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Addendum 1

3.1: The following shall be added, and the rest of the section shall be renumbered:

3.1.4
bolting
An assembly of a nut(s) and a stud for fastening objects together.

3.1: The definition for soil-to-air interface shall be updated as follows:

3.1.68
soil-to-air interface
SAI
An area in which external corrosion may occur or be accelerated on partially buried pipe or buried pipe where it enters or leaves the soil.

NOTE 1 The zone of the corrosion will vary depending on factors such as the moisture and oxygen content of the soil and operating temperature. The zone generally is from 12 in. (30 cm) below to 6 in. (15 cm) above the soil surface.

NOTE 2 Pipe running parallel with the soil surface that contacts the soil is included.

3.2: The following shall be added:

FFS fitness-for-service

PVC polyvinyl chloride

PVDF polyvinylidene fluoride

RE residual element

4.7.3: The section shall be updated as follows:

Pipe support design considerations can differ depending on the support type or style. While some pipe support manufacturers offer innovative and proprietary designs to eliminate or minimize some of the credible damage mechanisms, the following is a list of some special piping support design parameters to take into consideration.

a) Pipe shoes—It is important that the shoe is long enough and/or guides or stops are provided on the structural steel to prevent the shoe from coming off the support, which could cause tearing or other damage to the pipe. Also, some pipe shoes may trap water between the pipe and shoe (e.g. clamp-on, bolt-on, saddles that have been stitch welded, etc.) and make inspection difficult to determine the condition of the pipe.

b) Pipe sleeves—Pipe sleeves are often used where pipe passes through a wall, under a roadway, or through an earthen berm. When used, design precautions should be taken to prevent corrosion on both the pipe and the pipe sleeve. Centering devices should also be considered to keep the inner pipe centered and prevent coating damage and corrosion. Fully welded and/or sealed sleeves may be considered if loss of containment detection and control are necessary. It should be noted that sleeves can make future pipe inspections and examinations more difficult.

c) Doubler plates, half soles, and wear pads—Additional plates may be attached to a pipe system at points where the pipe rests on bearing surfaces. Plates should be fully welded to avoid crevice corrosion except in hydrogen-charging environments, where a weep hole should be included that will not lead to moisture ingress. The use of adhesive-bonded stainless steel or composite half soles may be considered, but it is very important to make sure that the adhesive is fully bonded and maintained to effectively eliminate water entrapment. Galvanic corrosion should also be considered when using dissimilar materials for this purpose.

d) Plastic/insulating rod, nonmetallic/composite wraps—The use of these components at pipe supports may assist in limiting the trapping of water in intimate contact with the piping at the support location, reducing the severity of material loss in these areas (referred to as "contact point corrosion").

e) Dummy legs (trunnions)—Historically, dummy leg (trunnion) supports were simple open-ended lengths of pipe welded to a piping system from which the piping system was supported. An open-ended design can allow moisture and debris to become trapped inside the support and cause corrosion of the support and the pipe. Dummy leg design should include, as a minimum, drain holes no smaller than $^1/_4$ in. (6 mm) located at a low point, with the unattached end of the support being fitted with a fully welded cap or end plate to prevent debris or animals from entering. Trunnion design can be improved by using solid sections, such as "C" channels or "I/H" beams, to reduce the risk of this problem. However, even solid member sections can trap water and debris depending on their design and orientation. Incorporating a fully welded doubler pad to the pipe at the trunnion attachment location can provide additional corrosion protection and may help distribute loads more evenly. The end of a dummy leg support that is not attached to the pipe may or may not be anchored or restrained.

f) Supports on insulated lines—Special attention is necessary for the design of supports on insulated lines to minimize the possibility of water ingress and wicking of water into the insulation.

g) Accessibility—The accessibility, and therefore inspectability/maintainability, of pipe supports should be considered during design.

h) Welding—Paths for water ingress into hollow supports can be minimized with the use of fully welded seams. Avoid welding undercut or excessive penetration. Welding defects associated with supports can contribute to loss of containment events and, in some cases, be of sufficiently small size to make leak detection and source identification difficult. In hydrogen-charging environments, a weep hole should be provided to avoid the buildup of pressure between the plate and the pipe.

i) Anchors and restraints—A connection of a pipe to a stationary structure or foundation to restrict the movement of the pipe in one or more directions (X, Y, and/or Z plane). The attachment of an anchor or restraint to a pipe should preferably encircle the pipe to distribute the stresses evenly about the circumference of the piping component(s).

5.3.3.1: The section shall be updated as follows:

Nonmetallic materials are not covered by API 570. The term "nonmetallic" has a broad definition, but two groups are discussed in this section for informational purposes—the fiberglass-reinforced plastics group and the organic plastics group.

The fiberglass-reinforced plastics group encompasses the generic acronyms FRP (fiberglass-reinforced plastic) and GRP (glass-reinforced plastic), which are more commonly used in chemical processing applications. FRP and GRP are typically used interchangeably.

The organic plastics group is comprised of piping having a homogeneous structure produced by extrusion and includes the following common types:

a) polyethylene (e.g. low density, medium density, high density, cross-linked);

b) polyvinyl chloride (PVC);

c) chlorinated PVC;

d) polyvinylidene fluoride (PVDF);

e) polypropylene.

Nonmetallic materials have limited application to specific piping systems in the process industry, such as in utilities. For example, typical service applications of FRP piping include service water, process water, cooling medium, potable water, sewage/gray water, nonhazardous waste, nonhazardous drains, nonhazardous vents, chemicals, firewater ring mains, firewater deluge systems, and produced and ballast water.

Nonmetallic materials have significant advantages over more familiar metallic materials, but they also have unique construction and deterioration mechanisms that can lead to premature failures if not addressed adequately. The primary advantages are resistance to corrosion and improved flow characteristics over metallic piping. The main disadvantages are ultraviolet (UV) degradation and support requirements. Fluoropolymer plastics (e.g. PVDF) have inherent UV blocking characteristics.

The design of these piping systems is largely dependent on the application. Thermal expansion and temperature resistance vary widely across different types of plastic piping. Many companies have developed their own specifications that outline the materials, quality, fabrication requirements, and design factors. It is noted that other codes and standards have requirements and guidance. In particular:

— ASME NM.2 and ASME B31.3, Chapter VII, cover design requirements for nonmetallic piping;

— the American Water Works Association is an organization that also provides guidance on FRP pipe design and testing.

These codes and standards, however, do not offer guidance as to the right choice of corrosion barriers, resins, fabricating methods, and joint systems for a particular application. The user should consider other sources, such as resin and pipe manufacturers, for guidance on their application.

Additional information on organic plastic piping is available from:

— the Plastic Pipe and Fittings Association (PPFA);

— the Plastics Pipe Institute (PPI).

5.3.3.3: The title and content of the section shall be updated as follows:

5.3.3.3 Qualification of FRP Assemblers

The qualification of bonders and jointers is as important for FRP fabrication as the qualification of welders is for metal fabrication. Due to limitations in NDE methods, emphasis should be placed on procedure and bonder qualifications and testing.

Similarly, because the material stiffness is much less than metal and because FRP has different types of shear, small-bore connections will not withstand the same shear stress, weight loadings, or vibrations that are common with metallic piping. Proper support of piping and attachments, such as valves, on small-bore connections should be analyzed in detail to prevent premature failure of the system.

6.2: The second paragraph shall be updated as follows:

Leakage can occur at flanged joints in piping systems for a variety of reasons, including corrosion, cracking, bolting tightness issues, and gasket issues. In addition, thermal expansion issues can cause leaks particularly for joints in high-temperature or cryogenic services during start-ups and shutdowns, and sometimes during normal operation. For these reasons, process plant practices should include quality assurance/control procedures to help ensure flanged joint integrity after maintenance activities where the joints have been disassembled. Procedures typically include, for example, proper gasket and stud selection, assembler qualifications, proper assembly instruction, inspection, and testing requirements. Refer to ASME PCC-1 for flange joint assembly practices.

7.3.4: The list shall be updated as follows:

a) measure and ensure that the data distribution is appropriate for the analysis methodology selected;

b) provide an estimate of the standard error of the data;

c) identify any significant outlying data/points that do not fit within the analysis parameters or distribution;

d) provide an estimate of the minimum sample size (data population) for the statistical methodology used (statistical significance);

e) provide for a statistical corrosion rate (or thickness) and confidence for the circuit;

f) identify if there may be mixed modes of corrosion damage (localized/generalized);

g) identify if there may be a shift in the corrosion rate data over time.

7.4.3: The section title and the first and second paragraphs shall be updated as follows:

7.4.3 Soil-to-Air Interfaces

External corrosion can occur at the interface where partially buried pipe or buried pipe enters or leaves soil (and/or concrete). Note that areas where the pipe is unintentionally, but permanently, contacting the soil (e.g. due to soil movement) should be treated as SAIs as well. Typically, the corrosion can extend from 12 in. (30 cm) below to 6 in. (15 cm) above the soil surface.

Inspection should include checking for coating damage, bare pipe, and pit depth measurements. If significant corrosion is noted, thickness measurements and excavation may be required to assess whether the corrosion is localized to the SAI or can be more pervasive to the buried system. Thickness readings at SAIs can expose the metal and accelerate corrosion if coatings and wrappings are not properly restored.

7.5.9: The following shall be added as the last paragraph in the section:

UV damage is a common mechanism affecting FRP equipment exposed to sunlight. External coatings have been developed to mitigate this damage. All FRP should be inspected for signs of UV damage on a frequency deemed appropriate by the owner-operator based on industry guidance and/or local experience. Chalking is an early sign of UV attack. If discovered in its early stages, simple corrective actions (resin coating or painting with UV stabilizing materials) can be taken to arrest the damage and extend the life of the asset. If the fiber windings are visible, extensive repairs may be necessary and an FRP subject matter expert should be consulted.

7.6: The section title and content shall be updated as follows:

7.6 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 promote new damage mechanisms. When a change in the damage rate occurs or is anticipated, the recommended inspection interval may need adjustment.

An open dialogue should be established between Inspection and Operations 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. An example is Operations finding valve internal pieces in a pump suction strainer, which may indicate upstream valve deterioration and a potential indicator of piping deterioration.

7.9: The section title and content shall be updated as follows:

7.9 Newly Commissioned Piping Inspection

7.9.1 General

Newly installed piping presents an opportunity to obtain valuable data for the management of the piping life cycle. It is important to understand that obtaining this information may be required depending on certain jurisdictional requirements. Working with the project teams so that they understand the data needed and the format conducive to directly loading it into the Inspection Data Management System (IDMS) should be considered.

New piping, where internal degradation is expected, should be inspected per API 570. Where thickness monitoring will be part of the ongoing inspection requirements, external baseline thickness measurements should be obtained prior to being placed in service or within a time frame defined by the owner-operator. 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 measurements of components.

7.9.2 Considerations for Newly Commissioned Piping Inspections

7.9.2.1 General

There are a variety of things to consider when commissioning piping and performing inspections. Owner-operators should have a work process that addresses the steps below. Most steps are the same or similar to inspecting existing piping for the first time but may have been in service. There should be a work process, such as MOC/prestart-up safety review or other work process that triggers setting up new piping in the IDMS.

7.9.2.2 Data Collection and Inspection Planning

Typical steps in developing inspection plans for newly commissioned piping are, for example:

a) Collect design information with a clear definition of what information is minimally required vs. desired. Information should include any special design conditions such as PWHT. This design information is typically provided with piping line lists.

b) Perform systemization and circuitization for the new piping.

c) Determine credible damage mechanisms for each piping circuit and update IOWs, corrosion control documents, and other site-specific documents.

d) Determine if there are any specialty inspections required, such as SAI, deadleg(s), injection points, mix points, CUI, contact point corrosion, SBP, critical specification breaks, etc.

e) Set up in the IDMS or other permanent system of record with appropriate information. This typically includes the following:

   1) creating new inspection isometrics or other applicable types of drawing(s);

   2) updating existing piping isometrics as needed;

   3) assigning CMLs to obtain baseline data.

f) Determine and document inspection plan for each pipe circuit. This typically includes the following:

   1) external baseline thickness NDE;

   2) external visual examination;

   3) identifying the need for an internal visual examination (size permitting) or other NDE inspection;

   4) inspection tasks associated with special emphasis program items;

   5) inspection interval or frequency for tasks.

g) Determine if the inspection(s) needs to be completed within a certain time frame before or after start-up.

h) Schedule the inspections.

7.9.2.3 Field Inspections, Validations, and Quality Assurance and Quality Control

Commission baseline inspection/examination of piping installations should include, for example:

a) performing an audit of pressure testing and NDE results, including those for weld quality;

b) verifying flange ratings and gasket types and materials on pipe systems;

c) verifying valve trim specifications;

d) verifying material test report/PMI data against the owner-operator specification;

e) verifying special support designs/features such as spring cans with design settings;

f) examining coatings used and mill thickness data reports against the owner-operator specifications;

g) examining insulation installations for adherence to the owner-operator specifications;

h) verifying overpressure protection devices and settings.

Some tasks may be handled by others, such as project quality assurance and quality control teams. Auditing documentation may be included in addition to physical verification and validation as deemed appropriate by the owner-operator.

7.9.2.4 Post Field Inspections

All field inspections and verifications/validations are normally completed prior to commissioning. Field inspection data and reports should be completed, reviewed, approved, and entered into the IDMS within 90 days of commissioning. To avoid delays, piping circuits should be created in the IDMS as an early step so that data can be entered directly as they are accumulated.

8.3: The section shall be updated as follows:

8.3 Opportunities for Inspection

8.3.1 Offline Inspection

A common limitation to performing inspections or examinations while piping is in operation is elevated temperatures as inspection and nondestructive testing equipment often has temperature limitations. In addition, the radiant heat from operating piping may pose a safety risk for inspection personnel. For these reasons, some piping inspections may need to be done while the piping is offline or not in active operation.

In low-temperature services, ice buildup may occur on the exterior of the piping while the equipment is in operation, thus the inspection and NDE cannot be completed on-stream. Such frozen piping circuits may need to be scheduled for an offline inspection to allow the ice to thaw prior to the inspection.

Signs of wet insulation should be noted when piping is offline. Water dripping onto insulation may not show dampness during operation because heat from the pipe causes surface water to evaporate, but water deeper in the insulation can still cause CUI. If dampness is noted during a shutdown, the damp piping should be considered for CUI inspection.

When piping is opened for any reason, it should be inspected internally as far as accessibility permits. Some piping is large enough for internal inspection, which can occur only while the piping is offline.

Adequate follow-up inspections should be conducted to determine the causes of defects, such as leaks, misalignment, vibration, and swaying, that were detected while the unit was operating.

8.3.2 On-stream Inspection

8.3.2.1 Technical Reasons for Inspecting On-stream

Certain kinds of external inspections should be done while the piping is operating. Vibration and swaying are evident with the process flow through the pipe. The proper position and function of supports, hangers, and anchors are most apparent while piping is in operation at temperature. The inspector should look for distortion, settlement, or foundation movement, which could indicate improper design or fabrication. Pipe rollers and slide plates should be checked to ensure that they operate freely.

Leakage is often more obvious during operation. Inspectors should look for signs of leakage both coming from each pipe and onto each pipe. The leakage from a pipe can indicate a hole in the pipe, and leakage onto a pipe can indicate a leak from an unobserved source (e.g. beneath insulation).

Thermal imaging should be done under operating conditions. For example, thermal imaging:

a) can show blockage and/or maldistribution of flow that can affect corrosion mechanisms;

b) can show wet insulation that can lead to CUI;

c) can show a breakdown of internal insulating refractory, which can lead to high-temperature corrosion of the pipe wall;

d) may show malfunctions of heat tracing, which could allow unexpected damage mechanisms to operate; for example, tracing that is too hot may cause caustic SCC of carbon steel carrying caustic solutions, and tracing that is too cold may allow dew-point corrosion.

RT can be as effective during operation as when the piping is offline. On-stream RT could detect fouling that might be washed out of piping during unit entry preparation.

8.3.2.2 Practical Reasons for Inspecting On-stream

On-stream inspection can increase unit run lengths by giving assurance that piping is fit for continued service. When piping has to be replaced, on-stream inspection allows an inspector to define the extent of replacement necessary and have replacement piping fabricated before the shutdown.

Units are often crowded during a shutdown, and on-stream piping inspection can increase the safety and efficiency of shutdown operations by reducing the number of people who need to be in the unit during that time. On-stream inspection can reduce surges in workload and thus stabilize personnel requirements.

8.4: The section title and content shall be updated as follows:

8.4 Inspection Scope

Piping inspection should be frequent enough to ensure that all piping has sufficient thickness to provide both pressure containment and mechanical support. For pipes undergoing uniform corrosion, calculating the corrosion rate and remaining life at each CML and then setting the inspection interval based on the half-life have traditionally provided that assurance. The inspector, often in consultation with corrosion specialists and piping engineers, determines the number and locations of CMLs (see API 570). RBI may be used to determine interval or due date and extent.

For damage mechanisms other than uniform corrosion, the inspector should determine the type of inspection, the frequency, the extent, and the locations of CMLs. Corrosion specialists and piping engineers have typically helped in this process as well.

Sections 8.5 and 8.6 shall be deleted.

9.1.2: The section title and content shall be updated as follows:

9.1.2 Precautions Regarding the Use of Breathing Air

For many companies, confined entry into piping systems containing unbreathable atmospheres is not allowed. On occasion, it may be desirable to enter a piping system 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 PPE (i.e. breathing air) for such entry as given in API 2217A.

9.1.3: The section title and content shall be updated as follows:

9.1.3 Precaution Regarding Confined Space Entry

Confined space entry, in combination with complicated interior spaces and the mobility involved in completing inspections, can make internal inspections hazardous if the right precautions are not taken. In addition to any facility-specific confined space entry procedures, the following safety precautions for confined space entry are advisable.

a) Read any permits and job safety analysis or its equivalent that might be required in the facility.

b) Prior to entry, the piping system should be isolated from all sources of liquids, gases, or vapors, using blinds or blind flanges of suitable pressure and temperature rating. The piping system should be drained, purged, cleaned, and gas tested before it is entered. This preparation 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 piping system to be entered should be worn. Details of the precautions to be followed are covered in API 2217A.

c) Prior to entry, the inspector should perform a damage assessment to ensure that the piping system can withstand the additional weight from inspection activity. External scaffolding may be erected at potential concern areas as fall protection.

d) Prior to entry, ensure that the entry attendant(s) is familiar with the internal configuration of the piping system and understands the physical basics of the task, such as navigating the piping system and access and egress point(s) that have been approved.

e) 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.

f) Prior to entry, ensure that scaffolding is installed where required for entry, access to the internals, and/or egress from the piping system.

g) 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.

h) Internal components of piping systems should not be utilized for weight bearing activity during navigation unless the internal components are assessed for load bearing prior to inspection activity. Care should be taken to distribute weight evenly while performing damage assessments. Use of fall protection and/or retrieval devices is recommended as applicable, given the piping system configuration. All internal and external piping system components should be temporarily removed to allow access and emergency egress.

i) 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 should be used in conjunction with the rope, strap, or other soft ladders.

9.3: The section shall be updated as follows:

All possible preparatory work should be done before the scheduled start of the inspection. Scaffolds should be erected, insulation removed, and surface preparation completed where required. Buried piping should be excavated at the points to be inspected. Equipment required for personal safety should be checked to determine its availability and condition. Any necessary warning signs should be obtained in advance, and barricades should be erected around all excavations. The appropriate signs and barricades, as required by the site and jurisdiction, should be in place before RT is performed.

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

During the preparation of piping systems for inspection, PPE should be worn when required either by regulations, the owner-operator, or the repair organization.

The tools needed for inspection should be checked for availability, proper working condition, calibration, and accuracy. The following tools and instruments are often used in the inspection of piping:

a) hammer;

b) scraper;

c) wire brush;

d) mirror;

e) flashlight or portable lighting;

f) steel ruler or measuring tape;

g) pit-depth gauge;

h) weld profile or contour gauge;

i) ID, OD, or other direct-reading calipers;

j) magnet;

k) magnifying glass;

l) marking devices (e.g. temperature- and material-appropriate paint pen, crayon, marker, or high-visibility marking paint);

m) camera;

n) remote video equipment (borescope, fiber-optic equipment, remote camera, etc.);

o) temperature indicator (contact pyrometer, temp sticks, infrared devices, etc.);

p) portable hardness tester;

q) alloy analyzer or PMI equipment;

r) ultrasonic equipment;

s) liquid penetrant equipment;

t) magnetic particle equipment;

u) radiographic equipment;

v) eddy current flaw detection/ACFM crack inspection equipment;

w) electromagnetic acoustic transducer (EMAT), guided wave testing, real-time radiography;

x) leak detector (sonic, gas test, or soap solution);

y) drone or unmanned aerial system.

In addition to the list above, grit blasting or comparable equipment may be required to remove paint and other protective coatings, dirt, or corrosion products so that the surface is properly prepared for the inspection technique (e.g. inspection for cracks with MT).

9.4: The section title and content shall be updated as follows:

9.4 Cleaning and Surface Preparation for Inspection

For piping subject to internal inspections, the cleaning and surface preparation of internal surfaces are similar to pressure vessel inspections and should be conducted with methods and procedures outlined in API 510 and API 572.

For piping subject to external inspection methods, the degree of surface preparation required will depend on the type and extent of damage expected, and the inspection technique to be used. Thorough cleaning to expose bare metal may be needed at CMLs where UT thickness measurements are taken. When cracking or extensive pitting is suspected, thorough cleaning of a large area may be needed for surface examination techniques. Cleaning can be performed with a wire brush, abrasive-grit blasting, water blasting with low-, medium-, or high-pressure water, or power chipping when warranted by circumstances. Hand tools, such as a scraper, wire brush, or file, can clean small spots.

Where better cleaning for larger areas is needed, power wire brushing or abrasive-grit blasting may be economical and more effective than using hand tools. Due to contamination concerns, the material of construction of the wire wheel should match that of the component to be cleaned. With abrasive-grit blasting, selection of the abrasive media and the blasting equipment should be appropriate for the intended component and purpose.

When the credible damage mode is cracking (such as with SCC), powered wire wheels should be avoided for surface preparation. Wire wheels can smear the metal surface being cleaned making detection more difficult with PT, MT, and ET.

Abrasive-grit blasting can also impede the effectiveness of nondestructive testing methods. In many cases, a two-step cleaning process may be required, such as abrasive-grit blast followed by sanding with powered grinders using sanding disc. Another example of a two-step surface preparation is wire wheel buffing followed by sanding disc.

To maximize sensitivity of nondestructive testing examinations for detection of surface breaking flaws, etching can be performed. Etching improves sensitivity by minimizing smearing of cracks, which impedes PT, MT, and ET examinations.

Cleaning and surface preparation work on operating equipment should be performed only after careful review. It may be necessary to use several inspection techniques to minimize exposure. When it is necessary to remove corrosion product, some things to consider include the thickness of the scale, remaining corrosion allowance, and inspection effectiveness. Activities such as grit blasting and scraping areas should be avoided on live equipment. When that is impractical, a job hazards review should be considered.

10.3.2.2: The section shall be updated as follows:

Sites should have a program to ensure that flanges are made up properly. Proper makeup of every flange in a piping system is important for reliability. Proper makeup includes the use of the proper gasket and stud (material, type, and size), proper positioning of the gasket, and proper tightening (e.g. torquing, tensioning, etc.) of the joint. The assurance program should include procedures for gasket and stud selection and assembly. ASME PCC-1 offers good guidance on the proper makeup of bolted flange joints.

The program can incorporate varying degrees of sampling, visual inspection, field testing, and destructive testing of components. Gasket selection can usually be confirmed by visual examination of the gasket’s color and markings on the OD surface. Spiral-wound gaskets should be marked and color-coded in accordance with ASME B16.20. Studs can be visually examined for proper stampings or markings and PMI tested in accordance with API 578.

Proper gasket positioning and assembly depend on the training and craftsmanship of the pipefitters making up the flanges. Gasket positioning can be checked visually; however, proper assembly is difficult to check. Any observed flange deformation can be a sign of improper assembly.

Flanged joints should be visually inspected for cracks and metal loss caused by corrosion and erosion when they are opened. See 10.2.2 for methods of inspection for cracks. Inspection of gasket faces is covered in 10.2.3. Flange joints can be inspected while in service by applying single-element or phased-array UTs to the external surfaces to measure flange face corrosion and to detect ring groove cracking.

Flange studs should be inspected for stretching and corrosion. Where excessive stud loading is indicated or where flanges are deformed, a simple inspection can be performed where a nut is rotated along the entire length of the stud. If the stud is stretched, the thread pitch will be changed, and the nut will not turn freely. The inspection involves checking to determine whether studs of the proper specification have been used, and it may involve chemical analysis or physical tests to determine the yield point and the ultimate strength of the material.

If flanges are assembled too tightly, they can bend until the outer edges of the flanges are in contact. When this occurs, the pressure on the gasket can be insufficient to ensure a tight joint. Visual inspection of the joint will reveal this condition. Permanently deformed flanges should be replaced or refaced.

10.3.4: The section shall be updated as follows:

10.3.4 Vibration

10.3.4.1 Existing Piping

When excessive piping vibration or movement is noted during operation, an inspection should be performed to identify abrasion, external wear, cracks. The visual inspection methods described in 10.1.5 should be followed. This inspection should be supplemented by other appropriate NDE methods as applicable. The conditions causing excessive vibration or movement should be corrected. The extent of the inspection may need to include areas some distance away from the vibration source as the induced vibration and damage may not be immediately at the source. Transient conditions (such as start-ups, shutdowns, upsets, etc.) can create intermittent, but severe, vibrating conditions; hence, the absence of visible physical vibration during steady state operations is not necessarily evidence that vibration is not a problem.

10.3.4.2 Small Bore Piping Connections

SBP connections, including threaded connections, have historically experienced an elevated incidence of mechanical fatigue failure due to vibration. Specific SBP connections to piping that can be subject to vibration and resulting mechanical fatigue failure include those associated with, but not limited to:

a) reciprocating and centrifugal compressors and steam turbines;

b) reciprocating and centrifugal pumps;

c) machinery where rotating or reciprocating component speed range is 60–1000 rpm;

d) piping or equipment subject to process-induced vibration or turbulent flow;

e) piping or equipment subject to flow-induced pressure pulsations;

f) pressure relieving devices.

During external visual examination of these piping locations, inspectors should investigate evidence of vibration and installations that could promote mechanical fatigue cracking. Some of this evidence can include identifying the following:

1) piping vibration through visual, touch, or audible sensory detection;

2) connected valves with loose or missing handwheels;

3) fretting damage on the pipe where rubbing can occur, such as U-bolt clamps, resting supports, deck penetrations, insulation jacket/cladding terminations, and at temporary supports;

4) components with weld geometry that can result in stress concentrations (e.g. socket-weld with sharp notch), insufficient weld fill (e.g. weld-o-let with inadequate weld fill per ASME B31.3), and inherent notches (e.g. weld undercut);

5) SBP threaded connections that have not been properly fully backwelded and/or braced/gusseted;

6) SBP connections with a long length and heavy unsupported valve/instrument;

7) damaged, missing, and ineffective pipe supports that may allow or promote movement;

8) broken or improperly installed bracing/gusseting.

When evidence of vibration and/or installations that could promote mechanical fatigue cracking are identified, analysis by a piping engineer may be needed to assess the potential likelihood of mechanical fatigue failure. References that may aid in the assessment include, but are not limited to:

— ASME OM, Part 3 par. 5.1.1 or Part 3 Appendix I;

— *Guidelines for the Avoidance of Vibration Induced Fatigue Failure in Process Pipework*, Energy Institute.

NOTE At the time of this publication, guidance is being developed for API 579-1/ASME FFS-1 as Part 15.

Inspection of SBP connections for mechanical fatigue cracks may not be effective in preventing mechanical fatigue failures, particularly for connections that experience unpredictable or significant vibration. In most cases, mitigation of mechanical fatigue cracking is through proper design and installation of the connection appropriate for vibrating services. Some appropriate actions include the following:

1) replacing existing threaded connections with socket-welded ones or single integrally reinforced, forged components (e.g. extended body valve);

2) fully backwelding/bridge welding existing threaded connections;

3) installing gusseting in two planes between the pipe and the small-bore pipe;

4) providing support to heavy valves/instruments.

Owner-operators often use risk assessment to provide priority of addressing individual findings with in-service piping. Further, owner-operators have updated pipe specifications to exclude designs and installations that may have been acceptable in the past but are more prone to mechanical fatigue failure.

10.4.4: The new section shall be added:

10.4.4 Thickness Screening Examination Techniques

Thickness screening examination techniques (e.g. guided wave examination, Lamb wave, RT density measurements, etc.) are typically limited to the qualitative data results (i.e. volumetric percentage of wall loss vs. actual discrete thickness values). These screening techniques have been used for a variety of applications (e.g. screening long pipe lengths, SAIs, buried lines, contact point corrosion, etc.). If used, screening examination techniques are considered to fulfill the requirements for thickness measurement inspection provided they are used complementary to an inspection plan that also includes periodic quantitative examination techniques to establish actual baseline thickness data or to prove up screening technique examination results conducted at appropriate intervals.

10.5.1.1: The section shall be updated as follows:

Minimum required thickness values for piping components are established using evaluation methods that consider stresses induced by pressure loads, sustained loads, and occasional loads. These evaluation methods are described in industry standards such as API 570, ASME B31.3, and API 579-1/ASME FFS-1. Generally, minimum required thickness values for piping components are categorized as either a pressure design thickness or a structural minimum thickness. The required thickness determined through an evaluation considering the governing design load case (i.e. greater of pressure or structural) is traditionally referred to as a component's minimum required thickness.

The minimum required thickness is a key variable in remaining life calculations. The value is utilized along with the corrosion rate and the minimum measured thickness values obtained during inspection to establish the remaining life of a piping component and is often an input into the owner-operators IDMS. Conceptually, the minimum required thickness represents the thickness where there is zero remaining life. However, the minimum required thickness can be determined by different methods with varying degrees of conservatism (i.e. design margin or safety factor). In general order of decreasing conservatism, the common methods are as follows.

a) Nominal pipe wall thickness minus design corrosion allowance. This, generally, is the most conservative approach since the piping engineer usually has to specify a larger pipe schedule to account for thickness under tolerance defined by the pipe standard. This often results in a more actual corrosion allowance than originally designed.

b) The greater of either:

    1) pressure design thickness (refer to 10.5.1.2) or

    2) structural minimum thickness (refer to 10.5.1.3).

c) FFS analysis (refer to API 579-1/ASME FFS-1).

Owner-operators often have a procedure detailing how they manage pipe life and scheduling of future inspection and repair/replacement plans for a piping component through minimum required thickness assignment. A progression of more detailed analysis and calculation of required thickness is common as remaining life decreases. The use of less conservative values in the detailed analysis results in increased calculated remaining life. Similarly, another common approach uses a minimum alert thickness value. Minimum alert thicknesses values are greater than traditional minimum required thickness values and serve as a signal to the inspector that a more detailed remaining life assessment is necessary.

10.5.1.3: The section shall be updated as follows:

In some low- to moderate-pressure and temperature applications, the required pressure design wall thickness for piping can be so thin that the pipe would not have sufficient structural strength. For this reason, an absolute minimum thickness to prevent sag, buckling, and collapse at supports should be determined by the user for each size of pipe, dependent upon the piping size, span, material of construction, and design temperature. The pipe wall should not be permitted to deteriorate below this minimum thickness regardless of the results obtained by the ASME B31.3 or Barlow formulas.

The owner-operator shall specify how structural minimum thicknesses are determined. Example tables of calculated structural minimum thickness for straight spans of carbon steel pipe at 400 °F (205 °C) and 750 °F (400 °C), of 1-1/4Cr-1/2Mo at 750 °F (400 °C) and 1100 °F (595 °C), and of austenitic stainless steel at 400 °F (205 °C) and 1000 °F (540 °C), at various pressure classes is provided in Annex D. Annex D also lists the assumptions used in calculating the thicknesses and limitations of the calculated values. For complete details on all the assessment assumptions, methodology, and results, refer to API 593.

The temperature listed for the tables applies only to reduction in allowable stress. These results do not consider thermal expansion stresses caused by restrained piping at temperature. Such effects are outside this scope and should be considered in management of the piping retirement thickness.

Additional consideration and allowances may be required for the following conditions:

a) screwed piping and fittings;

b) piping diameters greater than 24 in. (610 mm);

c) temperatures exceeding the upper limits noted above for the respective materials;

d) higher alloys (other than carbon steel, 1-1/4Cr-1/2Mo and austenitic stainless steel);

e) spans more than those listed in Table D.1 or 20 ft (6 m), whichever is less;

f) high external loads (e.g. refractory lined, pipe that is also used to support other pipe, rigging loads, and personnel support loading);

g) fatigue service includes vibration;

h) insulation thicknesses and densities greater than those assumed in the original calculations (refer to API 593).

Engineering calculations, typically using a computerized piping stress analysis program, may be required in these instances to determine structural minimum thickness.

Table 5 shall be removed, and the remainder of the tables shall be renumbered.

10.5.1.4: The section shall be updated as follows:

Generally, piping is replaced and/or repaired when it reaches the minimum required thickness unless an FFS analysis has been performed, which defined additional remaining life. The minimum required thickness is the greater value of the pressure design thickness or the structural minimum thickness. The following steps should be followed when determining the minimum required thickness at a CML.

a) Step 1: Calculate the pressure design thickness per rating code.

b) Step 2: Determine the structural minimum thickness per the owner-operator table or engineering calculations.

c) Step 3: Select the minimum required thickness. This is the larger of the pressure design thickness or structural minimum thickness determined in Step 1 and Step 2.

EXAMPLE 1: Determine the minimum required thickness for Class 150 NPS 2, ASTM A106, Grade B pipe designed for 100 psig @ 100 °F (0.69 MPag @ 38 °C). P = 100 psig (0.69 MPag), D = 2.375 in. (60.3 mm), S = 20,000 psi (138 MPa), E = 1.0 (since seamless), W = 1, Y = 0.4.

Step 1: Calculate pressure design thickness per rating code. (In this example, the ASME B31.3 design formula was used.)

$$t = \frac{P \times D}{2\left(S \times E \times W + (P \times Y)\right)} = \frac{100 \times 2.375}{2\left(20{,}000 \times 1 \times 1 + (100 \times 0.4)\right)} = 0.006 \text{ in.}$$

$$t = \frac{P \times D}{2\left(S \times E \times W + (P \times Y)\right)} = \frac{0.69 \times 60.3}{2\left(138 \times 1 \times 1 + (0.69 \times 0.4)\right)} = 0.15 \text{ mm}$$

NOTE If this NPS 2 pipe was 100 % supported (e.g. laying on flat ground), then 0.006 in. (0.15 mm) wall thickness would contain the 100 psig (0.69 Mpag) of pressure. Even though the pressure thickness includes a factor of safety of 3 on tensile and 1.5 on yield stresses, it could have insufficient structural strength if unsupported across a span.

Step 2: Determine structural minimum thickness per owner-operator table or engineering calculations. From Table D.2a (Table D.2b), the default structural minimum thickness is 0.050 in. (1.27 mm).

Step 3: Select the minimum required thickness. This is the larger of the pressure design thickness or structural minimum thickness determined in Step 1 and Step 2. The larger value of 0.006 in. (0.15 mm) and 0.050 in. (1.27 mm) is 0.050 in. (1.27 mm).

EXAMPLE 2: Determine the minimum required thickness for a Class 300 NPS14, ASTM A106, Grade B pipe designed for 600 psig @ 100 °F (4.14 MPag @ 38 °C, P = 600 psig (4.14 MPag), D = 14 in. (355.6 mm), S = 20,000 psi (138 MPa), E = 1.0 (seamless), W = 1, Y = 0.4.

Step 1: Calculate pressure design thickness per rating code. (In this example, the ASME B31.3 design formula was used.)

$$t = \frac{P \times D}{2\left(S \times E \times W + (P \times Y)\right)} = \frac{600 \times 14.0}{2\left(20{,}000 \times 1 \times 1 + (600 \times 0.4)\right)} = 0.208 \text{ in.}$$

$$t = \frac{P \times D}{2\left(S \times E \times W + (P \times Y)\right)} = \frac{4.14 \times 355.6}{2\left(138 \times 1 \times 1 + (4.14 \times 0.4)\right)} = 5.27 \text{ mm}$$

Step 2: Determine structural minimum thickness per owner-operator table or engineering calculations. From Table D.2a (Table D.2b), the structural minimum thickness is 0.155 in. (3.94 mm).

Step 3: Select the minimum required thickness. This is the larger of the pressure design thickness or structural minimum thickness determined in Step 1 and Step 2. The larger value of 0.208 in. (5.27 mm) and 0.155 in. (3.94 mm) is 0.208 in. (5.27 mm).

10.5.1.5: The section shall be updated as follows:

Users may establish a minimum alert thickness with values greater than either the minimum structural thickness or the pressure design thickness (whichever governs the minimum required thickness). Alert thicknesses are often input into the facility's IDMS. The alert thickness signals the inspector that it is time for a remaining life assessment. This could include a detailed engineering evaluation of the structural minimum thickness, an FFS assessment, or the development of future repair plans. In addition, when a CML reaches the alert thickness, it raises a flag to consider the extent and severity at other possible locations for the damage mechanism. Alert minimum thicknesses are usually not intended to mean that pipe components must be retired when one CML reaches the default limit.

10.6.1: The section title and content shall be updated as follows:

10.6.1 Special Methods of Detecting Mechanical Damage

Visual examination will reveal most mechanical damage (dents, gouges, and cracks). MT (wet or dry) and PT methods may be useful for crack detection. Other methods, such as radiography, angle beam UT, etching, and sample removal, are available and may be used when conditions warrant. ET, ACFM, and UT methods are available for the detection of surface breaking flaws.

Radiography and angle beam UT are used to analyze flaws not visible on the surface of the metal, usually in welded seams.

10.6.2: The section title and content shall be updated as follows:

10.6.2 Metallurgical Changes and In Situ Analysis of Metals

There are in situ techniques available to assess metallurgical changes for piping. Some examples are as follows.

a) FMR (field metallographic replication) is a useful technique to supplement MT/PT or UT; however, it only provides detail of the surface that the replica is lifted from, and it may not represent the entire thickness. It can identify what the relevant indications constitute and discern damage mechanism such as:

   1) creep damage (e.g. fissures and voids) of various alloys;

   2) carburization of carbon steel and Cr-Mo steels;

   3) spheroidization (softening) of carbon steel and low-alloy steels (e.g. after prolonged exposure to temperatures > 850 °F or short exposure to temperatures > 1300 °F during fire scenario);

   4) graphitization of carbon steel and C-1/2Mo steels after prolonged exposure to temperatures between 800 °F and 1100 °F.

b) Hardness testing may indicate:

   1) carburization of carbon steel;

   2) presence of martensite microstructures (e.g. from pipe forming or from welding) of carbon steel and low-alloy steels;

   3) spheroidization (softening) of carbon steel and low-alloy steels (e.g. prolonged exposure to temperatures > 850 °F or short exposure to temperatures > 1300 °F during fire scenario);

4) material softening or hardening due to temperature-related events, such as fires, quenches, or abnormal operating conditions;

5) strain aging damage of carbon steel and C-1/2Mo steels.

c) ET can detect carburization, oxidation, and the formation of martensite or other microstructures that lead to hardness changes, as per list in item b) above.

d) Degree of sensitization electrochemical technique to determine sensitization of austenitic stainless steels.

e) Time-of-flight diffraction, phased-array ultrasonic testing, and full matrix capture/total focusing method are NDE techniques capable of detecting early-stage high-temperature hydrogen attack fissures (micro-cracks) and voids. Refer to API 941.

10.6.3: The section title and content shall be updated as follows:

10.6.3 Positive Material Identification

The owner-operator should establish a material verification program. This program should indicate the extent and type of PMI testing to be conducted during repair, maintenance, and altering of piping. Material verification programs focus on alloy materials of construction and ensure that there is no inadvertent use of a nonspecified material of construction. Welding consumables, insert plates, and pipe components used in repairs and alterations of alloy piping should be verified. Material identification can be determined by using X-ray fluorescence or optical emission spectroscopy instruments. Refer to API 578 for general information on material verification programs and information on PMI technology that can be useful in defining a program for piping.

Although material verification focuses on alloy materials of construction, there may be a need to verify carbon steel compositions. In HF service, special attention is given to the composition of carbon steel components and weldments that have high residual element (RE) content. Refer to API 751 for additional information on the effect of REs on the corrosion behavior of carbon steel in HF acid services.

10.6.4: The section title and content shall be updated as follows:

10.6.4 Metal Sample Extraction

Sample removal can be used to spot-check welds; to investigate cracks, laminations, and other flaws; and to determine properties of unknown materials of construction. Small metal samples from the affected area are removed via scoop or boat samples (for partial thickness) or full thickness samples. The sample is then analyzed under a microscope or with an ordinary magnifying glass. If they can be adequately cleaned, the filings obtained during the cutting operation may be used in making a chemical analysis of the metal. Samples can be used for tensile testing, metallurgical analysis to identify material of construction, and metallography to examine the microstructure of the material.

The decision to remove samples should be made by someone who is familiar with the evaluation of and performing the repair of the affected area. The sample removal areas in the pipe wall should be evaluated by FFS assessments and repaired if they may affect pressure equipment integrity. Refer to ASME PCC-2, Article 304 Flaw Excavation and Weld Repair and Mandatory Appendix 304-I for additional information.

13.2: The section title and content shall be updated as follows:

13.2 Types of Pressure Tests

Various types of pressure tests that satisfy the intent of verifying integrity and/or leak tightness of a pressure system are recognized by industry standards. These test methods are generally categorized by the medium utilized to conduct the test [i.e. hydrostatic (liquid), pneumatic (gas), or hydropneumatic (liquid/gas)]. The pressure testing intent, test pressure, and boundaries of the equipment being tested are also used to further categorize pressure testing methods (i.e. tightness test, leak test, localized pressure test). ASME PCC-2, Article 501 recognizes the following pressure and tightness testing nomenclature:

a) hydrostatic pressure test;

b) pneumatic pressure test;

c) hydropneumatic pressure test;

d) tightness test;

e) in-service leak test.

Hydrostatic, pneumatic, and hydropneumatic pressure tests are utilized to verify gross integrity of a piping component or system. Hydrostatic pressure tests utilize a liquid, typically water, as the test medium, whereas pneumatic pressure tests utilize a gas, generally nitrogen or air. Hydropneumatic pressure tests utilize a combination of liquid and gas as the test medium. Hydrostatic pressure tests are more commonly performed than pneumatic pressure tests due to the safety implications in the event of a failure of the equipment being tested. Pneumatic testing is potentially much more hazardous than hydrostatic testing due to the higher levels of potential energy in the pressurized system; therefore, all reasonable alternatives are usually considered before this option is selected. The test pressure of hydrostatic or pneumatic pressure tests should be according to the original construction code, considering also any subsequent engineering analysis deemed necessary. In general, the test pressure for a pneumatic pressure test is usually lower than that required for a hydrostatic pressure test.

Tightness tests are usually performed to ensure overall leak tightness of a piping system before the process medium is introduced. It may be performed on systems that have previously been pressure tested, for closure welds on piping systems, and on systems exempt from hydrostatic or pneumatic testing. Tightness tests typically utilize air (or other inert gases) as the test medium. A sensitive leak test per ASME B31.3 is the preferred method for conducting a tightness test. The applied test pressure for piping should not exceed 35 % of the design pressure, although leakage at flanged joints may be evident at much lower pressures when using sensitive leak detection methods.

In-service leak tests are performed during equipment start-up when structural integrity does not need to be verified and the consequences of leakage of the process medium are acceptable. In-service leak tests utilize the process medium of the pressure equipment as the test medium.

Visual examination is performed as part of pressure, tightness, and in-service leak tests to determine if any leakage is occurring. When visual examination is not possible, monitoring of system pressure for pressure drop during tightness or in-service leak test may be substituted when approved by the owner-operator.

13.4: The section title and content shall be updated as follows:

13.4 Pressure Testing Considerations

Pressure testing consists of filling a piping component or system with liquid or gas and increasing the internal pressure to a desired level. During the pressure test, the peak test pressure is held for a specified time and monitored for change. A pressure change can occur over the test duration from a change in test media temperature or leakage. After a reduction in test pressure, the external surfaces are given a thorough visual examination for leaks and signs of deformation. The test pressure, duration, and procedures used should be in accordance with the applicable construction code requirements consistent with the existing thickness of the piping component or system and applicable owner-operator procedures.

When water is used to conduct a pressure test, care should be taken to remove all water from the equipment when the test is complete. When water cannot be completely removed, it may be necessary to treat the water to prevent corrosion (e.g. add chemical corrosion inhibitors to prevent the potential for microbiological corrosion) while the equipment is out of service. In addition, when testing Type 300 series SS piping, consider the potential for CSCC. Appropriate precautions should be taken regarding the chloride content of the water used for testing.

When testing pneumatically, a UT leak detector or soap solution or both should be used to aid visual inspection. The soap solution is brushed over the seams and joints of the piping system. The piping system is then examined for evidence of bubbles as an indication of leakage. A UT leak detector may be used to pick up leaks in joints and the like that cannot be reached with a soap solution without scaffolds or similar equipment. Very small leaks may be detected and located with the leak detector.

14.1: The section shall be updated as follows:

The necessity of keeping complete records in a detailed and orderly manner is an important responsibility of the inspector, as well as a requirement of many regulations (e.g. OSHA 29 *CFR* 1910.119). Accurate records allow an evaluation of service life on any piping, valve, or fitting. From such records, a comprehensive picture of the general condition of any piping system can be determined. When properly organized, such records form a permanent record from which corrosion rates, inspection intervals, and probable replacement or repair intervals can be determined. A computer program (e.g. IDMS) can be used to assist in a more complete evaluation of recorded information and to determine the next inspection date.

Inspection records should contain the following:

a) original date of installation;

b) specifications of the materials used;

c) original thickness measurements (i.e. baseline measurements);

d) locations and dates of all subsequent thickness measurements;

e) calculated retirement thickness;

f) repairs and replacements;

g) temporary repairs;

h) pertinent operational changes (i.e. change in service);

i) FFS assessments;

j) RBI assessments.

These and other pertinent data should be arranged on suitable forms so that successive inspection records will furnish a chronological picture. Each owner-operator should develop appropriate inspection forms. Owner-operators should consider minimizing the use of hard copies and maximizing the use of electronic tools to capture all field information. These tools can simplify loading data and reports into the IDMS.

Inspection records are required by API 570. These records form the basis of a scheduled maintenance program and are an important component of an overall mechanical integrity program. A complete record file should contain three types of information:

1) basic data (i.e. permanent records per API 570);

2) field notes;

3) the data that accumulate in the “continuous file” over time (i.e. progressive records per API 570).

Basic data include the manufacturer’s/fabrication/construction drawings, data reports and specifications, design information, and the results of any material tests and analyses.

Field notes consist of notes and measurements recorded on site either on prepared forms or in a written or electronic field notebook. These notes should include in rough form a record of the condition of all parts inspected and the repairs required.

The continuous file includes all information on the piping circuit's operating history, descriptions and measurements from previous inspections, corrosion rate tables (if any), and records of repairs and replacements.

Some organizations have developed software for the computerized storage, calculation, and retrieval of inspection data (e.g. IDMS). When the data are kept up-to-date, these programs are effective in establishing corrosion rates, retirement dates, and schedules. The programs permit quick and comprehensive evaluation of all accumulated inspection data.

14.3: The section title and content shall be updated as follows. Figure 35 shall be moved to 14.2.3.

14.3 Reports

Types of inspections that should be documented in an inspection report include the following:

a) internal visual inspection;

b) on-stream inspection;

c) thickness measurement inspection;

d) various NDE examinations;

e) external visual inspection;

f) vibrating piping inspection;

g) supplemental inspections (e.g. contact point corrosion and trunnion inspections);

h) CUI inspection;

i) one-time neighboring events to note integrity threats that have been observed, but not fully inspected; a few examples include (but not limited to):

   1) nearby major leaks;

   2) hydro-jetting of overhead equipment;

   3) flooding/hurricanes;

   4) fire especially on overhead structures/equipment.

Inspection reports specifically recommending repairs often include the following details:

— location of the repairs, including a piping isometric attachment highlighting location;

— description of the conditions found;

— reasons the conditions found need repair;

— supporting data on the piping, such as corrosion rates, wall thickness measurements, estimation of remaining life;

— references to any NDE reports that were performed as part of the inspection being documented;

— details of the repair plan;

— the recommended date by which the repairs are to be completed.

Annex D shall be added:

Annex D
(informative)

Example Minimum Structural Thicknesses Tables

Tables D.2a–d, D.3a–d, and D.4a–d contain calculated minimum structural thicknesses for carbon steel, austenitic stainless steel, and 1-1/4Cr-1/2Mo. The following summarizes critical assumptions used in the calculations and limitations of the values calculated. The owner-operator should consider these when reviewing the tables and values.

a) These tables assume that the piping aligns with a five-span simply supported beam for the calculation of the required thickness. The five span was chosen to best represent a typical piping system between equipment with intermediate supports. For piping systems that have a layout such that this assumption cannot be applied, the individual unique piping layout will require its own minimum thickness assessment. See API 593 for a comparison between a single span and five span.

b) Limited to 400 °F (205 °C) and 750 °F (400 °C) for carbon steel, 400 °F (205 °C) and 1000 °F (540 °C) for austenitic stainless steel, and 750 °F (400 °C) and 1100 °F (595 °C) for 1-1/4Cr-1/2Mo. Interpolation/ extrapolation between tables and values is not advised.

c) Results assume unsupported flange pair and valve at midspan plus an additional 250 lb (113 kg) force.

    1) For size NPS 2 and lower, the 250 lb (113 kg) force is neglected.

    2) For pressure Classes 900 and greater, the valve weight is neglected. Tables are not applicable if the system has Class 900 and higher valves that are not individually supported.

    3) For pressure Class 2500 and sizes NPS 14 and greater, there are no standard flanges in ASME B16.5; thus, flange weight is neglected. For systems with Class 2500 NPS 14 and larger flanges, these tables are not applicable.

d) Results are limited to maximum span lengths listed in Table D.1, which align with ASME B31.1 span lengths for water filled piping but with a maximum span length of 20 ft (6.1 m). These tables are not applicable when the span lengths exceed those shown in Table D.1.

e) Results for 1-1/4Cr-1/2Mo assume a weld strength reduction factor of 1.0.

f) Finite element analysis buckling assessment on shoe support for NPS 10 to NPS 24 carbon steel piping limited the required structural thicknesses for only the Class 150 systems. These same required structural thicknesses for the Class 150 carbon steel piping were used for austenitic stainless steel and 1-1/4Cr-1/2Mo materials Class 150 systems in the tables. The owner-operator may develop their own minimum structural thickness for austenitic stainless steel and 1-1/4Cr-1/2Mo materials at supports.

g) Finite element analysis buckling assessments were performed for NPS 10 to NPS 24 pipe sizes for all pressure classes. The results indicate that the minimum structural thickness is governed by local support stresses for Class 150 NPS 10 to NPS 24 piping. Note that pipe sizes below NPS 10 were not included in the finite element analysis buckling assessments, and such concern for local buckling is outside the scope of these structural thickness limits.

h) The tables are limited to NPS 24 and smaller pipe sizes.

i) These results are not applicable to piping with spring supports.

j) These charts were developed for specific grades of material, but they can be applied to other grades which have similar allowable stresses.

1) Carbon steel charts were developed for ASME SA106-B pipe so these tables can apply to other grades of carbon steel pipe with similar allowable stress.

2) Austenitic stainless steel charts were developed for ASME SA312-316 pipe so these tables can apply to other austenitic stainless steel pipe with similar allowable stress.

3) The 1-1/4Cr-1/2Mo charts were developed for ASME SA335-P11 pipe, but the resulting numbers for that material may be applied to other ASME *BPVC*, Section IX P- No. 4, P-No. 5A, and P-No. 5B materials.

k) These tables are based on distributed weight loading from the pipe nominal thickness, full of water, and calcium silicate insulation thickness and density listed in API 593. These tables are not applicable for piping systems with higher external loading (e.g. heavier or thicker insulation, refractory lining, pipe supporting other pipe, rigging loads, personnel support loading, etc.).

l) These tables are not applicable to piping systems experiencing vibration more than typical vibration screening criteria.

m) These table values were calculated with the inclusion of the maximum pressure allowed at temperature as defined by ASME B16.5. Owner-operators can alter the minimum structural thickness for their actual pressure.

n) These tables assume that the pipe is full of water (specific gravity = 1.0). If the process has a significantly lower or higher specific gravity than water, a different minimum structural thickness may be warranted but would require an individual assessment for the actual piping system.

Table D.1—Maximum Span Lengths

NPS	Span Length ft (m)
0.5	5 (1.5)
0.75	5.8 (1.8)
1	7 (2.1)
1.5	8.5 (2.6)
2	10 (3)
3	12 (3.7)
4	14 (4.3)
6	15.5 (4.7)
8	19 (5.8)
10–24	20 (6.1)

Table D.2a—Carbon Steel Minimum Structural Thickness (in.) at 400 °F (205 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	0.050	0.050	0.050	0.050	0.055	0.080
0.75	0.050	0.050	0.050	0.050	0.060	0.090
1	0.050	0.050	0.055	0.055	0.070	0.105
1.5	0.050	0.050	0.070	0.070	0.090	0.145
2	0.050	0.055	0.080	0.080	0.115	0.180
3	0.065	0.095	0.135	0.135	0.195	0.295
4	0.060	0.095	0.155	0.155	0.225	0.350
6	0.050	0.100	0.175	0.190	0.295	0.475
8	0.060	0.115	0.215	0.240	0.375	0.605
10	0.080	0.130	0.245	0.290	0.455	0.745
12	0.090	0.145	0.270	0.335	0.530	0.865
14	0.090	0.155	0.300	0.365	0.585	0.885
16	0.100	0.175	0.330	0.410	0.655	1.005
18	0.110	0.185	0.355	0.455	0.730	1.125
20	0.120	0.210	0.385	0.500	0.805	1.245
24	0.140	0.245	0.450	0.595	0.960	1.485

Table D.2b—Carbon Steel Minimum Structural Thickness (mm) at 400 °F (205 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	1.27	1.27	1.27	1.27	1.40	2.03
0.75	1.27	1.27	1.27	1.27	1.52	2.29
1	1.27	1.27	1.40	1.40	1.78	2.67
1.5	1.27	1.27	1.78	1.78	2.29	3.68
2	1.27	1.40	2.03	2.03	2.92	4.57
3	1.65	2.41	3.43	3.43	4.95	7.49
4	1.52	2.41	3.94	3.94	5.72	8.89
6	1.27	2.54	4.45	4.83	7.49	12.07
8	1.52	2.92	5.46	6.10	9.53	15.37
10	2.03	3.30	6.22	7.37	11.56	18.92
12	2.29	3.68	6.86	8.51	13.46	21.97
14	2.29	3.94	7.62	9.27	14.86	22.48
16	2.54	4.45	8.38	10.41	16.64	25.53
18	2.79	4.70	9.02	11.56	18.54	28.58
20	3.05	5.33	9.78	12.70	20.45	31.62
24	3.56	6.22	11.43	15.11	24.38	37.72

Table D.2c—Carbon Steel Minimum Structural Thickness (in.) at 750 °F (400 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	0.050	0.050	0.050	0.055	0.070	0.100
0.75	0.050	0.050	0.055	0.055	0.075	0.110
1	0.050	0.050	0.075	0.075	0.085	0.130
1.5	0.050	0.050	0.090	0.090	0.110	0.175
2	0.050	0.070	0.100	0.100	0.135	0.215
3	0.090	0.130	0.180	0.180	0.245	0.365
4	0.080	0.125	0.200	0.200	0.270	0.420
6	0.060	0.125	0.225	0.230	0.350	0.565
8	0.065	0.145	0.270	0.290	0.445	0.710
10	0.085	0.160	0.305	0.345	0.535	0.875
12	0.090	0.175	0.330	0.395	0.620	1.010
14	0.100	0.190	0.365	0.430	0.680	1.015
16	0.110	0.210	0.400	0.480	0.765	1.150
18	0.110	0.225	0.430	0.530	0.850	1.285
20	0.130	0.250	0.460	0.585	0.935	1.420
24	0.140	0.290	0.535	0.690	1.110	1.690

Table D.2d—Carbon Steel Minimum Structural Thickness (mm) at 750 °F (400 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	1.27	1.27	1.27	1.40	1.78	2.54
0.75	1.27	1.27	1.40	1.40	1.91	2.79
1	1.27	1.27	1.91	1.91	2.16	3.30
1.5	1.27	1.27	2.29	2.29	2.79	4.45
2	1.27	1.78	2.54	2.54	3.43	5.46
3	2.29	3.30	4.57	4.57	6.22	9.27
4	2.03	3.18	5.08	5.08	6.86	10.67
6	1.52	3.18	5.72	5.84	8.89	14.35
8	1.65	3.68	6.86	7.37	11.30	18.03
10	2.16	4.06	7.75	8.76	13.59	22.23
12	2.29	4.45	8.38	10.03	15.75	25.65
14	2.54	4.83	9.27	10.92	17.27	25.78
16	2.79	5.33	10.16	12.19	19.43	29.21
18	2.79	5.72	10.92	13.46	21.59	32.64
20	3.30	6.35	11.68	14.86	23.75	36.07
24	3.56	7.37	13.59	17.53	28.19	42.93

Table D.3a—Austenitic Stainless Steel Minimum Structural Thickness (in.) at 400 °F (205 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	0.050	0.050	0.050	0.050	0.050	0.075
0.75	0.050	0.050	0.050	0.050	0.055	0.080
1	0.050	0.050	0.055	0.055	0.065	0.095
1.5	0.050	0.050	0.065	0.065	0.080	0.130
2	0.050	0.050	0.075	0.075	0.100	0.160
3	0.070	0.095	0.130	0.130	0.175	0.265
4	0.060	0.090	0.145	0.145	0.200	0.310
6	0.055	0.090	0.160	0.170	0.260	0.420
8	0.060	0.105	0.195	0.210	0.325	0.530
10	0.080	0.120	0.220	0.255	0.395	0.650
12	0.090	0.130	0.240	0.290	0.460	0.755
14	0.090	0.140	0.265	0.315	0.505	0.760
16	0.100	0.155	0.290	0.355	0.565	0.865
18	0.110	0.165	0.315	0.390	0.630	0.965
20	0.120	0.185	0.335	0.430	0.695	1.065
24	0.140	0.215	0.390	0.510	0.820	1.270

Table D.3b—Austenitic Stainless Steel Minimum Structural Thickness (mm) at 400 °F (205 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	1.27	1.27	1.27	1.27	1.27	1.91
0.75	1.27	1.27	1.27	1.27	1.40	2.03
1	1.27	1.27	1.40	1.40	1.65	2.41
1.5	1.27	1.27	1.65	1.65	2.03	3.30
2	1.27	1.27	1.91	1.91	2.54	4.06
3	1.78	2.41	3.30	3.30	4.45	6.73
4	1.52	2.29	3.68	3.68	5.08	7.87
6	1.40	2.29	4.06	4.32	6.60	10.67
8	1.52	2.67	4.95	5.33	8.26	13.46
10	2.03	3.05	5.59	6.48	10.03	16.51
12	2.29	3.30	6.10	7.37	11.68	19.18
14	2.29	3.56	6.73	8.00	12.83	19.30
16	2.54	3.94	7.37	9.02	14.35	21.97
18	2.79	4.19	8.00	9.91	16.00	24.51
20	3.05	4.70	8.51	10.92	17.65	27.05
24	3.56	5.46	9.91	12.95	20.83	32.26

Table D.3c—Austenitic Stainless Steel Minimum Structural Thickness (in.) at 1000 °F (540 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	0.050	0.050	0.050	0.050	0.060	0.085
0.75	0.050	0.050	0.050	0.050	0.060	0.085
1	0.050	0.050	0.065	0.065	0.065	0.100
1.5	0.050	0.050	0.080	0.080	0.085	0.135
2	0.050	0.065	0.085	0.085	0.105	0.165
3	0.080	0.115	0.155	0.155	0.195	0.285
4	0.070	0.110	0.170	0.170	0.210	0.325
6	0.050	0.105	0.180	0.180	0.265	0.425
8	0.055	0.120	0.215	0.215	0.330	0.535
10	0.085	0.130	0.240	0.255	0.395	0.655
12	0.090	0.140	0.255	0.290	0.455	0.750
14	0.100	0.150	0.285	0.315	0.500	0.740
16	0.110	0.165	0.305	0.350	0.555	0.835
18	0.110	0.175	0.325	0.385	0.615	0.930
20	0.130	0.190	0.345	0.420	0.675	1.025
24	0.140	0.225	0.400	0.495	0.800	1.215

Table D.3d—Austenitic Stainless Steel Minimum Structural Thickness (mm) at 1000 °F (540 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	1.27	1.27	1.27	1.27	1.52	2.16
0.75	1.27	1.27	1.27	1.27	1.52	2.16
1	1.27	1.27	1.65	1.65	1.65	2.54
1.5	1.27	1.27	2.03	2.03	2.16	3.43
2	1.27	1.65	2.16	2.16	2.67	4.19
3	2.03	2.92	3.94	3.94	4.95	7.24
4	1.78	2.79	4.32	4.32	5.33	8.26
6	1.27	2.67	4.57	4.57	6.73	10.80
8	1.40	3.05	5.46	5.46	8.38	13.59
10	2.16	3.30	6.10	6.48	10.03	16.64
12	2.29	3.56	6.48	7.37	11.56	19.05
14	2.54	3.81	7.24	8.00	12.70	18.80
16	2.79	4.19	7.75	8.89	14.10	21.21
18	2.79	4.45	8.26	9.78	15.62	23.62
20	3.30	4.83	8.76	10.67	17.15	26.04
24	3.56	5.72	10.16	12.57	20.32	30.86

Table D.4a—1-1/4Cr-1/2Mo Minimum Structural Thickness (in.) at 750 °F (400 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	0.050	0.050	0.050	0.055	0.070	0.100
0.75	0.050	0.050	0.055	0.055	0.075	0.105
1	0.050	0.050	0.075	0.075	0.085	0.125
1.5	0.050	0.050	0.090	0.090	0.110	0.170
2	0.050	0.070	0.100	0.100	0.135	0.205
3	0.085	0.140	0.190	0.190	0.245	0.360
4	0.075	0.140	0.210	0.210	0.280	0.420
6	0.060	0.125	0.220	0.225	0.345	0.565
8	0.070	0.150	0.280	0.280	0.435	0.710
10	0.085	0.165	0.310	0.330	0.525	0.865
12	0.090	0.175	0.330	0.380	0.610	0.995
14	0.100	0.190	0.360	0.415	0.670	1.010
16	0.110	0.210	0.395	0.465	0.755	1.140
18	0.110	0.220	0.420	0.520	0.835	1.275
20	0.130	0.245	0.450	0.570	0.920	1.405
24	0.140	0.285	0.525	0.675	1.095	1.675

Table D.4b—1-1/4Cr-1/2Mo Minimum Structural Thickness (mm) at 750 °F (400 °C)

NPS	Pressure Class					
	150	300	600	900	1500	2500
0.5	1.27	1.27	1.27	1.40	1.78	2.54
0.75	1.27	1.27	1.40	1.40	1.91	2.67
1	1.27	1.27	1.91	1.91	2.16	3.18
1.5	1.27	1.27	2.29	2.29	2.79	4.32
2	1.27	1.78	2.54	2.54	3.43	5.21
3	2.16	3.56	4.83	4.83	6.22	9.14
4	1.91	3.56	5.33	5.33	7.11	10.67
6	1.52	3.18	5.59	5.72	8.76	14.35
8	1.78	3.81	7.11	7.11	11.05	18.03
10	2.16	4.19	7.87	8.38	13.34	21.97
12	2.29	4.45	8.38	9.65	15.49	25.27
14	2.54	4.83	9.14	10.54	17.02	25.65
16	2.79	5.33	10.03	11.81	19.18	28.96
18	2.79	5.59	10.67	13.21	21.21	32.39
20	3.30	6.22	11.43	14.48	23.37	35.69
24	3.56	7.24	13.34	17.15	27.81	42.55

Table D.4c—1-1/4Cr-1/2Mo Minimum Structural Thickness (in.) at 1100 °F (595 °C)

NPS	Pressure Class				
	300	600	900	1500	2500
0.5	—	—	—	—	—
0.75	—	—	—	—	—
1	0.285	—	0.245	0.275	—
1.5	0.250	—	0.225	0.255	—
2	—	—	0.270	0.315	—
3	—	—	—	—	—
4	—	—	0.580	—	—
6	0.465	—	0.465	0.670	1.325
8	0.490	1.005	1.005	1.005	1.460
10	0.470	0.920	0.920	0.920	1.655
12	0.450	0.835	0.835	0.945	1.705
14	0.480	0.925	0.925	1.035	1.300
16	0.495	0.920	0.920	1.095	1.415
18	0.490	0.905	0.905	1.175	1.535
20	0.545	0.895	0.895	1.255	1.655
24	0.580	0.975	0.975	1.430	1.905

Table D.4d—1-1/4Cr-1/2Mo Minimum Structural Thickness (mm) at 1100 °F (595 °C)

NPS	Pressure Class				
	300	600	900	1500	2500
0.5	—	—	—	—	—
0.75	—	—	—	—	—
1	7.24	—	6.22	6.99	—
1.5	6.35	—	5.72	6.48	—
2	—	—	6.86	8.00	—
3	—	—	—	—	—
4	—	—	14.73	—	—
6	11.81	—	11.81	17.02	33.66
8	12.45	25.53	25.53	25.53	37.08
10	11.94	23.37	23.37	23.37	42.04
12	11.43	21.21	21.21	24.00	43.31
14	12.19	23.50	23.50	26.29	33.02
16	12.57	23.37	23.37	27.81	35.94
18	12.45	22.99	22.99	29.85	38.99
20	13.84	22.73	22.73	31.88	42.04
24	14.73	24.77	24.77	36.32	48.39

Bibliography: The following references shall be added, and the remainder of the references shall be renumbered:

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

API Recommended Practice 572, *Inspection Practices for Pressure Vessels*

API Technical Report 593

ASME NM.2, *Glass-Fiber-Reinforced Thermosetting-Resin Piping Systems*

ASME OM, *Operation and Maintenance of Nuclear Power Plants, Part 3—Vibration Testing of Piping System*

Energy Institute, *Guidelines for the Avoidance of Vibration Induced Fatigue Failure in Process Pipework*