

Inspection Practices for Pressure Vessels

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Inspection Practices for Pressure Vessels

1 Scope

This recommended practice supplements API 510 by providing pressure vessel inspectors with information that can improve skills and increase basic knowledge of inspection practices. This recommended practice describes inspection practices for the various types of pressure vessels (e.g. towers, exchanger, air-cooled heat exchanger, reactors, and spheres) used in the hydrocarbon and chemical process industry. This recommended practice addresses vessel components, inspection planning processes, inspection intervals, methods of inspection and assessment, methods of repair, records, and reports. API 510 has requirements and expectations for inspection of pressure vessels.

2 Normative References

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

API 510, *Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration*

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

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

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

API 579-1/ASME FFS-1¹, *Fitness-For-Service*

API Recommended Practice 580, *Risk-Based Inspection*

API Recommended Practice 2217A, *Safe Work in Inert Confined Spaces in the Petroleum and Petrochemical Industries*

ASME Boiler and Pressure Vessel Code, Section VIII: *Rules for Construction of Pressure Vessels*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

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, the addition of any reinforced nozzle less than or equal to the size of existing reinforced nozzles, and the addition of nozzles not requiring reinforcement.

3.1.2

cladding

A metal integrally bonded onto another metal under high pressure and temperature whose properties are better suited to resist damage from the process than the substrate material.

¹ American Society of Mechanical Engineers, Two Park Avenue, New York, New York 10016, www.asme.org.

3.1.3

condition monitoring locations

CMLs

Designated areas on pressure vessels where periodic examinations are conducted to directly assess and monitor the condition of the vessel using a variety of examination methods and techniques based on damage mechanism susceptibility. CMLs may contain one or more examination points and can be a single small area on a pressure vessel [e.g. a 2 in. (50 mm) diameter spot] or plane through a section of a nozzle where recording points exist in all four quadrants of the plane.

NOTE CMLs include but are not limited to what were previously called TMLs.

3.1.4

corrosion specialist

A person acceptable to the owner-operator, who is knowledgeable and experienced in the specific process chemistries, damage mechanisms, materials selection, corrosion mitigation methods, corrosion monitoring techniques, and their impact on equipment.

3.1.5

corrosion under fireproofing

CUF

Corrosion of piping, pressure vessels, and structural components resulting from water trapped under fireproofing.

3.1.6

corrosion under insulation

CUI

External corrosion of piping, pressure vessels, and structural components resulting from water trapped under insulation. External chloride stress corrosion cracking of austenitic and duplex stainless steel under insulation is also classified as CUI damage.

3.1.7

damage mechanism

Any type of damage 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). See API 571 for a comprehensive list and description of damage mechanisms.

3.1.8

damage mode

The physical manifestation of damage (e.g. wall thinning, pitting, cracking, and rupture).

3.1.9

defect

A discontinuity or discontinuities that by nature or accumulated effect render a part or product unable to meet minimum applicable acceptance standards or specifications (e.g. total crack length). The term designates rejectability.

3.1.10

design temperature

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

3.1.11

examination point

recording point

measurement point

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

A more specific location located within a CML. CMLs may contain multiple examination points, e.g. a vessel nozzle may be a CML and have multiple examination points (an examination point in all four quadrants of the CML on the nozzle).

3.1.12**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, and supports). The external inspection may be done either while the vessel is operating or while the pressure vessel is out of service and can be conducted at the same time as an on-stream inspection.

3.1.13**flaw**

Imperfections or other discontinuities noted during inspection that may or may not exceed the applicable acceptance criteria.

3.1.14**in-service**

The life-cycle stage of a pressure vessel that begins after initial installation (where typically initial commissioning or placing into active service follows) and ends at decommissioning. Pressure vessels that are idle in an operating site and vessels not currently in operation because of a process outage are still considered in-service pressure vessels.

NOTE Does not include pressure vessels that are still under construction or in transport to the site prior to being placed in service nor does it include pressure vessels that have been decommissioned.

3.1.15**inspection plan**

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

3.1.16**inspector**

A shortened title for an authorized pressure vessel inspector qualified and certified in accordance with API 510.

3.1.17**integrity operating window****IOW**

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

3.1.18**jurisdiction**

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

3.1.19**lining**

A nonmetallic or metallic material installed on the interior of a vessel whose properties are better suited to resist damage from the process than the substrate material.

3.1.20**maximum allowable working pressure****MAWP**

The maximum gauge pressure permitted at the top of a pressure vessel in its operating position for a designated temperature. This pressure is based on calculations using the minimum (or average pitted) 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 and seismic). The MAWP may refer to either the original design or a rerated MAWP obtained through a Fitness-For-Service (FFS) assessment.

3.1.21**minimum design metal temperature/minimum allowable temperature
MDMT/MAT**

The lowest permissible metal temperature for a given material at a specified thickness based on its resistance to brittle fracture. In the case of MAT, it may be a single temperature or an envelope of allowable operating temperatures as a function of pressure. It is generally the minimum temperature at which a significant load can be applied to a pressure vessel as defined in the applicable construction code [e.g. ASME *Boiler and Pressure Vessel Code* (ASME Code) Section VIII, Division 1, Paragraph UG-20(b)]. It might also be obtained through an FFS evaluation.

3.1.22**on-stream**

A condition whereby a pressure vessel has not been prepared for internal inspection.

3.1.23**owner-operator**

An owner or operator of pressure vessels who exercises control over the operation, engineering, inspection, repair, alteration, maintenance, pressure testing, and rerating of those pressure vessels.

3.1.24**pressure design thickness**

Minimum wall thickness needed to hold design pressure at the design temperature as determined using the rating code formula. It does not include thickness for structural loads, corrosion allowance, or mill tolerances.

3.1.25**pressure vessel**

A container designed to withstand internal and/or external pressure/loads. This pressure may be imposed 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.

NOTE Specific limits and exemptions of equipment covered by this inspection code are provided in API 510—Section 1 and Annex A.

3.1.26**pressure vessel engineer**

A person acceptable to the owner-operator 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. The pressure vessel engineer, by consulting with appropriate specialists, should be regarded as a composite of all entities necessary to properly assess the technical requirements. Wherever the term “engineer” is used in this recommended practice, it refers to a pressure vessel engineer.

3.1.27**repair**

The work necessary to restore a vessel to a condition suitable for safe operation at the design conditions. If any of the restorative work results in a change to the design temperature, minimum design metal temperature (MDMT), or MAWP, the work shall be considered an alteration and the requirements for rerating shall be satisfied. Any welding, cutting, or grinding operation on a pressure-containing component not specifically considered an alteration is considered a repair.

3.1.28**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 (rerating below original design conditions) is a permissible way to provide for additional corrosion allowance.

3.1.29**risk-based inspection****RBI**

An inspection planning methodology that incorporates a risk assessment process that considers both the probability of failure and consequence of failure. The methodology is primarily aimed at managing unacceptable risks, reducing loss of containment failures and optimization of the inspection strategy.

3.1.30**strip lining**

Strips of metal plates or sheets that are welded to the inside of a 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.

3.1.31**testing**

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

3.1.32**weld buildup**

The use of weld metal of similar composition to the base metal for the purpose of restoring base metal thickness.

3.1.33**weld overlay**

The use of weld metal of a composition different than the base metal to provide corrosion and/or erosion resistance to the base metal.

3.2 Acronyms and Abbreviations

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

ACFM	alternating current field measurement
ASME Code	ASME <i>Boiler and Pressure Vessel Code</i> , including its addenda and code cases
AUT	automated ultrasonic examination
CCD	corrosion control document
CML	condition monitoring location
CUF	corrosion under fireproofing
CUI	corrosion under insulation
ET	eddy current examination
FFS	Fitness-For-Service
FRI	fractionation research incorporated

FRP	fiber-reinforced plastic
H ₂ S	hydrogen sulfide
HF	hydrofluoric acid
HTHA	high-temperature hydrogen attack
IDMS	inspection data management system
IOW	integrity operating window
MAT	minimum allowable temperature
MAWP	maximum allowable working pressure
MDMT	minimum design metal temperature
MOC	management of change
MPRT	minimum practical renewal thickness
MT	magnetic particle examination
NDE	nondestructive examination
PEC	pulsed eddy current
PMI	positive material identification
PRD	pressure relief device
PT	liquid penetrant examination
PTA SCC	polythionic acid stress corrosion cracking
RBI	risk-based inspection
RE	residual element
RT	radiographic examination
UT	ultrasonic examination
WFMT	wet fluorescent magnetic particle examination

4 Introduction to Pressure Vessels

4.1 General

A pressure vessel is any asset designed and constructed in accordance with an applicable construction code (e.g. ASME *Code*, Section VIII, Division 1 and Section VIII, Division 2). Examples include columns, towers, drums, reactors, heat exchangers, condensers, air-cooled heat exchanger, bullets, spheres, and accumulators. A pressure vessel may have been constructed in accordance with other recognized pressure vessel codes or as approved by the jurisdiction.

Pressure vessel codes typically limit the design basis to an external or internal design pressure no less than 15 psig (103 kPa). However, this recommended practice includes vessels that operate at lower pressures. External pressure on a vessel can be caused by an internal vacuum or by fluid pressure between an outer jacket and the vessel wall. Vessels subject to external pressure are usually inspected in the same manner as those subject to internal pressure. API 510—Annex A provides code exemptions; however, the integrity of these vessels can still be assessed using the principals within this recommended practice. Storage vessels subject to internal pressures up to 15 psig (103 kPa) are covered in API 575 and API 620.

Pressure vessels are designed in various shapes. They may be cylindrical (with flat, conical, toriconical, torispherical, semi-ellipsoidal, or hemispherical heads), spherical, spheroidal, boxed (with flat rectangular or square plate heads, such as those used for the headers of air-cooled exchangers), or lobed. They may be of modular construction. Cylindrical vessels may be either vertical or horizontal in orientation.

Pressure vessels may be supported by steel columns, cylindrical plate skirts, or plate lugs attached to the shell. Spherical vessels are usually supported by steel columns attached to the shell or by skirts. Spheroidal vessels are partially or completely supported by resting on the ground. Jacketed vessels are those built with a casing or outer shell that forms a space between itself and the main shell.

Pressure vessels are used throughout the processes in a refinery or petrochemical plant. They are used to contain process fluids. A pressure vessel can be used for many different purposes, including (but not limited to) as a:

- thermal reactor or a catalytic reactor to contain the chemical change required by the process;
- fractionator to separate various constituents produced in the reaction;
- separator to separate gases, chemicals, or catalyst from a product;
- surge drum for liquids;
- settling drum to permit separation of a chemical from a treated product;
- regenerator to restore a catalyst or chemical to its original properties;
- heat exchanger, condenser, cooler.

4.2 Tower

Towers all either directly enrich a gas or liquid, strip a gas or liquid, or fractionate a liquid. These processes are collectively called “mass transfer.” Towers or columns (the terms tower and column are used interchangeably within the petrochemical industry) come in a wide variety of shapes and sizes, but the one thing they all have in common is base purpose—that is, they all, at the very basic level, promote, cause, contain, allow, encourage, or otherwise make “mass transfer” happen. The difference in concentration of a particular molecule is the prime mover in mass transfer. Molecules move from an area of high concentration to an area of low concentration. The mass transfer in a tower is usually from a liquid to a gas or from a gas to a liquid. Figure 1 shows a process tower.



Figure 1—Example of a Process Tower

The most common types of towers use contacting elements, such as trays or packing, to facilitate mass transfer between a gas and a liquid (see Figure 2 and Figure 3). Both packing and trays accomplish this by increasing the available surface area for the gas/liquid contact.

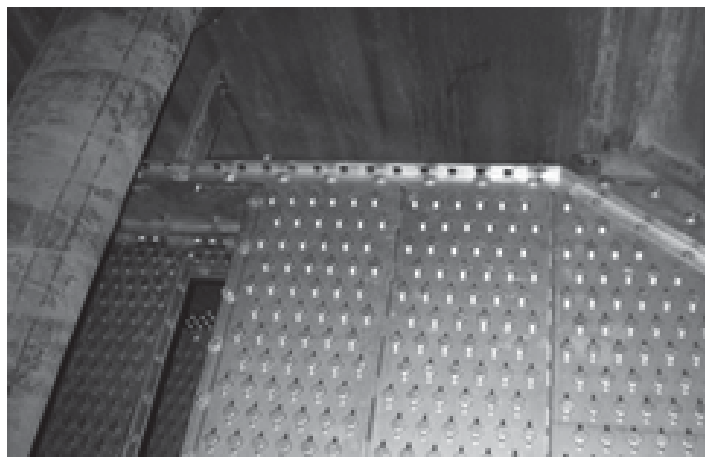


Figure 2—Typical Trays in a Tower

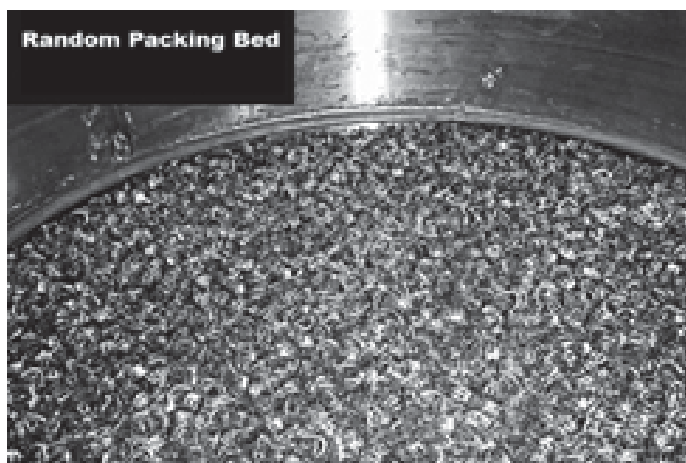


Figure 3—Random Packing in a Tower

In addition to increasing contact area (and increasing contact time), trays allow additional distillation to take place at each tray.

Tray decks both increase the available contact area and provide additional distillation stages to take place as the hot gases rise through the tray perforations. Liquid levels are maintained on the trays via weirs, and a vapor seal is maintained via downcomers. Figure 4 diagrams how the trays with downcomers work.

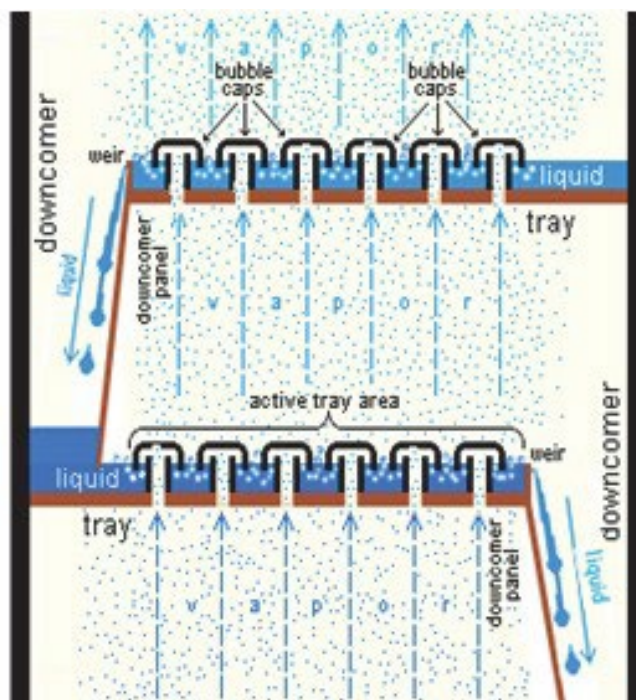


Figure 4—Trays with Downcomers

Gases/vapors, released from the feed liquid (after being heated), travel up the column through the tray perforations (the bubble cap depicted in Figure 5 is a type of tray perforation) while liquid flows across the trays and down the tower via the downcomers from the feed inlet down to the stripping section (countercurrent flow). The area above the feed inlet is known as the rectification or enrichment section. The enrichment section utilizes a liquid reflux of condensed overhead gas to further enrich the overhead product.

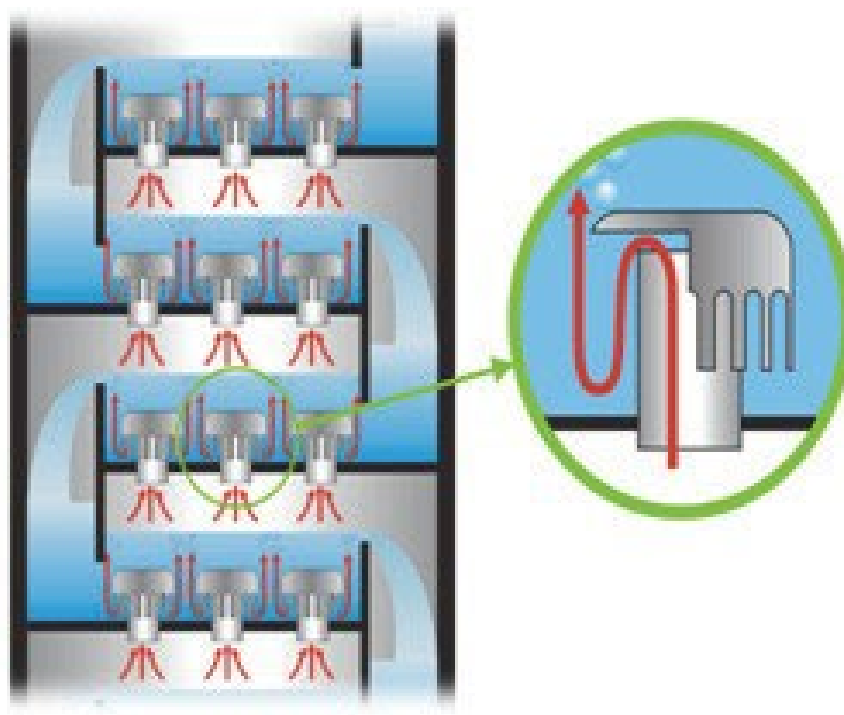


Figure 5—Bubble Cap Flow Path

Most of the towers used in the petrochemical industry utilize the distillation-type stripping process described above and depicted in Figure 6; however, in cases where distillation is impractical, liquid-liquid extraction accomplishes mass transfer utilizing the difference between the chemical structures of two liquids. Liquid-liquid extraction necessitates recovery of solvent or raffinate via distillation stripping. Some other types of mass transfer operations that utilize distillation-type stripping are stripping, absorption (also known as scrubbing), and dehydration. Fractionation uses simple distillation via selective cooling to remove and collect those fractions of the feed that boil and condense at different temperatures. The heat source needed to cause phase change (liquid to gas) can be fired heaters, steam injection, steam reboilers, or reboilers using preheated process streams.

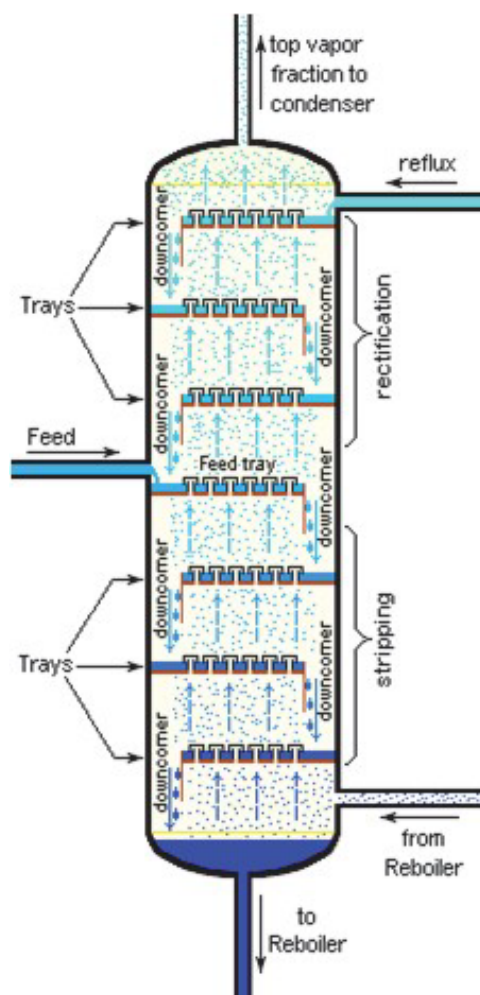


Figure 6—Tower Stripping and Rectification Section

Annex B provides a detailed introduction to towers.

4.3 Exchanger

Exchangers are used to change the temperature of one fluid by the transfer of heat to another fluid without mixing fluids. Exchangers are called condensers when the temperature of a vapor is reduced to the point where some or all of the vapor becomes liquid by the transfer of heat to another fluid, usually water. When a hot fluid is cooled to a lower desired temperature by the transfer of heat to another fluid, usually water, the exchanger is usually referred to as a cooler.

Shell and tube heat exchangers have internal tube bundles with baffles or support plates, which vary with the service and heat load the exchanger is designed to handle. Pass partitions are usually installed in the channels and sometimes installed in the floating tubesheet covers to provide multiple pass flow through the tubes. The flow through the shell may be single pass, or longitudinal baffles may be installed to provide multiple passes. The baffling used in the shell determines the location and number of shell nozzles required. Figure A.1 and Figure A.2 show various channel and shell baffle arrangements. Frequently, an impingement baffle or plate is placed below the shell inlet nozzle to prevent erosion damage of the tubes due to impingement of the incoming fluid. Figure 7 and Figure 8 are examples of heat exchangers.

Annex A provides a detailed introduction to heat exchangers.



Figure 7—Example of a Horizontal Heat Exchanger



Figure 8—Example of Vertical Heat Exchanger

4.4 Air-cooled Heat Exchangers

Air-cooled heat exchangers, also known as fin fans, are a type of heat exchanger that takes advantage of surrounding air conditions being cooler than the process and usually uses fans to blow air over finned tubes to cool the process (e.g. in the same way that a radiator functions). They are usually used when the outlet temperature of the fluid being cooled is more than 20 °F above the maximum air temperature. An air-cooled heat exchanger operates on the principle of passing air, via fans, over finned tubes. There are two methods of moving air over the fins—forced (pushed) and induced (pulled). Fins are added to the tubes to increase the amount of heat transfer possible by increasing the surface area of the tubes. Fin fans are most commonly used to cool or condense the gases coming off the top of a tower or reactor. They are often used to condense lighter hydrocarbons coming off the top of a fractionator (e.g. distillation tower) or a flash drum to send to further separation.

4.5 Reactor

A reactor is a pressure vessel in which chemical reactions are initiated and sustained. Within a reactor, raw materials are combined at various flow rates, pressures, and temperatures, and they react to form a product. These reactions can be either batch or continuous. Batch reactions are complete loads done start to finish and then removed.

An example of batch reactors found in a refinery are coke drums. Located in coker units, they are found in sets of two with one drum containing a reaction, while the other drum empties and prepares for the next reaction. Once the chemical reaction is completed, the drums switch uses so there can always be a “batch” running to induce the reaction.

Continuous reactions are an ongoing process with raw materials entering and product being removed from the reactor. Reactors come in many shapes and sizes. The most common types of reactors are stirred tank, fixed bed, fluidized bed, and tubular or plug flow. The type of catalyst and the properties of the reactants determine which type of reactor will be used.

In continuous stirred tank reactors, reactants are introduced into a reactor with an impeller that constantly stirs to ensure a uniform composition throughout. In this type of reactor, the products are being removed constantly. This type of reactor can typically be found in petrochemical units.

In fixed bed reactors, gases typically flow through a fixed catalyst “bed” that induces a chemical reaction. The catalyst is typically in the form of small pellets. This type of reactor can typically be found in polymerization units. Like fixed bed reactors, fluid bed reactors pass gases through a catalyst to induce reactions. The very fine catalyst, in the form of a powder, is mixed with the gases to form a fluid until the reaction is complete, then the catalyst and products are separated so that the catalyst can be reused. This type of reactor can typically be found in fluidized catalytic cracking units.

In tubular or plug flow reactors, fluids flow through tubes at high velocities inducing chemical reactions. The chemical reaction proceeds as the fluids travel through the reactor and the concentration of products increases. This type of reactor can typically be found in hydrotreating units.

4.6 Sphere

Many industries use spherical pressure vessels, including oil, gas, petrochemical, chemical, and aerospace. They can also serve as processing, testing, containment, surge, and vacuum vessels, or hyperbaric or environmental chambers. A spherical shape offers uniform stress distribution under internal loading resulting in highly efficient pressurized storage. They are ideal for ambient temperature liquid, low-temperature liquid, cryogenic liquid, and gas storage. Sphere storage results in the lowest land space for pressurized storage and offers lower costs for foundations, coatings, accessories, and piping than other options.

An advantage of spherical storage vessels is that they have a smaller surface area per unit volume than any other shape of vessel. This means that the quantity of heat transferred from warmer surroundings to the liquid in the sphere will be less than that for cylindrical storage vessels. Spheres can store many products, such as anhydrous ammonia, liquefied petroleum gas, natural gas liquids, gasoline, naphtha, butadiene, ethylene, hydrogen, oxygen, nitrogen, argon, liquefied natural gas, biogas, sewage gas, and wastewater. Figure 9 is an example of a sphere, and Figure 10 is an example of a Horton spheroid (noded).

Spheres can be built from 1000 barrels to 75,000 barrels of capacity.

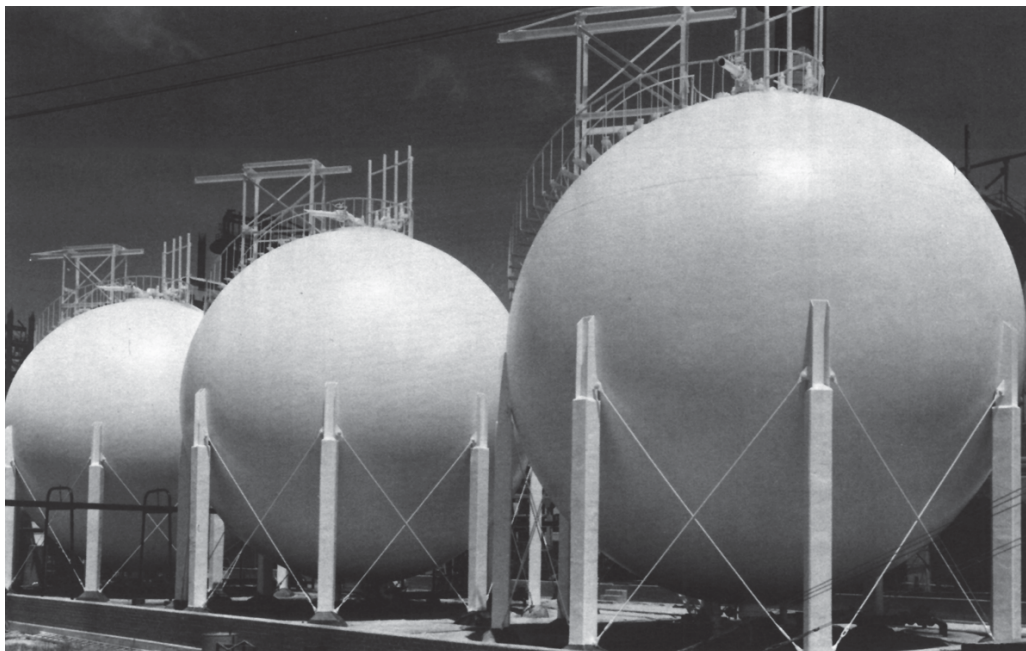


Figure 9—Spheres

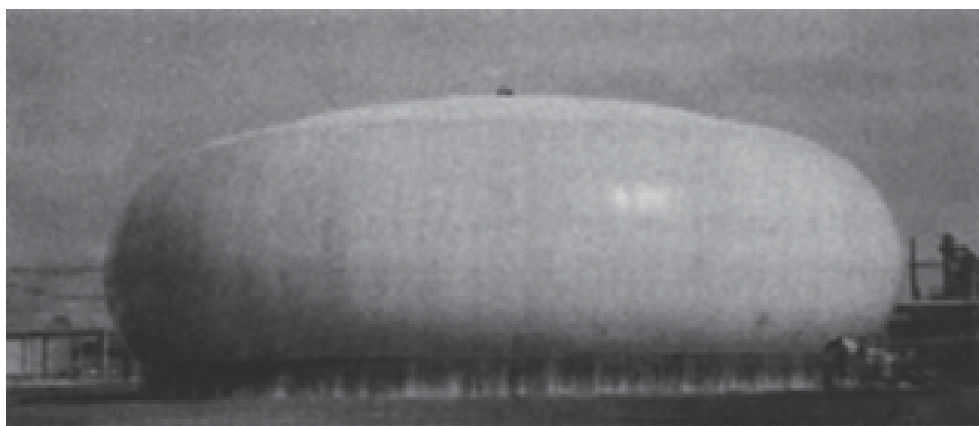


Figure 10—Horton Spheroid (Noded)

4.7 Other Vessels

There are many other types of pressure vessels utilized within oil processing—for example, accumulator, separator, knockout vessel, flash chamber, expansion separator, scrubber, and filter. These vessels come in many different sizes and can be vertical or horizontal in orientation. Figure 11 is an example of a horizontal vessel. Like towers, they may have internals to effectively process the fluids going through them. Depending on the purpose of the vessel, the amount and configuration of the internals will vary.

A baffle, metal plate, may be placed at strategic positions inside a vessel, which alters the flow of the material in the vessel and can help to facilitate mixing.

In liquid-liquid separation, a weir plate may be used to hold back the heavier liquid allowing lighter liquids to flow over the weir plate and therefore resulting in the separation of the two liquids. Using residence time, chemicals, or heat, two immiscible liquids are allowed to separate.

In long horizontal vessels, it is necessary to install wave breakers or stilling baffles, which are nothing more than vertical baffles spanning the gas-liquid interface and perpendicular to the flow. Wave breakers serve multiple functions. By minimizing the amount of waves, the oil and water separation process is stabilized. This prevents large amounts of wet oil (emulsion) from spilling over the weir.

A splash plate, inlet diverter, or inlet deflector may be used to change the direction of the inlet flow. An inlet diverter can be a spherical dish, flat plate, angle iron, or another type of structural steel. The rapid change in direction and change of velocity causes the gas to break out of the liquid. The design of the diverter must be such that it can resist the impact momentum of the incoming fluid. An advantage of using devices such as a half sphere or cone as a splash plate is that they create less disturbance than plates or angle iron.

Pressure vessels may also contain a boot. The boot is a section at the bottom of a process vessel where water or other unwanted fluid is collected and removed. This area is located at the lowest section of the vessel.

NOTE Typically, internal components of pressure equipment are not considered part of the pressure-containing design of the equipment.



Figure 11—Horizontal Vessel

5 Pressure Vessel Design and Construction

5.1 Design and Construction Standards

Most pressure vessels in the United States were built to conform either to the *API/ASME Code for Unfired Pressure Vessels for Petroleum Liquids and Gases* or to Section VIII of the *ASME Code*. Publication of the *API/ASME Code for Unfired Pressure Vessels for Petroleum Liquids and Gases* was discontinued on December 31, 1956, and is no longer used. Prior to the early 1930s, most unfired pressure vessels for refineries were built to the design and specifications of the owner-operator or manufacturer.

Section VIII of the *ASME Code* is divided into three parts—Division 1, Division 2, and Division 3. Section VIII, Division 1 provides requirements applicable to the design, fabrication, inspection, testing, and certification of pressure vessels operating at either internal or external pressures exceeding 15 psig (103 kPa). Most pressure vessels for US refineries are now built to conform to the latest edition of Section VIII, Division 1. Section VIII, Division 2 provides alternative and more stringent rules for the design, fabrication, and inspection of vessels than those found in Division 1. Some high-pressure vessels are designed and built in accordance with the specifications of Division 2. Section VIII, Division 3 provides alternative rules for construction of high-pressure vessels with design pressure generally above 10,000 psig (70 MPa).

In the United States, heat exchangers and condensers are designed and built in accordance with *ASME Code*, TEMA Standards, API 660, and API 661. Other countries may have equipment design requirements other than ASME, TEMA, and API.

Both Divisions 1 and 2 of Section VIII of the *ASME Code* require the manufacturer of a vessel to have a quality control system.

The *ASME Code* lists materials that may be used for construction, gives formulas for calculating thickness, provides rules on methods of manufacture, and specifies the procedures for testing completed vessels. Inspection is required during construction and testing of vessels. The *ASME Code* also prescribes the qualifications of the persons who perform the construction inspections.

After an authorized inspector (as defined by the *ASME Code*) certifies that a vessel has been built and tested as required by the *ASME Code*, the manufacturer is permitted to stamp the vessel with the appropriate symbol of the *ASME Code*. The symbol stamped on a pressure vessel is an assurance by the manufacturer that the vessel has been designed, constructed, tested, and inspected as required by the *ASME Code*.

Design and construction codes are periodically revised as the designs of pressure vessels improve and as new construction materials become available. A refinery or petrochemical facility inspector should be familiar not only with the latest editions of codes but also with previous editions of the codes and with other specifications under which any vessels they inspect were built. The inspector should be familiar with any regulations (including city, county, parish, provincial, state, or national, such as OSHA, regulations) governing inspection and maintenance of pressure vessels in the refinery.

5.2 Methods of Construction

Several different methods are used to construct pressure vessels. Most pressure vessels are constructed with welded joints. Shell rings are usually made by rolling plate at either elevated or ambient temperature. The cylinder is fabricated by welding the ends of the rolled plate together. This yields a cylinder with a longitudinal weld.

Prior to the development of welding, riveting was the most common method of construction. Seams were either lapped and riveted or butted with butt straps then riveted. To prevent leakage, the edges of the seams and rivet heads were caulked. At high temperatures, it was difficult to keep this caulking tight. After the technique of welding was developed, a light bead of weld was applied to the caulking edges. Although some vessels of this type can still be found in older refineries, this method of construction is seldom used today.

Hot forging is another method of making cylindrical vessels. Some vessel manufacturers hot forge cylindrical shell rings for high-pressure, heavy-wall vessels, such as those used for hydrotreater or hydrocracker reactors. This method does not produce a longitudinal seam in the cylinder.

In the multilayer method, the cylindrical section is constructed from a number of thin concentric cylinders fabricated together, one over the other, until the desired thickness is obtained. Multilayer construction is sometimes used for heavy-wall reactors and vessels subject to high pressure.

5.3 Materials of Construction

5.3.1 Base Material

A wide range of materials are used to construct pressure vessels depending on compatibility with the service. Carbon steel is the most common material used to construct pressure vessels; other examples include austenitic or ferritic alloy, Alloy 400, nickel, titanium, high-nickel alloys, or aluminum alloys. Copper and copper alloys (except Alloy 400) are seldom used in refinery vessels but are common with heat exchanger tubes and may be found in petrochemical plant vessels.

Materials used to construct the various parts of pressure vessels are selected to safely handle the service and intended function. Materials that will most economically resist the type of damage mechanism expected are selected. Pressure vessels may be lined with a corrosion-resistant material.

5.3.2 Liners

5.3.2.1 General

If carbon steel would not resist the corrosion or erosion expected or would cause contamination of the product, vessels may be lined with other metals or nonmetals. A lined vessel is usually more economical than one built of a solid corrosion-resistant material. When the pressure vessel operates at a high temperature, a high pressure, or both, solid alloy steels may be both necessary and economical.

5.3.2.2 Metallic Liners

5.3.2.2.1 General

Metallic liners may be fabricated of a ferritic alloy, Alloy 400, nickel, lead, or any other metal resistant to the corrosive agent. Metallic liners are installed in various ways and can be either integrally bonded or nonintegrally bonded.

5.3.2.2.2 Integrally Bonded Liners

Integrally bonded liners are composites of two or more metals joined in a continuous manner by a metallurgical bond usually referred to as cladding. They may be an integral part of the plate material rolled or explosion bonded before fabrication of the vessel. Corrosion-resistant metal can also be applied to the vessel surfaces by various weld overlay processes. Figure 12 is an example of weld metal surfacing.



Figure 12—Weld Metal Surfacing

5.3.2.2.3 Nonintegrally Bonded Liners

Nonintegrally bonded liners are corrosion-resistant lining attached intermittently to the vessel wall. They may consist of sheet, strip, or plate that is intermittently attached to the vessel by acceptable welding processes. Nonintegrally bonded metallic liners are not counted as part of the pressure boundary of a pressure vessel. Nonintegrally bonded liners are no longer commonly used because they have proven difficult and expensive to inspect and maintain. Figure 13 and Figure 14 show methods for applying nonintegrally bonded liners.



Figure 13—Strip-lined Vessel

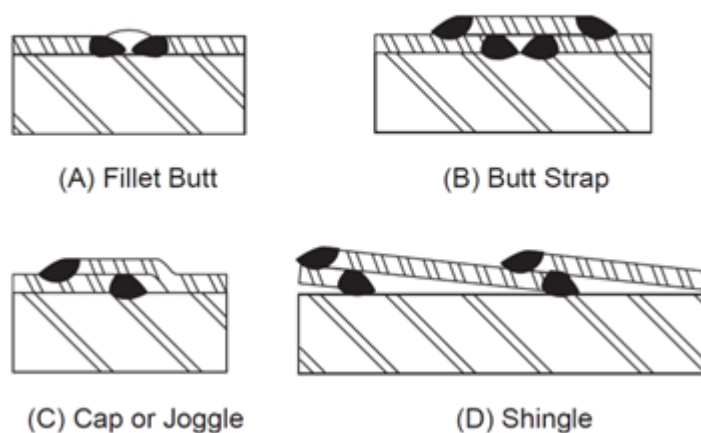


Figure 14—Principal Strip-lining Methods

5.3.2.3 Nonmetallic Liners

Nonmetallic liners may be used to resist corrosion and erosion, reduce fouling potential (i.e. exchanger tubes), or to insulate and reduce the temperature on the walls of a pressure vessel. The most common nonmetallic lining materials are reinforced concrete, acid brick, refractory material, insulating material, carbon brick or block, rubber, polymeric coatings, glass, and plastic. Figure 15 and Figure 16 show the Hex mesh installation to support the refractory lining and the reinforced refractory lining.

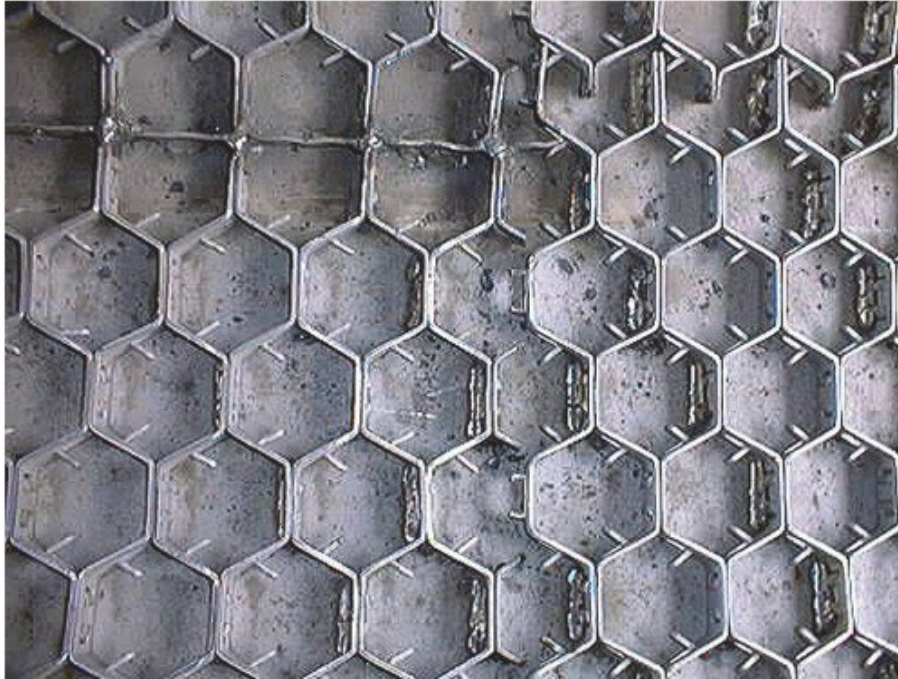


Figure 15—Hex Mesh Installation for Refractory Lining

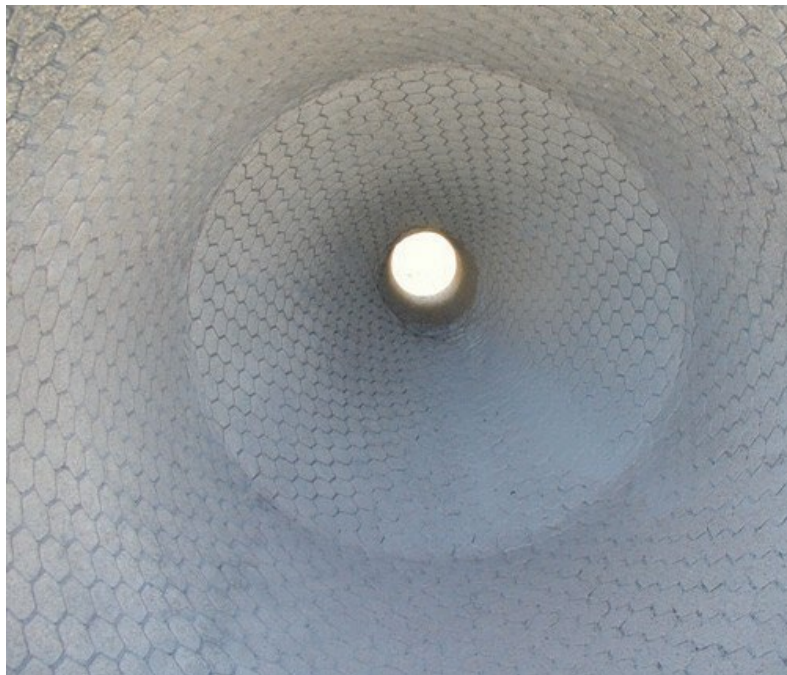


Figure 16—Reinforced Refractory

5.3.3 Nonmetallic Pressure Vessels

Pressure vessels constructed out of nonmetallic materials are usually fabricated from fiber-reinforced plastic (FRP) and can be more resistant to some corrosive services. FRP is made with different resins as the matrix material and typically use glass fiber as the reinforcement. Reinforced thermoset plastics are a type of FRP that is more rigid due to the use of a thermoset resin for the matrix rather than a thermoplastic. Both of these nonmetallic materials have varying strength due to the type of fiber used, fiber weave, the lay-up of the fiber layers, and what thermoplastic resin has been used to reinforce fiber layers.

5.3.4 Heat Exchanger Tube Bundles

Tubes and tubesheets for exchanger bundles may be a variety of materials. Where water is the cooling or condensing medium, materials such as carbon steel (clad or solid), all grades of stainless steel, copper and copper alloys, aluminum and aluminum alloys, titanium, or nickel alloys may be used (see API 571 on cooling water corrosion). In water applications where copper alloys, steels, or higher-alloy material will not provide sufficient corrosion protection, the tube ID may be coated (baked epoxy or similar). Titanium may be used in seawater applications. Where the exchange is between two different hydrocarbons, the tubes may be fabricated of steel or a suitable corrosion-resistant alloy. In some cases, heat exchanger tubes may be fabricated with an inner layer of one material bonded to an outer layer of a different material (i.e. bimetallic fabrication). Tubes such as these address corrosion resistance from two different corrosive mediums.

6 Reasons for Inspection

6.1 General

The primary reason for inspection is to determine the current physical condition of the vessel and its suitability for continued service. In this process, identification and/or verification of the active damage mechanism(s) along with their specific mode, rate, and causes should be determined. This allows for the proper planning of steps to monitor, mitigate, or prevent future deterioration. This information should be carefully documented after each inspection. The information gained from any inspection contributes to the planning of future inspections, repairs, and replacement and yields a history that may form the basis of an effort, such as risk-based inspection (RBI) assessment, integrity operating windows (IOWs), corrosion control document (CCD), FFS, etc. Any damage found during inspection should be addressed by recommendations for further evaluation, more detailed inspection, repair, or replacement as appropriate.

6.2 Safety

Periodic scheduled inspections are intended to identify damage that could result in a process safety incident, such as loss of containment, which could lead to fire, toxic exposure, or environmental hazard.

6.3 Regulatory Requirements

It is important for the inspector to be knowledgeable in local regulatory requirements. Some regulators have inspection requirements written within their regulation, whereas other regulatory bodies require adherence to a specific industry code or standard. API 510 was developed to provide an industry standard for the inspection of in-service pressure vessels, and the latest edition should be followed unless superseded by jurisdictional regulations. In addition, there may be other local or national regulations, such as OSHA 29 *CFR* 1910.119 in the United States, that require operating sites to follow recognized and generally accepted good engineering practice when performing inspection and repair activities.

6.4 Reliability

It is important to maintain the integrity of pressure equipment as a loss of containment event can cause a significant reduction in a facility's reliability, availability, and maintainability. Inspections performed while the

equipment is in operation using NDE techniques may reveal important information without requiring entry inside of the equipment. The data from NDE help contribute to evaluating the integrity of a pressure vessel. Therefore, these data can aid in maximizing the period of operation without an unplanned shutdown. In addition, repair and replacement requirements can be planned and estimated in advance of a planned shutdown to more effectively utilize downtime. These efforts can contribute to overall plant reliability by reducing the number or duration of unplanned shutdowns.

7 Inspection Plans

7.1 General

The primary goal of the inspection plan is to organize inspections (and supporting activities) enabling the owner-operator to assess the condition of the pressure vessel. Inspection plans should be drawn up for each type of inspection for vessels in accordance with API 510—Section 5.1. Inspection plans should be detailed enough to provide guidance to the inspector so that all credible damage mechanisms are assessed and documented in the inspection report. The following factors should be considered during the development of an inspection plan:

- a) known or anticipated damage mechanisms and modes;
- b) primary areas susceptible to the damage mechanisms;
- c) expected damage rate/susceptibility;
- d) remaining useful life;
- e) inspection technique(s) to effectively target the damage modes identified;
- f) safe accessibility of equipment or parts of the equipment;
- g) potential negative impacts of inspection to integrity and damage mechanisms, such as:
 - 1) the removal of protective films,
 - 2) the stress on equipment due to start-up and shutdown,
 - 3) exposure to air and moisture potentially accelerating some environmental cracking mechanisms [e.g. polythionic acid stress corrosion cracking (PTA SCC)];
- h) possible risks to personnel involved in inspection activities;
- i) whether equipment is to be inspected on-stream in lieu of conducting internal inspection;
- j) on-stream monitoring requirements for known flaws previously evaluated and found acceptable for continued service (without repairs); examples include hydrogen blistering, locally thin areas due to erosion/corrosion, etc.

Complete inspection plans for pressure vessels should include the inspection interval or next inspection date (see Section 8), the type of inspection activities that should be performed, and the portion of the equipment to which the inspection activities should be applied.

7.2 Developing Inspection Plans

7.2.1 Identification of Damage Mechanism

API 510 requires the identification of credible damage mechanism(s) affecting the pressure vessel and locations of susceptibility. This can be done by reviewing the material of construction and process environment (e.g. process fluid, temperature, pressure, and external process environment, etc.) and understanding the damage mechanisms that can occur from the exposure. Industry sources exist that describe damage mechanisms, susceptible materials of construction, and the process environments causing the damage. API 571 is an example reference that provides a comprehensive listing and description of damage mechanisms affecting fixed equipment in the refining industry.

Determine if the damage mechanism is a general or localized corrosion mechanism and if the mechanism is more likely to occur at specific locations in the pressure vessel. Examples of location-specific damage mechanisms are as follows:

- a) liquid-to-vapor interfaces;
- b) fluid-to-fluid interfaces;
- c) welds and heat affected zones;
- d) bottoms (where deposits are likely to form, especially important with microbiologically induced corrosion);
- e) temperature transitions;
- f) impingement areas;
- g) fluid injection points (i.e. nozzles, quills, downcomers, drool locations);
- h) high velocity areas;
- i) fluid separation and transition areas;
- j) concentration changes.

Determine if the material of construction is susceptible to cracking mechanisms. Examples of fluid/material pairs that could point to a credible damage mechanism are as follows:

- a) chlorides/stainless;
- b) wet hydrogen sulfide (H_2S)/carbon steel;
- c) amine/carbon steel;
- d) high-temperature hydrogen/carbon and low-alloy steel;
- e) anhydrous ammonia/carbon steel;
- f) hydrofluoric acid (HF)/alloy 400 and/or carbon steel;
- g) caustic/carbon steel and/or stainless.

NOTE The above list of examples is simply a few examples of materials/environments that could lead to cracking. Documentation of the identified damage mechanism should be documented per guidance of API 970 or API 580.

7.2.2 Selecting Inspection Activities

Inspection plans should address credible damage mechanisms identified by a corrosion specialist and/or the unit CCD in accordance with API 510—Section 5.4. Identifying and understanding all potential damage mechanisms that can cause deterioration of a pressure vessel is key in developing an effective inspection plan. Without adequately identifying what damage mechanisms can affect a vessel, a proper inspection plan and risk assessment cannot be performed in order to prevent unexpected high corrosion rates or additional damage mechanisms. This can be done utilizing API 571 in conjunction with process and equipment information. Once all credible mechanisms have been established, the appropriate inspection technique(s) should be aligned with the expected damage mechanisms and the corresponding modes of damage.

To determine if a vessel is subject to degradation and will require internal inspection, on-stream inspection, and/or thickness monitoring, the following factors should be considered.

- a) Credible damage mechanisms—The availability of process corrodents, such as water, oxygen, H_2S , etc., that may act on the materials of construction, as determined by a corrosion specialist.
- b) Process controls (IOWs) in place to identify when the process has been changed such that it becomes damaging to the material.
- c) New process design—If the vessel is in a new process where there is some uncertainty about whether the process will work as designed, it should not be designated as being in noncorrosive service until proven through operation and inspection.
- d) Process stability—If the process is such that a small change in operation can introduce conditions where the damage mechanism could become active versus the case where introduction of a corrodent such as water would not be compatible with operation (such as the cryogenic portion of an ethylene plant).
- e) Presence of protection against known damage mechanism, such as corrosion-resistant weld overlay, cladding, coating, lining, or refractory.

Some equipment may not require much, if any, inspection because of lack of credible damage mechanisms. Typical examples of systems with no credible internal damage mechanism:

- a) ethylene plant equipment operating under cryogenic conditions;
- b) liquefied natural gas plants downstream of the mercury removal beds and water removal;
- c) process units alloyed up for product purity where any corrosion would result in product going off specification;
- d) a new vessel replaced in kind with a proven history of no credible internal damage mechanism but was replaced due to external damage mechanism such as CUI;
- e) aluminum core plate exchangers in hydrocarbon service without mercury;
- f) refrigerant grade fluid vessels that are without any contamination.

7.2.3 Location for Inspection

Inspection locations, CMLs, should be selected once credible damage mechanisms have been identified. The number of CMLs selected will depend on the technique's probability of detection, degree of localization of the damage and how predictable the damage mechanism is. Additional CMLs may also be added for equipment with high likelihood or high risk of failure.

Understanding factors and conditions that affect the likelihood a damage mechanism will be active is important in developing a focused inspection plan and selecting the appropriate location for inspection. Previous inspection results can also be used to identify active mechanisms and better predict areas to be inspected. Equipment susceptible to uniform damage can be inspected at any convenient location; however, it may be necessary to inspect larger areas or employ multiple techniques to ensure that localized damage is detected.

Matching the various surface and volumetric NDE techniques to localized corrosion damage mechanisms is key in capturing the correct corrosion data. Predicting where damage will occur, specifically localized damage, is difficult even when credible damage mechanism(s) is well understood. Consultation with a corrosion specialist and/or review of the process unit CCD can help in understanding CML selection and placement for localized damage mechanisms. Selecting appropriate inspection locations for equipment subject to localized damage is as critical as applying the appropriate technique. If sufficient levels of inspection have been performed over time, the results of those inspections could be used to identify locations of damage. Once established, these mechanisms and their associated modes can be used in conjunction with equipment availability (will equipment be shut down or remain on-stream) to plan inspection techniques.

Visual checks of the external parts of a vessel should be performed periodically. These inspections may be conducted at comparatively short intervals (e.g. compared to a 10-year internal inspection interval), the interval depending on the service and previous condition of the particular equipment involved. External inspection of pressure vessels should be conducted in accordance with API 510—Section 6.4. It is important to understand the process conditions prior to the external visual inspection to determine whether CUI inspections should be planned. See API 571 and API 583 for more information on issues that may assist in the development of CUI inspection plans. CUI Inspection plans should be in accordance with API 510.

The list of techniques identified for the pressure boundary should be compared against internal or process-based inspection and maintenance requirements (such as potential fouling or mechanical problems) to ensure all areas of the vessel are assessed as needed. All of these are combined into one set of complete inspection activities. Then, based on damage rates and remaining life, appropriate timing should be identified (see Section 8).

7.3 Reviewing and Updating Inspection Plans

Inspection plans should be reviewed and updated, as necessary, under the following circumstances:

- a) following inspection and testing activities;
- b) deviations from IOW limits;
- c) physical or mechanical damage;
- d) changes in process or environmental conditions;
- e) periodically to evaluate effects of process creep;
- f) modifications to equipment;
- g) new industry knowledge (i.e. recent industry loss of containment event in similar services) and experience of damage mechanisms or other parameters that could affect the equipment integrity or reliability;
- h) availability of new inspection, testing, and monitoring data;
- i) limitations of existing inspection and testing techniques based on new information;
- j) recommendation from an FFS analysis.

When changes in process operations are implemented, they should be reviewed to determine whether they might affect the damage rate or provide new damage mechanisms. When a change in the damage rate occurs or is anticipated, the recommended inspection interval should be changed accordingly.

An open dialogue should be established between inspection and operation to discuss operating issues. A check of the operating records while equipment is in service can be helpful in determining and locating the cause of equipment malfunctions and/or deterioration. For example:

- a) An increased drop in pressure may indicate blockage from excessive corrosion deposits.
- b) Reduced exchange of heat from exchangers or coolers may indicate heavy corrosion deposits on or in the bundle tubes.
- c) The inability to draw the product of fractionation or distillation from certain trays may indicate fouling or loss of tray parts in a process tower.
- d) Product deterioration may indicate loss of trays, tray parts, or other internal equipment in process vessels.

7.4 Integrity Operating Windows

IOWs should be established where possible for each credible damage mechanism in accordance with API 584 as per API 510—Section 4.1.4. The standard IOW typically represents the operating limits in which the equipment can operate with predictable corrosion or damage rates. Operating conditions should be monitored to avoid degradation that can occur when operating outside of the designated IOWs. The inspection plan may not be valid if equipment is operated outside the IOWs.

When the process goes outside the limits of the IOW for the pressure vessel, predefined actions should be taken. This may include a revision of the inspection plan or executing an unplanned on-stream inspection. Detailed examinations may be needed to assess the impact on equipment integrity of operation outside the IOW, e.g. reactor runaway conditions. API 584 outlines the essential elements in defining, monitoring, and maintaining IOWs as an essential component of an integrity management program.

IOWs should also be updated when changes in process operations are implemented. These types of changes are typically managed as part of the management of change (MOC) program. API 510—Section 4.1.3 provides additional information on MOC requirements.

7.5 Newly Commissioned Vessel Inspection

New vessels, where internal degradation is expected, should be inspected per API 510—Section 7.1.2.

Where thickness monitoring will be part of the ongoing inspection requirements, external baseline thickness measurements should be obtained prior to being placed in service. Taking thickness measurements at identified CMLs provides more accurate development of corrosion rates from the data obtained at the first inspection as opposed to taking random thickness inspections of components. When nonthinning damage mechanisms may be present, baseline inspection using applicable NDE technique may be prescribed.

8 Strategies for Establishing Frequency and Performing Inspection

8.1 General

The frequency with which a pressure vessel should be inspected can be established based on time, remaining life, condition, and/or risk-analysis and set in accordance with API 510 and any applicable jurisdictional requirements. A service history record should be established after the first inspections and reviewed when setting the inspection frequency.

Insurance and jurisdictional requirements may also affect the inspection interval of pressure vessels. Those responsible for inspection and maintenance of equipment should familiarize themselves with the applicable requirements.

8.2 Fixed Interval

Time and condition-based intervals are set such that the time between inspections is normally at least half the remaining service life or at a regular interval. When establishing inspection intervals in accordance with API 510, a remaining life shall be evaluated to verify the vessel can safely continue operation at least until the next scheduled inspection. API 510—Section 7 includes guidelines for evaluating corrosion rates, remaining life, and MAWP. It should be noted that short-term corrosion rates can have significant amount of error based upon measurement error associated with the inspection technique. The predetermined frequency of inspection allows for unanticipated changes in damage rates to be found during the inspection.

8.3 Risk-Based Inspection

Risk-based intervals per API 580 are set based upon the probability of the damage occurring combined with the consequence of a failure. Risk-based intervals require input from operations, process engineering, and materials corrosion and inspection personnel and allow the intervals to be set appropriately and move beyond time and condition-based limits. When RBI is used to determine inspection intervals and the type and extent of future inspection/examinations, it should be in accordance with API 510 and API 580. In some cases, risk-based intervals will be shorter as the operating conditions combined with the equipment conditions identify integrity issues that are best monitored on a shorter interval. API 581 details an RBI methodology that has all of the key elements defined in API 580.

8.4 On-stream in Lieu of Internal Inspection

API 510 permits an on-stream inspection to be conducted in lieu of an internal inspection under certain conditions. The intent of this section is to give guidance to the owner-operator on how to set up and determine the extent of an on-stream in lieu of internal inspection of a pressure vessel as a supplement to API 510—Section 6.5.2 or API 510—Section 9 for upstream E&P vessels. Methodology should be based on historical or predicted damage mechanisms for the candidate vessels. It should be noted that all requirements of API 510—Section 6.5.2.1 a) or b) be fulfilled unless an RBI approach is taken as noted in API 510—Section 6.5.2.2 prior to implementing an on-stream in lieu of internal inspection. A pressure vessel in upstream exploration and production can also utilize the approach of on-stream in lieu of internal.

The intent of performing an on-stream in lieu of internal inspection is to give the owner-operator an alternative inspection regime that substitutes placing a person inside a vessel. This alternative should give the owner-operator confidence that an adequate inspection is performed for a defined damage mechanism, which is predictable, based on historical data from same or similar service vessels. To achieve a level of confidence for the owner-operator to endorse an on-stream in lieu of internal inspection, UT point measurement is often not enough based on the damage mechanism(s) the vessel may be subjected:

- a) best practices for setting up on-stream in lieu of internal inspections for a group of vessels in similar service or by individual vessel include information required to determine applicability of an on stream in lieu of internal inspection;
- b) personnel needed for a damage mechanism review;
- c) requirements and documentation needed for a damage mechanism review;
- d) NDE method selection (application of the fit-for-purpose inspection technique for the damage mechanism);
- e) extent of inspection (and what to do about areas not determined to be susceptible areas);
- f) economics and advantages.

The following information should be obtained prior to determining the applicability of an on-stream in lieu of internal inspection:

- a) the material of construction of the pressure vessel (e.g. post-weld heat treatment, hardness control, linings, coatings);
- b) the process fluid properties (i.e. fluid type, temperature, pressure, corrosive content, erosive content, potential for scaling, potential for bacteria);
- c) operating envelope (i.e. pressure, temperature, concentration ranges);
- d) trace contents;
- e) dissimilar metals in or connected to the vessel;
- f) cathodic protection present or not;
- g) condensing or evaporation inside equipment (this can have concentration impact, i.e. condensing acids inside a condenser or evaporating acids inside a reboiler);
- h) P&IDs;
- i) maximums and minimums (i.e. MAWT, MAWP, maximum/minimum concentrations);
- j) insulation, heat traced;
- k) historical operating, maintenance, and inspection history and relevant MOC;
- l) previous damage mechanism review/CCD.

8.5 Opportunities for Inspection

8.5.1 General

When an inspection is conducted will usually be determined through the collaboration of process, mechanical, and inspection groups, or by the mandate of a jurisdiction.

8.5.2 Scheduled Shutdowns

Internal inspections are often performed when a plant is shut down for maintenance. When scheduling a unit for shutdown, the following is often taken into consideration: catalyst run life, equipment fouling, integrity issues, and compliance with local regulation. Some refined and petrochemical products have seasonal demand or are manufactured via batch process, which will provide more opportunities for maintenance and inspection activities.

8.5.3 Unscheduled Shutdowns

Unscheduled shutdowns due to mechanical or process difficulties sometimes present opportunities for intermediate inspections of vessel areas where rapid corrosion, erosion, or other damage is known or suspected to occur. Partial shutdowns of units for process reasons may provide opportunities for internal inspections to determine conditions or verify on-stream inspection findings. This time may be used to perform identified repairs. However, internal inspections during unscheduled shutdowns should be motivated by specific process or inspection needs.

Inspections during the following opportunities are possible.

- a) Advantage should be taken of the opportunity to inspect exchangers when they are removed for routine cleaning in order to identify repair/replacement needs that can be scoped and scheduled for a future unit outage.
- b) Vessels or process towers removed from service to clean trays and other internals provide access to perform internal visual inspections.

8.5.4 On-stream Inspection

On-stream inspections may be performed while a vessel is in service. On-stream inspections can be planned and executed without shutting down equipment. This may require special provisions to access areas for inspection, such as scaffolding, insulation removal, rope access provisions, and surface preparation (buffing to remove surface scale/deposits).

On-stream inspection methods may be used to detect damage and to measure wall thickness. For example, thickness can be determined by using ultrasonic equipment or profile radiography where applicable.

8.5.5 External Inspection

External inspections may be performed while a vessel is in service. Inspection work performed while the equipment is in service will reduce the workload during an outage. These inspections should cover the condition of the foundation, supports, insulation, paint, and other structural elements. Ladders, platforms, walkways, and other nonsupport elements associated with fixed equipment should be assessed for integrity as determined by the owner-operator. See 10.2 on external inspection.

9 Safety Precautions and Preparatory Work

9.1 Safety Precautions

9.1.1 General

Safety precautions should be taken before entering a vessel, including consulting and complying with all applicable safety regulations. Due to limited access and egress within confined spaces, safety precautions are critical for internal vessel inspection work. API 510—Section 5.3 provides additional guidance on preparation for inspection.

The use of safety precautions will minimize danger from toxic gases, oxygen deficiency, explosive mixtures, and irritating chemicals. Clothing that will protect the body and eyes from the hazards existing in the vessel to be entered should be worn. Details for safe work practices should be detailed in facility procedures to cover all regulatory safety requirements.

The use of NDE devices for inspection is subject to safety requirements customarily used in gaseous atmospheres. The use of hydrocarbon-based MT and/or PT can change the environment of a confined inspection space. Therefore, procedures should be in place that recognize the potential change in the gaseous atmosphere. Such procedures may include periodic gas tests, limiting other activities in or near the subject vessel, and housekeeping requirements to minimize the accumulation of accelerants and rags.

Before the inspection starts, all persons working around a vessel should be informed that people will be working inside the vessel. The posting of tags on the manways of tall towers is a worthwhile precaution. A safety guard should be stationed at the manway nearest the area under inspection. Workers inside a vessel should be informed when any work will be done on the exterior of the vessel to prevent them from becoming alarmed by unexpected or unusual noise.

9.1.2 Precautions Regarding the Use of Breathing Air

For many companies, confined entry into vessels containing unbreathable atmospheres is not allowed. On occasion, it may be desirable to enter a vessel before it has been properly cleaned to search for internal

causes of poor operation. In this case, the inspector should exercise the special precautions and utilize additional personal protective equipment (i.e. breathing air) for such entry as given in API 2217A.

Breathing air should be supplied from cylinders or a dedicated air compressor system that is certified for breathing air. At least two independent breathing-air sources shall be used. Breathing-air hose couplings shall be incompatible with the couplings for other utility gas systems or nonbreathing plant air system in order to prevent the inadvertent cross connection of breathing-air hoses with gases that should not be inhaled. Fatalities have occurred when cross connections have been made or when breathing-air cylinders did not contain the necessary oxygen levels. Refer to API 2217A for guidelines to follow for ensuring that breathing-air supplies are safe for use.

9.1.3 Precaution Regarding Confined Space Entry

Confined space entry, combined with large complicated interior spaces and the mobility involved in completing inspections, can make internal inspections potentially hazardous if all the right precautions are not taken. In addition to the normal precautions associated with confined space entry for internal visual inspection, the following safety precautions are advisable.

- a) Read any permits and job safety analysis or its equivalent that might be required in the facility in which are working.
- b) Prior to entry, ensure that the entry attendant(s) is familiar with the internal configuration of the tower and understands the physical basics of the task, such as climbing on and across trays, moving between trays, and of the access and egress point(s) that have been approved.
- c) Prior to entry, ensure that the entry attendant, the inspector(s), and any other persons involved with the internal inspection understand the limits of the approved communication method. When visual contact is lost, most facilities rely on radio communication between the entrant(s) and the entry attendant. The extreme noise level inherent to common forced ventilation methods may prevent verbal communication. Communication sounds and meanings should be worked out in advance to be effective.
- d) Prior to entry, ensure that scaffolding is installed where required for entry, access to the internals, and/or egress from the vessel. The presence of scaffold from the bottom head to the bottom tray (see Figure 17) and bridging any extra-wide tray spacing, such as that found at distributors or transition sections, should be confirmed prior to performing this visual inspection.
- e) Release of gases and vapors from under debris and/or from under liquids, such as water left after washing or steam out, is possible. Such conditions should be addressed prior to beginning the inspection where visible, and prior to completion of the inspection when discovered in situ. Figure 18 depicts standing oil and water condition that shall be assessed and dealt with prior to internal inspection.
- f) Upset tray decks should not be used as platforms for climbing. Care should be taken to distribute weight evenly while performing damage assessments. Use of fall protection and/or retrieval devices is highly recommended under upset conditions. Fall protection is also highly recommended in towers where severe tray thinning is suspected. All distributors that are obstructing internal or external manways should be temporarily removed to allow access and emergency egress.
- g) Wherever possible, hard ladders, such as scaffold ladders, should be utilized to allow sufficient time and stability for visual inspection. Where hard ladders are not possible, yo-yo type fall protection (see Figure 19) should be used in conjunction with the rope, strap, or other soft ladders.

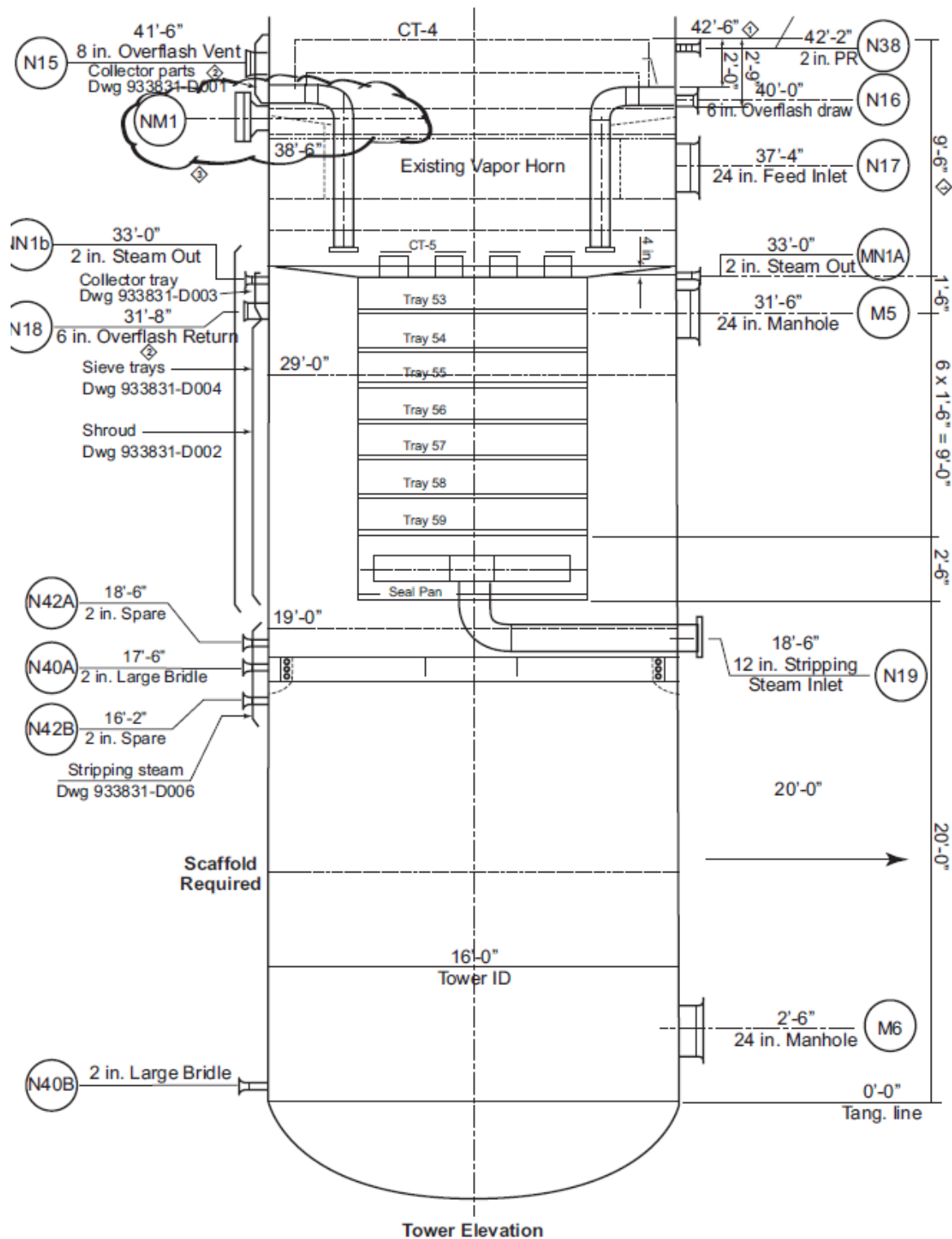


Figure 17—Diagram of Suggested Scaffolding

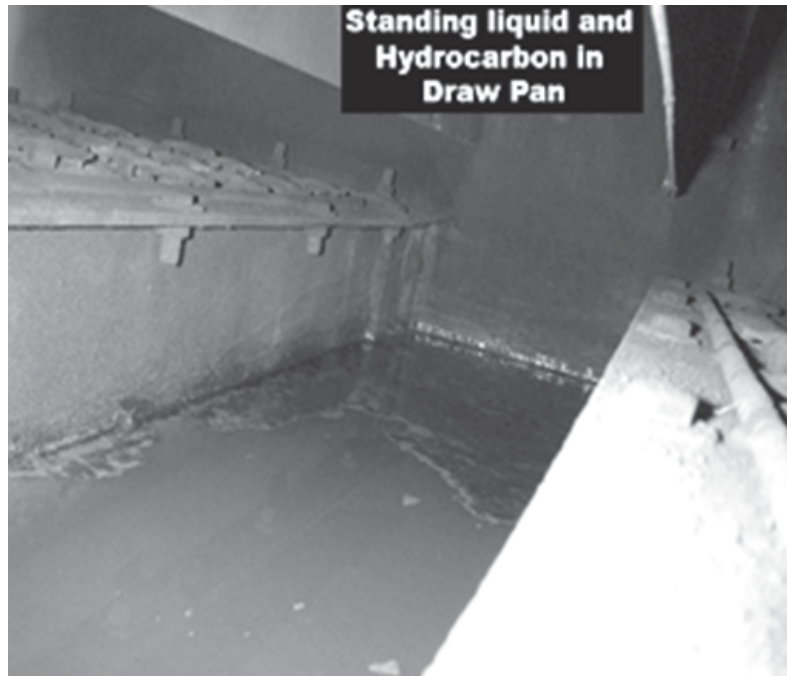


Figure 18—Standing Oil and Water

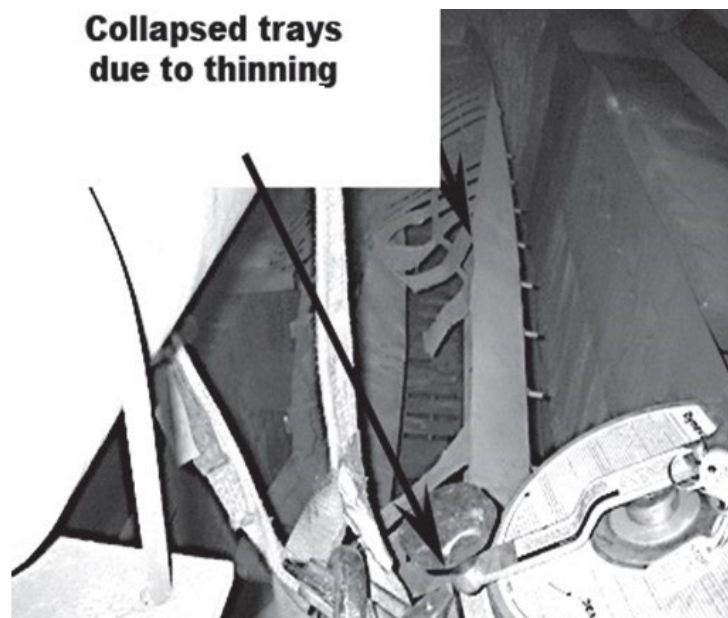


Figure 19—Trays Collapsed

9.2 Preparatory Work

Prior to inspection of a pressure vessel, the inspector should determine the operating conditions (pressure, temperature, IOW excursions, and service conditions) under which the vessel has been operated since the last inspection. The inspector should also be aware of equipment construction details, including materials of construction, the presence of internal attachments, and weld details. The inspector should confer with operations to determine whether there have been any abnormal operating conditions or disturbances, such

as excessive pressures or temperatures. These data may offer valuable clues to the type and location of corrosion and to other forms of damage that may have occurred such as scaling, bulging, and warping. The inspector should develop and exercise sound judgment on the extent and kinds of inspection required for each vessel.

If this is not the first inspection, the initial step in preparation for an internal inspection is to review the previous records of the vessel to be inspected. The inspection history may inform the inspector of the history associated with the work they are going to perform. For example, if the inspector is going to perform a wet fluorescent magnetic particle examination (WFMT) examination, they may need to understand if previous inspections have found anything or if there were previous repairs to the inspection areas.

The tools needed for vessel inspection, including tools and equipment needed for personnel safety, should be checked for availability and proper working condition prior to the inspection. Any necessary safety signs should be installed prior to work in vessels.

Some of the tools that should be available for pressure vessel inspections are as follows:

- a) portable lights, including a flashlight;
- b) thin-bladed knife and/or pocket knife;
- c) broad chisel or scraper and pointed scraper;
- d) mirrors;
- e) inside and outside calipers;
- f) steel tape [50 ft (15 m)];
- g) flange square;
- h) an inspector's hammer or ball peen hammer (4 oz or 8 oz);
- i) ultrasonic thickness measurement equipment;
- j) tube gauges (inside diameter);
- k) steel rule and straightedge;
- l) pit depth gauge and hook gauge;
- m) paint or crayons;
- n) notebook and pencils;
- o) wire brush;
- p) plumb bob and line;
- q) magnet;
- r) magnifying glass;
- s) plastic bags for corrosion product samples.

The following tools should be available if required:

- a) surveyor's level;
- b) carpenter's or plumber's level;
- c) MT inspection equipment;
- d) micrometer;
- e) three-ball micrometer for tube ID measurement;
- f) radiographic equipment;
- g) ground tester;
- h) sandblasting equipment;
- i) high-pressure water blasting equipment;
- j) portable hardness-testing equipment;
- k) eddy current examination (ET) equipment;
- l) sonic and radiation-measuring equipment;
- m) fiber-optic flexible scopes;
- n) surveyor's transit;
- o) temperature-indicating crayons;
- p) thermocouples;
- q) metal sample-cutting equipment;
- r) material identification kit or machine;
- s) camera;
- t) UT flaw-detection equipment;
- u) PT inspection equipment;
- v) sand- or water-blasting equipment;
- w) borescope;
- x) plumb lines and levels;
- y) spotting scope or binoculars;
- z) neutron backscatter equipment for moisture detection;
- aa) magnetic flux leakage equipment.

9.3 Vessel Cleaning and Surface Preparation

The vessels should be cleaned prior to inspections. Cleaning can be performed with a wire brush or by abrasive-grit blasting, grinding, water blasting with low-, medium-, or high-pressure water, or power chipping when warranted by circumstances. These extra cleaning methods in addition to routine cleaning may be necessary when stress corrosion cracking, wet sulfide cracking, hydrogen attack, and other metallurgical forms of damage are suspected.

The degree of surface preparation needed for internal inspection will vary with several factors. Foremost among these factors are the following:

- a) the type of damage expected;
- b) the location of any damage;
- c) type of inspection technique to be applied.

The degree of surface preparation required for external inspection will depend on the type and extent of damage expected. Under normal conditions, thorough cleaning to bare metal will be needed only at those points where UT thickness measurements are taken. When cracking or extensive pitting is suspected, thorough cleaning of a large area (possibly the entire vessel shell) may be required.

Usually, the cleanliness required by the vessel operators will be sufficient for inspection purposes. This would entail the usual cleaning methods of washing with hot water, steaming, using solvents, and ordinary scraping. Hand tools, such as a pointed scraper, a wire brush, a scraper, and a file, can be used to clean small spots.

Where better cleaning is needed, for larger areas, power wire brushing or abrasive blasting will usually be cheaper and more effective than the use of hand tools. Caution should be taken when wire brushing on noncarbon steel equipment with a carbon steel brush due to the risk of contamination.

The cleaning methods mentioned should be supplemented by power wire brushing, abrasive-grit blasting, grinding, high-pressure water blasting [e.g. 8000 psig to 12,000 psig (55.2 MPa to 82.7 MPa)], or power chipping when warranted by circumstances. These extra cleaning methods are necessary when stress corrosion cracking, wet sulfide cracking, hydrogen attack, or other metallurgical forms of damage are suspected. Extensive cracking, deep pitting, and extensive weld damage require thorough cleaning over wide areas. If the entire inside of the vessel is not accessible from one opening, the procedures discussed in 10.3 should be followed at each access opening.

If conditions warrant, rope inspection or scaffolding may be erected around a vessel to permit access to all surfaces.

10 Inspection Methods and Limitations

10.1 General

One of the primary focuses of the pressure vessel inspection is the establishment of a pressure vessel's ability to safely continue operation. There are a number of steps involved in performing a condition assessment, each requiring different data, tools, and degrees of expertise. Condition assessment should be a formal part of every inspection, and the determination of acceptable vessel condition should be formally documented. The condition will generally be defined as:

- a) "like new" condition, not requiring any additional actions before the next scheduled inspection;
- b) requiring minor repairs, such as repainting, cleaning, or minor surface work;
- c) requiring major repair or replacement of all or a section of the vessel.

When possible, a preliminary general visual inspection is the next step. The type of corrosion (localized, pitted, or uniform), its location, and any other obvious data should be established. In refinery process vessels, certain areas corrode much more rapidly than others do. This unevenness of corrosion is covered in detail in each applicable article in API 571. Data collected for vessels in similar service will aid in locating and analyzing corrosion in the vessel being inspected.

A pre-inspection of a vessel is helpful to determine other forms of inspection that may need to be performed. Appropriate surface preparation is essential to all inspection methods. The extent to which special surface preparation may be required depends on the particular circumstances involved.

A visual inspection, comparing design parameters and original conditions (or conditions at the time of the last formal assessment) of the pressure vessel to current conditions, is the most basic form of condition assessment. The inspector should evaluate if the vessel meets the original construction parameters by inspecting the condition of the vessel walls, welds, internals, supporting equipment, etc. If the inspector determines the vessel to meet the original specifications, the vessel may be identified to be in satisfactory condition. However, any degradation, damage, or other potential issues should be noted.

In cases where an inspector locates damage in a pressure vessel, care should be taken to ensure that this damage either:

- a) does not affect the ability of the vessel to continue safe operation;
- b) is removed by repair or replacement of the vessel component experiencing the damage; or
- c) that the structural integrity and design parameters of the vessel are maintained or reevaluated to ensure that the vessel meets the applicable code of construction.

Damage may be determined to be inconsequential if the effective wall beneath the damage is greater than required thickness, and the remaining life is determined to exceed the next scheduled inspection. The inspector should consider both the nature and the ongoing susceptibility of the equipment item to this damage mechanism. It should be determined whether the damage mechanism will continue in a consistent or inconsistent manner in order to predict the remaining life. API 571 provides guidelines on damage mechanisms, causes, etc. In cases where the damage or defects are severe enough, further evaluation is required. API 579-1/ASME FFS-1 provides guidelines for evaluating damage and associated remaining life.

If external or internal linings, such as refractory linings, or corrosion-resistant linings are in good condition and without evidence of damage, it may not be necessary to remove them for inspection of the vessel. However, it may sometimes be advisable to remove small portions to investigate their condition and the condition of the metal behind them, particularly if previous inspections have indicated corrosion going on under the lining. When any lining is found to be defective, a sufficient amount of the lining in the vicinity of the defect should be removed to find out whether the base metal is deteriorating and to determine the extent of the damage.

Where operating deposits, such as coke, are permitted to remain on a vessel surface, it may be important to determine the condition of the vessel surface behind the deposits. This may require removal of the deposit in selected critical areas for spot-check examination. Discussion with a corrosion specialist may be needed to assess the potential for such deterioration. Alternatively, performing automated ultrasonic scans on the external surface of the vessel can be used to determine the condition of the surface. In some instances, samples of corrosion deposits may be useful in verifying credible damage mechanisms. In some instances, it may be inadvisable to remove protective deposits or scales.

Where vessels are equipped with removable internals, the internals may not need to be completely removed, provided reasonable assurance exists that damage is not occurring beyond that found in more readily accessible parts of the vessel. External CMLs can allow internal areas of the pressure vessel to become more accessible by external examination. Cutouts in a vessel's insulation at the CML points allow for visual examination of the exterior of the vessel and allow for NDE measurements of the vessel wall to be conducted.

10.2 External Inspection

10.2.1 General

Much of the external inspection can be performed while the vessel is in operation. Any inspection performed during vessel operation may reduce the period during which the vessel will be out of service, as well as potentially reduce turnaround workload.

10.2.2 Inspection of External Pressure Boundary

10.2.2.1 External Inspection of Damage

10.2.2.1.1 General

Certain types of damage may be found on external surfaces of a vessel. Among these are atmospheric corrosion, CUI, caustic embrittlement, hydrogen blistering, and soil corrosion. These types of damage mechanisms are covered in more detail in API 571.

10.2.2.1.2 Atmospheric Corrosion

The extent of atmospheric corrosion on the outside of an uninsulated vessel will vary with local climatic, coating, and service conditions. In humid areas and in areas where corrosive elements are present in the air, corrosion of external shell surfaces may be a problem. Vessels operating in a temperature range that will permit moisture to condense are most susceptible. Corrosion of this type is usually found by visual inspection (see 12.1).

10.2.2.1.3 CUI

If the vessel is insulated, small sections of insulation should be removed, particularly where moisture might accumulate, to gain a general idea of whether external corrosion is occurring. CUI is covered extensively in API 510 and API 583. Any removed insulation and cladding/jacketing should be repaired/replaced in such a way to prevent future water ingress.

10.2.2.1.4 Caustic Embrittlement

If a caustic is stored or used in a vessel, the condition of the materials and the operating conditions might make the vessel susceptible to caustic embrittlement. The external surface of the vessel should be checked for caustic SCC. This type of embrittlement is most likely to occur at connections for internal heating units and in areas of residual or other high stress. The more susceptible areas are around nozzles and in or next to welded seams. Frequently, visual inspection will disclose this type of embrittlement. The caustic material seeping through the cracks will often deposit white salts that are readily visible. MT (wet or dry), PT, and angle beam UT may also be used to check for caustic embrittlement.

10.2.2.1.5 Hydrogen Blistering

Those areas below the liquid level in vessels that contain acidic corrosion products are more likely to be subject to hydrogen blistering. Hydrogen blistering is typically found on the inside of a vessel. However, hydrogen blisters may be found on either the ID or OD surface, depending on the location of the void where the atomic hydrogen collects. Blisters are found most easily by visual examination. A flashlight beam directed parallel to the metal surface will sometimes reveal blisters. When many small blisters occur, they can often be found by running the fingers over the metal surface.

10.2.2.1.6 Soil Corrosion

Vessels that are partially or completely buried are subject to soil corrosion wherever they are in contact with the ground. This corrosion will be particularly intense in areas where cinder fills were used or where acid splash-over has occurred. Inspection of the vessel surface will require thorough cleaning. Abrasive blasting will usually provide the best surface preparation. Visual examination, supplemented by picking and

tapping, will disclose most faults. The location of any deep pitting should be recorded. Good judgment should be used in determining how much of the surface should be uncovered to permit this inspection. The most severe corrosion will usually be found between ground level and up to several inches below.

10.2.2.1.7 Leaks and Cracking

The external surfaces of the vessels should be examined not only for corrosion but also for leaks and cracks.

Unless readily visible, leaks are best found by pressure or vacuum testing the vessel. If there are visual or other indications that a leak comes through a crack, more thorough methods of examination should be employed.

In welded vessels, cracks are most commonly found at nozzle connections, in welded seams, and at bracket and support welds. In riveted vessels, the most common location is at metal ligaments between the rivets. Usually, close visual inspection with some picking or scraping will disclose most cracks. When cracking is suspected in an area, the entire area should be cleaned by an appropriate method such as wire brushing, high-pressure water blasting, or abrasive-grit blasting to facilitate inspection. If visual inspection is not sufficient (often the case in the detection of amine and deaerator cracking), wet or dry MT, angle beam UT, PT, or acoustic emission analysis may be used to locate and provide additional information on the structural significance of cracks or other discontinuities. The WFMT analysis is more sensitive than dry MT techniques.

Inspect external supports of vessels in cyclic service for fatigue cracking using either PT or MT.

10.2.2.1.8 Deformation

Buckles and bulges will normally be quite evident. Mechanical damage, such as gouges and dents, should be inspected. The depth and extent of any surface gouge should be measured when the gouge seems large enough to affect the strength of the vessel. All gouges should be reported. While some distortion is normal, determining the cause of distortion is very important. Causes of distortion, such as internal vapor explosions or excessive internal corrosion, will be disclosed by the internal inspection. Settlement, earthquakes, extensive distortion in connected piping, and other sources can often be determined by external inspection. The extent of bulging or buckling can be determined by measuring the changes in circumferences or by making profiles of the vessel wall. Profiles are made by taking measurements from a line parallel to the vessel wall (see Figure 20). A surveyor's transit or an 180° optical plummet may also be used.

10.2.2.1.9 Hot Spots

Hot spots that have developed on the shell or heads of vessels that are internally insulated should be inspected at frequent intervals while the vessel is in service. Evidence of bulging should be noted and recorded. A check of the skin temperature of the metal in the hot spot area can be obtained using a portable thermocouple, infrared equipment, or temperature-indicating crayons or special paints. Infrared imaging cameras are especially effective in identifying and mapping local hot spots on in-service equipment. A complete dimensional check in the hot-spot area should be performed when the vessel is shut down. Using replication techniques or taking a material sample (a boat or other sample) should be considered if carbon steel temperatures were in the range of 750 °F to 1000 °F (399 °C to 538 °C) for an extended period of time. Depending on operating conditions and alloy (or if hydrogen attack is possible), or if temperatures in the creep range are suspected, an experienced metallurgist or engineer should be consulted.

The existence and location of abnormally high metal temperatures or hot spots on internally insulated units can also be detected during an on-stream inspection.

10.2.2.1.10 Laminations

The external surfaces should be checked for laminations. Laminations that come to the surface can be detected by visual inspection.

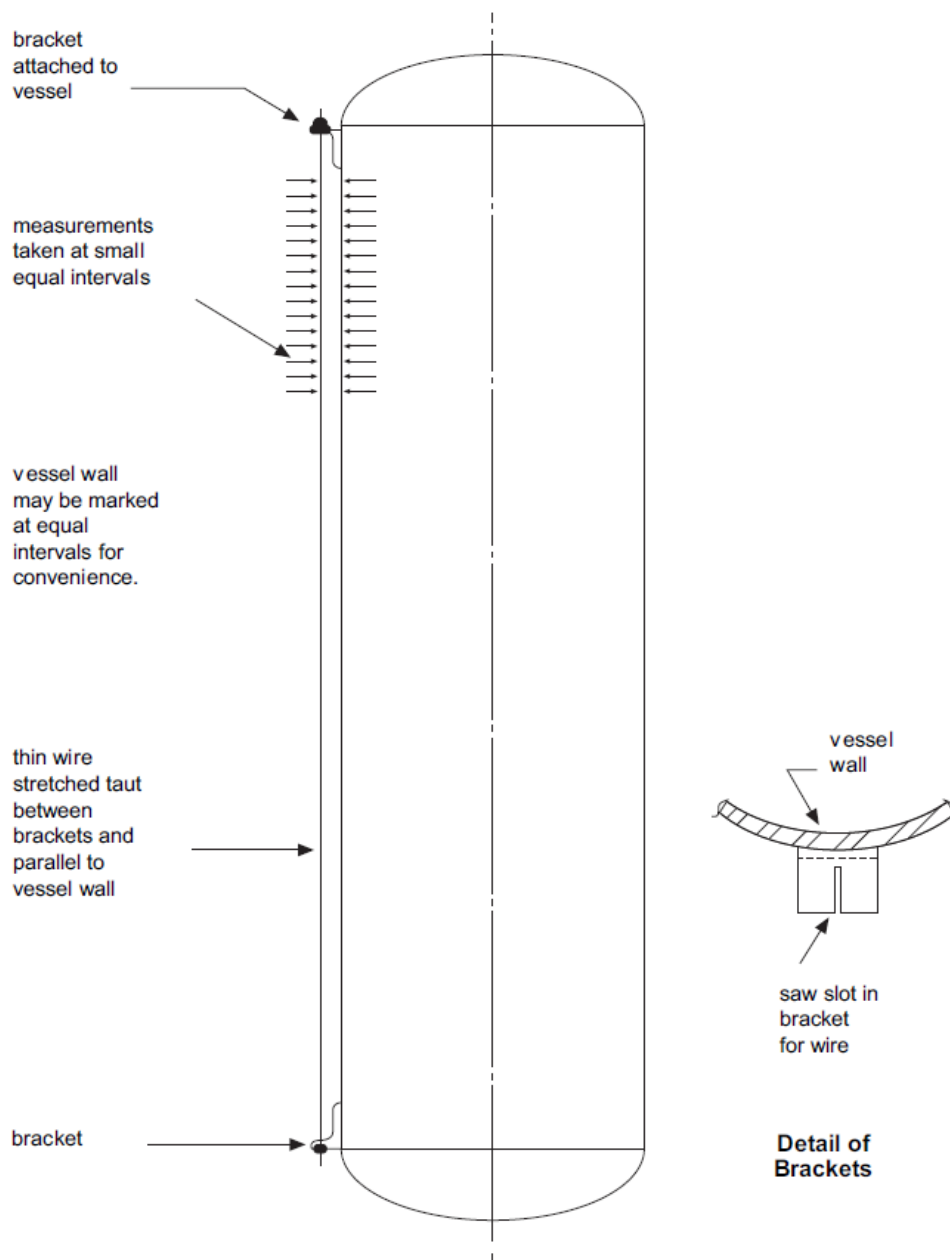


Figure 20—Method of Obtaining Vessel Profile Measurements

10.2.2.2 External Inspection of Nozzles

If any settling of the vessel has occurred, nozzles and adjacent shell areas should be inspected for distortion and cracking. The inspector should contact the owner-operator to review any cases where the inspector deems the settlement has occurred. Excessive pipeline expansions, internal explosions, earthquakes, and fires may also damage piping connections. Flange faces may be checked with a flange square for distortion. If there is any evidence of distortion or cracks in the area around the nozzles, all seams and the shell in this area should be examined for cracks. The area should be abrasive-grit blasted or wire brushed. MT (wet or dry), PT, angle beam UT, or replication techniques may be used to supplement visual examination. Catalytic reformer equipment operating at temperature more than 900 °F (482 °C) may experience creep embrittlement damage during operation. Replication is a useful technique in detecting this damage.

Wall thickness of nozzles should be measured. Calipers, UT thickness instruments, or radiographic techniques may be used. These measurements should be recorded and compared with previous or original thickness readings. Any losses should be analyzed and appropriate action should be taken, such as renewal if thickness is near or at minimum, installing a lining if feasible, monitoring on shorter intervals, and using corrosion inhibitors.

Reinforcing plates around nozzles should be examined to ensure that they are intact and the vent hole is not physically plugged or leaking. Normally, weep holes in reinforcing plates (re-pads) should remain open to provide visual evidence of leakage. If weep holes are plugged to exclude moisture, they should not be plugged with material capable of sustaining pressure behind the reinforcing plate.

For unreinforced pipe attachments to a vessel, leaks may occur at/adjacent to the weld. Leaks can be located visually while the vessel is in service or under test conditions. Evidence of a leak is usually left in the form of discoloration to the vessel, insulation, fireproofing, or paint or damage to or wetting of the insulation.

10.2.2.3 External Inspection of Rivets

Although uncommon, riveted vessels may still be found in process facilities. Inspection should include examination of the rivet head, butt strap, plate, and caulk.

The inspector should verify that rivets are of sufficient length to completely fill the rivet holes and are driven to give a full rivet head without showing any depression in the sheet from the dies. Finished rivet heads may have had known geometric proportions to ensure adequate reinforcement according to a specification, and conformance to that specification may have been ensured at the time of construction, so relative deviation from that uniform shape is notable. Rivets and the metal in the vicinity of the rivets should be examined for evidence of cracking. Look for rivet tightness within the holes; the presence of a gap between the shank and hole may lead to crevice corrosion. If rivet-shank corrosion is suspected, hammer testing (see 10.4.6 for more information on hammer testing technique) or radiography at an angle to the shank may be useful to determine the extent of the corrosion. Holes for rivets in the vessel wall or in parts attached are to have been drilled or punched; finished holes were intended to have been true, clean, and concentric.

When looking at the riveted joint, the thickness of butt strap and shell plates should be measured; look for evidence of corrosion. Ensure that the plates and butt strap follow the contour of shell properly; signs of local deformation may indicate looseness in the overall joint. The butt strap and shell plates may not be fabricated of the same material. Therefore, especially prior to welding, it is recommended the inspector take the necessary steps to confirm base metals are as expected.

If caulk is found to be in service, the inspector is advised to look for evidence of looseness that may have been initiated when previous repairs were made.

10.2.3 Inspection of External Axillary Components

10.2.3.1 Ladders, Stairways, Platforms, and Walkways

The external inspection of pressure vessels and exchangers should start with ladders, stairways, platforms, or walkways connected to or bearing on the vessel. Inspection of ladders, platforms, walkways, and other non-support elements should be performed by an individual as determined by the owner-operator and does not necessarily need to be the authorized inspector.

The external visual inspection should check for corroded or broken parts, cracks, the tightness of bolts, the condition of paint or galvanizing material, the wear of ladder rungs and stair treads, the security of handrails, and the condition of flooring on platforms and walkways. Visual inspection should be supplemented by hammering and scraping to remove oxide scales or other corrosion products. Floor plates can be removed to check supporting members. The tightness of bolts can be determined by tapping with an inspector's hammer or a small ball peen hammer or by trying the nuts with a wrench. Wear on metal stair treads and flooring may not only weaken them but also make them slippery if worn smooth. Depressions in platforms should be closely checked because water lying in depressions can accelerate corrosion. Crevices should

be checked by picking at them with a pointed scraper. Loose or broken parts are easily found by tapping with a small ball peen hammer or an inspector's hammer. If desired, thickness measurements of the platforms and structural members can be taken with transfer calipers.

External corrosion is most likely to occur where moisture can collect. On ladders and stairs, corrosion is likely to concentrate where rungs or treads fit into the runners or stringers. Crevice corrosion may exist around the heads of bolts and nuts, at bracket connections between stair treads and angle supports, and at connections between intermediate supports and the vessel wall. Welded bracket connections are particularly susceptible to corrosion as the welds are usually rough and it is difficult to apply a good, void-free paint coating to them. Corrosion may exist beneath a paint film and will be indicated by rust stains showing through the paint or by a blister or general lifting of the paint film.

The condition of most metallic parts can be determined by hammering. Where corrosion appears to be severe, the actual thickness should be determined using a caliper or by other means. When using a hammer to determine condition, caution should be taken near corroded areas so the act of inspection does not cause a failure.

10.2.3.2 Foundations and Supports

Foundations for vessels are almost invariably constructed of steel-reinforced concrete or structural steel fireproofed with concrete. They should be inspected for damage, such as spalling, cracking, and settling.

The foundations for exchangers usually consist of steel cradles on concrete piers. Occasionally, the supports are fabricated entirely of steel. Figure 21 shows a typical exchanger foundation.

The crevice formed between an exchanger shell or a horizontal vessel and a cradle support should be carefully checked. Moisture lying in the crevice can cause rapid corrosion on carbon steel and on low-chrome-molybdenum steels. If the cradle is sealed with a mastic compound, this seal should be checked to make sure that it is intact. Cradles are often seal-welded to vessel shells to prevent moisture from accumulating in the crevice and causing corrosion.

Excessive heat, mechanical shock, corrosion of reinforcing steel, or the freezing of entrapped moisture can cause cracking in and around supports. Inspection for this type of damage should consist of visual observation and scraping. Measurements of the depth of such damage can usually be taken with a straightedge or a steel rule. For additional investigation, the inspection may consider the use of nondestructive examinations developed for this purpose.

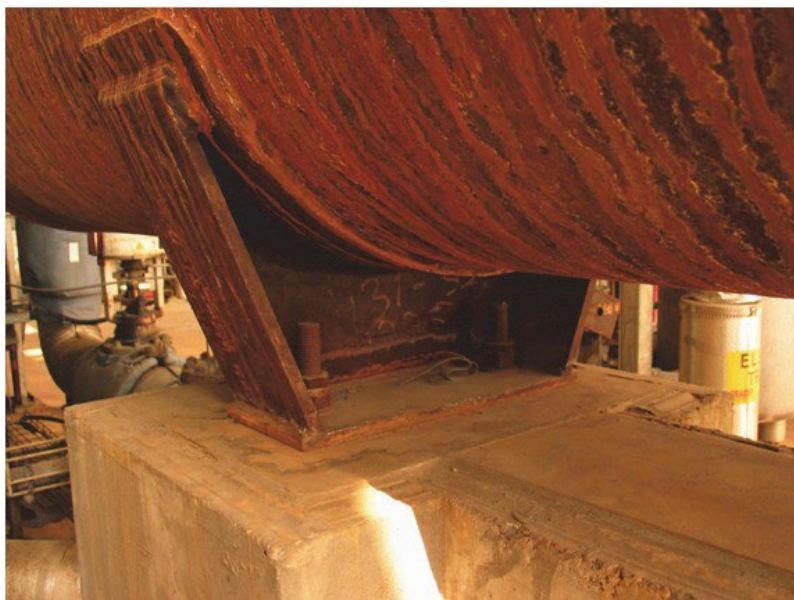


Figure 21—Exchanger Installation and Foundation

Cracks in concrete or fireproofing may be caused by excessive heat, poor design, mechanical shock, weathering, corrosion of reinforcement steel, or unequal settlement. Inspection for cracks is typically visual. Some picking with a pointed scraper may be helpful. Repairs should be recommended as needed when cracking has resulted in a potential threat to the integrity of the supports.

Very small openings or cracks in concrete or fireproofing caused by high temperature or by temperature changes can usually be identified by their hair-like appearance. Such cracks are not usually serious unless they expose the steel to corrosion.

When major cracks appear and propagate, and measurements indicate that no settlement has taken place, the cracks are probably the result of fatigue (temperature cycling due to process or weather conditions), poor design, or poor material. In such cases, a complete check or engineering study may be required. If such investigations show that the design is correct, then the cracks are most likely caused by fatigue or the use of poor concrete material. Careful visual examination and minor chipping with a hammer will usually confirm the diagnosis, but removal of a core for testing may be required.

Records of settlement should be maintained on vessels known to be settling. A rough check for uneven settling can be obtained with a plumb line and steel rule. When accurate measurements are desired, a surveyor's level may be used. When settlement is appreciable, it can be observed by noting the misalignment of the foundation with the surrounding paving or ground. The frequency with which settlement measurements should be taken depends on the rate and the seriousness of the settlement. Measurements should be taken until the settlement stops. Settlement should be evaluated to determine if it is excessive and should be corrected before serious damage occurs. Vessels supported on long concrete slabs or on two or more separate foundations are more likely to undergo uneven settlement. When foundation or support settlement has occurred, the condition of connected pipping should be checked.

10.2.3.3 Anchor Bolts

Although the condition of anchor bolts cannot always be completely determined by visual inspection, the area of contact between the bolts and any concrete or steel should be scraped and closely examined for corrosion. Although this will not reveal the condition below the top surface of the base plate or lugs, a sidewise blow with a hammer may reveal complete or nearly complete deterioration of the anchor bolt below the base plate (see Figure 22). Distortion of anchor bolts may indicate serious foundation settlement. The nuts on anchor bolts should be inspected to determine whether they are properly tightened. UT may also be used to test bolts.

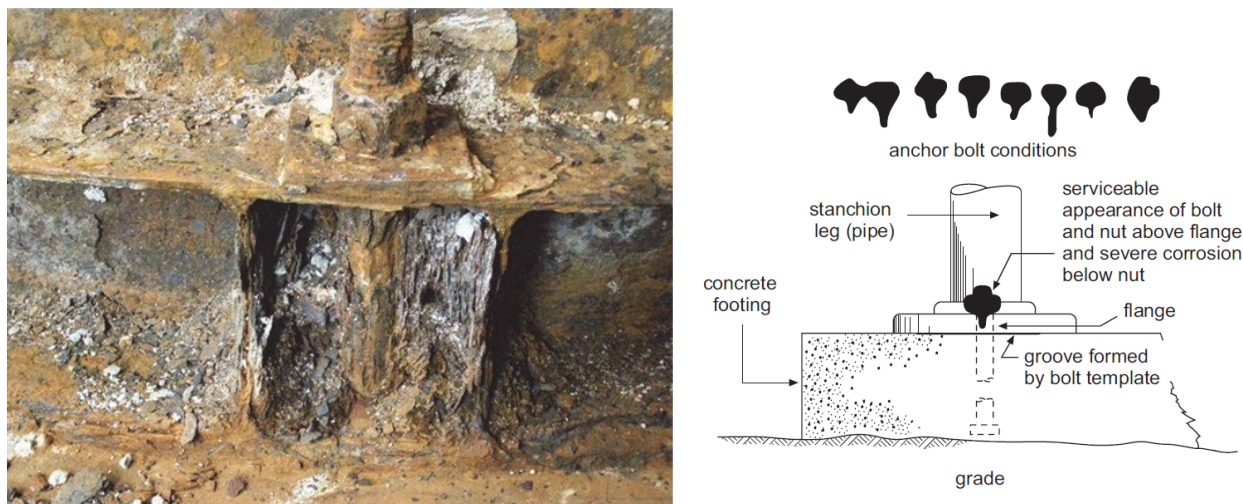


Figure 22—Severe Deterioration of Anchor Bolts