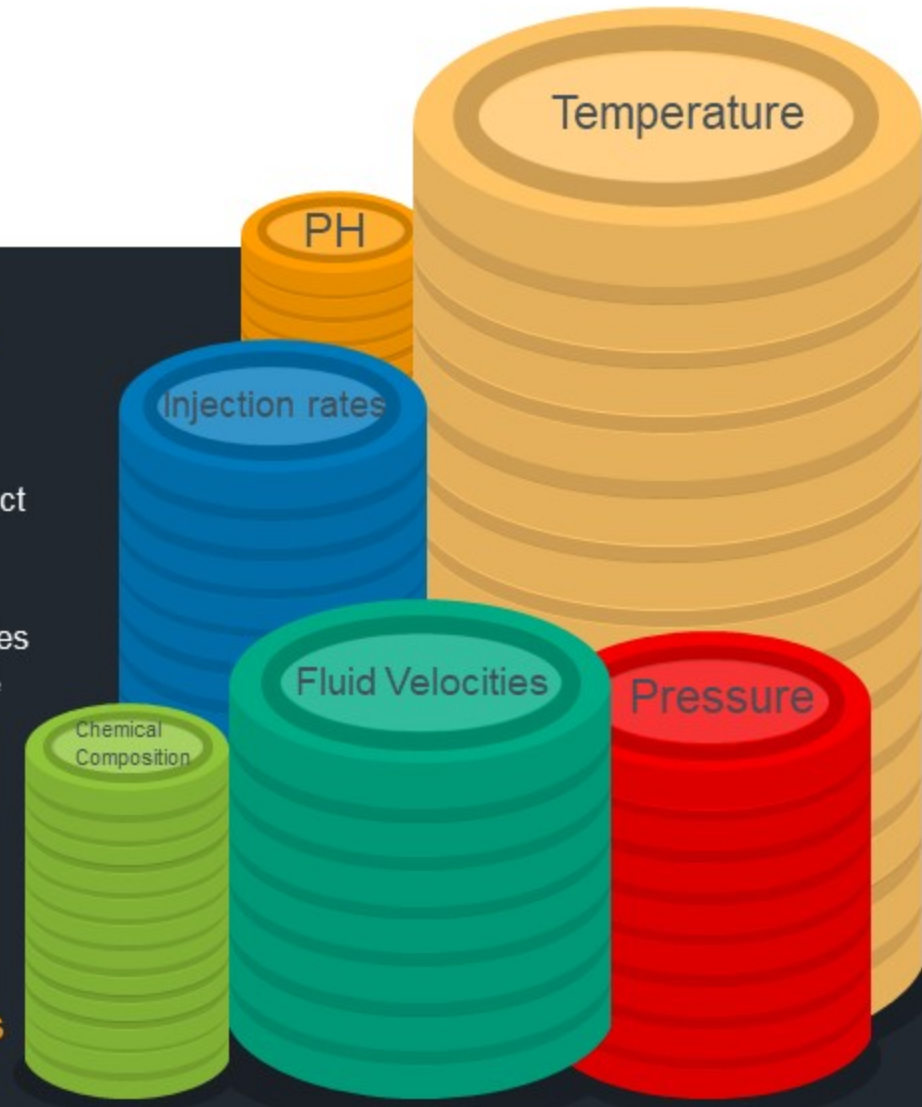
1. to avoid process parameter exceedances that may have an un-predict impact on pressure equipment integrity
2. Without an effective IOW, there often is no warning of changing operating conditions that could affect the damage mechanisms and rates and subsequently impact the integrity of equipment, or validation of the current inspection plan
3. inspection/engineering can modify or create new inspection plans depending upon the seriousness of the exceedance.

Limits

IOWs for key process parameters may have both upper and lower limits established, as needed

Attention

Particular attention to monitoring integrity operating windows should also be provided **during start-ups, shutdowns and significant process upsets**



Process Parameters (both physical and chemical)

OWNER/USER INSPECTION ORGANIZATION

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Inspector



- All examination results shall be evaluated and accepted by inspector who will then make appropriate recommendations repairs, replacements, or fitness for continued service

Results

Owner

shall be responsible to the owner/user to assure that the inspection, NDE, repairs, and pressure testing activities meet API 510 code requirements

shall be directly involved in the inspection activities, especially visual inspections, which in most cases will require field activities to ensure that procedures and inspection plans are followed

Involved in

Others

may be assisted in **performing inspections** by other properly trained and qualified individuals, who may or may not be inspectors (e.g. examiners and operating personnel).

Annex B

RP



Inspectors shall be certified in accordance with the provisions of Annex B.

The inspector can be an employee of the owner/user or be a contractor acceptable to the owner/user.

Inspector Certification

B.1 Examination

A written examination to certify inspectors within the scope of API 510 shall be based on the current API 510 *Inspector Certification Examination Body of Knowledge* as published by API.

To become an authorized API pressure vessel inspector, candidates must pass the examination.

B.2 Certification

To qualify for the certification examination, the applicant's 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 510;~~
- 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 pressure vessels, of which one year must be in supervision of inspection activities or performance of inspection activities as described in API 510;~~
- c) ~~a high school diploma or equivalent, plus three years of experience in the design, construction, repair, inspection, or operation of pressure vessels, of which one year must be in supervision of inspection activities or performance of inspection activities as described in API 510;~~
- d) ~~a minimum of five years of experience in the design, construction, repair, inspection, or operation of pressure vessels, of which one year must be in supervision of inspection activities or performance of inspection activities as describe in API 510.~~

B.3 Recertification

B.3.1 Recertification is required three years from the date of issuance of the API 510 authorized pressure vessel inspector certificate. Recertification by written examination will be required for inspectors who have not been actively engaged as inspectors within the most recent three-year certification period. Exams will be in accordance with all provisions contained in API 510.

B.3.2 "Actively engaged as an inspector" shall be defined by one of the following provisions:

- a) a minimum of 20 % of time spent performing inspection activities or supervision inspection activities or engineering support of inspection activities as described in the API 510 inspection code over the most recent three-year certification period;
- b) performance of inspection activities or supervision of inspection activities or engineering support of inspection activities on 75 pressure vessels as described in API 510 over the most recent three-year certification period.

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

B.3.3 Once every other recertification period (every six years), inspectors actively engaged as an inspector shall demonstrate knowledge of revisions to API 510 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 pressure vessel inspector within the most recent three-year certification period shall recertify as required in B.3.1.

OWNER/USER INSPECTION ORGANIZATION

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Examiner



1 Shall perform the NDE in accordance with job requirements, NDE procedures, and owner/user specifications.

2 The examiner does not need API 510 inspector certification and does not need to be an employee of the owner/user.

3 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

- ASNT SNT-TC-1A
- ASNT CP-189
- AWS QC1
- CGSB (Canadian General Standards Board)

3

2

1

4

5



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.

Inspectors conducting their own examinations with NDE techniques shall also be appropriately qualified in accordance with owner/user requirements.

OWNER/USER INSPECTION ORGANIZATION

Others



Other Personnel

Operating, maintenance, engineering (process and mechanical), or other personnel who have special knowledge or expertise related to particular pressure vessels shall be responsible for timely notification to the inspector or engineer of potential issues that may affect vessel integrity such as the following:

- a) any action that requires MOC;
- b) operations outside defined IOW;
- c) changes in source of feedstock and other process fluids that could increase process related corrosion rates or introduce new damage mechanisms;
- d) vessel failures, repair actions conducted, and failure analysis reports;
- e) cleaning and decontamination methods used or other maintenance procedures that could affect pressure vessel integrity;
- f) reports of experiences that may come to their attention that other plants have experienced with similar or same service pressure vessel failures;
- g) any unusual conditions that may develop (e.g. noises, leaks, vibration, movements, insulation damage, external vessel deterioration, support structure deterioration, significant bolting corrosion, etc.);
- h) any engineering evaluation, including FFS assessments, that might require current or future actions to maintain mechanical integrity until next inspection.



Piping Engineer

The pressure vessel engineer is responsible to the owner/user for activities involving design, engineering review, analysis, or evaluation of pressure vessels and pressure-relieving devices as specified in this inspection code.

Repair Organization

All repairs and alterations shall be performed by a qualified repair organization. The repair organization is responsible to the owner/user and shall provide the materials, equipment, QC, and workmanship that is necessary to maintain and repair the vessel or pressure-relieving device in accordance with the requirements of this inspection code. See definition of a repair organization in 3.1.63.

OWNER/USER INSPECTION ORGANIZATION

Inspection Organization Audits



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Owner

- Should be **audited periodically to determine** if they are meeting the requirements of an authorized inspection agency as defined in this inspection Code.
- **should receive a report** of the audit team's scope and findings.
- When nonconformances are found, the owner/user authorized inspection agency shall take the necessary corrective actions

Audit Team

- consist of people **experienced** and competent in the application of this Code
- should typically be **from** another owner/user plant site, company central office or from a third party organization



- The requirements and principles of this inspection Code are being met;
- Inspection data analysis, evaluation, and recording are adequate;

Owner/user responsibilities are being properly discharged;

Documented inspection plans are in place for covered pressure vessel;

Intervals and extent of inspections are adequate for covered pressure vessel;

- General types of inspections and surveillance are being adequately applied;
- Repairs, re-ratings and alterations comply with this Code.

Responsible Party	API 510 Paragraph – Responsibilities
Inspector	¶4.2.4: responsible to the owner/user to assure that the inspection, NDE, and pressure testing activities meet API 510 requirements. The Inspector shall be directly involved in the inspection activities. All NDE results must be evaluated and accepted by the inspector.
	¶5.10.3: to assess preferential weld corrosion of in-service welds and joints
	¶5.3.4: shall familiarize themselves with prior history of the vessels they are responsible for, reviewing the vessel's prior inspection results, prior repairs, and current inspection plan in particular
	¶5.5.2.1: to perform internal inspection of vessels in accordance with the inspection plan
	¶5.5.3.1: to authorize and approve all on-stream inspection work performed by an examiner
	¶5.9.1: to verify that all new materials used during repairs or alterations are consistent with the specifications
	¶6.2.1.1: to inspect pressure vessels at the time of installation
	¶7.3.4: to approve of thickness measurement procedures when confirming pressure vessel thickness
	¶8.1.1: to authorize any repair or alteration work before the work is started, and designate the hold points that are required
	¶8.1.2.1: to approve all proposed methods of design, execution, materials, welding procedures, NDE, and testing before any repairs or alterations are performed, and may establish hold points to be implemented during the work execution
	¶8.1.2.2: to approve all specified repair and alteration work at designated hold points and after completion of the work in accordance with the repair plan
	¶8.1.5.2.2: to approve the NDE procedures should ultrasonic inspection be performed in place of radiography for insert plate welds
	¶8.1.5.4.3: to assure compliance with repair requirements during repairs to stainless steel weld overlay and cladding
	¶8.1.6.3: to assure that the minimum preheat temperature used in making welding repairs is measured and maintained
Inspector or Engineer	¶5.1.1.1: to develop the inspection plan for all pressure vessels
	¶5.8.5: to consider the personnel and property risks associated with pneumatic testing for cases where hydrostatic testing is impractical
	¶6.4.1: to establish the visual external inspection interval in accordance with the owner/user's quality assurance program

Responsible Party	API 510 Paragraph – Responsibilities
Inspector and Engineer	¶6.3.2: When a risk-based inspection interval for the internal or on-stream inspection exceeds the 10-year limit, the risk-based investigation assessment shall be reviewed and approved by the engineer and inspector at intervals not to exceed 10 years, or more often if warranted by process, equipment, or consequence changes.
	¶8.1.5.1.1: to evaluate, approve and document all temporary repairs that are to remain in place beyond the next available maintenance opportunity
	¶8.1.5.1.2.1: to approve all temporary repairs performed using fillet-welded patches
	¶8.1.5.1.3: to approve and document the design for all lap bend repairs
	¶8.1.5.4.1: to review and approve the repair procedure to restore removed, corroded, or missing clad or overlays areas before implementation
	¶8.1.7.3: to approve alternative NDE techniques where those specified by the code are not practical or possible
Inspector, in consultation with a Corrosion Specialist or an Engineer	¶5.7.1: to define the type of damage, the NDE technique, and the extent of examination during pressure vessel operation
Inspector, in consultation with a Corrosion Specialist	¶5.5.2.3: to determine when it is necessary to remove deposits or linings to perform adequate inspections of pressure vessels
	¶7.1.1.2: shall select the corrosion rate that best reflects the current conditions when long-term and short-term corrosion rates are being compared
Inspector or Examiner	¶5.5.3.1: shall conduct all on-stream inspection required by the inspection plan
	¶5.5.5.1: shall obtain thickness measurements to verify the thickness of vessel components
	¶5.9.1: can perform material testing using suitable methods such as optical spectrographic analyzers, or x-ray fluorescence analyzers
Inspector's Employer	¶4.2.5.3: shall maintain certification records of the examiners employed

Responsible Party	API 510 Paragraph – Responsibilities
Examiners	¶3.20: to assist the inspector by performing specific non-destructive examinations on pressure vessel components, but does not evaluate the results of those examinations unless specifically trained and authorized by the owner/user
	¶4.2.5.1: to perform the NDE in accordance with job requirements
	¶4.2.5.2: to be trained and competent in the NDE procedures used, and may be required to prove competency by holding certification in these procedures

Responsible Party	API 510 Paragraph – Responsibilities
Owner/User	¶4.1: responsible for the function of an Authorized Inspection Agency in accordance with the provisions of this inspection code
	¶4.1: to execute the inspection plan including the established schedule
	¶4.2.1: developing, documenting, implementing, executing, and assessing pressure vessel/pressure-relieving device inspection systems and inspection/repair procedures that meet the requirements of this inspection code, including: – organization and reporting structure for inspection personnel – documenting of inspection and quality assurance procedures – documenting and reporting inspection and test results – developing and documenting inspection plans – developing and documenting risk-based assessments – establishing and documenting the appropriate inspection intervals – corrective action for inspection and test results – internal auditing for compliance with the quality assurance inspection manual – review and approval of drawings, design calculations, and specifications for repairs, alterations, and reratings – ensuring that all jurisdictional requirements for pressure vessel inspection, repairs, alterations, and rerating are continuously met – reporting to the inspector any process changes or other conditions that could affect pressure vessel integrity – training requirements for inspection personnel regarding inspection tools, techniques, and technical knowledge base – controls necessary so that only qualified welders and procedures are used for all repairs and alterations – controls necessary so that all repairs and alterations are performed in accordance with this inspection code and applicable specifications – controls necessary so that only qualified NDE personnel and procedures are utilized – controls necessary so that only materials conforming to the applicable construction code are utilized for repairs and alterations – controls necessary so that all inspection measurement, NDE and testing equipment are properly maintained and calibrated – controls necessary so that the work of contract inspection or repair organizations meets the same inspection requirements as the owner/user organization – internal auditing requirements for the quality control system for pressure-relieving devices
	¶5.5.5.4: to assure that all individuals taking thickness readings are trained and qualified in accordance with the applicable procedure used during the examination.
	¶5.7.1.2: shall specify industry-qualified UT shear wave examiners when the owner/user wants the following: – detection of interior surface (ID) breaking flaws when inspecting from the external surface (OD) – where detection, characterization, and/or through-wall sizing is required of defects
	¶5.8.7.2: shall specify industry-qualified UT shear wave examiners for cases where UT is substituted for radiographic inspection

Responsible Party	API 510 Paragraph – Responsibilities
Owner/User	¶7.8.1: to maintain permanent and progressive records of their pressure vessels and pressure-relieving devices. Permanent records will be maintained throughout the service life of each equipment item; progressive records will be regularly updated to include new information pertinent to the operation, inspection, and maintenance history of the equipment.
	¶9.3.1: Each owner or user of Section 9 vessels shall have an inspection program that will assure that the vessels have sufficient integrity for the intended service. Each E&P owner or user shall have the option of employing, within the limitations of the jurisdiction in which the vessels are located, any appropriate engineering, inspection, classification, and recording systems which meet the requirements of this document.

Responsible Party	API 510 Paragraph – Responsibilities
Operating, Maintenance, and Other Personnel	¶4.2.6: responsible for promptly making the inspector or engineer aware of any unusual conditions that may develop

Responsible Party	API 510 Paragraph – Responsibilities
Engineer	¶4.2.2: responsible to the owner/user for activities involving design, engineering review, analysis, or evaluation of pressure vessels and pressure-relieving devices covered by this inspection code
	¶7.4.4.2: shall perform the analysis when alternative evaluation methods for thinning are used
	¶8.1.1: to authorize alterations to pressure vessels that comply with ASME Section VIII, Divisions 1 and 2, and for repairs to pressure vessels that comply with ASME Section VIII, Division 2
	¶8.1.2.1: to approve all proposed methods of design, execution, materials, welding procedures, NDE, and testing before any alterations are performed
	¶8.1.3: to approve all nozzle installations
	¶8.1.5.2.2: to review weld proximity to existing welds for insert plates
	¶8.1.6.3: must approve all exceptions where preheating temperatures are not in accordance with the applicable code and qualified welding procedure
	¶8.1.6.4.2.1.1: to assure that proposed alternatives to post-weld heat treatment are suitable for the application by conducting a metallurgical review
Manufacturer or Owner/User Engineer experienced in pressure vessel design, fabrication or inspection	¶8.2.1: shall perform the calculations required to justify rerating of pressure vessels
Engineer or Other Qualified Individual	¶6.6.2.1: to determine the inspection interval for all pressure relieving devices as per the User/Owner's quality assurance system
Engineer and/or Corrosion Specialist	¶5.10.3: shall assess crack-like flaws and environmental cracking of in-service welds

Responsible Party	API 510 Paragraph – Responsibilities
Corrosions Specialist	¶5.1.1.1: shall be consulted as needed to clarify potential damage mechanisms and specific locations where they may occur
	¶5.1.1.1: shall be consulted when developing the inspection plan for vessels that operate at temperatures above 750°F (400°C)
	¶5.6.3.2: should be consulted in circumstances where CML's will be substantially reduced or eliminated

Responsible Party	API 510 Paragraph – Responsibilities
Repair Organization	¶4.2.3: responsible to the owner/user to provide the materials, equipment, quality control, and workmanship that is necessary to maintain and repair the vessel or pressure-relieving device in accordance with the requirements of this inspection code
	¶6.6: repair organization experienced in valve maintenance shall test and repair pressure-relieving devices in accordance with API 576
	¶6.6.1.1: to have a fully documented quality control system
	¶6.6.1.2: to have a fully documented training program to ensure that repair personnel are qualified within the scope of the repairs
	¶8.1.6.2.1: shall use welders and welding procedures that are qualified in accordance with applicable requirements of the construction code
	¶8.1.6.2.2: shall maintain records of its qualified welding procedures and its welding performance qualifications, and these records shall be available to the inspector before welding begins



5



INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES





CH 5

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Flanged Joints

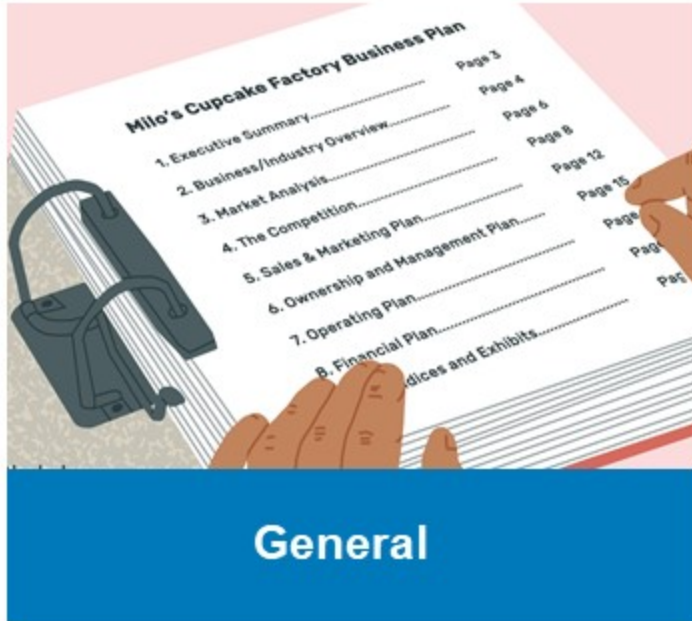
5.12

Inspection of Shell and Tube Heat Exchangers

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Inspection Plans



An inspection plan shall be established for all pressure vessels and PRVs within the scope of this code.

Development of an Inspection Plan



Who ..? (Team)

The inspection plan shall be developed by:

- **inspector and/or engineer.**
- A corrosion specialist shall be consulted when needed to designate potential damage mechanisms and specific locations where damage mechanisms may occur.

Review

Inspection plans **shall be reviewed as needed when:** variables that may impact damage mechanisms and/or deterioration rates are identified such as those contained in **inspection reports** or **MOC**

How ..? (Sources)

- (1) The inspection plan is developed **from the analysis of several sources of data including** the vessel inspection records
- (2) The inspection plan should be developed using the most **appropriate sources of information including those references listed in Section 2**
- (3) **Generic inspection** plans based on industry standards and practices may be used.

Evaluation required ..

- Equipment **shall be evaluated** based on present or potential types of damage mechanisms.
- The methods and the extent of NDE **shall be evaluated** to assure that the specified techniques can adequately identify the damage mechanism and the extent and severity of damage.

Minimum Contents of an Inspection Plan



Pressure Envelope	
UP FLARE DRUM	97-V-03
UFG No. 00-00-B-01202	
General Information	
Operator/User	Asset
Location	Date Commissioned
PID Pass Number	P & ID / Drawing Number
System	
Design and Operation	
Design Pressure (Bar)	Design Temperature (°C)
Operating Pressure (Bar)	Operating Temperature (°C)
Design Code/Standard	ASME BPVC VIII Div. 1, U-1 stamp
Shell Material	CS-15
Head(s) Material	CS
Internal Coating	Uncoated / PIP
Examination Boundary	
The pressure boundary is the first G/F Flange face of the pressure vessel (shell, heads and nozzles) and vessel bridle. Safety / protective equipment located shall be visually inspected.	
Scope of Examination	
Inspections shall be carried out in accordance with industrial documents API 575 5.2.2 and recommended Practice no. API 572. In addition, following site work instruction shall apply: 01-E-002-002, 01-E-002-005, 01-E-004-002 and 01-E-004-004.	
External Visual Inspection	
Perform general external visual inspection (EDV) on the external surface of the vessel. Inspection shall cover at minimum shell, head, nozzles and vessel bridle for soundness. Inspect vessel supporting and access structural elements. Should EDV reveals any questionable condition Close visual inspection shall be performed (CVI). Anchorage and earthing system shall be examined for soundness. Close visual inspection of pressure relief device (PRD). Ensure the piping connected to the vessel is complying with design (i.e. free to move) once such situation may introduce fatigue threat to the nozzles.	
Internal Visual Inspection	
Perform close internal visual inspection of accessible location of the pressure vessels including shell, nozzles, heads and vessel internals & vortex breaker. Prior to vessel low-up, inspector shall inspect the internal surface cleanliness and readiness to operation.	
Inspection Limitations	
Reporting Criteria	
Pressure Relief and Instrumented Protective Devices	
Preparatory Work	
Modifications and Repairs	

The inspection plan **shall contain the inspection tasks and schedule required** to monitor damage mechanisms and assure the mechanical integrity of the equipment (pressure vessel or pressure-relieving device). The plan should:

- define the type(s) of inspection needed (e.g. internal, external);
- identify the next inspection date for each inspection type;
- describe the inspection and NDE techniques;
- describe the extent and locations of inspection and NDE;
- describe the surface cleaning requirements needed for inspection and examinations;
- describe the requirements of any needed pressure test (e.g. type of test, test pressure, and duration); and
- describe any previously planned repairs.
- describing the types of damage anticipated or experienced in the equipment,
- defining the location of the damage, and
- defining any special access requirements.

Pressure Envelope				UFD No. 00-GD-B-01202																																							
LP FLARE DRUM				97-V-03																																							
General Information																																											
Operator/User		Location		Unit 97		Asset																																					
PFD Pass Number		System		Utilities		Date Commissioned																																					
						P & ID / Drawing Number																																					
						Item Description																																					
Risk Assessment and Inspection Requirement Overview																																											
Risk Assessment Overview																																											
Internal Risk	Internal Interval	Internal Due	External Risk	External Interval	External Due	Overall Risk	Overall Due																																				
Medium	48	Dec-10	Low	60	May-15	Low	Dec-10																																				
Identify the next inspection date for each inspection type;																																											
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17C		18D		14C																																							

Inspection and Anomaly History	
Inspection History	Anomaly History
GL-IRR-928 CVI 17/05/2010 Coating damaged and slightly external corrosion on shell, head, nozzles, and steel supports.	Anomaly Status: No anomaly still opened
UGDC-P-UT-08-010/10A 2012 UT thickness Reports	
GL-IRR-4058 GVI 10/17/2015 The vessel appeared to be in a satisfactory condition without any obvious signs of damage or deformation that may be considered an imminent integrity threat.	
Describe the types of damage anticipated or experienced in the piping systems	

Deterioration Mechanisms	
Internal	External
Internal localized & general Thinning is expected. Carbon dioxide (CO ₂) corrosion results when CO ₂ dissolves in water to form carbonic acid (H ₂ CO ₃). The acid may lower the pH and sufficient quantities may promote localized and general internal thinning. Carbonic acid corrosion typically manifest itself as a general thinning at pressure vessel component, often causing initial failures in areas where system metals are already thin. Areas of turbulence may suffer deep pitting and grooving.	Atmospheric corrosion is A form of corrosion that occurs from moisture associated with atmospheric conditions. Marine environments and moist polluted industrial environments with airborne contaminants are most severe. The attack will be general or localized, depending upon if the moisture is trapped. If there is no coating or if there is a coating failure, corrosion or loss in thickness can be general. Metal loss may not be visually evident, although normally a distinctive iron oxide (red rust) scale forms.

Inspection Requirements	
Internal	External
Inspect all accessible vessel internal surfaces. Nominally 2-3 % Ultrasonic Scanning Coverage (automated or manual), or profile radiography or external spot thickness	Inspect all exposed surfaces (shell, nozzles& connected piping). Visual inspection of >30% of the exposed surface area with follow-up by UT, RT or pit gauge as required. Expected Locations
Likely to be most severe where water is present (i.e.; bottom of the vessel, i.e.; 6 o'clock position), drain point or other low points where water can collect in multi-phase conditions.	Inspect the external surface of the vessels and assess the condition.
Describe Inspection Requirements	

Pressure Envelope				UFD No. 00-GD-B-01202			
LP FLARE DRUM				97-V-03			
General Information							
Operator/User		Location		Unit 97		Asset	
PFD Pass Number		System		Utilities		Date Commissioned	
						P & ID / Drawing Number	
						Item Description	
Design and Operation							
Design Pressure (Barg)	3.5	Design Temperature (°C)	150/15 C°.				
Operating Pressure (Barg)	0.3	Operating Temperature (°C)	Horizontal				
Design Code/Standard	ASME BPVC VIII Div. 1, U-1 stamp	Vessel orientation	CS				
Shell Material	CS/FS	Nozzles / Flanges Material	CS				
Head/s Material	CS/FS	Internals	No				
Internal Cladding	NO	Insulated / PFP	No				

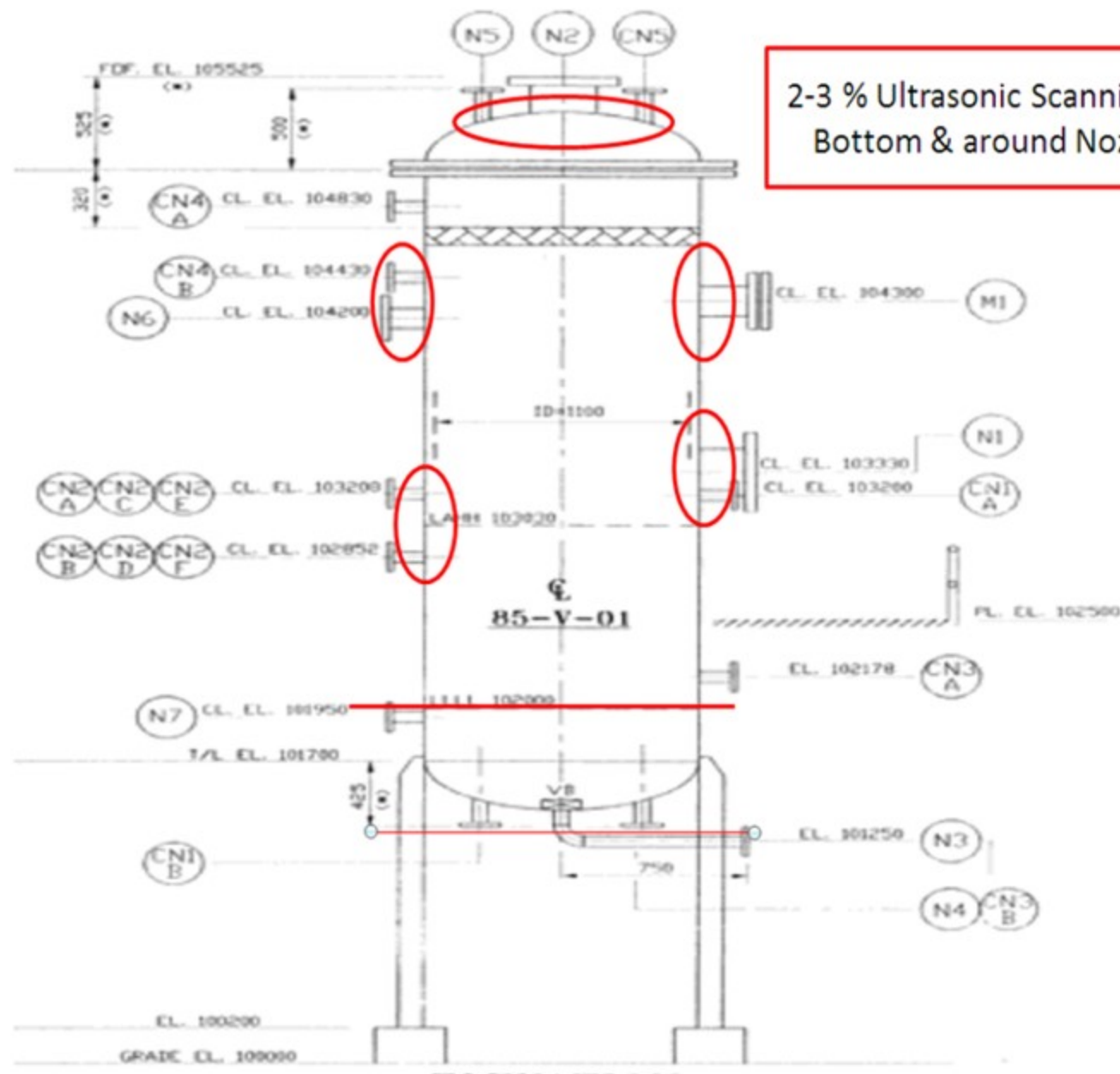
Examination Boundary	
The pressure boundary till the first Off Flange face of the pressure vessel (shell, heads and nozzles) and vessel bridges. Safety / protective equipment devices shall be visually inspected.	describe the inspection methods and NDE

Scope of Examination	
Inspections shall be carried out in conformance with industrial documents API STD 510 and recommended Practice no. API RP 572. In addition, following site work instruction shall apply: GL-E-002-002, GL-E-002-005, GLIS-E-004-002 and GLIS-E-004-004.	
Non-destructive Examination	
Method	Locations
☐ DPI	Internals & Vortex Breaker (due to accessibility)
☐ MT	Sample Welds (Girth, Longitudinal and T-Joints) , , CS internals
☒ UT A-Scan	Band Scan from inside
☐ TOFD	Nozzles
☐ PA	
☐ RT	
☐ Replica	
☐ IRIS	
☐ PEC	
☐ Other	
Notes: Ultrasonic testing can be done either using manual A-Scan or Phased Array. TOFD can be used for Welds and Nozzle Inspection	
Inspection Limitations	Reporting Criteria
- Fracture - Cracking - Localized Metal - General metal loss - Pitting	- Painting deterioration - Disrobement - Dents - Distortion - Earthing disconnected - Dissimilar metal - Deformation - Loss bolts - Missing Bolts - Out of level

Pressure Relief and Instrumented Protective Devices	
☐ PSV	☐ BDV
☐ SDV	☐ Rupture Disk
☐ Vacuum Breaker	

Preparatory Work			
☐ Hot Work Permit	☐ External Scaffolding	☐ Confined Spaced Entry	☐ Other (Explain)
☐ Internal Scaffolding	☐ Remove Thermal Insulation	☐ Work at High Permit	

Modifications and Repairs	
Only external painting 5/2013	Define any special access and preparation needed
Describe any required	



2-3 % Ultrasonic Scanning on
Bottom & around Nozzles

RBI



RBI Analysis

shall include

Used to

Systematic Evaluation for

COF

POF

1. determine inspection intervals or due dates
2. the type and extent of future inspection/examinations
 - Shall include all of the inspection planning elements noted in API 580

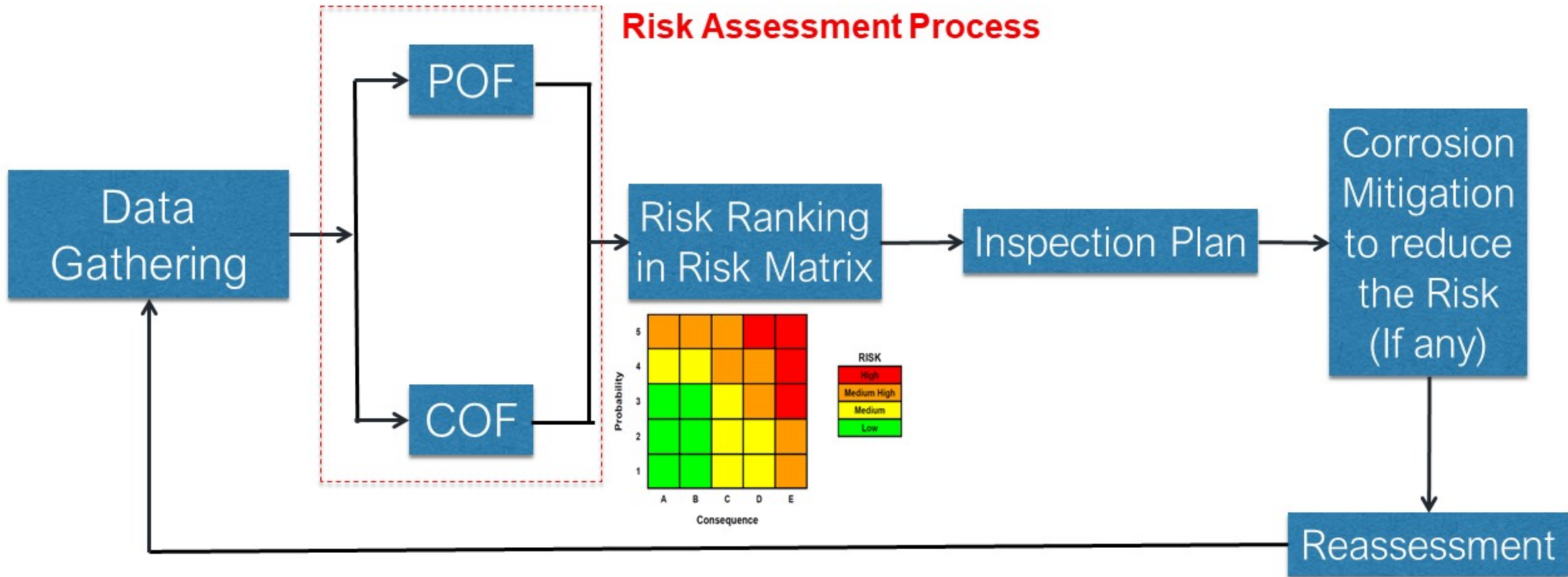
Identifying and evaluating

- the process fluid(s),
- potential injuries,
- environmental damage,
- equipment damage and equipment downtime

Identifying and evaluating:

- potential damage mechanisms,
- current equipment condition and
- the effectiveness of the past inspections

Generic RBI Process – API 580



RBI Analysis

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Shall

Probability Assessment

- be in accordance with the requirements in **API 580**
- be based on **all forms of damage** that could reasonably be expected to affect equipment in any particular service.
- Evaluate the **effectiveness of the inspection practices**, tools, and techniques used for finding the potential damage mechanisms

Other factors that should be considered in a POF include:

- a) appropriateness of the materials of construction;
- b) vessel 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 QA/QC programs;
- f) both the pressure retaining and structural requirements; and
- g) operating conditions, both past and projected.

Shall

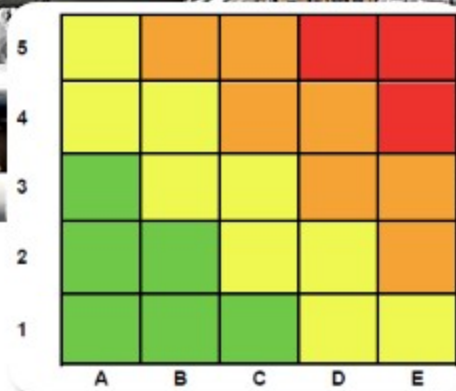
Consequence Assessment

- be in accordance with the requirements in API 580
- consider the potential incidents that may occur as a result of
 1. fluid release,
 2. the size of a potential release, and
 3. the type of a potential release (includes explosion, fire, or toxic exposure.)

The assessment should also determine: 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.

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Documentation

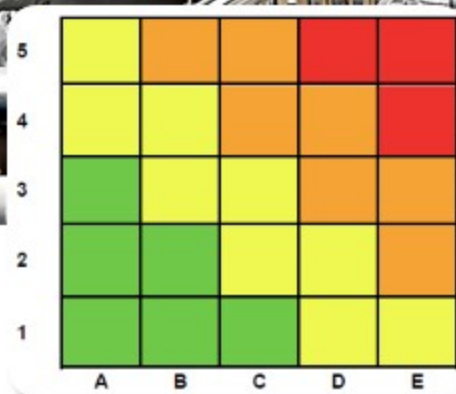
All RBI assessments be thoroughly **documented** in accordance with the requirements in API 580 clearly defining all the factors contributing to both the probability and consequence of a failure of the equipment.

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 or due date 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 vessel failure. (e.g. repairs, process changes, inhibitors, etc.).

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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5	Green	Yellow	Orange	Red	Red
4	Yellow	Yellow	Orange	Orange	Red
3	Green	Yellow	Yellow	Orange	Orange
2	Green	Green	Yellow	Yellow	Orange
1	Green	Green	Green	Yellow	Yellow
	A	B	C	D	E

Frequency of RBI Assessments

When RBI assessments are used to set equipment inspection intervals or due dates, the **assessment shall be updated after each equipment inspection** as defined in API 580 Section 15. The RBI assessment shall be updated when:

- **Hardware changes** are made that could significantly affect damage rates or damage mechanisms
- Anytime an **unanticipated failure occurs** due to a damage mechanism..

Preparation for Inspection



Preparation for Inspection

Records Review

Safety Precautions

- Inspectors shall familiarize themselves with **prior history of the pressure vessel** for which they are responsible

Inspectors should review

- The pressure vessel's prior inspection results,
- Prior repairs,
- Current inspection plan, and/or other similar service inspections

- Are important in pressure vessel inspection and maintenance activities because some process fluids are harmful to human health
- Pressure vessels are enclosed spaces, and **internal activities** involve exposure to all of the hazards of confined space entry
- Regulations (OSHA) govern many aspects of pressure vessel inspection and **shall be followed** where applicable
- The owner/user's **safety procedures** shall be reviewed and followed (as Permits)
- Refer to API 572, Section 8 for more information on inspection safety.

Preparation for Inspection



Preparation for Inspection

Communication

Equipment

Before starting any vessel inspection and maintenance activities (e.g. NDE, pressure testing, repair, or alteration), personnel should obtain **permission to work** in the vessel area (internal or external) from operating personnel responsible for the pressure vessel.

When individuals are inside a vessel, all persons working around the vessel **should be informed** that people are working inside the vessel.

Individuals working inside the vessel should be informed when any work is going to be done on the interior or exterior of the vessel while they are inside the vessel (**Column as example**)

- **All tools, equipment, and personal protective equipment** used during vessel work (inspection, NDE, pressure testing, repairs, and alterations) should be checked prior to use.
- **NDE equipment** and the repair organization's equipment is subject to the owner/user's safety requirements for electrical equipment.
- **Other equipment** that might be needed for the vessel work, such as planking, scaffolding, and portable ladders, should be checked before being used.
- **Personal protective equipment** shall be worn when required either by regulations, the owner/user, or the repair organization.
- Refer to API 572, Section 8 for more information on inspection tools.

Preparation for Inspection



Preparation for Inspection

Vessel Entry (Confined Space)

INSPECTOR

Work Permit

Positively isolated

Drained, purged, cleaned, ventilated

Gas tested (no. of times)

Continuous safe ventilation

Rescue Plan

Personnel protective equipment

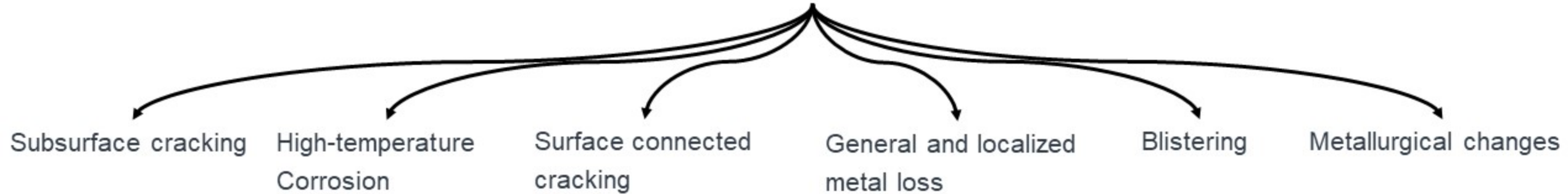
All safe entry procedures and jurisdiction shall be followed



Pressure vessel Damage Types



Inspection for Different Types of Damage Mechanisms and Failure Modes



- API 571 describes common damage mechanisms and inspection techniques to identify them
- The presence or potential of damage in a vessel 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/or damage mechanisms

a) General and localized metal loss:

- 1) sulfidation and high-temperature H_2S/H_2 corrosion—
- 2) oxidation—refer to API 571, Section 4.4.1;
- 3) microbiologically induced corrosion—refer to API 571, Section 4.4.2;
- 4) naphthenic acid corrosion—refer to API 571, Section 4.4.3;
- 5) erosion/erosion-corrosion—refer to API 571, Section 4.4.4;
- 6) galvanic corrosion—refer to API 571, Section 4.3.1;
- 7) atmospheric corrosion—refer to API 571, Section 4.4.5;
- 8) corrosion under insulation (CUI)—refer to API 571, Section 4.4.6;
- 9) cooling water corrosion—refer to API 571, Section 4.4.7;
- 10) boiler water condensate corrosion—refer to API 571, Section 4.4.8;
- 11) soil corrosion—refer to API 571, Section 4.3.2;
- 12) ammonium bisulfide and chloride corrosion—refer to API 571, Section 4.4.9;
- 13) carbon dioxide corrosion—refer to API 571, Section 4.4.10;

b) Surface connected cracking:

- 1) mechanical fatigue cracking—refer to API 571, Section 4.2.1;
- 2) thermal fatigue cracking—refer to API 571, Section 4.2.2;
- 3) caustic stress corrosion cracking—refer to API 571, Section 4.2.3;
- 4) polythionic stress corrosion cracking—refer to API 571, Section 4.2.4;
- 5) sulfide stress corrosion cracking—refer to API 571, Section 4.2.5;
- 6) chloride stress corrosion cracking—refer to API 571, Section 4.2.6;

c) Subsurface cracking:

- 1) hydrogen induced cracking—refer to API 571, Section 4.2.7;
- 2) wet hydrogen sulfide cracking—refer to API 571, Section 4.2.8;

d) High-temperature microfissuring/microvoid formation and eventual macrocracking:

- 1) high-temperature hydrogen attack—refer to API 941, Section 6;
- 2) creep/stress rupture—refer to API 571, Section 4.2.8.

e) Metallurgical changes:

- 1) graphitization—refer to API 571, Section 4.2.9;
- 2) temper embrittlement—refer to API 571, Section 4.2.10;
- 3) hydrogen embrittlement—refer to API 571, Section 4.2.11;

f) Blistering:

- 1) hydrogen blistering—refer to API 571, Section 4.2.12;

Vessels in cyclic service



mole sieves,



coke drums



pressure swing adsorbers

Should be evaluated for potential **fatigue cracking failures** and have appropriate inspections planned

The following considerations should be evaluated where applicable for vessels in cyclic service.

- The **fatigue design criteria** from the original code of construction and any special precautions and/or fabrication details (e.g. **ground flush welds**)
- The types of vessel internal and external **attachments and nozzles** (e.g. **fillet welded** attachments and nozzle reinforcing pads),
- The **potential for internal or external corrosion** (e.g. CUI) and environmental/stress corrosion cracking and their potential effect on the fatigue life of the vessel.
- The appropriate NDE and inspection frequency** to detect fatigue cracking (e.g. external UT angle beam flaw detection, external and/or internal wet fluorescent MT)

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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General Types of Inspection and Surveillance

Inspections shall be conducted in accordance with the inspection plan for each vessel



INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Internal Visual Inspection



Internal Visual Inspection

The internal inspection **shall be performed by an inspector** in accordance with the inspection plan; other properly qualified personnel (e.g. NDE examiner) may assist the inspector **(but not replace)** in the internal inspection, when approved and under the direction of the authorized inspector

Internal inspection methods:

- **Conducted from inside the vessel** and shall provide a thorough check of internal pressure boundary surfaces for damage.
- **Through Manway or inspection port inspections only** when the vessel is too small to safely enter or all internal surfaces can be clearly seen and adequately examined from the manway or inspection port.
- **Remote visual inspection** techniques may aid the check of internal surfaces.

A primary goal of the internal inspection is to find damage that **cannot be found by on-stream inspections**.

Specific NDE techniques may be required by the inspection plan.

When vessels are equipped with **removable internals**, internals may need to be removed, to the extent necessary, to allow inspection of pressure boundary surfaces

- The inspector, in consultation with the **corrosion specialist**, should determine when it is necessary to remove deposits or **linings** to perform adequate inspections
- **If internal linings are in good condition** and there is no reason to suspect that damage is occurring behind them
- **If the lining appears damaged**, bulged, or cracked, it may be advisable to remove portions of the linings to investigate the condition of the lining and the vessel surface beneath

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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On-stream Inspection



- 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** (as Phased Array) to check for various types of damage which identified during inspection planning

Techniques used in on-stream inspections are chosen for their ability to:

- **identify particular damage mechanisms from the exterior**
- perform at the on-stream conditions of the pressure vessel (e.g. metal temperatures)

The external thickness measurement inspection may be a part of an on-stream inspection

On-stream inspection may be acceptable in lieu of internal inspection for vessels under the specific circumstances defined in 6.5.2.

In situations where on-stream inspection is acceptable, such inspection may be conducted either while the vessel is depressurized or pressurized



3D Model

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Thickness Measurement Inspection and Various NDE Examinations



Thickness measurements

- To calculate the **corrosion rates** and **remaining life** of the pressure vessel
- Shall be obtained **by the inspector or the examiner** as required and scheduled by the inspection plan
- **The inspector shall review the results** of the thickness inspection data to look for possible anomalies

When the short-term corrosion rate changes significantly from the previous:

- (1) The inspector should consult with a corrosion specialist to determine the cause
- (2) Additional UT thickness readings, performing UT scans in suspect areas
- (3) Revisions to the vessel's inspection plan.

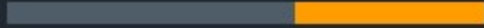


3D Model

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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External Visual Inspection



External Visual Inspection

Visual external inspections are **normally performed by an inspector**; however, other **qualified personnel** may conduct the external inspection when **acceptable to the inspector**

- External inspections are performed according to checklist
- **Any signs of leakage** should be investigated so that the sources can be established.
- Normally, weep holes in reinforcing plates should remain open to provide visual evidence of leakage as well as to prevent pressure buildup behind the reinforcing plate.

Vessels **shall** be examined for visual indications of bulging, out-of-roundness, sagging, and distortion. If any distortion of a vessel is suspected or observed, the overall dimensions of the vessel **shall be checked** to determine the extent of the distortion

Any personnel who observe vessel deterioration should report the condition to the inspector.

Inspection of Buried Vessels

The inspection interval shall be based on:

- Assessment of the cathodic protection system (if any exists) effectiveness
- **Corrosion rate information** obtained from one or more of the following methods:
 - 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 vessel, or
 - d) from a vessel in similar circumstances.

Scanning UT thickness readings and/or other appropriate scanning NDE methods for determining the condition of the external surface condition could **be conducted on the vessel internally** to monitor for external corrosion.

3D Model

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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CUI Inspection



Inspection for CUI shall be considered for externally insulated vessels and those that are in **intermittent service** or **operate at temperatures** between:

- a) 10 °F (−12 °C) and 350 °F (177 °C) for carbon and low alloy steels,
- b) 140 °F (60 °C) and 350 °F (177 °C) for austenitic stainless steels,
- c) 280 °F (138 °C) and 350 °F (177 °C) for duplex stainless steels.

Carbon and low alloy steels

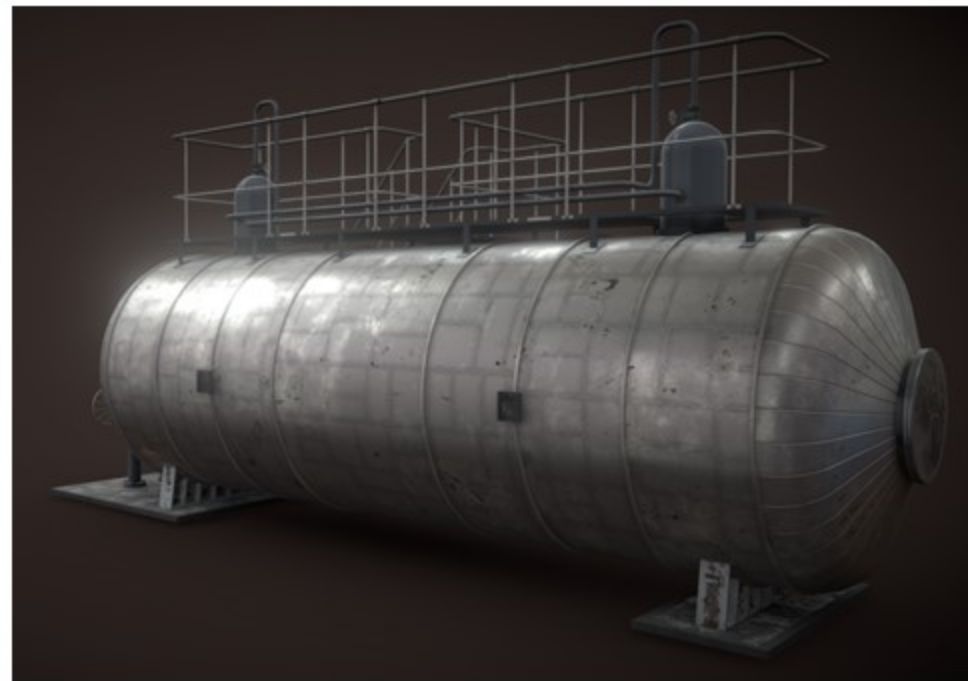
Localized corrosion

Austenitic and duplex stainless steel

External chloride stress corrosion cracking

Most susceptible areas include:

- a) above insulation or stiffening rings;
- b) nozzles and manways;
- c) other penetrations (e.g. ladder clips, pipe supports);
- d) damaged insulation with areas of potential water ingress;
- e) areas with failed insulation caulking;
- f) **top and bottom heads;**
- g) other areas that tend to trap water.



3D Model

If CUI damage is found, the inspector should inspect other susceptible areas on the vessel. See API 583 on CUI for more detailed information.

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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CUI Inspection



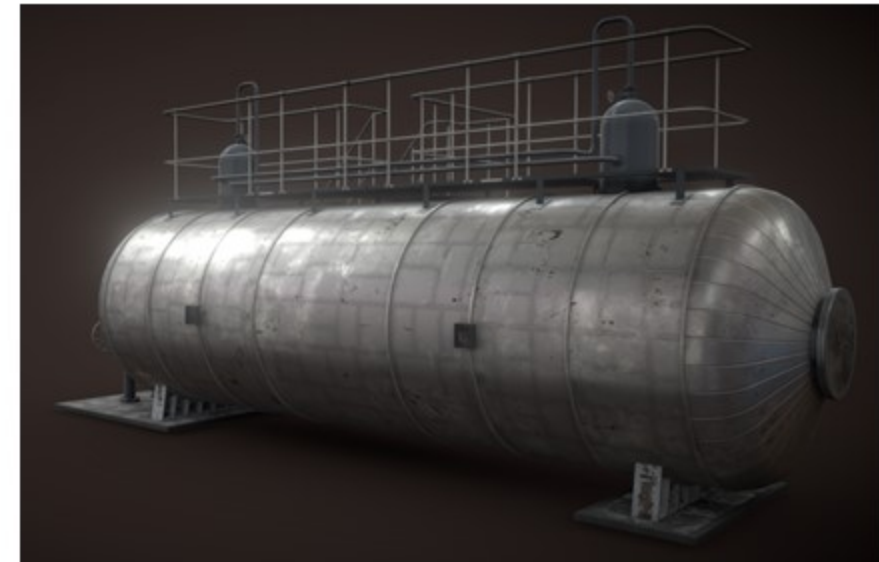
Insulation Removal

Although external insulation may appear to be in good condition, CUI damage may still be occurring underneath it. CUI inspection may require removal of some or all insulation (i.e. removing selected windows in the 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 vessel

Considerations on the need for insulation removal are not limited to but include:

- a) consequences of CUI leakage;
- b) history of CUI for the vessel or comparable equipment;
- c) visual condition of the external covering and insulation;
- d) evidence of fluid leakage (e.g. stains);
- e) equipment in intermittent service;
- f) condition/age of the vessel coating under insulation, if applicable;
- g) potential for the type of insulation to absorb/hold more water (e.g. calcium silicate versus cellular glass);
- h) ability to apply specialized NDE that can effectively locate CUI without insulation removal.

Alternatively, shell thickness measurements done internally at typical CUI problem areas may be performed during internal inspections, but the inspector should be aware that CUI damage is often highly localized and therefore may be difficult to detect from the inside diameter of a vessel.



3D Model

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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CUI Gallery



CUI Gallery



INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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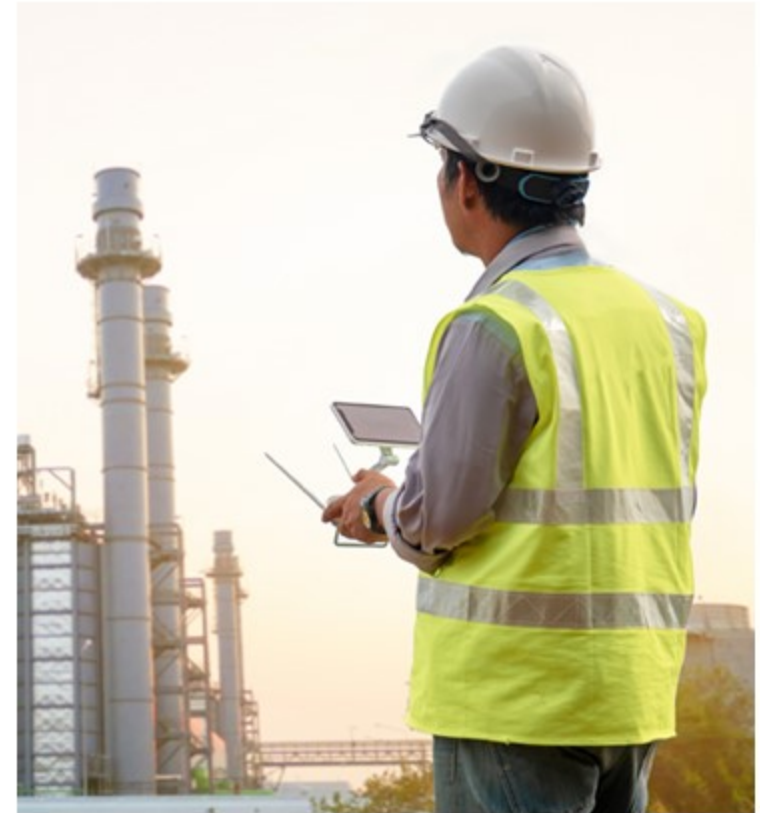
Supplemental Inspection



Operator Surveillance

Operators making their rounds or as part of their normal duties in the process unit should be advised **to report anything unusual associated with pressure vessels** and pressure-relieving devices to the unit inspector. Such things include:

- Vibration,
- Signs of leakage,
- Unusual noises,
- Insulation deterioration,
- Relief device having opened,
- Distortion,
- Denting,
- Temperature deviation,
- Presence of rust stain coming out from under insulation, or other barriers or crevices



INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Steps of Inspection



The type of CML selected and placement of CMLs shall consider

- Potential for localized corrosion
- service-specific damage including locations for thickness measurement, locations for stress corrosion cracking examinations, and locations for high-temperature hydrogen attack examinations.

Each pressure vessel shall be monitored by conducting a representative number of examinations at CMLs to satisfy the requirements for an internal and/or on-stream inspection

More CMLs and be monitored more frequently required when:

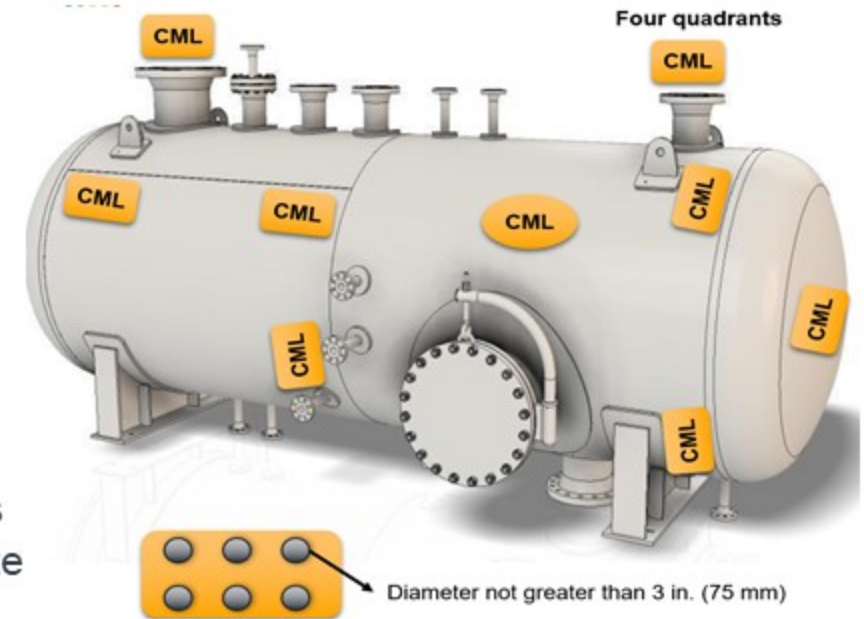
- High potential consequences if failure should occur
- Subject to higher corrosion rates and high rates of damage from other mechanisms
- Localized corrosion (corrosion specialists should be consulted about the appropriate placement and number of CMLs)

when localized corrosion is expected:

using scanning methods such as profile RT, scanning UT techniques, and/or other suitable NDE

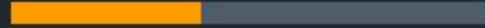
CMLs and examination points should be permanently recorded, (e.g. marked on inspection drawings and/or on the equipment) to allow repetitive measurements at the same CMLs

The thinnest reading or an average of several measurement readings taken within the area of an examination point shall be recorded and used to calculate the corrosion rates



INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

CML Selection and Placement



CMLs should be **distributed** appropriately over the vessel to provide adequate monitoring coverage of major components and nozzles.

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
- The potential consequence of loss of containment

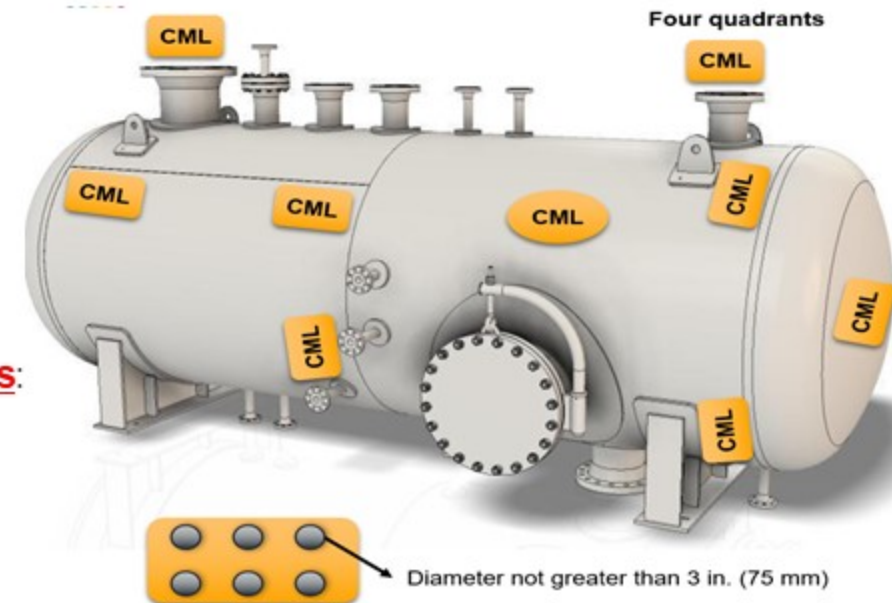
CMLs may be eliminated or the number significantly reduced when the probability and/or consequence of failure is low (e.g. clean noncorrosive hydrocarbon service). In circumstances where CMLs will be substantially reduced or eliminated, a **corrosion specialist should be consulted**.

More CMLs should be selected for pressure vessels with any of the following characteristics:

- a) higher potential for creating an immediate safety or environmental emergency in the event of a leak, unless the internal corrosion rate is known to be relatively uniform and low;
- b) higher expected or experienced corrosion rates;
- c) higher potential for localized corrosion.

Fewer CMLs can be selected for pressure vessels 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 contents,
- c) **generally uniform corrosion rates**.



INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Examination Technique Selection

In selecting the technique(s) to use during Pressure vessel 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

Adequate surface preparation (depends on the individual circumstances and NDE technique) is important for proper VT and for the satisfactory application of any NDE procedures.

NDE	Damage Mechanism
MT	cracks and other linear discontinuities that extend to the surface of the material in ferromagnetic materials
PT or Fluorescent	disclosing cracks, porosity, or pin holes that extend to the surface of the material and for outlining other surface imperfections, especially in nonmagnetic materials
RT	internal imperfections such as porosity, weld slag inclusions, cracks, and thickness of components
UTT and UT	Thickness and internal and surface breaking cracks and other elongated discontinuities
Current flux Leakage	surface-breaking cracks and elongated discontinuities.
Eddy current	localized metal loss, cracks, and elongated discontinuities
Field metallographic replication	identifying metallurgical changes
Acoustic emission	detecting structurally significant defects
Thermography	determining temperature of components, blockages, debris/sediment levels, and flow verification.
Pressure testing	detecting through-thickness defects
Hardness	for identifying variations in mechanical properties due to changes in material.
Advanced ultrasonic backscatter	for detecting high-temperature hydrogen attack referenced in API 941, Section 6.

Table A-110
Imperfection vs. Type of NDE Method

	Surface [Note (1)]		Subsurface [Note (2)]		Volumetric [Note (3)]				
	VT	PT	MT	ET	RT	UTA	UTS	AE	UTT
Service-Induced Imperfections									
Abrasive Wear (Localized)	⊙	⊕	⊕	...	⊙	⊕	⊕	...	⊕
Baffle Wear (Heat Exchangers)	⊙	...	...	⊕	...	...	...	...	...
Corrosion-Assisted Fatigue Cracks	⊙	⊕	⊙	...	⊙	⊙	...	⊙	...
Corrosion	...	...	...	...	...	...	...	...	...
-Crevice	⊙	...	...	...	...	...	...	...	⊙
-General / Uniform	...	...	...	⊙	⊕	...	⊕	...	⊙
-Pitting	⊙	⊙	⊙	...	⊙	⊙	⊙	⊕	⊙
-Selective	⊙	⊙	⊙	...	...	...	...	...	⊙
Creep (Primary) [Note (4)]	...	...	...	...	...	...	...	...	...
Erosion	⊙	...	...	...	⊙	⊙	⊕	...	⊕
Fatigue Cracks	⊙	⊙	⊙	⊕	⊕	⊙	...	⊙	...
Fretting (Heat Exchanger Tubing)	⊕	...	...	⊕	...	...	...	...	⊕
Hot Cracking	...	⊕	⊕	...	⊕	⊙	...	⊕	...
Hydrogen-Induced Cracking	...	⊕	⊕	...	⊙	⊕	...	⊕	...
Intergranular Stress-Corrosion Cracks	...	...	...	...	...	⊙	...	...	...
Stress-Corrosion Cracks (Transgranular)	⊙	⊕	⊙	⊙	⊕	⊕	...	⊕	...
Welding Imperfections									
Burn Through	⊙	...	...	...	⊙	⊕	...	...	⊙
Cracks	⊙	⊙	⊙	⊕	⊕	⊕	⊙	⊙	...
Excessive/Inadequate Reinforcement	⊙	...	...	...	⊙	⊕	⊙	...	⊙
Inclusions (Slag/Tungsten)	...	...	⊕	⊕	⊙	⊕	⊙	⊙	...
Incomplete Fusion	⊕	...	⊕	⊕	⊕	⊙	⊕	⊕	...
Incomplete Penetration	⊕	⊙	⊙	⊕	⊙	⊙	⊕	⊕	...
Misalignment	⊙	...	...	...	⊙	⊕	...	...	...
Overlap	⊕	⊙	⊙	⊙	...	⊙	...	...	...
Porosity	⊙	⊙	⊙	...	⊙	⊕	⊙	⊙	...
Root Concavity	⊙	...	...	...	⊙	⊕	⊙	⊙	⊙
Undercut	⊙	⊕	⊕	⊙	⊙	⊕	⊙	⊙	...
Product Form Imperfections									
Bursts (Forgings)	⊙	⊙	⊙	⊕	⊕	⊕	⊕	⊙	...
Cold Shuts (Castings)	⊙	⊙	⊙	⊙	⊙	⊕	⊕	⊙	...
Cracks (All Product Forms)	⊙	⊙	⊙	⊕	⊕	⊕	⊙	⊙	...
Hot Tear (Castings)	⊙	⊙	⊙	⊕	⊕	⊕	⊙	⊙	...

Table A-110
Imperfection vs. Type of NDE Method (Cont'd)

	Surface [Note (1)]		Subsurface [Note (2)]		Volumetric [Note (3)]				
	VT	PT	MT	ET	RT	UTA	UTS	AE	UTT
Inclusions (All Product Forms)	...	...	⊙	⊙	⊙	⊙	⊙	⊙	...
Lamination (Plate, Pipe)	⊙	⊙	⊙	...	...	⊙	⊙	⊙	⊙
Laps (Forgings)	⊙	⊙	⊙	⊙	⊙	...	⊙	⊙	...
Porosity (Castings)	⊙	⊙	⊙	...	⊙	⊙	⊙	⊙	...
Seams (Bar, Pipe)	⊙	⊙	⊙	⊙	⊙	⊙	⊙	⊙	...

Legend:

AE — Acoustic Emission

ET — Electromagnetic (Eddy Current)

MT — Magnetic Particle

PT — Liquid Penetrant

RT — Radiography

UTA — Ultrasonic Angle Beam

UTS — Ultrasonic Straight Beam

UTT — Ultrasonic Thickness Measurements
VT — Visual

⊙ — All or most standard techniques will detect this imperfection under all or most conditions.

⊙ — One or more standard technique(s) will detect this imperfection under certain conditions.

⊙ — Special techniques, conditions, and/or personnel qualifications are required to detect this imperfection.

GENERAL NOTE: Table A-110 lists imperfections and NDE methods that are capable of detecting them. It must be kept in mind that this table is very general in nature. Many factors influence the detectability of imperfections. This table assumes that only qualified personnel are performing nondestructive examinations and good conditions exist to permit examination (good access, surface conditions, cleanliness, etc.).

NOTES:

(1) Methods capable of detecting imperfections that are open to the surface only.

(2) Methods capable of detecting imperfections that are either open to the surface or slightly subsurface.

(3) Methods capable of detecting imperfections that may be located anywhere within the examined volume.

(4) Various NDE methods are capable of detecting tertiary (3rd stage) creep and some, particularly using special techniques, are capable of detecting secondary (2nd stage) creep. There are various descriptions/definitions for the stages of creep and a particular description/definition will not be applicable to all materials and product forms.

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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UT Angle Beam Examiners

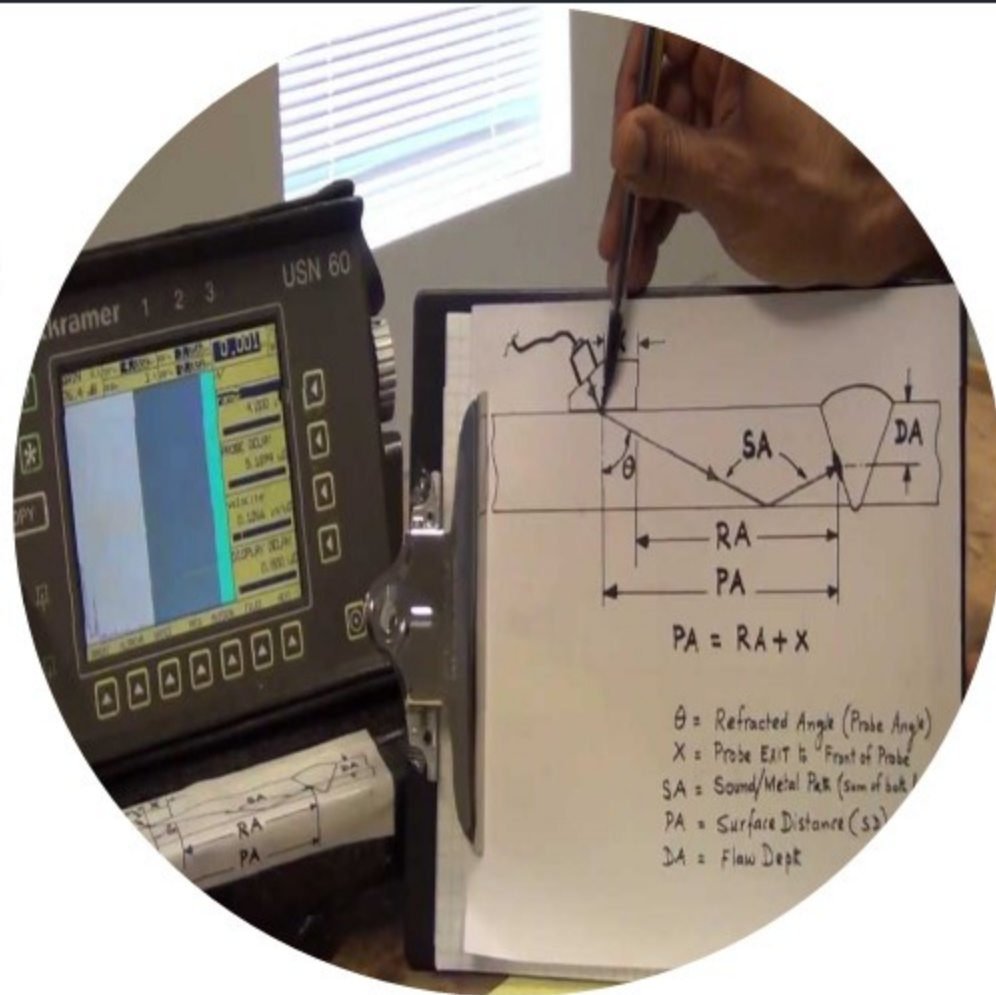


The owner/user shall specify industry-qualified UT angle beam examiners when the owner/user requires the following:

- 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 angle beam examiners include

- detecting and sizing planar flaws from the external surface
- collecting data for Fitness-For-Service evaluations.



INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Thickness Measurement Methods



UTT

Uniform loss

may be difficult to detect visually, so thickness measurements are usually necessary to determine its extent

Corrosion

Localized loss

may be thinner than they appear visually, and when there is uncertainty about the original surface location or depth of metal loss, thickness determinations may also be necessary.

Pitted appearance

Measurements may be obtained as follows:

- **Any suitable NDE, such as UT** or profile RT
- The depth of corrosion may be determined by gauging (depth gauge) from the uncorroded surfaces within the vessel
- **Ultrasonic thickness measuring instruments**

Ultrasonic scanning or radiographic profile techniques are preferred where :

- corrosion is localized
- or the remaining thickness is approaching the required thickness.

Corrective procedures should be utilized when metal temperatures (typically above 150 °F [65 °C]) impact the accuracy of the thickness measurements obtained. Instruments, couplants, and procedures should be used that will result in accurate measurements at the higher temperatures. Typically, procedures will involve calibrating with hot test plates or adjusting measurements by the appropriate temperature correction factor.

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Condition Monitoring Methods



UTT

Factors that can contribute to reduced accuracy of ultrasonic measurements include the following:

- a) improper instrument calibration;
- b) external coatings or scale;
- c) excessive surface roughness;
- d) excessive “rocking” of the probe (on curved surfaces);
- e) subsurface material flaws, such as laminations;
- f) temperature effects [at temperatures above 150 °F (65 °C)];**
- g) small flaw detector screens;
- h) doubling of the thickness response on thinner materials.

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Pressure Testing



Pressure Testing

Pressure tests are not normally conducted **as part of a routine inspection** but normally required:

- **After an alteration or major repair**
- After repairs (other than major repairs) are completed, a pressure test shall be **applied if the inspector believes** that one is necessary and specifies it in the repair plan

Pressure tests

Are typically performed on an entire vessel.

Vessel components/sections can be performed in lieu of entire vessels (e.g. a new nozzle) **and engineer should be consulted**

Prior to 1999 addendum:

$$\text{Test Pressure} = 1.5 \text{ MAWP} \times \left(\frac{S_{\text{test temp}}}{S_{\text{design temp}}} \right)$$

1999 addendum and later:

$$\text{Test Pressure} = 1.3 \text{ MAWP} \times \left(\frac{S_{\text{test temp}}}{S_{\text{design temp}}} \right)$$

where:

$S_{\text{test temp}}$ = allowable stress at test temperature in ksi (MPa)

$S_{\text{design temp}}$ = allowable stress at design temperature in ksi (MPa).

What is the minimum hydrostatic test pressure for an existing vessel that is being rerated using the design allowable stress published in the 2007 edition of ASME Section VIII: Division I, where the MAWP is 1,000 psi and the allowable stress factor correction is 1.0?

Task: Determine the minimum hydrostatic test pressure.

Formula:
from API 510 ¶5.8.2.1:
for the 1999 addendum and later

$$\text{Test Pressure} = 1.3 \text{ MAWP} \times \left(\frac{S_{\text{test temp}}}{S_{\text{design temp}}} \right)$$

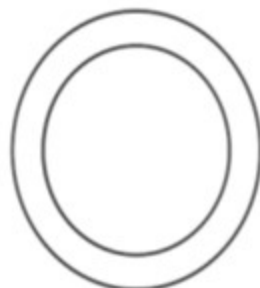
Required Variables:

MAWP = 1,000 psi

$$\left(\frac{S_{\text{test temp}}}{S_{\text{design temp}}} \right) = 1.0$$

$$\begin{aligned} \text{Test Pressure} &= 1.3 \text{ MAWP} \times \left(\frac{S_{\text{test temp}}}{S_{\text{design temp}}} \right) \\ &= 1.3 \times 1,000 \text{ psi} \times 1.0 \\ &= 1.3 \times 1,000 \text{ psi} \\ &= 1,300 \text{ psi} \end{aligned}$$

Drawing:



$$\begin{aligned} \text{MAWP} &= 1000 \text{ psi} \\ \frac{S_{\text{test temp}}}{S_{\text{design temp}}} &= 1.0 \end{aligned}$$

What is the minimum hydrostatic test pressure for an existing vessel that is being rerated using the design allowable stress published in the 1997 edition of ASME Section VIII: Division I, where the MAWP is 1,000 psi and the allowable stress factor correction is 1.0?

Task: Determine the minimum hydrostatic test pressure.

Formula:
From API 510 ¶5.8.2.1:
prior to the 1999 addendum

$$\text{Test Pressure} = 1.5 \text{ MAWP} \times \left(\frac{S_{\text{test temp}}}{S_{\text{design temp}}} \right)$$

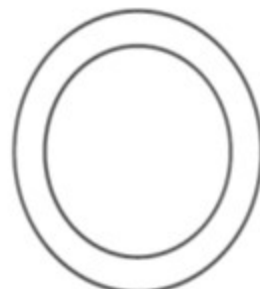
Required Variables:

MAWP = 1,000 psi

$$\left(\frac{S_{\text{test temp}}}{S_{\text{design temp}}} \right) = 1.0$$

$$\begin{aligned} \text{Test Pressure} &= 1.5 \text{ MAWP} \times \left(\frac{S_{\text{test temp}}}{S_{\text{design temp}}} \right) \\ &= 1.5 \times 1,000 \text{ psi} \times 1.0 \\ &= 1.5 \times 1000 \text{ psi} \\ &= 1,500 \text{ psi} \end{aligned}$$

Drawing:



$$\begin{aligned} \text{MAWP} &= 1000 \text{ psi} \\ \frac{S_{\text{test temp}}}{S_{\text{design temp}}} &= 1.0 \end{aligned}$$

When a non-code related pressure test (leak/tightness test) is performed after repairs, the test pressure may be conducted **at pressures determined by the owner/user**. Tightness test pressures are determined by the owner/user but are generally not for the purpose of proving strength of repairs

Pressure Test

After

PRVs and attachments removed during the pressure test shall be reinstalled or reactivated.

Vessel should be completely drained and dried (all high-point vents should be open during draining)

The inspector should verify the specified water quality is used and that the vessel has been drained and dried.

If potable water is not available or if immediate draining and drying is not possible:

- Water having a very low chloride level (e.g steam condensate),
- Higher pH (>10),
- Inhibitor addition should be considered to reduce the risk of pitting, chloride stress corrosion cracking, and MIC.

For **sensitized austenitic stainless steel** piping subject to **polythionic stress corrosion cracking (from sulfide scale + air + moisture = sulfur acids on the surface that then cause PTA SCC)**, consideration should be given to **using an alkaline-water solution** for pressure testing where accelerated corrosion of the sensitized region may be an issue

During

Safety of personnel: A close visual inspection of pressure vessel components should not be performed until the **vessel pressure is at or below the MAWP**

Before

If test pressure will exceed the set pressure of the PRVs, the PRVs should be removed. Or to use test clamps to hold down the valve disks.

Applying an additional load to the valve spring by turning the compression screw is prohibited.

Other attachments, that may be incapable of withstanding the test pressure should be removed or blanked off.

The **supporting structures, foundation, all instruments and other components** design should be reviewed

Type 300 series stainless steel should be conducted **with potable water or steam condensate having a chloride concentration of less than 50 ppm**

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Pneumatic Pressure Tests



Pneumatic Pressure Tests

Pneumatic testing (including combined hydro-pneumatic) may be used when hydrostatic testing is impracticable because of :

- Limited supporting structure or foundation,
- Refractory linings,
- Process reasons.

Engineer

A pneumatic test **procedure** should be developed by the engineer following the steps outlined in ASME PCC-2, Article 5.1.

Potential personnel and property risks of pneumatic testing shall be considered by an engineer before conducting the test

As a minimum, the inspection precautions contained in the ASME Code shall be applied when performing any pneumatic test.

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Test Temperature and Brittle Fracture Considerations



Brittle fracture is the sudden, very rapid fracture under stress (residual and/or applied) where the material exhibits little or no evidence of ductility or plastic degradation (there is no thinning or necking down)

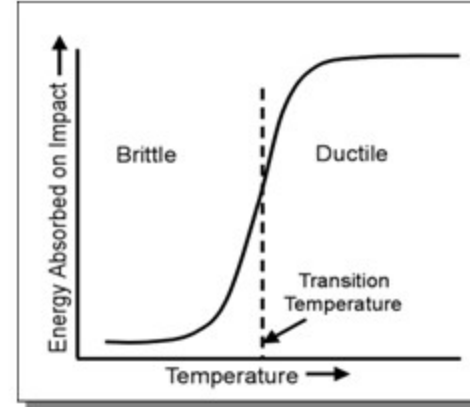
It breaks “like glass” without warning, and may in fact fracture into many pieces “like glass”

If the steel temperature is below its brittle-to-ductile transition temperature, then it will be susceptible to brittle fracture

“low temperature situation” + critical sized flaw + high stress on that flaw (either applied or residual)
= Brittle fracture

Temperatures below their transition temperature

Pressures greater than 20 % of the required hydrostatic test pressure



Brittle Fracture



INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

Test Temperature and Brittle Fracture Considerations



When hydrotesting solid or clad austenitic stainless steel, the water temperature should not exceed 120 °F (50 °C) to prevent possible chloride stress corrosion cracking.

Special attention should be given when testing low-alloy steels, especially 2 1/4Cr-1Mo, because they may be prone to temper embrittlement.

Temper embrittlement is the reduction in fracture toughness due to a metallurgical change that can occur in some low-alloy steels as a result of long-term exposure in the temperature range of about 650 °F to 1070 °F (345 °C to 575 °C)

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 vessel that is more than 2 in. (5 Cm) thick, or
- 10°F (6°C) above the MDMT for vessel that have a thickness of 2 in. (5 Cm) or less; and
- not exceed 120°F (50°C) **unless** there is information on the brittle characteristics of the vessel construction material indicating a higher test temperature is needed.



Brittle Fracture

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Pressure Testing Alternatives



NDE

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.**

In such cases, it is advisable to conduct a FFS assessment to identify the critical flaw size(s) to specify the acceptance criteria for the specified NDE technique(s).

For cases where manual UT is used to examine welds in lieu of pressure test, the owner/user shall specify industry qualified angle beam examiners

For use of UT in lieu of RT, ASME Code Case 2235 or ASME Section VIII, Division 2, 7.5.5 shall be followed.

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Material Verification and Traceability



During repairs or alterations of pressure vessels, **the inspector shall verify that all new materials** (including carbon steel as well as all alloys) are in compliance with the specifications. **At the discretion of the owner/user or the inspector, this assessment can be made by 100 % verification checking**, 100 % positive material identification (PMI), or by sampling a percentage of the materials depending upon the criticality of each service.

PMI testing can be done by the inspector or the examiner using suitable methods such as optical spectrographic analyzers or X-ray fluorescence analyzers. **The inspector or examiner shall be trained and qualified to conduct the PMI testing.** API 578 has additional guidance on material verification programs

If a pressure vessel component experiences accelerated corrosion or should fail because an incorrect material was inadvertently substituted for the specified material, the inspector shall consider the need for further verification of existing materials in the pressure vessel or other pressure vessels in same or similar service.

The extent of further verification will depend upon various factors including the consequences of failure and the probability of further material errors.

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

In-service Inspection of Welds



Inspection for weld quality is normally accomplished as a part of the requirements for **new construction, repairs, or alterations**. However, welds and weld heat-affected zones are often inspected for corrosion and/or service induced cracking as part of the in-service inspections. When preferential weld corrosion or cracking is noted, **additional welds of the pressure vessel should be examined** to determine the extent of damage.

API 577 provides additional guidance on weld inspection.

If crack-like imperfections are detected by RT or UT while the pressure vessel is in operation:

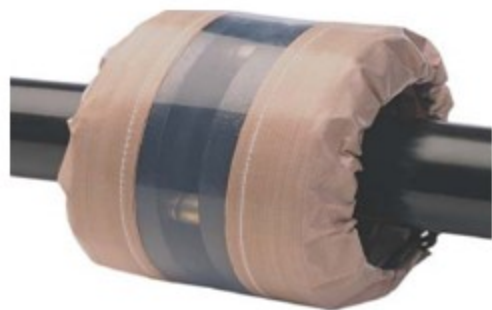
- Further inspection with weld quality RT and/or UT should be used to assess the magnitude of the imperfection
- Make an effort to determine whether the crack-like imperfections are from original weld fabrication or may be from an environmental cracking mechanism.

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**

INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Inspection of Flanged Joints



Splash-and-spray guards



lack of engagement

Flanged joints should be visually inspected **for leaks** (i.e., stains, deposits, or drips), keeping in mind that process leaks onto flange fasteners may result in **corrosion or environmental cracking**.

Flanged joints that have been clamped and pumped with sealant should be checked for leakage at the bolts since they may corrode or crack. If re-pumping is considered, then the affected fasteners should be renewed first.

If flanges are excessively bent or distorted, check their markings and thicknesses against the engineering requirements before taking corrective action.

Fasteners should be fully engaged. However, if a fastener is not fully engaged, it is acceptable **if the lack of engagement is not more than one thread**.

The markings on a representative sample of newly installed fasteners and gaskets should be examined to check the appropriate material specification.

Guidance on the inspection of flanged joints can be found in **ASME PCC-1**

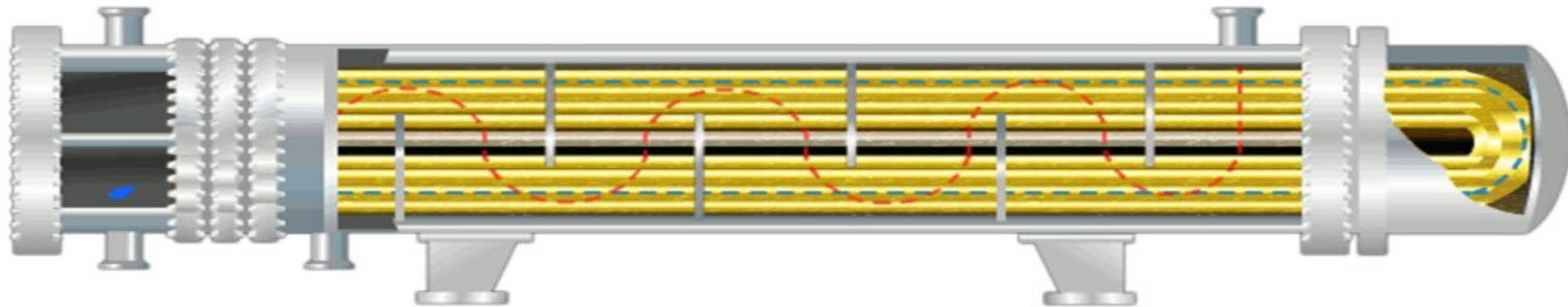
INSPECTION, EXAMINATION, AND PRESSURE TESTING PRACTICES

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Inspection of Shell and Tube Heat Exchangers



- Refer to **API 572**, Annex A for more information on inspection of several types of heat exchangers
- **ASME PCC-2**, Article 3.12 for guidance on the inspection and repair of shell and tube heat exchangers.





6



INTERVAL/FREQUENCY AND EXTENT OF INSPECTION





CH 6

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

CONTENT



6.1

General

6.2

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and Service Changes**

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RBI

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**Internal, On-stream, and
Thickness Measurement
Inspections**

6.6

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**Deferral of Inspections,
Examinations, and Tests**

6.8

**Deferral of Inspection Repair
Recommendation Due Dates**

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**Review of Inspection Repair
Recommendations**

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

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General



To ensure Pressure Vessel integrity

PURPOSE OF INSPECTION INTERVALS

Safe to operate

To operate safely until the next scheduled inspection

- ✓ All Pressure Vessel and PRVs **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

- ✓ The appropriate inspection shall provide the information necessary
- ✓ 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**

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

121

Inspection During Installation



Pressure vessels **shall be inspected** by an inspector **at the time of installation**.

Inspection During Installation

The purpose of installation inspection is to

- Verify that the vessel is **clean and safe for operation**,
- **Initiate plant inspection** records for the pressure vessel
- collect desired base line information and to obtain the **initial thickness readings** at designated CMLs

The minimum installation inspection should include the following items:

- a) Verify the **nameplate** information is correct per the manufacturer's data reports and design requirements;
- b) Verify equipment is **installed correctly**, supports are adequate and secured, exterior equipment such as ladders and platforms are secured, insulation is properly installed and flanged, and other mechanical connections are properly assembled and the vessel is clean and dry.
- c) Verify PRVs satisfy design requirements (correct device and correct set pressure) and are properly installed.

If damage did occur:

- document it and recommend appropriate repairs
- or engineering assessment that may be necessary to ensure the vessel is fit for service.

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

122

Vessel Service Change



If the **service conditions are changed**, such as process contents, maximum **operating** pressure, and the maximum and minimum **operating** temperatures,

- (1) Inspection intervals shall be established for the new service conditions,
- (2) Review of applicable PRVs settings.

If **both the ownership and the location** of the vessel are changed, the vessel **shall** be internally and externally inspected before it is reused.

This inspection should include:

- Baseline examinations for any predicted future examinations planned as a result of the new service
- the allowable service conditions and the inspection interval shall be established for the new service.
- The inspector should also assure that adequate documentation (process safety information) for the vessel is on file.

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

Setting Inspection Intervals with RBI



RBI Assessment

may be used to establish

- inspection intervals for internal, on-stream, and external inspections
- inspection and testing intervals for PRVs.

may allow previously established inspection intervals to be exceeded from limits specified in 6.4 and 6.5 including the 10-year inspection and one-half remaining life limits for internal and on-stream inspections and the 5-year inspection limit for the external inspections..

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

124

RBI



RBI assessment shall be reviewed and approved by the engineer and inspector at intervals not to exceed 10 years :

- When a RBI **interval for the internal or on-stream inspection** exceeds the 10-year limit
- If warranted by process, equipment, or consequence changes.

When a RBI assessment is used to **extend the internal or on-stream inspection interval**, the assessment should include a review of the inspection history and potential fouling of the vessel's PRVs

RBI assessments should be in compliance with the recommended practices of **API 580**.

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

125

External Inspection

External Inspection Intervals

Unless justified by an RBI assessment



Each aboveground vessel **shall** be given a visual external inspection at an interval that does not exceed the **lesser of :**
Five years or the **Required internal/on-stream inspection**

Preferred to perform this inspection while the vessel is in operation

The interval is established by the inspector or engineer in accordance with the owner/user's QA system.

For non-continuous service are the same as for vessels in continuous service

For equipment that is retired and abandoned in place, the owner/user **may need to conduct appropriate external inspections** to make sure that deterioration of insulation, vessel supports, and other pertinences do not deteriorate to the point where they become **a hazard to personnel**.

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

126

Internal, On-stream, and Thickness Measurement Inspections



the period between internal or on-stream inspections and UTT **shall not exceed one-half the remaining life of the vessel or 10 years, whichever is less.**

Whenever the remaining life is less than four years, the inspection interval may be the full remaining life **up to a maximum of two years**

The interval is established by the inspector or engineer in accordance with the owner/user's QA system.

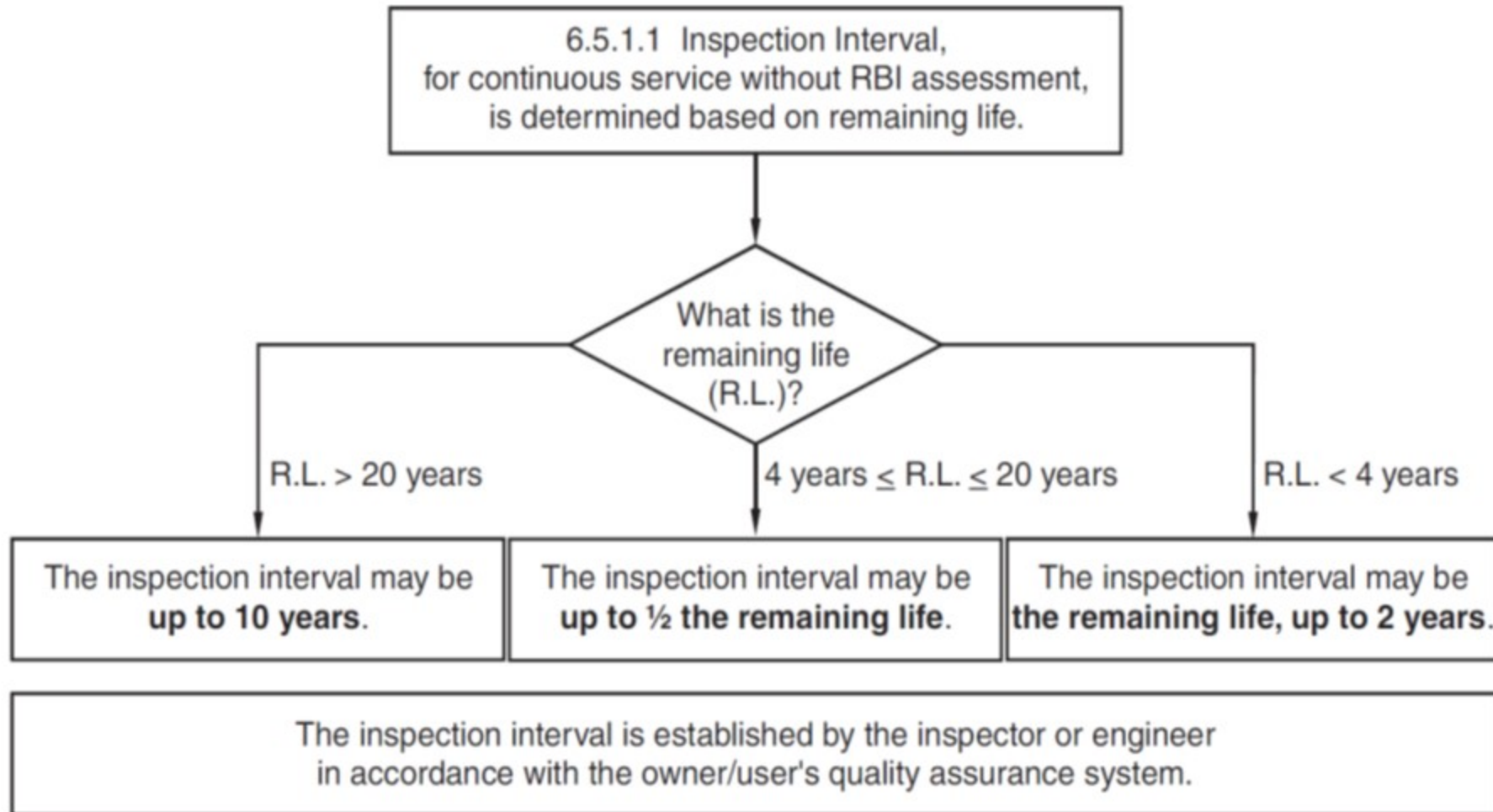
For non-continuous service, the **interval is based on the number of years of actual service** (vessel in operation) instead of calendar years, if the vessel is:

- a) isolated from the process fluids, and
- b) not exposed to corrosive internal environments (e.g. inert gas purged or filled with noncorrosive hydrocarbons).

Vessels that are in non-continuous service and not sufficient protected from corrosive environments may experience increased internal corrosion while idle (out of service). The corrosion rates should be **carefully reviewed** before setting the internal or on-stream intervals.

Internal, On-stream, and Thickness Measurement Inspections

Unless justified by an RBI assessment



When is the next inspection date for a pressure vessel last inspected on August 15, 2006, if the remaining life is determined to be 12 years?

Task: Determine the next inspection date.

Formula:

From API 510 ¶6.5.1.1:

for $RL \geq 4$ years,

$$I_{\text{interval}} = \text{lesser of } \frac{RL}{2} \text{ or 10 years}$$

Required Variables:

RL = 12 years

Last Inspection Date = August 15, 2006

The remaining life is greater than 4 years.

$$\begin{aligned} I_{\text{interval}} &= \text{lesser of } \frac{RL}{2} \text{ or 10 years} \\ &= \text{lesser of } \frac{12 \text{ years}}{2} \text{ or 10 years} \\ &= \text{lesser of 6 years or 10 years} \\ &= 6 \text{ years} \end{aligned}$$

The next inspection date is 6 years from the last inspection date, so it will be on August 15, 2012.

When is the next inspection date for a pressure vessel last inspected on August 15, 2008, if the remaining life is determined to be 3 years?

Task: Determine the next inspection date.

Formula:

From API 510 ¶6.5.1.1:

for $RL < 4$ years,

$$I_{\text{interval}} = RL \text{ up to a maximum of 2 years}$$

Required Variables:

RL = 3 years

Last Inspection Date = August 15, 2008

The remaining life is less than 4 years.

$$\begin{aligned} I_{\text{interval}} &= RL, \text{ up to a maximum of 2 years} \\ &= 2 \text{ years} \end{aligned}$$

The next inspection date is 2 years from the last inspection date, so it will be on August 15, 2010.

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

129

Internal, On-stream, and Thickness Measurement Inspections

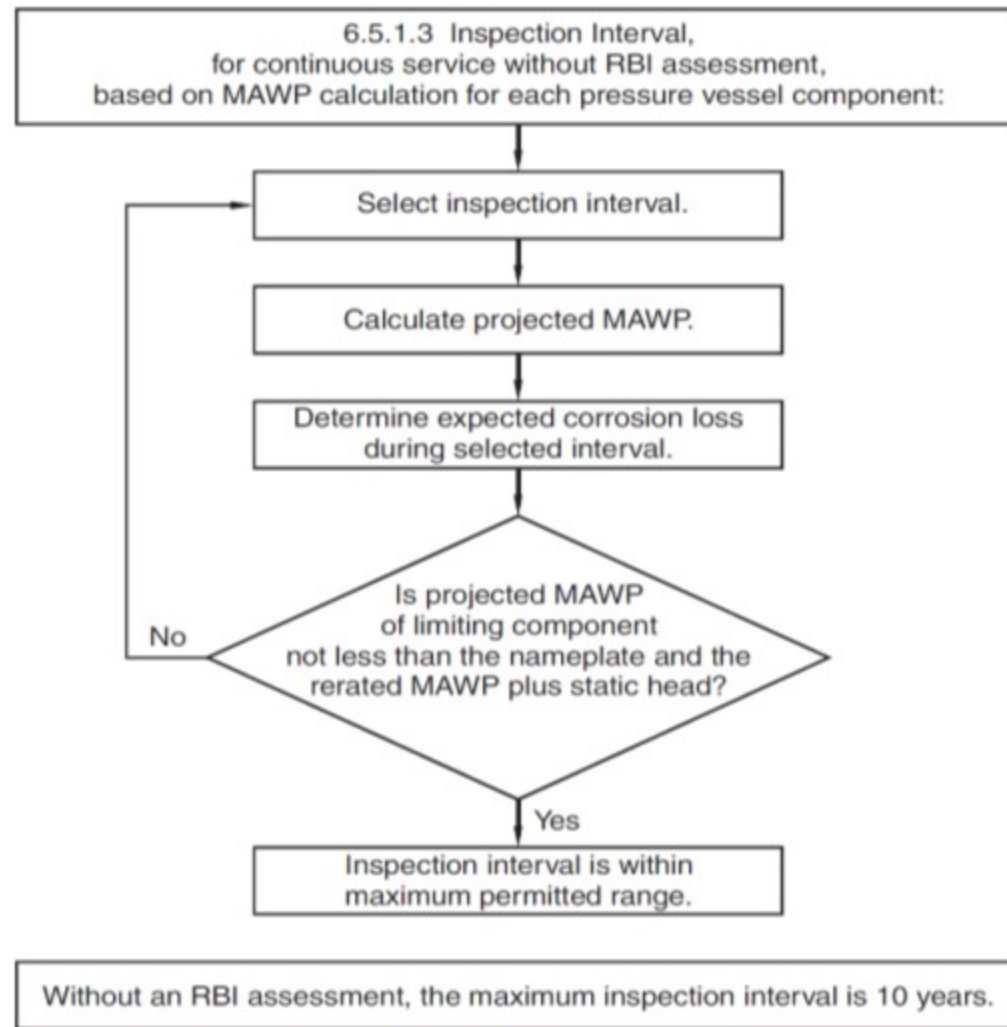
By calculating the **projected MAWP** of each vessel component as described in 7.3.

This procedure may be repetitive involving:

- Selection of an inspection interval,
- Determination of the corrosion loss expected over the interval,
- Calculation of the projected MAWP

The inspection interval is within the maximum permitted as long as the projected MAWP of the limiting component is not less than the lower of the nameplate or rerated MAWP plus applicable static head pressure.

The maximum inspection interval using this method is also 10 years.



An alternative method for inspection Interval

Unless justified by an RBI assessment

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

1
3
0

On-stream Inspection in Lieu of Internal Inspections



Size or configuration makes vessel entry for internal inspection physically impossible,

When vessel entry for internal inspection is physically possible and **all** of the following conditions are met:

General corrosion rate of a vessel is known to be less than 0.005 in. (0.125 mm) per year;

Remaining life is greater than 10 years;

Corrosive character of the contents, including the effect of trace components, has been established by at least five years of the same or similar service;

No questionable condition is discovered during the external inspection;

Operating T of vessel shell does not exceed the lower temperature limits for the creep rupture range of the vessel material referenced in API 579-1/ASME FFS, Part 4, Table 4.1;

Vessel does not have a non-integrally bonded liner such as strip lining or plate lining.

Vessel is not subject to environmental cracking or hydrogen damage from the fluid being handled;

On-stream inspection may be substituted for the internal inspection when:

Table 4.1 – Temperature Limit Used To Define The Creep Range

Material	Temperature Limit
Carbon Steel ($UTS \leq 414 MPa$ (60 ksi))	343°C (650°F)
Carbon Steel ($UTS > 414 MPa$ (60 ksi))	371°C (700°F)
Carbon Steel – Graphitized	371°C (700°F)
C-1/2Mo	399°C (750°F)
1-1/4Cr-1/2Mo – Normalized & Tempered	427°C (800°F)
1-1/4Cr-1/2Mo – Annealed	427°C (800°F)
2-1/4Cr-1Mo – Normalized & Tempered	427°C (800°F)
2-1/4Cr-1Mo – Annealed	427°C (800°F)
2-1/4Cr-1Mo – Quenched & Tempered	427°C (800°F)
2-1/4Cr-1Mo – V	441°C (825°F)
3Cr-1Mo-V	441°C (825°F)
5Cr-1/2Mo	427°C (800°F)
7Cr-1/2Mo	427°C (800°F)
9Cr-1Mo	427°C (800°F)
9Cr-1Mo – V	454°C (850°F)
12 Cr	482°C (900°F)
AISI Type 304 & 304H	510°C (950°F)
AISI Type 316 & 316H	538°C (1000°F)
AISI Type 321	538°C (1000°F)
AISI Type 321H	538°C (1000°F)
AISI Type 347	538°C (1000°F)
AISI Type 347H	538°C (1000°F)
Alloy 800	565°C (1050°F)
Alloy 800H	565°C (1050°F)
Alloy 800HT	565°C (1050°F)
HK-40	649°C (1200°F)

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

1
3
2

On-stream Inspection in Lieu of Internal Inspections



on-stream inspection can be performed if an RBI assessment determines that risk associated with the vessel is

- Acceptably low
- The effectiveness of the external NDE technique(s) is adequate for the expected damage mechanism.

This assessment should include a review of past process conditions and likely future process conditions.

For similar pressure vessel operating within the same or similar service and conditions:

the results of internal inspection can be used to determine whether an on-stream inspection can be substituted for an internal inspection or not.

The inspection of one vessel (preferably the worst case) may be taken as representative of the whole train when:

- Two or more pressure vessels are installed in series
- No potentially corrosive contaminants could potentially affect the vessel integrity,
- The operating conditions in any part of the train are the same,
- Provided that sufficient corrosion history has been accumulated

When an on-stream inspection is conducted, the type and extent of NDE should be specified in the inspection plan. This could include ultrasonic thickness measurements, radiography, or other appropriate means of NDE to measure metal thicknesses and/or assess the integrity of the pressure boundary (e.g. vessel wall and welds). When an on-stream inspection is conducted, **the inspector shall be given sufficient access to all parts of the vessel (heads, shell, and nozzles) so that an accurate assessment of the vessel condition can be made.**



INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

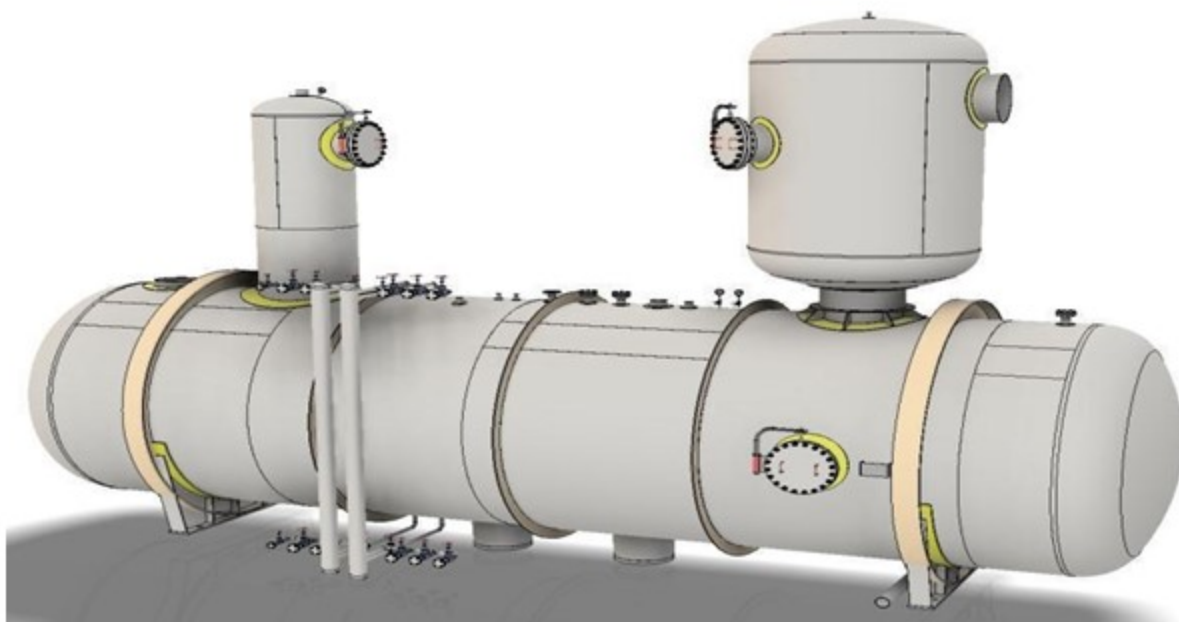
1
3
2

Multizone Vessels



For a **large vessel** with two or more zones of differing corrosion rates:

each zone may be treated independently when determining the inspection intervals or for substituting the internal inspection with an on-stream inspection. **Each zone shall be inspected based on the interval for that zone.**



INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

3

Pressure-relieving Devices



PRVs shall be tested and repaired by a repair organization qualified and experienced in PRVs maintenance

PRVs should be inspected, tested, and maintained in accordance with API 576.

Each repair organization shall have a fully documented QA process. As a minimum, the following shall be included in the QA manual:

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.

The inspection interval for all PRVs is determined by either the inspector, engineer, or other qualified individual per the owner/ user's QA system.

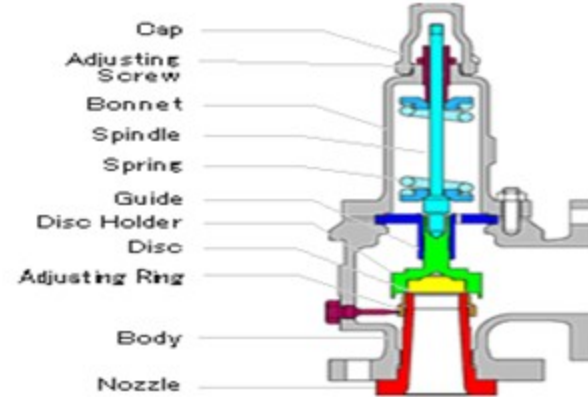
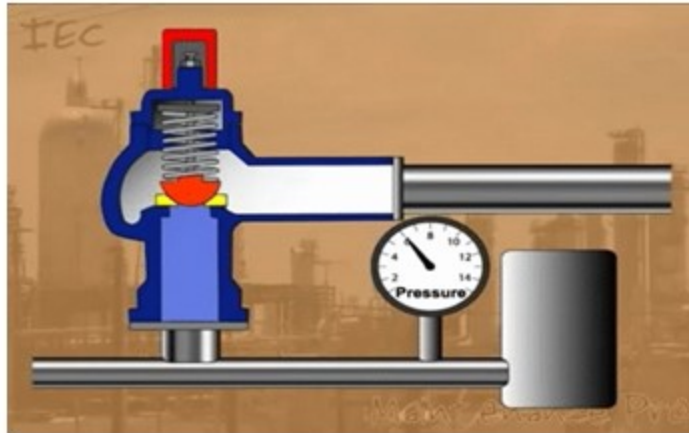
★ Unless documented experience and/or a RBI assessment indicates that a longer interval is acceptable, test and inspection intervals for PRVs should not exceed:

- a) 5 years for typical process services, and
- b) 10 years for clean (non-fouling) and noncorrosive services.

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

1
3
5

Pressure-relieving Devices



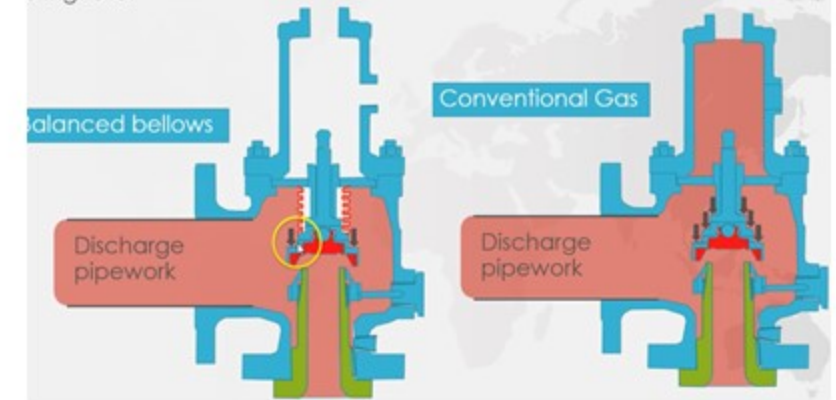
BACK PRESSURE

One question I asked myself is what about the back pressure on the bellows.

The forces on the bellows cancel each other out.



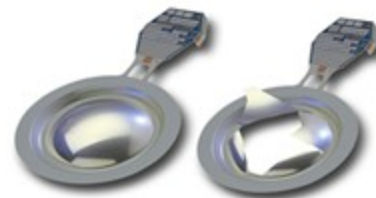
Comparing Balanced bellows & Conventional purging relief



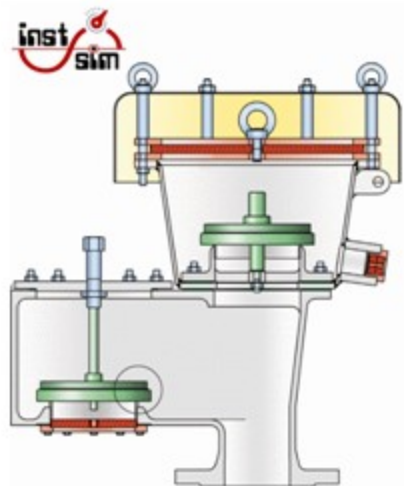
QA Manual Content



- a) title page;
- b) revision log;
- 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 QC manual;
- o) sample forms;
- p) training and qualifications required for repair personnel;
- q) requirements for handling of nonconformances;
- r) requirements for shop auditing for adherence to the QA process.



Rupture Disks



Vacuum Breaker Valves

INTERVAL/FREQUENCY AND EXTENT OF INSPECTION

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PRVs Testing and Inspection Intervals

When a pressure-relieving device is found to be heavily fouled or stuck shut, **the inspection and testing interval shall be reevaluated** to determine if the interval should be shortened. The review should try to determine the cause of the fouling or the reasons for the pressure-relieving device not operating properly.

Other pressure-relieving devices (e.g. rupture disks and vacuum-breaker valves) shall be inspected at intervals based on service conditions.



Figure 33—Moving Parts of Valve Fouled with Iron Sulfide (FeS_2)



Deferral



WHAT IS A DEFERRAL

Inspections, tests, or examinations for Pressure Vessel and associated pressure-relieving devices that cannot be completed by their due date **may be deferred for a specified period**, subject to the requirements in the following sub-sections.

Vessels or pressure-relieving devices that are **operated after the due date without** a valid deferral in accordance with these requirements **are not permitted by this code.**

Deferrals should be from time to time, not **a frequent occurrence.**

All deferrals **shall be documented.**

Pressure vessels or pressure-relieving devices that were granted a deferral can be operated to the new due date **without being considered overdue** for the deferred inspections, tests, or examinations.

DEFERRAL OF INSPECTIONS, TESTS, AND EXAMINATIONS

Simplified Deferral



A simplified short-term deferral

may be approved by the owner-user if all of the following conditions are met:

- (1) The current due date for the inspection, test, or examination **has not been previously deferred**.
- (2) The proposed new due date would **not increase** the current inspection/servicing interval or due date by **more than 10 % or six months, whichever is less**.
- (3) A **review** of the current operating conditions, as well as the vessels or pressure-relieving device history, has been completed with results that support a short-term/one-time deferral.
- (4) The deferral request **has the accept of** the inspector representing or employed by the owner-user and an appropriate operations management representative(s).
- (5) Updates to the vessels or pressure-relieving **device records with deferral documentation** are complete before it is operated after the original due date.

DEFERRAL OF INSPECTIONS, TESTS, AND EXAMINATIONS

140

Deferral

✓ Deferral

Deferral requests **not meeting the conditions** of a simplified deferral  **shall** follow **all of the following** minimum requirements:

a) **Perform a documented risk-assessment** or update an existing RBI assessment to determine if the proposed deferral date would increase risk above acceptable risk threshold levels as defined by the owner-user. The risk assessment may include any of the following elements as deemed necessary by the owner/user:

- fitness for service analysis results;
- consequence of failure;
- applicable damage mechanism susceptibilities and rates of degradation;
- calculated remaining life;
- historical conditions/findings from inspections, tests, and examinations and their technical significance;
- extent and/or probability of detection (i.e. effectiveness) of previous inspections, tests, or examinations, as well as the amount of time that has elapsed since they were last performed;
- considerations for any previous changes to inspection or test intervals (e.g. reductions in interval due to deteriorating conditions);
- disposition(s) of any previous requests for deferral on the same piping or pressure-relieving device;
- historical conditions/findings for piping or pressure-relieving devices in similar service, if available.

b) Determine if the deferral **requires** the implementation of, or modification to existing **integrity operating windows** or operating process control limits.

c) Review the **current inspection plan** to determine if modifications are needed to support the deferral.

d) Obtain the **accept and approval of appropriate piping personnel** including the inspector representing, or employed by the owner-user and appropriate operations management representative(s).

e) Updates to the piping or pressure-relieving device records with **deferral documentation** are complete before it is operated after the original due date.

DEFERRAL OF INSPECTIONS, TESTS, AND EXAMINATIONS

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Deferral

✓ Deferral of Inspection Repair Recommendation Due Dates

- Inspection repair recommendations that cannot be completed by their due date can be deferred for a specific period of time, if appropriate, by a documented change in date of required completion.
- The deferral of the due date shall be documented in the inspection records and have the concurrence with the appropriate pressure equipment inspection personnel including the inspector and the inspection supervisor.
- Inspection recommendations that have not been completed by the required due date without a documented and approved change of date are not permitted by this code and are considered overdue for completion.
- The deferral of inspection recommendations should be the occasional exception not a frequent occurrence.
- Equipment must remain within the limits of the minimum required thickness as determined in this code or by other engineering evaluation during the period of deferral.

✓ Review of Inspection Repair Recommendations

Inspector recommendations can be changed or deleted after review by pressure vessel engineer or inspection supervision. If that is the case, inspection records shall record the reasoning, date of change/deletion, and name of person who did the review.



7



INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING





CH 7

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

CONTENT



7.1

**Corrosion Rate
Determination**

7.2

**Remaining Life
Calculations**

7.3

(MAWP) Determination

7.4

**FFS Analysis of
Corroded Regions**

7.5

FFS Evaluations

7.6

Required Thickness Determination

7.7

**Evaluation of Existing Equipment with
Minimal Documentation**

7.8

Reports and Records

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

✓ Corrosion Rate Determination



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

The short-term (ST) corrosion rate shall be calculated from the following formula:

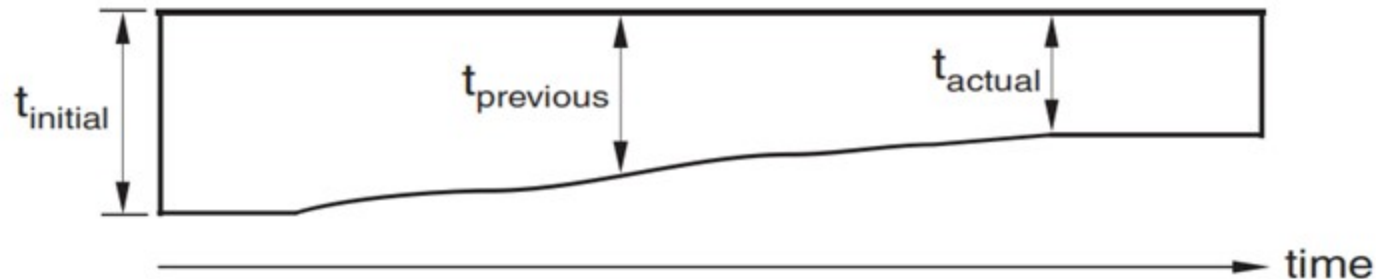
$$\text{Corrosion rate (ST)} = \frac{t_{\text{previous}} - t_{\text{actual}}}{\text{time between } t_{\text{previous}} \text{ and } t_{\text{actual}} \text{ (years)}}$$

where

t_{initial} is the initial thickness at the same CML as t_{actual} . It is either the first thickness measurement at this CML or the thickness at the start of a new corrosion rate environment, in in. (mm);

t_{actual} is the actual thickness of a CML, in in. (mm), measured during the most recent inspection;

t_{previous} is the previous thickness measured during the prior inspection. It is at the same location as t_{actual} measured during a previous inspection, in in. (mm).



Calculate the long-term corrosion rate from the following wall thickness data: original thickness was 0.500 in., year 2: 0.480 in.; year 4: 0.465 in., year 6: 0.447 in., year 8: 0.409 in., year 12: 0.401 in. (round-off to nearest 0.001 in.).

Task: Determine the long-term corrosion rate.

Formula:

From API 510 ¶7.1.1.1:

$$\text{LTCR} = \frac{t_{\text{initial}} - t_{\text{actual}}}{\text{time between } t_{\text{initial}} \text{ and } t_{\text{actual}} \text{ (years)}}$$

Required Variables:

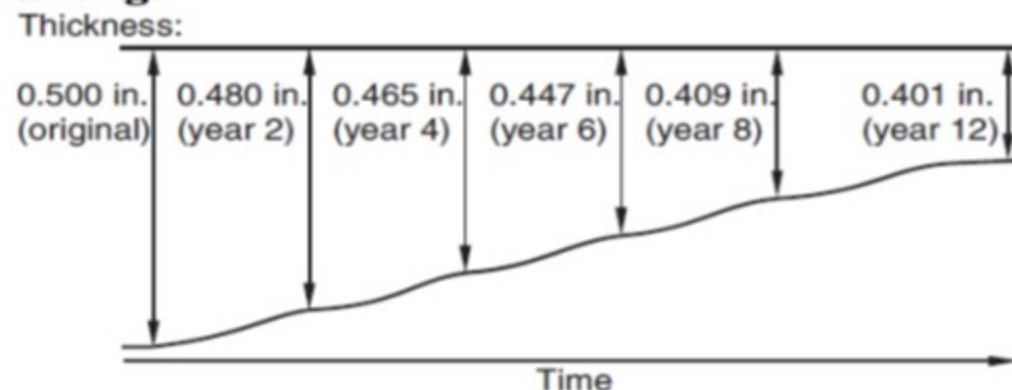
$$t_{\text{initial}} = 0.500 \text{ in.}$$

$$t_{\text{actual}} = 0.401 \text{ in. (year 12)}$$

$$\text{time between } t_{\text{initial}} \text{ and } t_{\text{actual}} = 12 \text{ years}$$

$$\begin{aligned} \text{LTCR} &= \frac{t_{\text{initial}} - t_{\text{actual}}}{\text{time between } t_{\text{initial}} \text{ and } t_{\text{actual}} \text{ (years)}} \\ &= \frac{0.500 \text{ in.} - 0.401 \text{ in.}}{12 \text{ years}} \\ &= \frac{0.099 \text{ in.}}{12 \text{ years}} \\ &= 0.008 \text{ in./year} \end{aligned}$$

Drawing:



INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

✓ Corrosion Rate Evaluation



When evaluating corrosion rates as part of the data assessment, **the inspector, in consultation with a corrosion specialist, shall select the corrosion rate that best reflects the current conditions.**

The following should be considered for calculating **remaining life** and the **next inspection due date**:

- a) whether the corrosion damage mechanism is **general** or **localized**;
- b) areas subject to **fluid impingement**, erosive fluid, or erosive-corrosive conditions;
- c) **estimated time of initiation of the corrosion problem** (if corrosion not occur from initial operation) as a basis for measuring wall loss and appropriate time interval for determining the corrosion rate;
- d) the potential point where **process change(s) occurred** that may have caused the corrosion (such as water wetting, chlorides entering the process, or lower PH);
- e) the effect of scale formation to either protect the component from corrosion or the loss of that protection (such as higher fluid velocity stripping the protective scale away from the vessel wall);
- f) the potential for accelerated corrosion in **stagnant areas** (such as where iron sulfide might accumulate);
- g) **continuing operation within the IOW.**

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

Newly Installed Pressure Vessels or Changes in Service



For a **new vessel** or for a **vessel for which service conditions are being changed**, one of the following methods shall be used to determine the vessel's probable corrosion rate. The remaining life and inspection interval can be estimated from this rate.

- a) A corrosion rate may be calculated from data collected by the owner/user on vessels operating in the same or similar service.
- b) A corrosion rate may be **estimated by a corrosion specialist**.
- c) A corrosion rate may be estimated from **published data** on vessels in same or similar service.
- d) If the probable corrosion rate cannot be determined by any of the above items, an **on-stream** determination shall be made after **three to six months** (from 0 to 3,6) **of service** by **using suitable corrosion monitoring devices** or **actual thickness measurements of the vessel**.
After that determinations shall be made at appropriate intervals until a real corrosion rate is established. If it is later determined that an inaccurate corrosion rate was assumed, the corrosion rate in the remaining life calculations shall be changed to the actual corrosion rate.

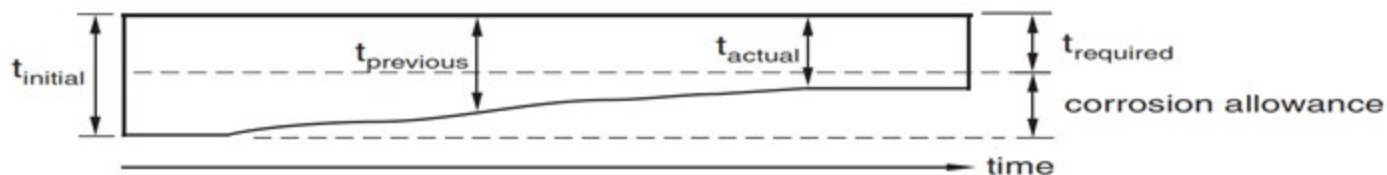
INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

✓ Remaining Life Calculations



$$\text{Remaining life} = \frac{t_{\text{actual}} - t_{\text{required}}}{\text{corrosion rate}}$$

where



t_{actual} is the actual thickness of a CML, in in. (mm), measured during the most recent inspection;

t_{required} is the required thickness at the same CML or component, in in. (mm), as the actual measurement. It is computed by the design formulas (e.g. pressure and structural) and does not include corrosion allowance or manufacturer's tolerances.

A statistical analysis may be used in the corrosion rate and remaining life calculations for the pressure vessel sections. This statistical approach may be applied for assessment of substituting an internal inspection [see 6.5.2.1 b)] or for determining the internal inspection interval. Care must be taken to ensure that the statistical treatment of data results reflects the actual condition of the vessel section, especially those subject to localized corrosion. Statistical analysis may not be applicable to vessels with random but significant localized corrosion. The analysis method shall be documented.

An ASTM A 414 Gr. C pressure vessel has a minimum required thickness of 0.205 in. and the initial thickness of 0.340 in. The following thickness measurements were taken over the 15 years of operating service: year 2: 0.335 in.; year 4: 0.329 in.; year 6: 0.320 in.; year 10: 0.312 in.; year 15: 0.230 in. (round-down to nearest year). What is the remaining life for the worst condition?

Task: Determine the remaining life.

Formula:

From API 510, §7.2.1:

$$\text{Remaining Life} = \frac{t_{\text{actual}} - t_{\text{required}}}{\text{corrosion rate}}$$

Required Variables:

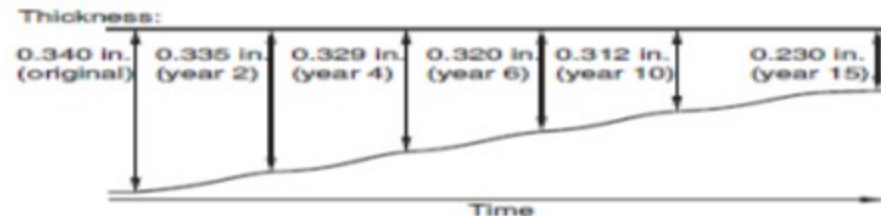
$$t_{\text{previous}} = 0.312 \text{ in. (year 10)}$$

$$t_{\text{actual}} = 0.230 \text{ in. (year 15)}$$

$$t_{\text{initial}} = 0.340 \text{ in.}$$

$$t_{\text{required}} = 0.205 \text{ in.}$$

Drawing:



The corrosion rate is the higher of the calculated short-term and long-term corrosion rates (API 510, §7.1.1.2).

$$\text{STCR} = \frac{t_{\text{previous}} - t_{\text{actual}}}{\text{time between } t_{\text{previous}} \text{ and } t_{\text{actual}}}$$

$$\text{LTCR} = \frac{t_{\text{initial}} - t_{\text{actual}}}{\text{time between } t_{\text{initial}} \text{ and } t_{\text{actual}}}$$

$$\begin{aligned} \text{time between } t_{\text{previous}} \text{ and } t_{\text{actual}} &= 15 \text{ yr.} - 10 \text{ yr.} \\ &= 5 \text{ yr.} \end{aligned}$$

$$\text{time between } t_{\text{initial}} \text{ and } t_{\text{actual}} = 15 \text{ yr.}$$

$$\begin{aligned} \text{STCR} &= \frac{0.312 \text{ in.} - 0.230 \text{ in.}}{5 \text{ years}} \\ &= \frac{0.082 \text{ in.}}{5 \text{ years}} \\ &= 0.016 \text{ in./year} \end{aligned}$$

$$\begin{aligned} \text{LTCR} &= \frac{0.340 \text{ in.} - 0.230 \text{ in.}}{15 \text{ years}} \\ &= \frac{0.110 \text{ in.}}{15 \text{ years}} \\ &= 0.007 \text{ in./year} \end{aligned}$$

In this case, the short-term corrosion rate is the highest, so it is used in the calculation for remaining life.

$$\begin{aligned} \text{Remaining Life} &= \frac{t_{\text{actual}} - t_{\text{required}}}{\text{corrosion rate}} \\ &= \frac{0.230 \text{ in.} - 0.205 \text{ in.}}{0.016 \text{ in./year}} \\ &= \frac{0.025 \text{ in.}}{0.016 \text{ in./year}} \\ &= 1 \text{ year} \end{aligned}$$

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

(MAWP) Determination



The MAWP for the continued use of a pressure vessel shall be based on computations that are determined using

- The latest applicable edition of the ASME Code or
- The construction code to which the vessel was built

The resulting MAWP from these computations **shall not be greater than the original MAWP** unless a **rerating is performed**

MAWP Calculation may be made only if the following essential details **comply with** the applicable requirements of the code being used:

- Head, shell, and nozzle reinforcement designs;
- Material specifications;
- Allowable stresses;
- Weld joint efficiencies;
- Inspection acceptance criteria;
- Cyclical service requirements.

$$t = \frac{PR}{SE - 0.6P} \quad \text{or} \quad P = \frac{SEt}{R + 0.6t}$$

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

(MAWP) Determination



In corrosive service, the wall thickness used in these computations shall be the actual thickness as following

$$t = t_{\text{actual}} - 2(C_{\text{rate}} \times I_{\text{internal}})$$

where

C_{rate} is the governing corrosion rate in in. (mm) per year;

I_{internal} **is the interval of** the next internal or on-stream inspection in years;

t_{actual} is the actual thickness of a CML, in in. (mm), measured during the most recent inspection.

Multiple thickness measurements shall be taken when the **actual thickness** determined by inspection of the component is **greater or lesser** than the **thickness reported in the material test report** or the manufacturer's data report, especially if the component was made by a forming process.

- The thickness measurement procedure shall be approved by the inspector.

What would be the thickness required for calculating the MAWP for continued service of a pressure vessel that had an original wall thickness of 0.250 in., original required minimum thickness of 0.200 in., an actual thickness of 0.230 in., a corrosion rate of 0.004 in./year, and the next inspection interval is 10 years?

Task: Determine the thickness required for calculating the MAWP.

Formula:

From API 510, ¶7.3.3:

$$t = t_{\text{actual}} - 2 (C_{\text{rate}} \times I_{\text{interval}})$$

Required Variables:

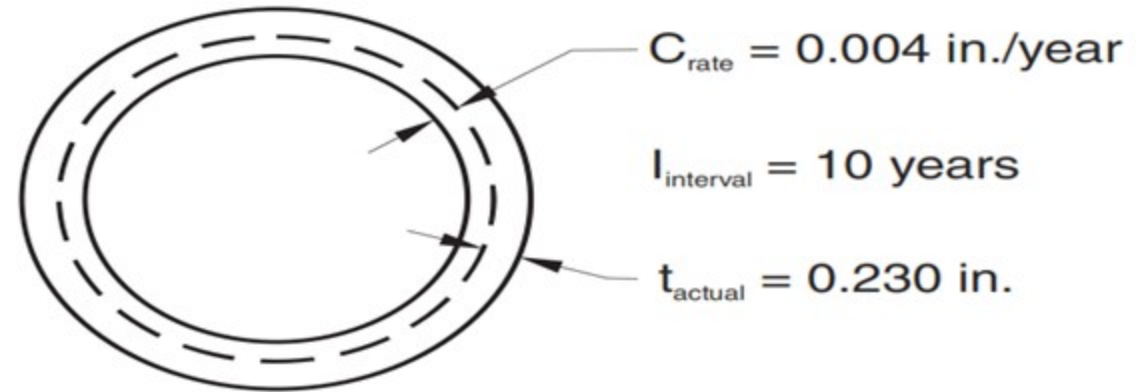
$$t_{\text{actual}} = 0.230 \text{ in.}$$

$$C_{\text{rate}} = 0.004 \text{ in./year}$$

$$I_{\text{interval}} = 10 \text{ years}$$

$$\begin{aligned} t &= t_{\text{actual}} - 2 (C_{\text{rate}} \times I_{\text{interval}}) \\ &= 0.230 \text{ in.} - 2 (0.004 \text{ in./year} \times 10 \text{ years}) \\ &= 0.230 \text{ in.} - 2 \times 0.040 \text{ in.} \\ &= 0.230 \text{ in.} - 0.080 \text{ in.} \\ &= 0.150 \text{ in.} \end{aligned}$$

Drawing:



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

Example



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)	0.01 in./year (0.254 mm/year)
Next planned inspection	5 years
Estimated corrosion loss by date of next inspection	$= 5 \times 0.01 = 0.05$ in. ($5 \times 0.254 = 1.27$ mm)
Estimated thickness minus twice the estimated corrosion loss, t	$= (0.32 - (0.05 \times 2)) = 0.22$ in. [$=(8.13 - (1.27 \times 2)) = 5.59$ mm]
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	$= 7 \times 0.01 = 0.07$ in. ($7 \times 0.254 = 1.78$ mm)
Estimated thickness minus twice the estimated corrosion loss, t	$= (0.32 - (0.07 \times 2)) = 0.18$ in. [$=(8.13 - (1.78 \times 2)) = 4.57$ mm]
MAWP In USC units	$= 2SEt/D = 450$ psig
In SI units	$= 3104$ kPa
Conclusion: <u>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.</u>	
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.	

Three options



Example (1)



Design pressure = 500 psig

t (actual) = 0.32 inch

Observed corrosion rate = 0.01 in./year

Next planned inspection = **5 Years**

Estimated corrosion loss by date of next inspection = $5 \times 0.01 = 0.05 \text{ in}$

Estimated thickness minus twice the estimated corrosion loss = $(0.32 - (0.05 \times \mathbf{2})) = 0.22 \text{ inch}$

MAWP = $2SEt/D = 550 \text{ psig}$ **>** Design pressure = 500 psig

2020

2025



1
5
5

Safety Factor



Example (2)



Design pressure = 500 psig
 t (actual) = 0.32 inch
 Observed corrosion rate = 0.01 in./year
 Next planned inspection = **7 Years**



Estimated corrosion loss by date of next inspection = $5 \times 0.01 = 0.07$ in

Estimated thickness minus twice the estimated corrosion loss = $(0.32 - (0.07 \times 2)) = 0.18$ inch

MAWP = $2SEt/D = 450$ psig $<$ Design pressure = 500 psig

Safety Factor

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

✓ FFS Analysis of Corroded Regions

A FFS analysis of corroded area for any parts of vessel can use an **adjusted actual thickness** and **maximum corrosion rate** at any inspection provided the following are considered

Evaluation of Locally Thinned Areas

Evaluation of Pitting

Alternative Evaluation Methods for Thinning

Joint Efficiency Adjustments

Corroded Areas in Vessel Heads

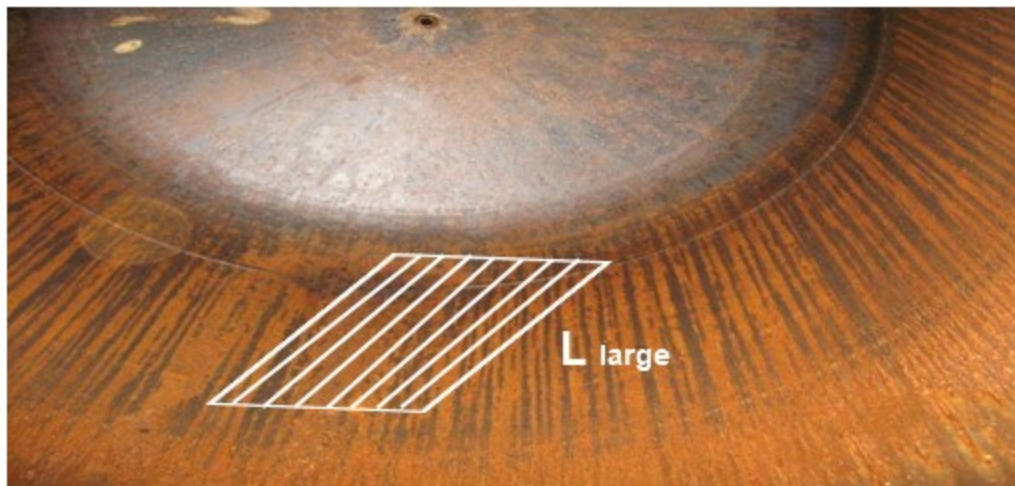
INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

Evaluation of Locally Thinned Areas



For a corroded area (less than required thickness) of considerable size the wall thicknesses may be averaged over a **length not exceeding** the following:

ID **greater** than 60 in. (150 cm)



$L_{\text{large}} = \frac{1}{3} \text{ ID or } 100 \text{ cm whichever is less}$

ID **less** than or equal to 60 in. (150 cm)



$L_{\text{small}} = \frac{1}{2} \text{ ID or } 50 \text{ cm whichever is less}$

- the thickness readings should be equally spaced along the designated length
- for larger areas, multiple lines in the corroded area may be required to determine the lowest average thickness.

Note: API 510, §7.4.2 does not define what is meant by “locally thinned” or “area of considerable size”. It is commonly left up to the inspector or engineer to determine “how thin is thin” and the dimensions of an “area of considerable size”.

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING



The following criteria **must be met** in order to use thickness averaging:

- the region of metal loss has relatively smooth contours without notches (i.e. negligible local stress concentrations),
- the equipment does not operate in the creep range,
- the component is not in cyclic service,
- **a minimum of 15 thickness readings** should be included in the data set,
- minimum reading must be included in the thickness average;
- lowest individual reading **cannot be less than 50 % of t_{required}**

For a corroded area of considerable size, what is the maximum length that thickness measurements can be averaged to determine the corrosion rate for a pressure vessel with a 4 ft inside diameter?

Task: Determine the maximum length that thickness measurements can be averaged to determine the corrosion rate for a pressure vessel.

Formula:

From API 510 ¶7.4.2.1:

For vessels with inside diameters less than or equal to 60 in.:
Maximum length = lesser of $\frac{1}{2}$ of vessel diameter or 20 in.

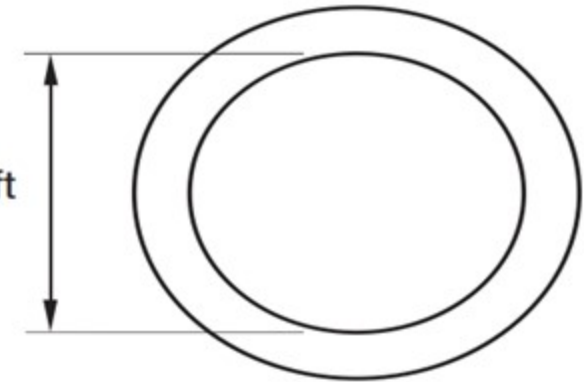
Required Variables:

$$\begin{aligned}\text{Vessel diameter} &= 4 \text{ ft} \times 12 \text{ in./ft} \\ &= 48 \text{ in.}\end{aligned}$$

Since the vessel diameter is less than 60 in., the maximum length would be determined as follows:

$$\begin{aligned}\text{Maximum length} &= \text{lesser of } \frac{1}{2} (48 \text{ in.}) \text{ or } 20 \text{ in.} \\ &= \text{lesser of } 24 \text{ in. or } 20 \text{ in.} \\ &= 20 \text{ in.}\end{aligned}$$

Drawing:



INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING



Governing Stresses Along Locally Thinned Area Designated Lengths

When evaluating pressure vessel with a locally thinned (corroded) area of considerable size for a fitness for service analysis, the governing stresses along a designated length must be considered as follows:

- when **Circumferential Stresses** govern (typical for most vessels),: thickness readings are taken along a longitudinal length
- when **Longitudinal Stresses** govern (because of wind loads, saddle support in horizontal vessels, or other factors),: thickness readings are taken along a circumferential length (an arc)

For a locally corroded area of considerable size, where the following thicknesses were measured over a 36 in. × 36 in. area to determine the corrosion rate for a pressure vessel with a 9 ft inside diameter, what average thickness would be used in a fitness for service analysis for continued service if the circumferential stresses governs?

Note: the numbered rows are in longitudinal direction (1a, 2a, 3a, 4a) and the lettered rows are in the circumferential direction (1a, 1b, 1c, 1d).

1a	0.200 in.	2a	0.225 in.	3a	0.218 in.	4a	0.202 in.
1b	0.202 in.	2b	0.220 in.	3b	0.215 in.	4b	0.222 in.
1c	0.220 in.	2c	0.202 in.	3c	0.198 in.	4c	0.211 in.
1d	0.225 in.	2d	0.200 in.	3d	0.195 in.	4d	0.196 in.

Task: Determine the average thickness to be used for circumferential stresses.

Formula:

From API 510 ¶7.4.2.2 and ¶7.4.2.3:

$$\text{average value} = \frac{\text{sum of all values}}{\text{total number of values}}$$

Required Variables:

The question gives all the thickness measurements in both the longitudinal and circumferential directions.

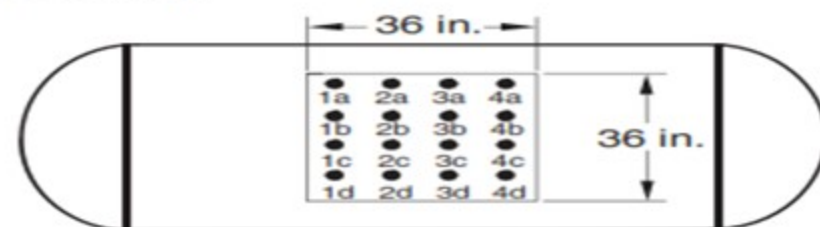
Draw a diagram to help determine correct orientation of longitudinal and circumferential directions.

Since the circumferential stresses govern, the principle stresses will be in the longitudinal direction (1a, 2a, 3a, 4a). The average stresses for the longitudinal direction are calculated as show in the table below. The lowest value is the thickness to be used.

	1	2	3	4	Total	Average
a	1a 0.200 in.	2a 0.225 in.	3a 0.218 in.	4a 0.202 in.	0.845 in.	0.211 in.
b	1b 0.202 in.	2b 0.220 in.	3b 0.215 in.	4b 0.222 in.	0.859 in.	0.215 in.
c	1c 0.220 in.	2c 0.202 in.	3c 0.198 in.	4c 0.211 in.	0.831 in.	0.208 in.
d	1d 0.225 in.	2d 0.200 in.	3d 0.195 in.	4d 0.196 in.	0.816 in.	0.204 in.

In this case, the lowest average thickness to be used is 0.204 in.

Drawing:



Circumferential stresses govern.

Therefore, principle stresses are in longitudinal direction.

Add in longitudinal direction. →

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING



Other Factors for Locally Thinned Area Designated Lengths

When performing thickness averaging **near structural discontinuities** (e.g. a **nozzle**, conical section transition, and flange connection), the limits for thickness averaging shall be considered separately for the reinforcement window area (or other area of high local stress) and the area outside/adjacent to the reinforcement window (or other area of high local stress).

a) When performing thickness averaging near a nozzle, **the designated length shall not extend within the limits of the reinforcement as defined in the construction code**. Consideration shall be given to any extra reinforcement included in the nozzle reinforcement design (e.g. a larger extended reinforcing pad diameter to address piping load considerations or wind loads).

b) Technical considerations for thickness averaging **within the reinforcement window** for structural discontinuities are provided in API 579-1/ASME FFS-1, Part 4.

- When performing remaining life calculations in 7.2, the **lowest average of any length in the corroded area is substituted for t_{actual}** .

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

Alternative Evaluation Methods for Thinning



As alternative evaluation methods for pressure vessels and their components **with thinning below the required thickness**, API 510 permits the use of design by analysis methods of:

- ASME Section VIII, Division 2, Appendix 4,
- or API 579 Appendix B.

These methods may also be used to evaluate blend ground areas of defect removal to ensure that there are no sharp corners to minimize stress concentration effects.

There is one additional rule when using ASME Section VIII, Division 2, Appendix 4 as an alternative method of evaluating thinned areas. This rule is based on substituting the S_m value of Division 2 with the stress value used in the original pressure vessel design, as follows:

- if the design stress is $\leq 2/3$ -specified minimum yield strength (SMYS) at temperature, then the stress value used in the original pressure vessel design may be used;
- if the original design stress is $> 2/3$ -specified minimum yield strength at temperature, then $2/3$ -specified minimum yield strength shall be substituted for S_m .

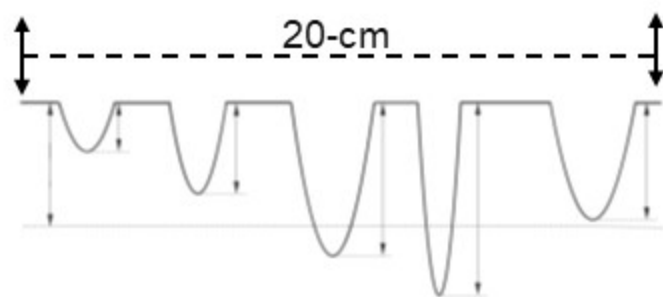
In either case, an engineer shall perform this analysis when used.

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

Evaluation of Pitting (widely scattered pits)

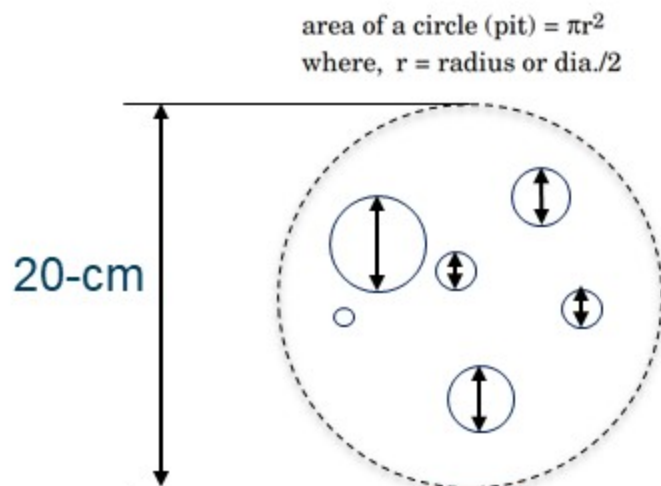
During the current inspection, widely scattered pits **may be ignored** as long as **all** of the following are true:

- 1 Remaining thickness below the pit is **greater than ($\frac{1}{2} t_{\text{required}}$)**
- 2 Total area of the pitting **that is deeper than the corrosion allowance** does not exceed (45 cm^2) within any (20-cm) diameter circle,
- 3 Sum of the pit dimensions **that is deeper than the corrosion allowance** along any straight (20-cm) line does not exceed (5 cm).



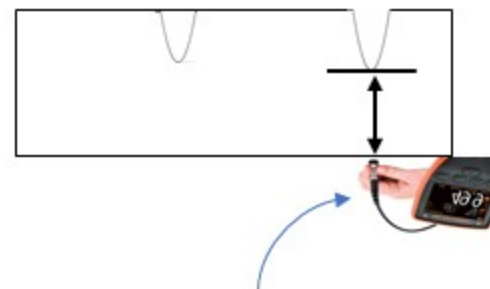
3

&



2

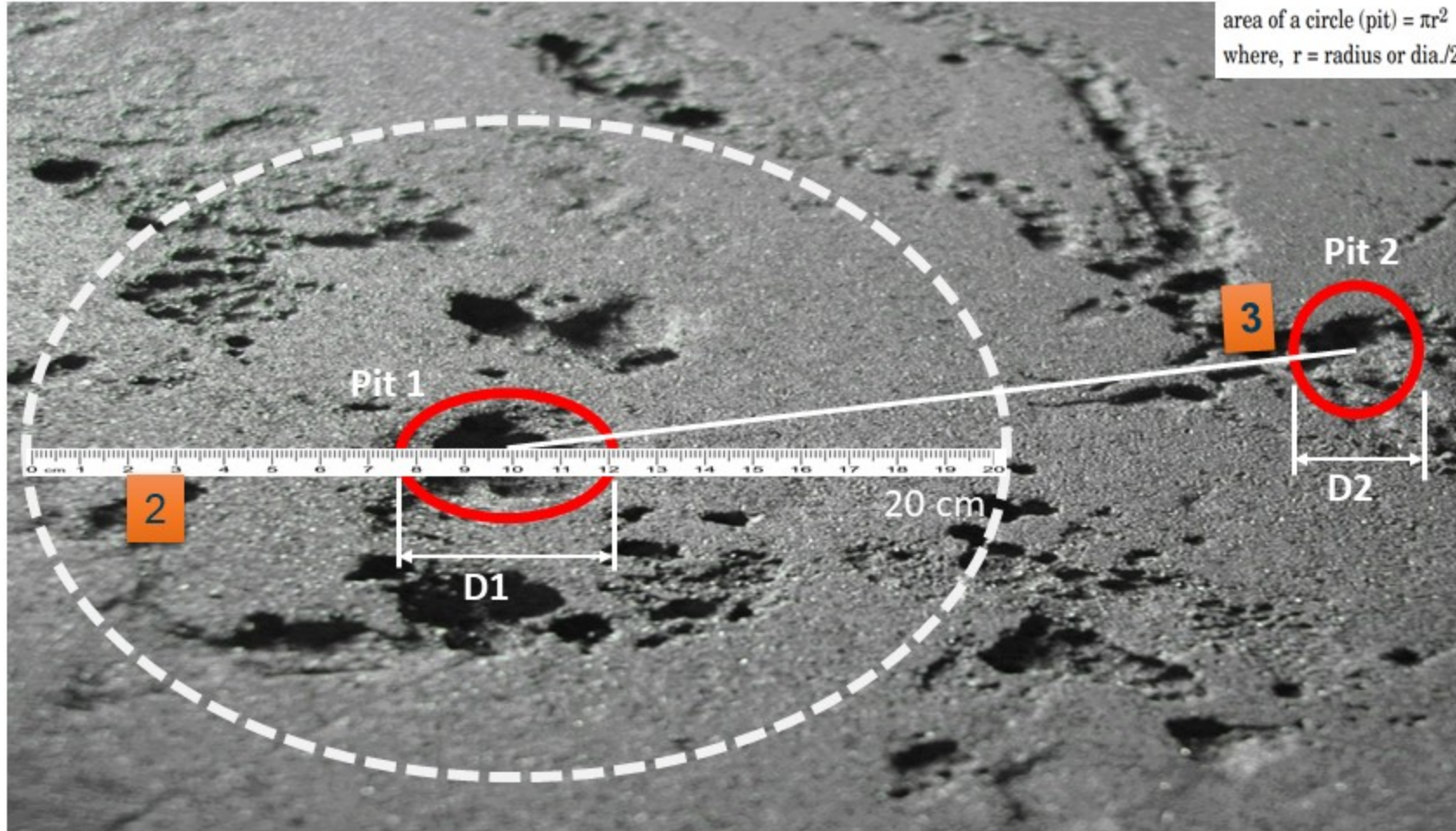
&



1

Pit 1 & Pit 2

- ✓ Deeper than the corrosion allowance
- ✓ Remaining thickness below the pit is greater than ($\frac{1}{2}$ t required)



When evaluating widely scattered pits as part of a fitness for service analysis of corroded regions in a pressure vessel the following data was recorded during the current inspection: inside diameter of 4 ft., required thickness of 1.00 in., corrosion allowance of 0.125 in., all pits are contained in a 8-in. diameter circle, no pit is greater than one-half the required thickness and the sum of the pit dimensions is satisfactory. What is the total area of the pitting with the following data and may these pits be ignored?

pit 1: 1 in. diameter pit 2: 1/2 in. diameter pit 3: 3/4 in. diameter
pit 4: 1/2 in. diameter pit 5: 3/4 in. diameter

Task: Determine the total area of pits
and whether or not they can be ignored.

Drawing:

Formula:

It is assumed that all pits are circular, and so the area of a pit can be calculated using the following formulas:

area of a circle (pit) = πr^2
where, r = radius or dia./2

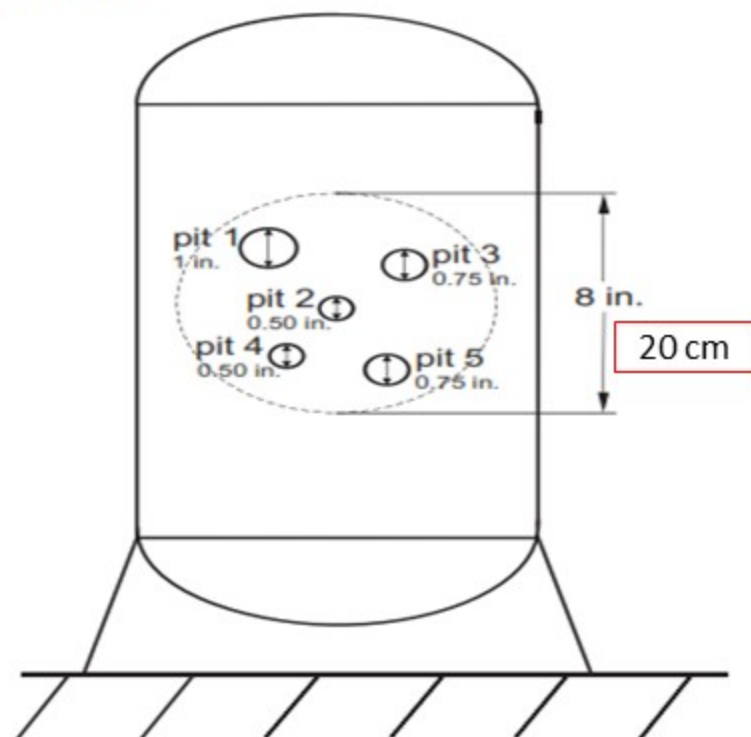
Required Variables: ¶ 7.4.3(b)

dia. (pit 1) = 1 in.
dia. (pit 2) = 0.5 in.
dia. (pit 3) = 0.75 in.
dia. (pit 4) = 0.5 in.
dia. (pit 5) = 0.75 in.

area (pit 1) = $\pi(1 \text{ in.}/2)^2 = 0.785 \text{ in.}^2$
area (pit 2) = $\pi(0.5 \text{ in.}/2)^2 = 0.196 \text{ in.}^2$
area (pit 3) = $\pi(0.75 \text{ in.}/2)^2 = 0.442 \text{ in.}^2$
area (pit 4) = $\pi(0.5 \text{ in.}/2)^2 = 0.196 \text{ in.}^2$
area (pit 5) = $\pi(0.75 \text{ in.}/2)^2 = 0.442 \text{ in.}^2$

total area = $0.785 \text{ in.}^2 + 0.196 \text{ in.}^2 + 0.442 \text{ in.}^2 + 0.196 \text{ in.}^2 + 0.442 \text{ in.}^2$
= 2.06 in.^2

Since the total area of 2.06 in.^2 is $\leq 7 \text{ in.}^2$, the pits can be ignored.

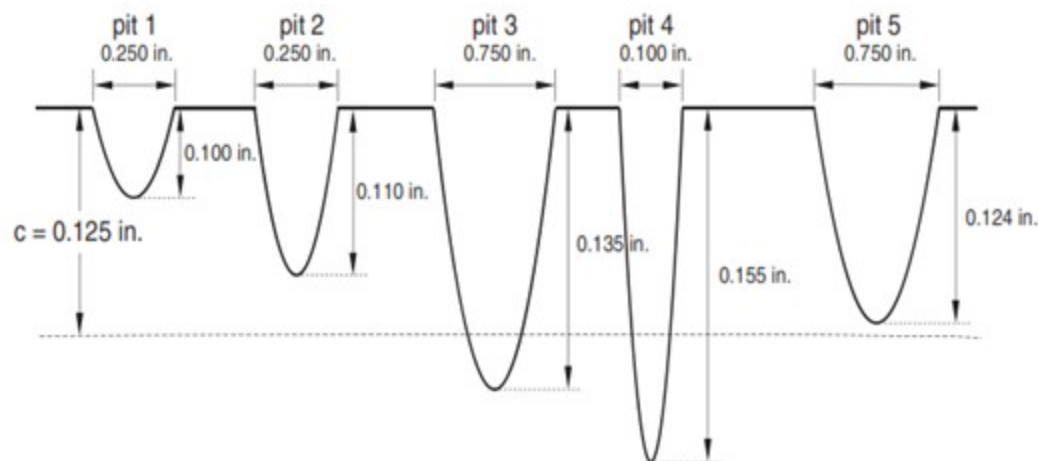


When evaluating widely scattered pits as part of a fitness for service analysis of corroded regions in a pressure vessel the following data was recorded during the current inspection: inside diameter of 4 ft., required thickness of 1.00 in., corrosion allowance of 0.125 in., no pit is greater than one-half the required thickness and the total area of pitting is satisfactory. What is the sum of the pit dimensions that is deeper than the corrosion allowance with the following data taken along a straight 8-in. line and may these pits be ignored?

pit 1: 0.250 in. dia., 0.100 in. deep pit 2: 0.250 in. dia., 0.110 in. deep
 pit 3: 0.750 in. dia., 0.135 in. deep pit 4: 0.100 in. dia., 0.155 in. deep
 pit 5: 0.750 in. dia., 0.124 in. deep

Task: Determine the sum of pit dimensions deeper than the corrosion allowance and whether or not they can be ignored.

Drawing:



Formula:

From API 510 ¶7.4.3(c): depth below c = pit depth - c

Required Variables:

pit 1 depth = 0.100 in. pit 2 depth = 0.110 in.
 pit 3 depth = 0.135 in. pit 4 depth = 0.155 in.
 pit 5 depth = 0.124 in.
 c = 0.125 in.

Pits that are deeper than the corrosion allowance will have a positive value for the depth below corrosion allowance.

pit 1 depth below c = 0.100 in. - 0.125 in. = -0.025 in.
 pit 2 depth below c = 0.110 in. - 0.125 in. = -0.015 in.
 pit 3 depth below c = 0.135 in. - 0.125 in. = 0.010 in.
 pit 4 depth below c = 0.155 in. - 0.125 in. = 0.030 in.
 pit 5 depth below c = 0.124 in. - 0.125 in. = -0.001 in.

Only pits 3 and 4 are deeper than the corrosion allowance:

dia. (pit 3) = 0.750 in.
 dia. (pit 4) = 0.100 in.

Sum of Pit Dimensions = 0.750 in. + 0.100 in.
 = 0.850 in.

The sum of pit dimensions is less than 2 in., so the pits can be ignored.

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

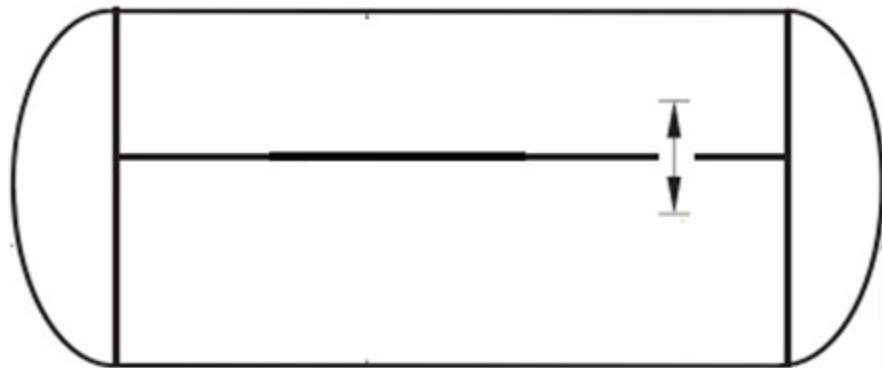
Joint Efficiency Adjustments



When the vessel surface away from a weld is corroded and the joint efficiency is less than 1.0, an independent calculation using the appropriate weld joint factor (typically 1.0) can be made.

When evaluating an in-service pressure vessel with **a corroded region on or near a weld** using a fitness for service analysis, the **weld joint efficiency (E)** may be required to be adjusted in accordance with API 510. For this analysis, the **surface at a weld** is defined as **the greater of:**

- 1 in. (2.5 cm = 25 mm) on either side of the weld, measured from the toe of the weld,
- or
- 2 x vessel required thickness, measured on either side of the weld.



$$t = \frac{PR}{SE - 0.6P} \quad \text{or} \quad P = \frac{SEt}{R + 0.6t}$$

An inspector is evaluating a longitudinal weld in a pressure vessel that has been corroded, as part of a fitness for service analysis. The pressure vessel is 9 ft in diameter, 40 ft long, made from ASME SA-516 Gr 70 normalized, with a required wall thickness of 0.550 in., and operates at 1,200 psi and 500°F. What is the minimum total width of the surface away from the weld that must be evaluated if the weld is 1 in. wide?

Task: Determine the minimum total length of the surface away from the weld that must be evaluated.

Formula:
From API 510 ¶7.4.5:

Length away from weld = greater of 1 in. or $2 \times t_{\text{required}}$

Note: the total length must include both sides of the weld (see diagram).

Total length = $2 \times (\text{length away from weld})$

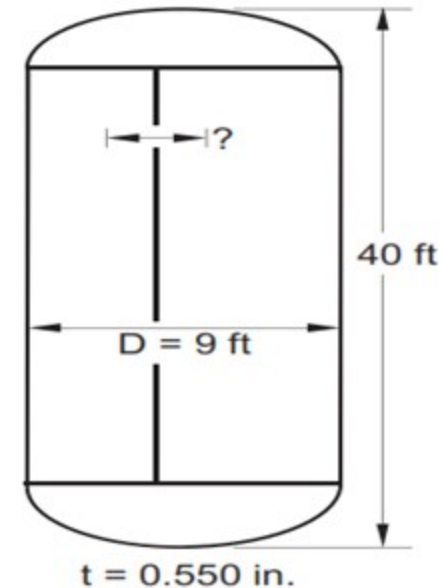
Required Variables:

$t_{\text{required}} = 0.550 \text{ in.}$

Length away from weld = greater of 1 in. or $2 \times t_{\text{required}}$
= greater of 1 in. or $2 (0.550 \text{ in.})$
= greater of 1 in. or 1.100 in.
= 1.100 in.

Total length = $2 (\text{length away from weld})$
= $2 (1.100 \text{ in.})$
= 2.200 in.

Diagram:



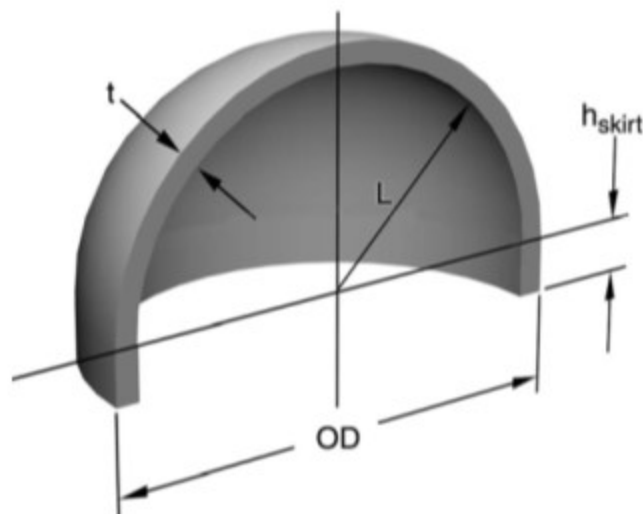
INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

7

Corroded Areas in Vessel Heads



Hemispherical head

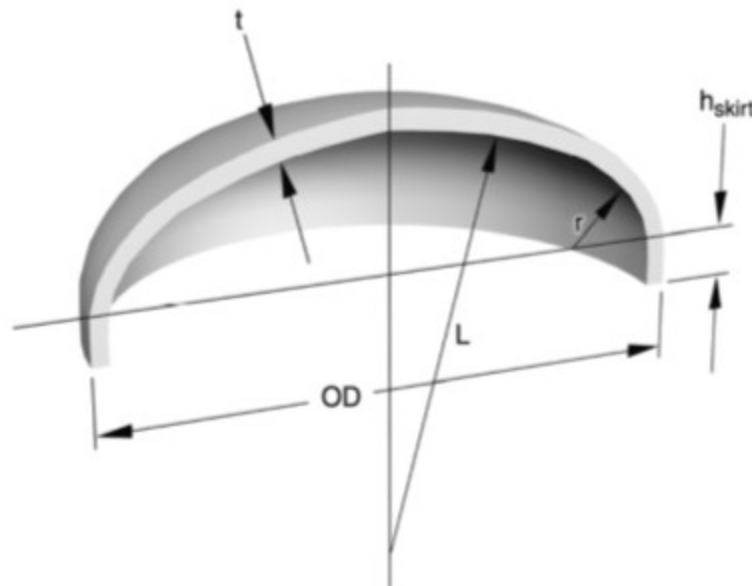


$$t = \frac{PL}{2SE - 0.2P}$$

or

$$P = \frac{2SEt}{L + 0.2t}$$

Tori spherical heads

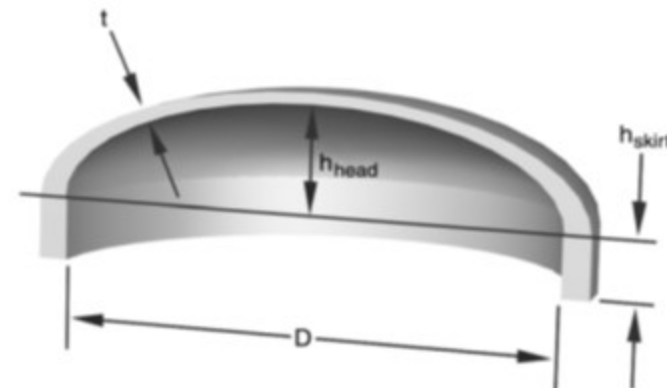


$$t = \frac{0.885PL}{SE - 0.1P}$$

or

$$P = \frac{SEt}{0.885L + 0.1t}$$

Ellipsoidal heads



The required minimum thickness for a 2:1 ellipsoidal head is:

$$t = \frac{PD}{2SE - 0.2P}$$

or

$$P = \frac{2SEt}{D + 0.2t}$$

(8)

where: t = minimum required thickness after forming, inches or mm

P = internal design pressure or maximum allowable working pressure, psi or kPa

D = inside diameter or inside length of the major axis of the head, inches or mm

S = maximum allowable tensile stress from Section II, Part D, psi or kPa depending on the version of the units employed in the vessel design

E = lowest efficiency of any point in the head.

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

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2

Corroded Areas in Vessel Heads



Table of Required Thickness Formulas for Heads with Corroded Regions

Head Type	Head Region	Formula
ellipsoidal (§7.4.6.1)	knuckle region	appropriate head formula in the construction code
	central portion	hemi-spherical head formula in the construction code
torispherical (§7.4.6.1)	knuckle region	appropriate head formula in the construction code
	central portion	hemi-spherical head formula in the construction code
Note: the central portion of the head is defined as the center of the head with a diameter equal to 80% of the shell diameter.		

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

Corroded Areas in Vessel Heads



Determining the Radius for Required Head Thickness Calculation in a Corroded Region

The rules for determining the appropriate radius (L) to use when calculating the required thickness for a corroded region within a head is shown in the following table.

Table Showing the Radius for Corroded Head Thickness Calculation

Head Type	Formula	Radius (L)
ellipsoidal (§7.4.6.3)	hemi-spherical head formula	$L = K_1 D^a$
torispherical (§7.4.6.2)	hemi-spherical head formula	$L = \text{crown radius}^b$
Notes: a. where D is the shell diameter (equal to the inside diameter) and K_1 is given in API 510, Table 7-1 b. for standard torispherical heads, L = the outside diameter of the shell, though other radii have been permitted (§7.4.6.2)		

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

Corroded Areas in Vessel Heads



Values of Spherical Radius Factor K_1 - Table 7-1

In API 510, Table 7-1, h is one-half the length of the minor axis, equal to the inside depth of the ellipsoidal head measured from the tangent line. For many ellipsoidal heads, $D/2h$ equals 2.0, or a 2:1 ratio. Interpolation is permitted for intermediate values with this table.

Table 7.1—Values of Spherical Radius Factor K_1

$D/2h$	K_1
3.0	1.36
2.8	1.27
2.6	1.18
2.4	1.08
2.2	0.99
2.0	0.90
1.8	0.81
1.6	0.73
1.4	0.65
1.2	0.57
1.0	0.50

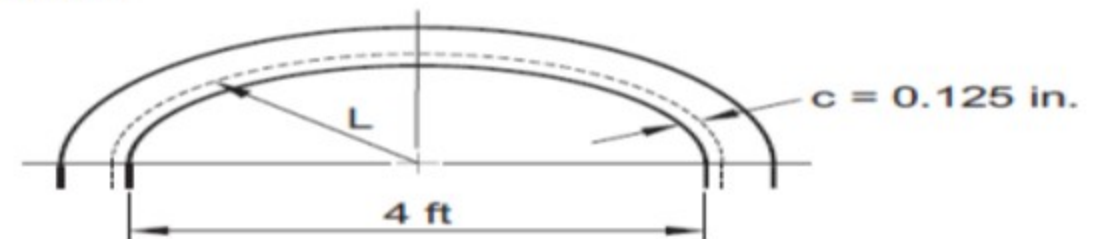
NOTE The equivalent spherical radius equals $K_1 D$; the axis ratio equals $D/2h$. Interpolation is permitted for intermediate values.

Example Q120: Radius for Hemi-Spherical Head Formula

When evaluating a corroded area in a 2:1 ellipsoidal head as part of a fitness for service analysis of corroded regions in a pressure vessel, determine the radius to use in the hemi-spherical head formula where the material is ASME SA-516 Gr. 60 normalized, shell inside diameter is 4 ft, required wall thickness is 0.750 in. with a corrosion allowance of 0.125 in., and operating at 1,200 psi and 550°F?

Task: Determine the radius to use in the hemi-spherical head formula.

Diagram:



Formula:

From API 510 ¶7.4.6.3:

$$L = K_1 D$$

Required Variables:

Inside Diameter = 4 ft

$c = 0.125$ in.

The inside diameter (ID) is given in the question, but we need the ID not including the corrosion allowance (c) on both sides, c cannot be used for pressure retaining calculations.

$$\begin{aligned} \text{ID} &= 4 \text{ ft} \times 12 \text{ in./ft} + c \text{ on both sides of the diameter} \\ &= 48 \text{ in.} + (2 \times 0.125 \text{ in.}) \\ &= 48.250 \text{ in.} \end{aligned}$$

From Table 7-1, for a 2:1 ellipsoidal head,

$$K_1 = 0.9$$

$$\begin{aligned} L &= K_1 D \\ &= 0.9 \times 48.250 \text{ in.} \\ &= 43.425 \text{ in.} \end{aligned}$$

Thickness



Required Thickness Determination

The required thickness shall be based on pressure, mechanical, and structural considerations using the appropriate design formulae and code allowable stress.



For services with high potential consequences if failure were to occur, the engineer should consider increasing the required thickness above the calculated minimum thickness to provide for unanticipated or unknown loadings, undiscovered metal loss, or resistance to normal abuse.

INSPECTION DATA EVALUATION, ANALYSIS, AND RECORDING

177

Assessment



Pressure containing components found to have degradation that could affect their load carrying capability [pressure loads and other applicable loads shall be evaluated for continued service or removed from service until corrective actions/repairs are performed.



Reporting and Records



Permanent and Progressive Records

Pressure Vessel owner/users shall maintain permanent and progressive records of their Pressure Vessel and pressure relieving devices. for their service life, including new information pertinent to the operation, inspection, and maintenance history.

Types of Pressure Vessel Records

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

- Fabrication, Construction and Design Information to the Extent Available
- Inspection History For example, inspection reports
- Repair, Alteration, and Re-rating Information
- Fitness-For-Service Assessment Documentation Requirements



Operating and Maintenance Records

Site operating and maintenance records, such as operating conditions, **should also be available to the inspector**, including:

- process upsets that may affect mechanical integrity,
- changes in service, and
- mechanical damage from maintenance.



For pressure vessels that have **no nameplate** and **minimal or no design** and **construction documentation**, the following steps may be used to verify operating integrity

1. Perform inspection to determine condition of the vessel.
2. Define design parameters and prepare drawings.
3. Perform design calculations based on applicable codes and standards (if the ASME Code was used then make appropriate allowable stress or other design adjustments significant changes made in the 1999 addenda).
4. Attach a nameplate or stamping showing the maximum allowable working pressure and temperature, minimum allowable temperature, and date.
5. Perform pressure test as soon as practical, as required by code of construction used for design calculations.



8



REPAIRS, ALTERATIONS, AND RERATING OF PIPING SYSTEMS





CH 8

REPAIRS, ALTERATIONS, AND RERATING OF PIPING SYSTEMS

CONTENT



8.1

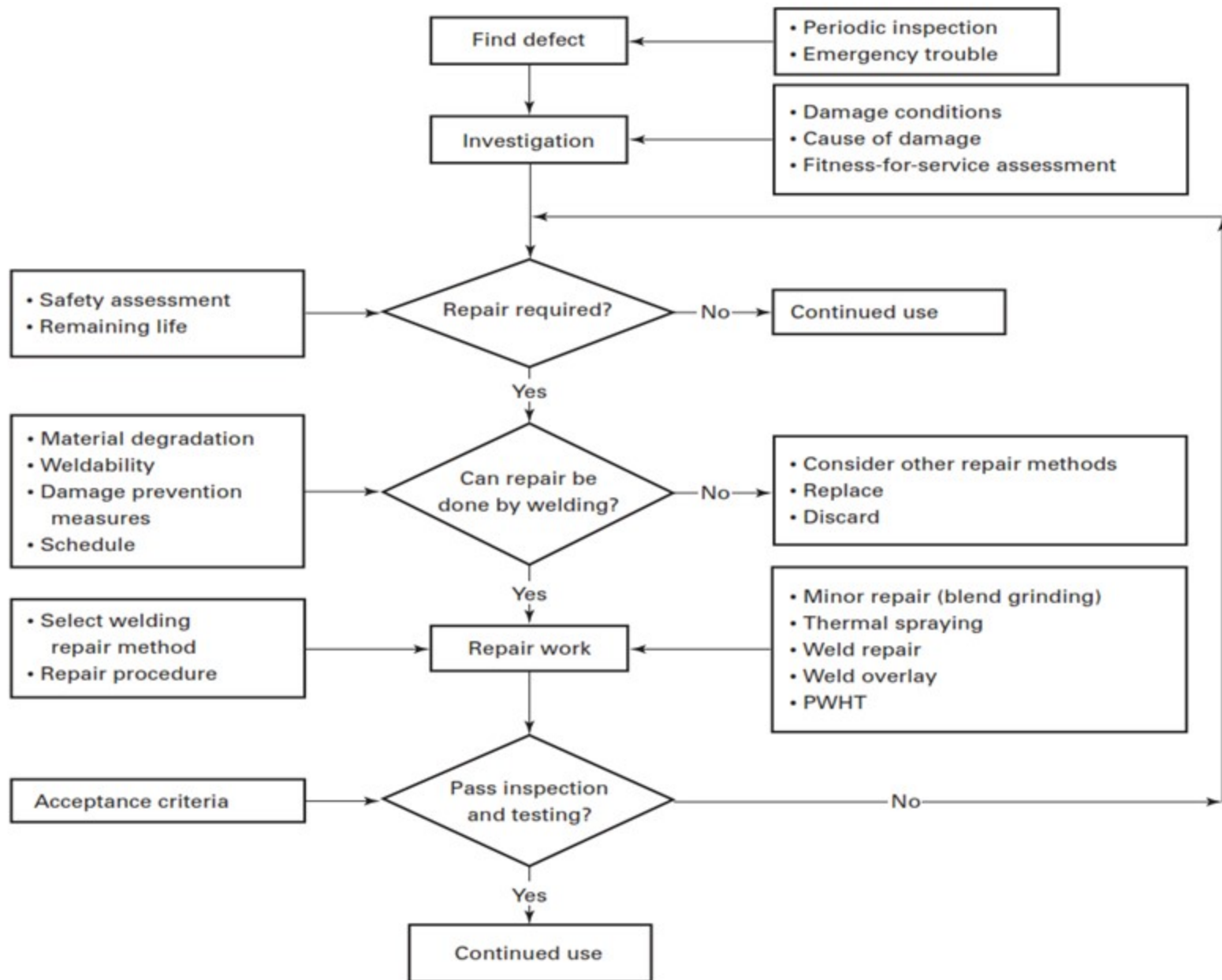
**Repairs, Alterations, and
Rerating of Pressure Vessels
and PRVs**

8.2

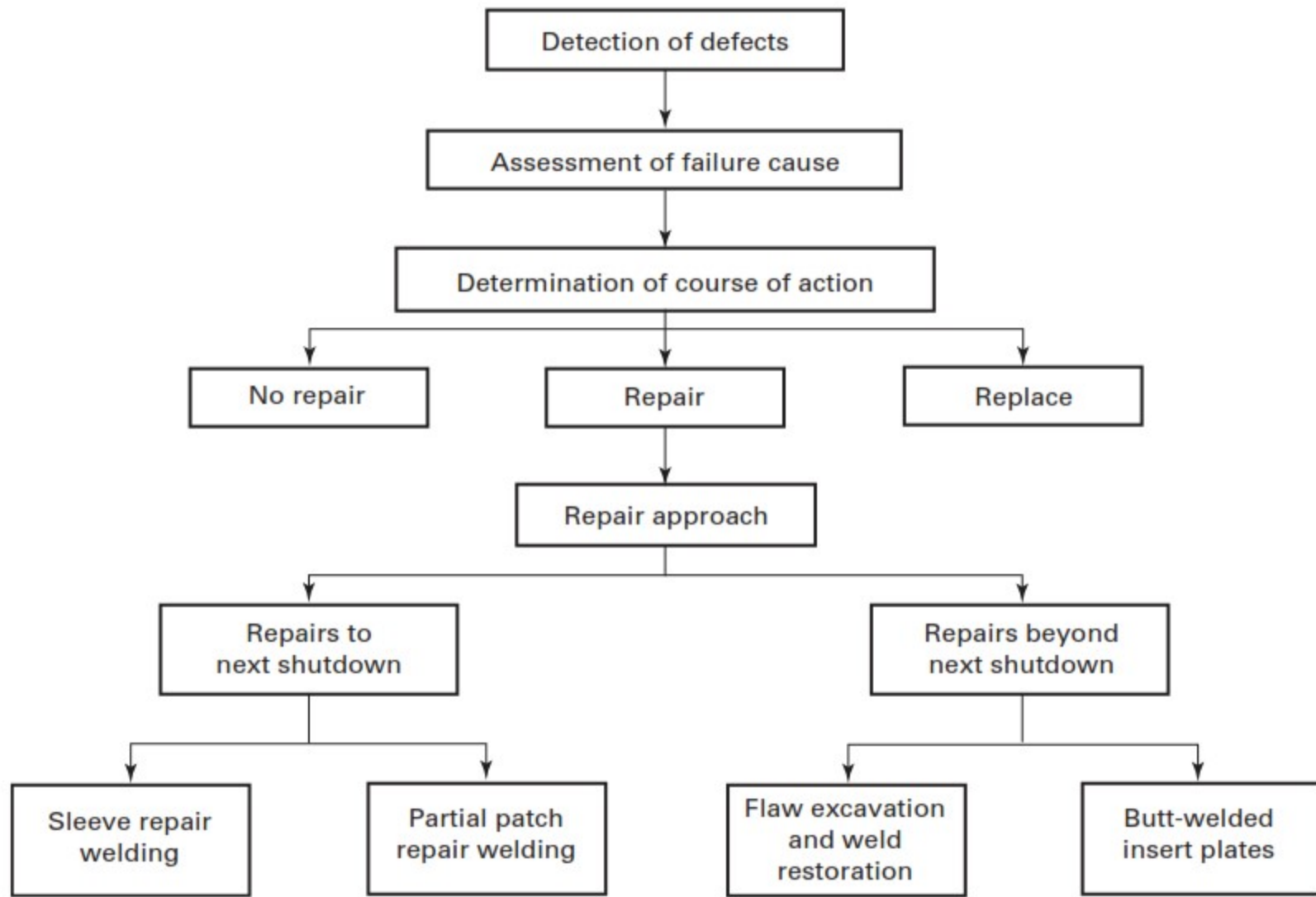
Repairs and Alterations

8.3

Re-rating



Standard Steps in Repair Welding



Flowchart for the Selection of Repair Welding Methods



8.1 REPAIR AND ALTERATION

8.1.1 General

ASME PCC-2-2018
(Revision of ASME PCC-2-2011)

Repair of
Pressure Equipment
and Piping

AN AMERICAN NATIONAL STANDARD



All repairs and alterations to pressure vessels **shall be performed by a repair organization in accordance** with :

- the applicable principles of the ASME Code
 - or the applicable construction
 - or repair code and the equipment specific repair plan prepared by the inspector or engineer
-
- Repairs to pressure-relieving devices should be in accordance with API 576 and the approved relief valve QA manual
-
- The repair organization shall follow all applicable safety requirements as designated in 5.3.

8.1 REPAIR AND ALTERATION



8.1.2 Authorization

Responsible Party	Responsibility for Work	Action
Inspector	repairs and alterations	inspector must authorize prior to work started by repair organization
Inspector	hold points	inspector designates hold points
Inspector and engineer	alterations for ASME VIII Div. 1 and Div. 2	must be authorized by the inspector and engineer
Inspector and engineer	repairs for ASME VIII Div. 2	must be authorized by the inspector and engineer

Repair
Organization

- All repair and alteration work **shall** be done by a repair organization

Inspector

- Repair organization **shall** be authorized by the inspector prior to its starting
- Will designate any inspection hold points required
- May give prior general authorization for limited or **routine repairs** (not require a pressure test or PWHT)

Piping
Engineer

Authorization for **alterations** to pressure vessels that comply with ASME Code, Section VIII, Divisions 1 and 2 and for repairs to pressure vessels that comply with ASME Code, Section VIII, Division 2 may not be given until an **engineer has also authorized the work**

8.1 REPAIR AND ALTERATION



8.1.3 Approval

Inspector

- Before any repairs or alterations are performed, all proposed methods of design, execution, materials, welding procedures, NDE, and testing **shall be approved by the inspector or engineer**
- The inspector shall approve all repair and alteration work at **designated hold points** and **after the repairs and alterations** have been completed

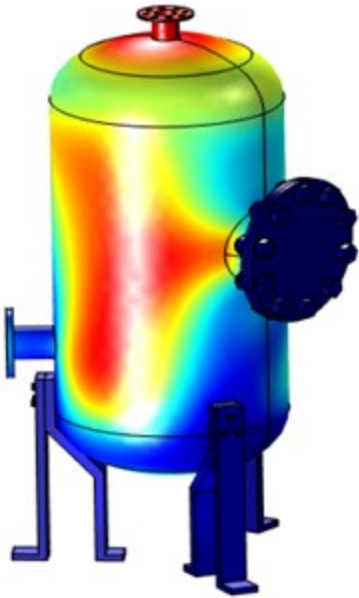
Piping Engineer

For **alterations**, major repairs, and temporary repairs, **approval by both the inspector and engineer is required.**

8.1 REPAIR AND ALTERATION



8.1.4 Design (New vessel component)

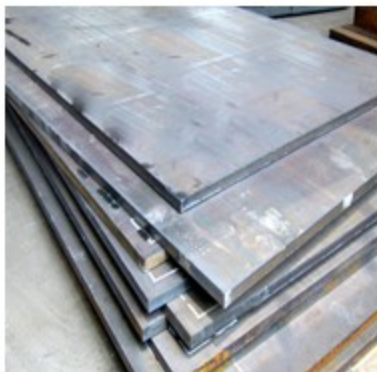


- New vessel nozzles, connections, or replacement parts **shall meet the design requirements** of the applicable construction code.
- The design of replacement parts and new nozzles shall employ the same allowable stress criteria as used for the vessel design.
- Design, location, and method of attachment **shall comply** with requirements of the applicable construction code.
- When damage to parts of a vessel is so great that repairs cannot restore them to design requirements, **the parts shall be replaced.**
- **An engineer shall approve all nozzle installations.**

8.1 REPAIR AND ALTERATION



8.1.5 Material



- The material used in making repairs or alterations **shall conform** to the applicable construction code.
- Material markings, material control practices and material test reports provided to owner/user **shall comply** with the applicable construction code.
- Materials used for welded repairs and alterations shall be of known **weldable quality** and be compatible with the original material.
- **Carbon or alloy steel with carbon content over 0.35 % shall not be welded** and carbon steel with carbon contents over 0.30 % (Less than 0.35%) may need special attention and preheating to avoid weld cracking.
- If the inspector believes there is any question about material verification documents, **PMI should be specified.**

8.1 REPAIR AND ALTERATION



Defect Repairs



Repairs to defects found in pressure vessel components may be made by several techniques often dependent upon :

- the size and nature of the defect,
- the materials of construction,
- the design requirements of the pressure vessel.

Refer to ASME PCC-2, Article 3.4 for guidance on flaw excavation and weld repair.

Repair techniques can be classified as **permanent** or **temporary** depending upon their design and conformance to the applicable construction code.

8.1 REPAIR AND ALTERATION



Article 3.4 Flaw Excavation and Weld Repair

Fig. 2 Excavation and Weld Repair of Embedded Flaw

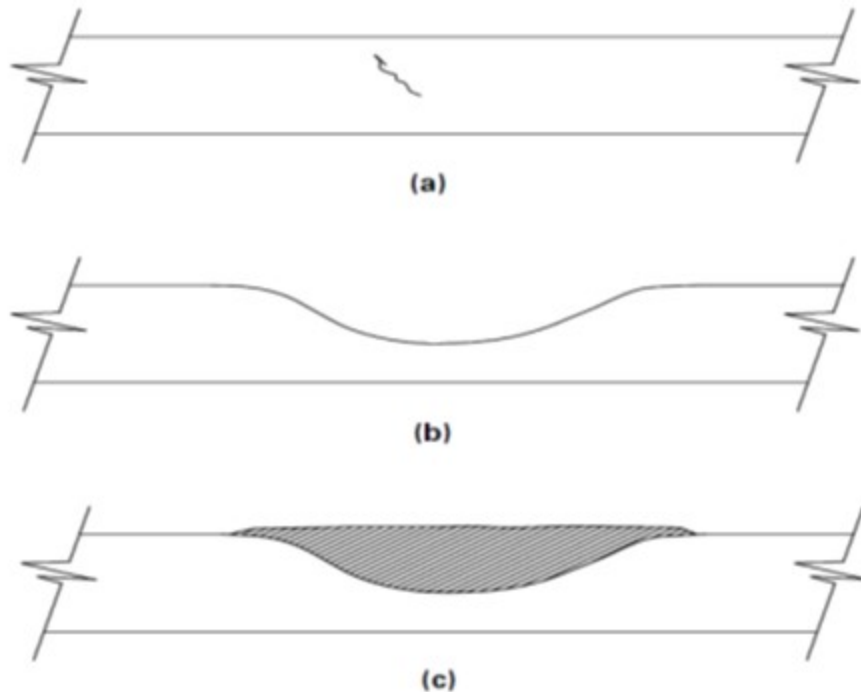
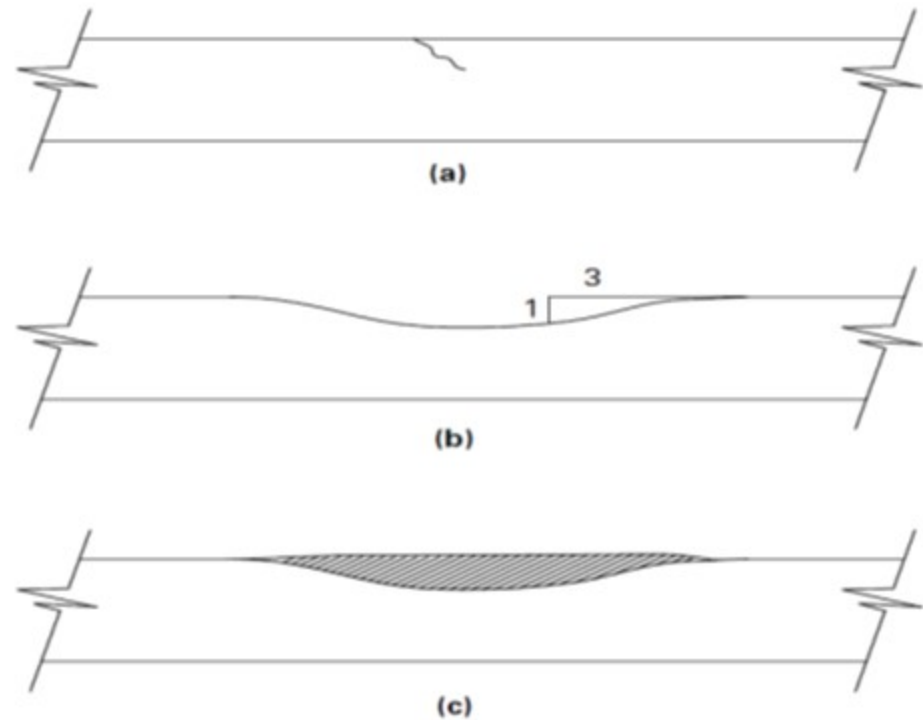


Fig. 1 Excavation and Weld Repair of Surface Flaw



8.1 REPAIR AND ALTERATION

Temporary Repairs



Temporary Repairs

may be conducted on pressure vessels as long as the **inspector and engineer** are **satisfied** that the repair will render the vessel fit for continued service until permanent repairs can be conducted.

should be removed and replaced with suitable permanent repairs at the next available maintenance opportunity.

may remain in place for a longer period of time only if evaluated, approved, and documented by the engineer and inspector.

8.1 REPAIR AND ALTERATION

Temporary Repairs



Documentation of **temporary repairs** should include:

- a) location of the temporary repair;
- b) specific details about the repair (e.g. material of construction, thickness, size of welds, NDE performed);
- c) details of analyses performed, including engineering calculations demonstrating that the vessel is fit for service until permanent repairs or replacement is completed;
- d) requirements for future inspections; and
- e) **due date for installing permanent repair.**

- The inspection plans shall include monitoring the integrity of the **temporary repair** until permanent repairs are complete.

8.1 REPAIR AND ALTERATION



Temporary Repairs

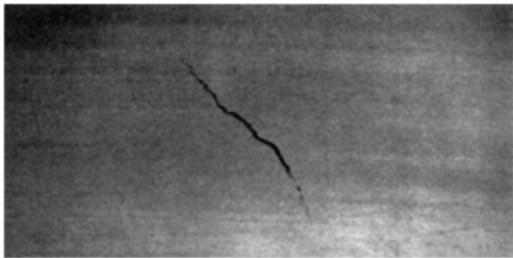
Nonpenetrating Nozzles

Lap Band Repairs

Fillet-welded Patches

8.1 REPAIR AND ALTERATION

Fillet-welded Patches



- Fillet-welded patches may be used to make temporary repairs to damaged, corroded, or eroded areas of pressure vessel components.
- **Cracks** shall not be repaired in this manner unless the engineer determines that the cracks will not be expected to propagate from under the patch. In some cases, the engineer may need to perform a FFS analysis.

Approved

Temporary repairs using fillet-welded patches shall be approved by an inspector and engineer.

8.1 REPAIR AND ALTERATION

Fillet-welded Patches



Fillet-welded patches require special design consideration, especially related to welded joint efficiency.

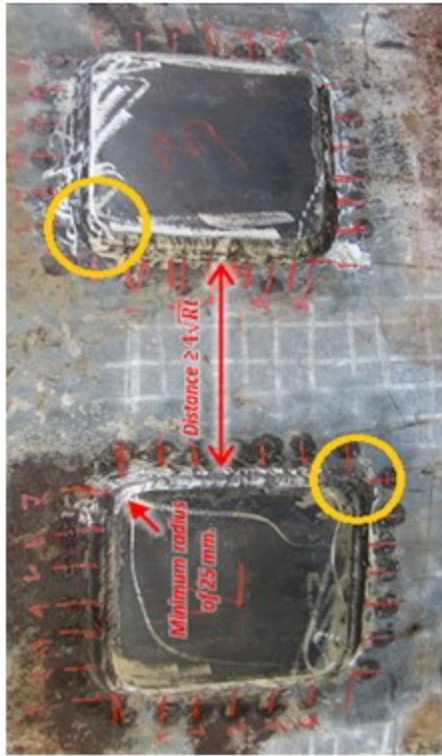
- a) Fillet-welded patches may be applied to the internal or external surfaces of shells, heads, and headers. They would preferably be applied **on the external surface** to facilitate **on-stream examination**.
- b) The fillet-welded patches are designed to absorb the membrane strain of the parts so that in accordance with the rules of the applicable construction code, the following result:
 - 1) The allowable membrane stress is not exceeded in the vessel parts or the patches.
 - 2) The strain in the patches does not result in fillet-weld stresses that exceed allowable stresses for such welds.

Exceptions to this requirement shall be justified with an **appropriate FFS analysis**.

- c) Article 2.12 of ASME PCC-2 may be used for **designing** a fillet-welded patch.

8.1 REPAIR AND ALTERATION

Fillet-welded Patches



A fillet-welded patch **shall not** be installed on top of an existing fillet-welded patch **except** as additional opening reinforcement, if permitted by the applicable construction code.

When installing a fillet-welded patch adjacent to an existing fillet-welded patch, **the distance between the toes of the fillet weld shall not be less than:**

$$d = 4\sqrt{Rt}$$

where

d is the minimum distance between toes of fillet welds of adjacent fillet weld attachments, in in. (mm);

R is the inside radius of the vessel, in in. (mm);

t is the actual thickness of the underlying vessel wall, in in. (mm).

Exceptions to this requirement in some low-consequence environments (e.g. low-pressure catalyst erosion services) shall be justified by an appropriate combination of FFS and risk analyses.

Fillet-welded patch plates shall have rounded corners with a minimum radius of 1 in. (25 mm) minimum radius.

8.1 REPAIR AND ALTERATION

Lap Band Repairs



A **full encirclement lap band** repair may be considered if the following requirements are met.

- a) The design is approved and documented **by the engineer and inspector**.
- b) **Cracks** shall not be repaired in this manner unless the engineer determines that the cracks will not be expected to propagate from under the lap band. In some cases, the engineer may need to perform a FFS analysis.
- c) The band is designed to **contain the full vessel design pressure**.
- d) All longitudinal seams in the repair band are **full-penetration butt welds** with the design joint efficiency and inspection consistent with the appropriate code.
- e) The circumferential fillet welds attaching the band to the vessel shell are designed to transfer the full longitudinal load in the vessel shell, using a joint efficiency of 0.45. Where significant, the eccentricity effects of the band relative to the original shell shall be considered in sizing the band attachment welds.
- f) Appropriate surface NDE shall be conducted on all attachment welds.
- g) Fatigue of the attachment welds, such as fatigue resulting from differential expansion of the band relative to the vessel shell, should be considered, if applicable.
- h) The band material and weld metal are suitable for contact with the contained fluid at the design conditions and an appropriate corrosion allowance is provided in the band.
- i) The damage mechanism leading to the need for repair shall be considered in determining the need for any additional monitoring and future inspection of the repair.

8.1 REPAIR AND ALTERATION

Nonpenetrating Nozzles



Nonpenetrating nozzles (including pipe caps attached as nozzles) **may be used as permanent repairs**, but **not covering cracks** when the design and method of attachment comply with the applicable requirements of the appropriate code.

The design and reinforcement of such nozzles shall consider the following:

- the loss of the original shell material enclosed by the nozzle.

- The nozzle material shall be suitable for contact with the contained fluid at the design conditions and an appropriate corrosion allowance shall be provided.

- The damage mechanism leading to the need for repair shall be considered in determining the need for any additional monitoring and future inspection of the repair.

8.1 REPAIR AND ALTERATION

Permanent Repair



Typical permanent repair with the following techniques :

- a) **Excavating the defect**, and blend-grinding to contour in accordance with API 579-1/ASME FFS-1, Part 5. Also refer to ASME PCC-2, Article 3.4 for guidance on flaw excavation and weld repair.
- b) Excavating a defect and repair welding of the excavation.
- c) **Replacing a section** or the component containing the defect (e.g. Using insert plate or Nonpenetrating nozzles)
- d) **Weld overlay of corroded area.**
- e) **Adding strip or plate lining to the interior surface.**

Repairing Cracks

Repairing a crack at a discontinuity, where stress concentrations are high (e.g. crack in a nozzle-to-shell weld), **should not be attempted without prior consultation with an engineer.**

8.1 REPAIR AND ALTERATION

Insert Plates



Damaged or corroded shell plates may be repaired by **removing a section and replacing it with an insert patch (flush patch) that meets the applicable code.**

Insert patches may be used if the following requirements are met.

- a) **Full-penetration groove welds are provided.**
- b) The welds are **radiographed** in accordance with the applicable construction code. **UT in accordance** with ASME Code Case 2235 or ASME Code, Section VIII, Division 2, may be substituted for the radiography **if the NDE procedures are approved by the inspector.**
- c) All insert plate corners that do not extend to an existing longitudinal or horizontal weld shall be rounded having a **1 in. (25 mm) minimum radius.**

Weld beside to existing welds shall be reviewed by the engineer.



Filler Metal Strength for Overlay and Repairs to Existing Welds



Overlay and Repairs to Existing Welds with Filler Metal/Base Metal of the same strength

The filler metal used for weld repairs to vessel base metal should have minimum specified tensile strength equal to or greater than the minimum specified tensile strength of the base metal.

Overlay and Repairs to Existing Welds with Filler Metal/Base Metal of different strength

If a filler metal is used that has a minimum specified tensile strength **lower than** the minimum specified tensile strength of the base metal, the compatibility of the filler metal chemistry with the base metal chemistry shall be considered regarding **weldability and service damage**. In addition, **all of the following shall be met**.

- a) The repair thickness shall not be more than 50 % of the required thickness of the base metal (this excludes corrosion allowance).
- b) The thickness of the repair weld shall be increased by a ratio of minimum specified tensile strength of the base metal and minimum specified tensile of the filler metal used for the repair.
- c) The increased thickness of the repair shall have **rounded corners** and shall be blended into the base metal using a 3-to-1 taper.
- d) The repair shall be made with a minimum of two passes.

$$T_{\text{fill}} = d \times \frac{S_{\text{base}}}{S_{\text{fill}}}$$

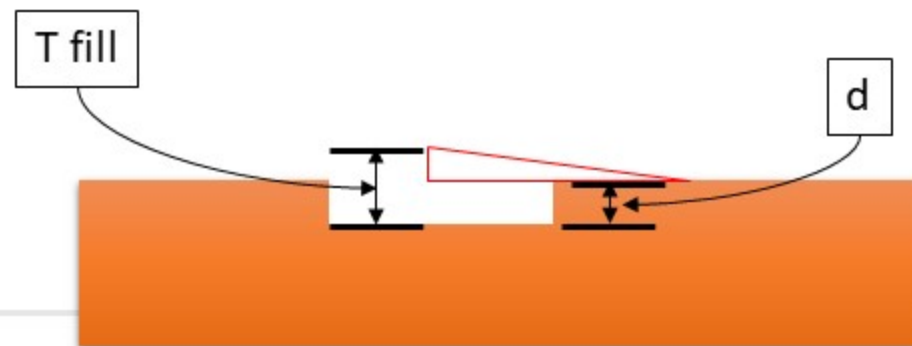
where:

T_{fill} = thickness of repair weld metal, in inches (mm),

d = depth of base metal lost by corrosion and weld preparation, in inches (mm),

S_{base} = base metal tensile strength, in ksi (MPa),

S_{fill} = filler metal tensile strength, in ksi (MPa).



A pressure vessel made from ASME SA-516 Gr. 70 has a corroded region that will be repaired by welding using a filler metal with that has a MSTs of 60,000 psi. What is the minimum required thickness of the repair weld if the depth of base metal lost by corrosion and weld preparation is 0.375 in.?

Task: Determine the minimum required thickness of the repair weld.

Formula:

From API 510, §8.1.5.3.2:

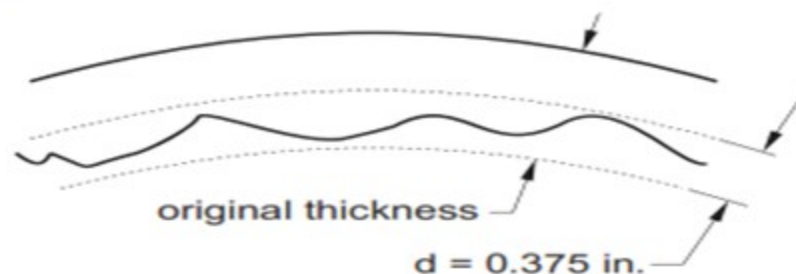
$$T_{\text{fill}} = d \times \frac{S_{\text{base}}}{S_{\text{fill}}}$$

Required Variables:

$$d = 0.375 \text{ in.}$$

$$S_{\text{fill}} = 60,000 \text{ psi}$$

Diagram:



The S_{base} (MSTS) of ASME SA-516 Gr. 70 can be found in ASME Section IX in Table QW/QB-422.

QW/QB-422 FERROUS/NONFERROUS P-NUMBERS AND S-NUMBERS (CONT'D)
Grouping of Base Metals for Qualification

Ferrous (CONT'D)											
Spec. No.	Type or Grade	UNS No.	Minimum Specified Tensile, ksi (MPa)	Welding				Brazing		Nominal Composition	Product Form
				P- No.	Group No.	S- No.	Group No.	P- No.	S- No.		
A 514	P	K21650	110 (760)	...	...	11B	8	...	102	1.25N+1Cr-0.5Mo	Plate, 2½ in. (64 mm) max.
A 514	Q	...	100 (690)	...	...	11B	9	...	102	1.3N+1.3Cr-0.5Mo-V	Plate > 2½ in.-6 in. (64 mm-152 mm), incl.
A 514	Q	...	110 (760)	...	...	11B	9	...	102	1.3N+1.3Cr-0.5Mo-V	Plate, 2½ in. (64 mm) max.
SA-515	60	K02401	60 (415)	1	1	...	...	101	...	C	Plate
SA-515	65	K02800	65 (450)	1	1	...	...	101	...	C-Si	Plate
SA-515	70	K03101	70 (485)	1	2	...	...	101	...	C-Si	Plate
SA-516	55	K01800	55 (380)	1	1	...	...	101	...	C-Si	Plate
SA-516	60	K02100	60 (415)	1	1	...	...	101	...	C-Mn-Si	Plate
SA-516	65	K02403	65 (450)	1	1	...	...	101	...	C-Mn-Si	Plate
SA-516	70	K02700	70 (485)	1	2	...	...	101	...	C-Mn-Si	Plate

$$S_{\text{base}} = 70 \text{ ksi or } 70,000 \text{ psi}$$

$$\begin{aligned} T_{\text{fill}} &= d \times \frac{S_{\text{base}}}{S_{\text{fill}}} \\ &= 0.375 \text{ in.} \times \frac{70,000 \text{ psi}}{60,000 \text{ psi}} \\ &= 0.375 \text{ in.} \times 1.167 \\ &= 0.438 \text{ in.} \end{aligned}$$

8.1 REPAIR AND ALTERATION

Repairs to Stainless Steel Weld Overlay and Cladding

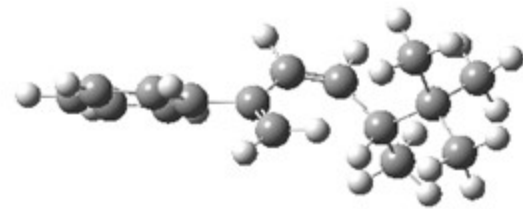


The repair weld procedure(s) to restore removed, corroded, or missing clad or overlay areas **shall be reviewed and approved by the engineer and inspector before implementation.**

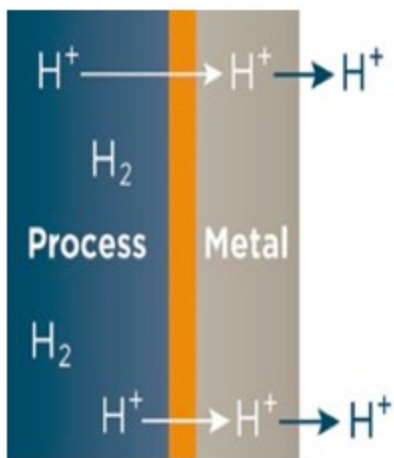
Consideration shall be given to important factors that may affect the repair plan. These factors include:

- ✓ stress level,
- ✓ P-number of base material, (i.e., alloy group)
- ✓ service environment,
- ✓ possible previously dissolved hydrogen,
- ✓ type of lining,
- ✓ deterioration of base metal properties (by temper embrittlement of Cr-Mo alloys or other damage mechanisms causing loss of toughness),
- ✓ minimum pressurization temperatures,
- ✓ future periodic examination.

8.1 REPAIR AND ALTERATION



Repairs to Stainless Steel Weld Overlay and Cladding



For equipment exposed to **atomic hydrogen migration (i.e., H+ not H₂)** in the base metal (operates in hydrogen service at an elevated temperature or has exposed base metal areas open to corrosion), **these additional factors must be** considered by the **engineer** when developing **the repair plan**:

- a) outgassing base metal; (i.e., diffusing the hydrogen out of base metal)
- b) hardening of base metal due to welding, grinding, or arc gouging;
- c) preheat and inter-pass temperature control;
- d) PWHT to reduce hardness and restore mechanical properties.

These repairs shall be monitored by an **inspector** to assure compliance to repair requirements.

After cooling to ambient temperatures, **the repair shall be inspected by the PT method**, according to ASME Code, Section VIII, Division I, Appendix 8.

For vessels constructed with **P-3, P-4, or P-5** base materials, the base metal in the area of repair should also be examined for cracking by the ultrasonic examination in accordance with ASME Code, Section V, Article 4, Paragraph T-473.

This inspection is most appropriately **accomplished following a delay of at least 24 hours after completed repairs** for alloys that could be affected by **delayed cracking**.

8.1 REPAIR AND ALTERATION

Welding and Hot Tapping



All repair and alteration welding shall be in accordance with the applicable requirements of the ASME Code or the applicable construction or repair code, except as permitted in (Filler Metal Strength for Overlay and Repairs to Existing Welds)

- Refer to API 582 and API 577 for additional welding considerations.
- Refer to API 2201 for safety aspects when making on-stream welds (e.g. **during hot tapping**) and to ASME PCC-2, Article 2.10 for technical guidance for in-service welding

8.1 REPAIR AND ALTERATION

Procedures, Qualifications, and Records



Repair Organization

- **Shall** use welders and welding procedures that are qualified in accordance with ASME Code, Section IX or those referenced by the construction code.
- **Shall** maintain records of its qualified welding procedures and its procedure qualification records.
- These records **shall** be available to the inspector before the start of welding.

Inspector

Inspectors **shall** verify that welders are welding within their ranges qualified on the welding procedure qualification(s) and within the ranges on the specified welding procedure specification (WPS).

API 577

- provides guidance on how to review**
- weld procedures WPS,
 - procedure qualification records PQR,
 - welder performance qualifications WPQ,
 - how to respond to welding nonconformances.

8.1 REPAIR AND ALTERATION

Preheating



Preheat temperature used in making welding repairs **shall be in accordance with the applicable code and qualified welding procedure.**

Exceptions shall be approved by the engineer, and will require a **new WPS** be applied if the exception is a cooler preheat than specified in the current WPS.

The inspector should assure that the minimum preheat temperature is measured and maintained.

For alternatives to traditional welding preheat, refer to ASME PCC-2, Article 2.8.

Article 2.8

Alternatives to Traditional Welding Preheat

8.2 WELDING AND HOT TAPPING

PWHT



PWHT of pressure vessel repairs or alterations should be made using the relevant requirements of :

ASME Code

applicable construction code

an approved alternative PWHT procedure

Alternatives

1. Preheat procedure
2. Controlled Deposition Welding Methods
3. Local PWHT may be substituted for 360° banding on local repairs on all materials

For example : Due to on stream repair weld

8.1 REPAIR AND ALTERATION

Local PWHT



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

- a) The application is reviewed, and a procedure is developed **by an engineer** experienced in the appropriate engineering specialties.
- b) The suitability of the procedure shall be evaluated considering the following factors:
 - 1) base metal thickness;
 - 2) decay thermal gradients;
 - 3) material properties (hardness, constituents, strength, etc.);
 - 4) changes due to local PWHT;
 - 5) the need for full-penetration welds;
 - 6) surface and volumetric examinations after local PWHT;
 - 7) the overall and local strains and distortions resulting from the heating of a local restrained area of the pressure vessel shell.
- c) A preheat of 300 °F (150 °C) or higher, as specified by specific welding procedures, is maintained during welding.
- d) The required local PWHT temperature shall be maintained for a distance of **not less than two times the base metal thickness** measured from the toe of the weld.
The local PWHT temperature **shall be monitored** by a suitable number of **thermocouples (at least two)**. When determining the number of thermocouples necessary, the size and shape of the area being heat treated should be considered.
- e) Controlled heat shall be applied to any nozzle or any attachment within the local PWHT area.
- f) When PWHT is performed for environmental-assisted cracking resistance, a **metallurgical review** shall be conducted to assess whether the procedure is acceptable.

8.1 REPAIR AND ALTERATION

Preheat or Controlled-deposition Welding (CDW) Methods as Alternatives to PWHT



Engineer

Preheat and CDW may be used in lieu of PWHT where PWHT is inadvisable or mechanically unnecessary.

Prior to using any alternative method, a **metallurgical review** conducted by an **engineer** shall be performed to assure the proposed alternative is suitable for the application.

The review should consider factors such as

the reason for the original PWHT of the equipment,
susceptibility to stress corrosion cracking,
stresses in the location of the weld,
susceptibility to high-temperature hydrogen attack,
susceptibility to creep, etc.

Inspector

Responsible for **verifying** that the methods used are in accordance with **owner/user specification** and the **requirements of this section**.

8.1 REPAIR AND ALTERATION

Welding method, Materials and Joint Efficiency

Welding method

Selection of the **welding method of CDW** used shall be based on **the rules of the construction code** applicable to the work, including technical consideration **(Metallurgical Review by Engineer)** of whether the **as-welded condition** is suitable for the operating and pressure test conditions.

Materials

Joint Efficiency

When one of the following methods is used as an alternative to PWHT, the PWHT joint efficiency factor may be continued if the factor has been used in the currently rated design.

8.1 REPAIR AND ALTERATION

Preheating Method (Notch Toughness Testing Not Required)



Limitation

1. P-No. 1, Group 1, 2, and 3, and to P-No. 3, Group 1 and 2 (excluding Mn-Mo steels in Group 2)
2. (SMAW), (GMAW), (GTAW)

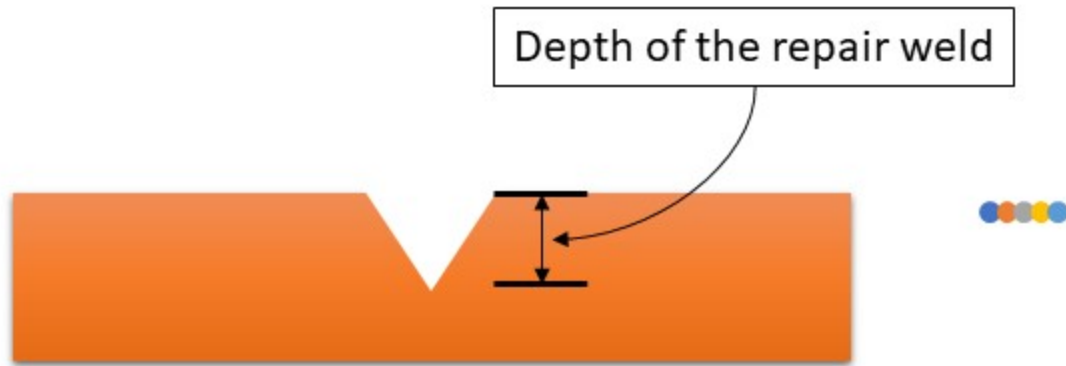
To Perform

a) The weld area shall be preheated and maintained at a minimum temperature of (150 °C) during welding.

b) 150 °C temperature should be checked to assure that 4 in. (100 mm) of the material or four times the material thickness (whichever is greater) on each side of the groove is maintained at the minimum temperature during welding.

The maximum inter-pass temperature shall not exceed (315 °C).

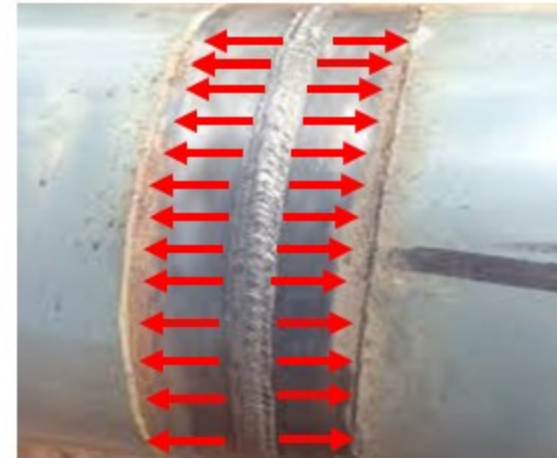
c) When the weld does not penetrate through the full thickness of the material, the minimum preheat and maximum Inter-pass temperatures need only be maintained at a distance of 4 in. (100 mm) or four times the depth of the repair weld, whichever is greater on each side of the joint.



4 in. (100 mm) or **four times the depth of the repair weld**, whichever is greater on each side of the joint.

Table Showing Welding Requirements for Using Preheat Method in Lieu of PWHT
for Pressure Vessel repairs and Alterations

Welding Variable	Requirement
minimum preheat temperature	300°F (150°C)
maximum interpass temperature	600°F (315°C)
preheat/interpass temperature zone for through-thickness welds	minimum of 4 in. (100 mm) of the material or four times the material thickness (whichever is greater) on each side of the groove
preheat/interpass temperature zone for partial-thickness welds	minimum of 4 in. (100 mm) or four times the depth of the repair weld, whichever is greater on each side of the joint.
Note: notch toughness testing is not required when using this preheat method in lieu of PWHT, in accordance with §8.1.6.4.2.2.2.	



4 in. (100 mm) or four times the material thickness (whichever is greater)

8.1 REPAIR AND ALTERATION

CDW Method (Notch Toughness Testing Required)



Limitation

1. The materials shall be limited to P-No. 1, P-No. 3, and P-No. 4 steels
2. (SMAW), (GMAW), (GTAW)

A weld procedure specification shall be developed and qualified for each application.

The welding procedure shall define :

- Preheat temperature
- Inter-pass temperature
- Post-heating temperature requirement.

To Perform

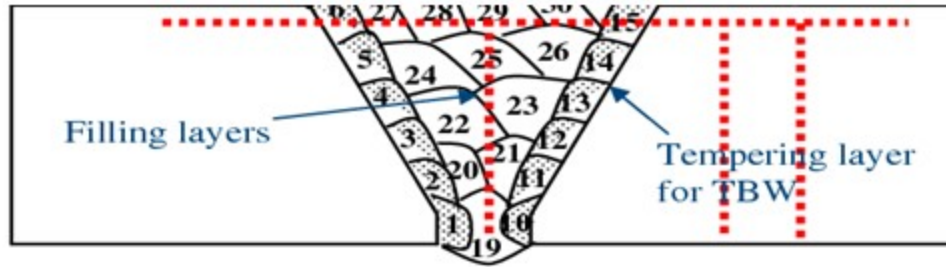
The qualification thickness for the test plates and repair grooves shall be in accordance with Table 8.1

Table 3—Welding Methods as Alternatives to Post-weld Heat Treatment Qualification Thickness for Test Plates and Repair Grooves

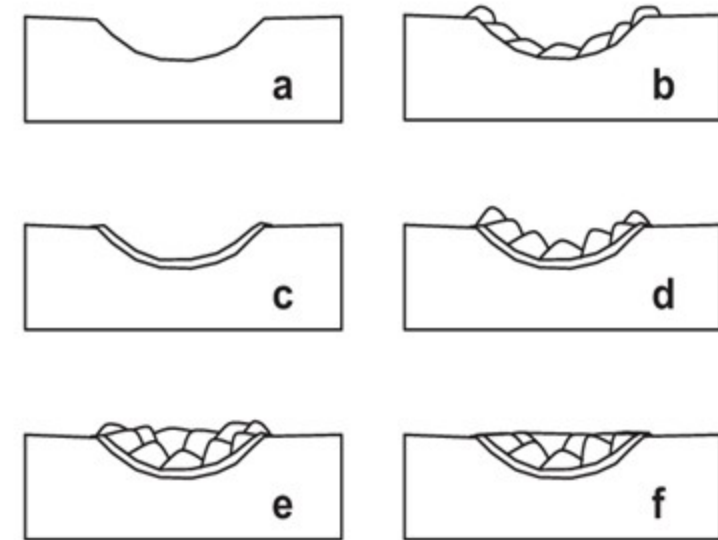
Depth t of Test Groove Welded	Repair Groove Depth Qualified	Thickness T of Test Coupon Welded	Thickness Base Metal Qualified
t	$< t$	< 2 in (50 mm)	$< T$
t	$< t$	≥ 2 in (50 mm)	2 in (50 mm) to unlimited

^a The depth of the groove used for procedure qualification must be deep enough to allow removal of the required test specimen

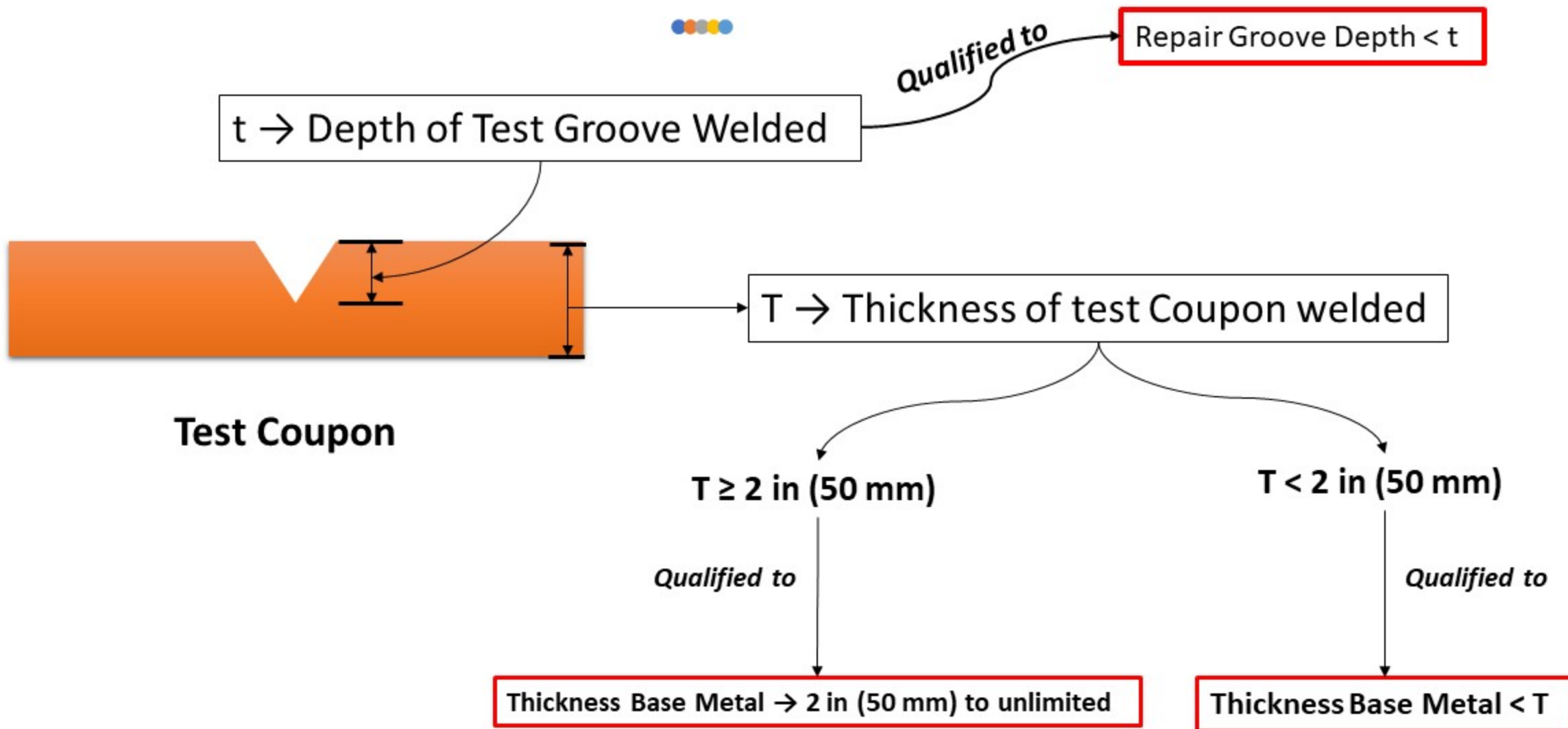
$t \rightarrow$ Depth of Test Groove Welded
 $T \rightarrow$ Thickness of test Coupon welded



Temper bead technique



half bead tempering technique



8.2 WELDING AND HOT TAPPING



Controlled-deposition Welding Method (Notch Toughness Testing Required)

Test Material

The test material for the welding procedure qualification shall be of the **same material** specification (including specification type, grade, class and condition of heat treatment) as the original material specification for the repair. If the original material specification is old, **the test material** used should conform as much as possible to the material used for construction, but in no case **shall the material be lower in strength or have a carbon content of more than 0.35 %.**

When impact tests are required by the construction code applicable to the work planned, **the PQR shall include sufficient tests** to determine if the toughness of the weld metal and the heat-affected zone of the base metal in the as-welded condition is adequate at the minimum design metal temperature

If special hardness limits are necessary (for example, as set forth in NACE RP 0472 and MR 0103) for corrosion resistance, **the PQR shall include hardness tests as well.**

8.2 WELDING AND HOT TAPPING



8.2.4.3 Controlled-deposition Welding Method (Notch Toughness Testing Required)

The WPS shall include the following additional requirements.

- 1) The **supplementary essential variables** of ASME Code, Section IX, Paragraph QW-250, shall apply.
- 2) The maximum weld **heat input** for each layer shall not exceed that used in the procedure qualification test.
- 3) The minimum **preheat temperature** for welding shall not be less than that used in the procedure qualification test.
- 4) The maximum **inter-pass temperature** for welding shall not be greater than that used in the procedure qualification test.

5) The preheat temperature shall be checked to assure that 4 in. (100 mm) of the material or four times the material thickness (whichever is greater) on each side of the weld joint will be maintained at the minimum temperature during welding.

When the weld does not penetrate through the full thickness of the material, the minimum preheat temperature need only be maintained at a distance of 4 in. (100 mm) or **four times the depth of the repair weld**, whichever is greater on each side of the joint.

6) For the allowed welding processes in Item c:

- Use only **electrodes and filler metals** that are classified by the filler metal specification with an optional supplemental diffusible-hydrogen designator of H8 or lower.

When shielding gases are used with a process, **the gas** shall exhibit a **dew point that is not higher than** (-50 °C).

Surfaces on which welding will be done shall be maintained in a **dry condition during welding and free of** rust, mill scale and hydrogen producing contaminants such as oil, grease and other organic materials.

8.2 WELDING AND HOT TAPPING



The WPS shall include the following additional requirements.

- 7) The welding technique shall be a controlled-deposition, temper-bead or half-bead technique. The specific technique shall be used in the procedure qualification test.
- 8) For welds made by SMAW:
 - once filling is completed do not allow the weldment to cool below the minimum preheat temperature. As well, **raise the weldment temperature to** (260 °C ± 30 °C) for a **minimum period of two hours**. This assists **out-gassing diffusion** of any weld metal hydrogen picked up during welding.
 - This hydrogen bake-out may be omitted when H4 filler metal (such as E7018-H4) is specified.
- 9) After the finished repair weld has cooled to ambient temperature, **the final temper bead reinforcement layer shall be removed substantially flush with the surface of the base material.**

Variable	Requirement or Limitation
Notch Toughness Testing	When impact tests are required by the original or applicable code of construction, the PQR shall include sufficient tests to determine if the toughness of the weld metal and the heat-affected zone of the base metal in the as-welded condition is adequate at the minimum design metal temperature.
Materials	ASME P-No. 1, P-No. 3, and P-No. 4
Welding Processes	SMAW, GMAW, GTAW
WPS	WPS qualified for each application and include: • preheat and interpass temperatures • PWHT requirements, see also ¶8.1.6.4.2.3(f)(8). • qualified test plates and repair grooves thickness shall be in accordance with Table 8-1 • WPS test material shall be of the same specification type, grade, class and heat treat condition as the original material specification for the repair • if the original material specification is obsolete, the test material used should conform as much as possible to the material used for construction, but in no case shall the material be lower in strength or have a carbon content of more than 0.35%
Additional Requirements for WPS	See the 9 detailed requirements listed in ¶8.1.6.4.2.3.
Harness Testing	If hardness is required, e.g., NACE RP 0472 or MR 0103, the PQR shall include hardness tests.

8.2 WELDING AND HOT TAPPING

NDE of repair and alteration Welds

Welding Processes, Inspection, and
Metallurgy

API RECOMMENDED PRACTICE 577
SECOND EDITION, DECEMBER 2013

API 577 provides guidance on NDE of weld joints and weldments.



Before

the area prepared for welding is examined using either the MT or PT technique to determine that no defects exist.

This examination is especially important after **removing cracks and other defects.**

After

it shall be examined again by the appropriate NDE technique specified in the repair specification to determine that no defects exist using acceptance standards **acceptable to the Inspector** or the applicable construction code.

8.2 WELDING AND HOT TAPPING

NDE of repair and alteration Welds



New welds

If required by construction code, shall be radiographically examined in accordance with the construction code

If is not practical to perform radiography



Other techniques are used rather than the UT in lieu of RT.
- The joint efficiency should be reduced to the value corresponding to no radiography

- New weld shall be fully examined using UT in lieu of RT **and/or** other appropriate NDE techniques to determine that no defects exist
- UT in lieu of RT shall follow ASME Code Case 2235 or ASME Code, Section VIII, Division 2, 7.5.5

Where use of **NDE techniques** specified by the construction code is not possible or practical, alternative NDE techniques may be used provided they are **approved by the engineer and inspector.**

8.2 WELDING AND HOT TAPPING

Weld Inspection for Vessels Subject to Brittle Fracture

Since flaws, notches, or other stress risers are prone to initiate brittle fracture subsequent to pressure testing or service in a pressure vessel that was weld repaired or altered, a fitness for service analysis may be performed to assist with preventing failure (§8.1.8).

When an API RP 579 or other fitness for service analysis determines that the pressure vessel material may be subject to brittle fracture from either normal or abnormal service (e.g., during startup, shutdown, and pressure testing), then appropriate inspection should be considered after welded repairs or alterations (§8.1.8).

Inspection techniques should be selected to detect critical flaws as determined by a fitness-for-service assessment, such as MT or other effective surface NDE methods.

8.2 WELDING AND HOT TAPPING

Re-Rating

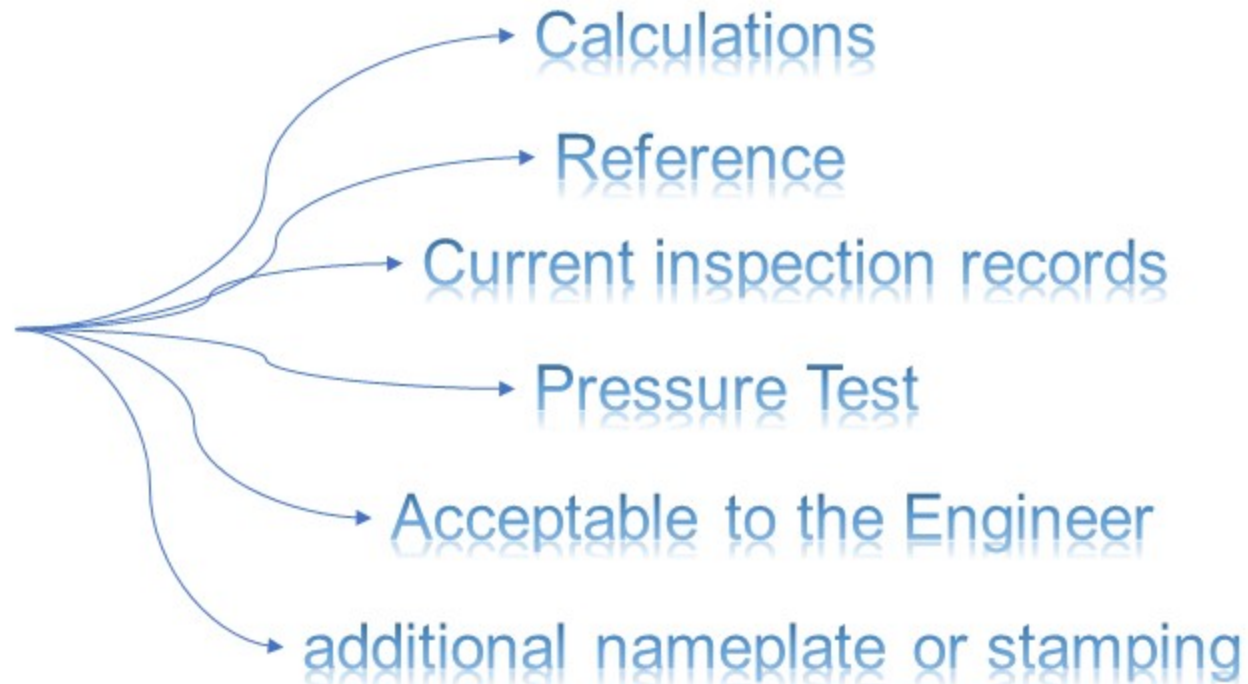
Rerating a pressure vessel by changing its

Design Temperature

MAWP

Minimum Metal Design Temperature

& may be done only after **all of the following requirements have been met:**



8.2 WELDING AND HOT TAPPING

1. **Calculations** performed by either:



- manufacturer
- owner/user engineer
- (or his/her designated representative) experienced in pressure vessel design, fabrication, or inspection shall justify rerating.

2. A rerating shall be performed in accordance with the requirements of the vessel's construction code. Alternately, calculations can be made using the appropriate formulas in the latest edition of the applicable construction code provided all of the vessel's essential details comply with the applicable requirements of the ASME Code.

- If the vessel was designed to an edition or addendum of the ASME Code earlier than the 1999 addendum and was not designed to ASME Code Case 2290 or ASME Code Case 2278, it may be rerated to the latest edition/addendum of the ASME Code if permitted by Figure 8.1.
- Notice that for vessels built to a code earlier than 1968 the original design allowable stress (based on design factor of 4.0 or 5.0) shall be used.

8.2 WELDING AND HOT TAPPING

3. **Current inspection records** verify that:



- pressure vessel is satisfactory for the proposed service conditions
- corrosion allowance provided is appropriate.

An increase in allowable working pressure or design temperature shall be based on **thickness data** obtained from a recent internal or on-stream inspection.

4. The vessel **shall be pressure tested** using the applicable testing formula from the code used to perform the rerating calculations **unless either of the following is true:**

- Pressure vessel has at some time been pressure tested to a test pressure equal to or higher than the test pressure required by the construction code and
- Vessel integrity is confirmed by special nondestructive evaluation inspection techniques in lieu of testing.

8.2 WELDING AND HOT TAPPING



6. The pressure vessel rerating will be considered complete with the attachment of an additional nameplate or additional stamping that carries the information in the following Figure

Rerated by: _____		
Date Rerated: _____	20	_____
SAP No: _____		
MAWP: _____ PSIG	@	_____ F
MDMT: _____ F	@	_____ PSIG
Test Pressure: _____ PSIG		

Sample Additional Nameplate



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FOR YOUR ATTENTION

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