Inspectioneering

A Guide to Corrosion Under Insulation Management

In partnership with

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Inspectioneering would like to thank all of those that contributed to the development of this work. For more downloadable resources, visit **inspectioneering.com/+/downloads**.

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Overview

Corrosion under insulation (CUI) is a form of external corrosion that can be widespread or localized, caused by trapped water/moisture on surfaces covered with insulation. Because these surfaces are not generally available/accessible for visual examination, the onset of corrosion cannot be easily identified, and in extreme cases, severe corrosion with consequential impairment of system integrity can occur. Furthermore, CUI is a prevalent industry problem affecting thermally insulated equipment in the onshore and offshore oil and gas industries, as well as the petrochemical, specialty chemical, fertilizer, and related industries.

In general, external thermal insulation is a necessity in process design for any or a combination of the following reasons [1]:

- Heat conservation (operating temperatures generally >200˚F (93˚C))
- Cold conservation (refrigeration/cryogenic systems usually <40˚F (10˚C)
- Personnel protection (usually >140˚F (60˚C))
- Freeze protection (e.g., heat tracing)
- Condensation control
- Acoustic (noise) reduction
- Fire protection
- Process control

Additionally, passive fireproofing can lead to corrosion under fireproofing (CUF). Fireproofing is commonly used on structural steel (most often carbon steel) to minimize the impact of high temperatures (e.g., changes in microstructure and subsequent loss of strength) generated during a fire. These extreme temperatures can damage structural supports for pressure vessels (i.e., support skirts) or piping systems (I-beams). Despite their different applications, CUI and CUF are similar degradation mechanisms in that corrosion of the carbon or low-alloy steel substrate may occur when water accumulates at the underlying steel surface. CUF is typically considered to be analogous to CUI in terms of damage mechanism classification and damage morphology. It is noted that External Chloride Stress Corrosion Cracking (ECSCC) is a surface-initiated cracking mechanism in austenitic and duplex stainless steels and some nickel base alloys under the combined action of tensile stress, temperature, and an aqueous chloride environment. ECSCC is often considered to be a special form of CUI where the damage morphology and failure modes differ from common CUI and CUF and involve the initiation and propagation of crack-like flaws.

This short primer is designed to provide the reader with a better understanding of what CUI is and how to effectively manage it. This primer begins with a brief explanation of what causes CUI and how it develops, followed by a discussion on the detection of CUI, including typical damage locations and common inspection techniques. This primer will also discuss useful engineering assessment techniques for evaluating CUI damage and offer practical guidance for qualifying CUI damage on carbon and low-alloy steels using fitness-for-service techniques. Finally, practical steps that can be taken to mitigate CUI damage for new component designs and in-service pressure equipment are outlined.

Description of CUI Chemical Reaction

Water or moisture must be present on the steel substrate to allow oxygen corrosion to occur. Water ingress usually occurs due to breaks in insulation jacketing, which generally results from either poor initial installation, damage during service, or deterioration of the insulation system over time. Furthermore, the source of water is usually rainwater, deluge systems, spillage from process operations, leaking steam tracing, or condensation on the metal surface in humid environments. Depending on the absorption properties of the thermal insulation and the operating temperature of the insulated component, water may be retained. In certain cases (if process conditions permit), saturated insulation may never be able to fully dry out. In general, CUI can be classified into one of four categories [2]:

- Low temperature (low temperature or cryogenic service)
- Sweating service (below dew point)
- High temperature
- Cyclic temperature

Figure 1 shows a schematic of the electrochemical reaction of typical CUI. This figure assumes the absence or breakdown of any protective coating on the external surface. Additionally, this reaction requires the presence of four elements: an anode, cathode, electrolyte, and electrical circuit or path.

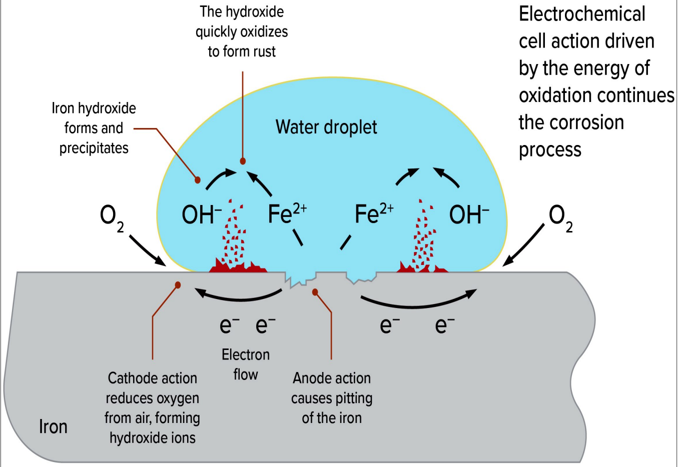


Figure 1. Schematic of CUI Electrochemical Reaction for Carbon Steel [2].

In its simplest form, the electrolyte is oxygenated water, which may contain contaminants that can accelerate the corrosion rate. ***Figure 2*** shows a practical application of the CUI electrochemical reaction on a thermally insulated pipe or pressure vessel. In this figure, after water penetrates the insulation, it is either absorbed or trapped. Once the water contacts the hot steel surface, it evaporates. Then, the evaporated water vapor moves through the insulation towards the colder external barrier or jacket where condensation occurs. This condensed water then migrates back through the insulation towards the hot metal surface, and the process repeats itself. Additionally, contaminants can end up being concentrated on the steel surface due to the cyclic nature of the evaporation and condensation process. These contaminants can degrade external coatings on the steel and eventually, CUI damage occurs. This cycle can also result in damaged insulation which may reduce the effectiveness of the insulation system. Intuitively, insulation systems that hold the least amount of water and that dry out the fastest are generally the most resistant to CUI damage. The integrity of the insulation jacketing and an intact external coating on the steel surface are also crucial factors that influence CUI susceptibility.

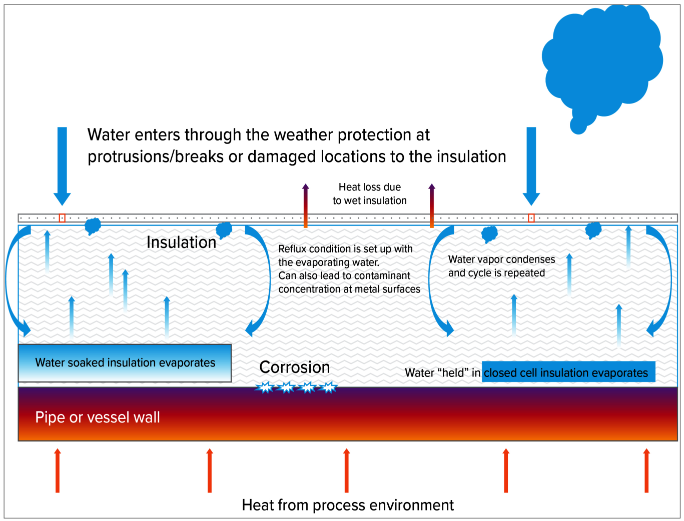


Figure 2. Schematic of CUI Mechanism Beneath Hot Thermal Insulation [2].

CUI Damage Morphology

CUI affecting carbon and low-alloy steels generally takes the form of localized corrosion or pitting, although damage can be widespread in severe cases. CUI on these steels is a form of oxygen corrosion (as described above) and occurs when exposed to moisture and oxygen. Damage occurs when water is absorbed by or collected beneath the insulation and the moisture contacts the underlying exposed steel at operating metal temperatures between 10°F (–12°C) and 350°F (175°C) for carbon and low-alloy steels [3,4]. Furthermore, after insulation is removed, CUI damage often appears as a loose, flaky scale covering the corroded component (as shown in ***Figure 3***). In some cases, the corrosion can appear to be carbuncle type pitting, typically found under a failed external paint or coating system (see ***Figure 4***). Often pin-hole leaks can result from localized CUI, and in severe cases, structural stability and/or pressure capacity can be compromised (that is, can lead to plastic collapse). In general, corrosion rates are exacerbated with increasing metal temperature, up to the point where the water evaporates quickly. For insulated components, corrosion can become more severe at metal temperatures between the boiling point 212°F (100°C) and 350°F (175°C), where water is less likely to vaporize, and insulation stays wet [3,4]. Furthermore, the extent and rate of wall loss in pressure equipment due to CUI is dependent on the following factors [5]:

- Wet exposure cycle characteristics (duration and frequency)
- Corrosivity of the aqueous environment
- Failure of protective barriers (such as paint or insulation jacketing)

Numerous controllable variables influence the above listed factors and overall susceptibility to in-service CUI, including design details, insulation and external coating selection, operating conditions, construction procedures, and maintenance/inspection practices.

Figure 3. Close-up of CUI (Localized Corrosion) of a Piping Tee after Insulation Removal [3].

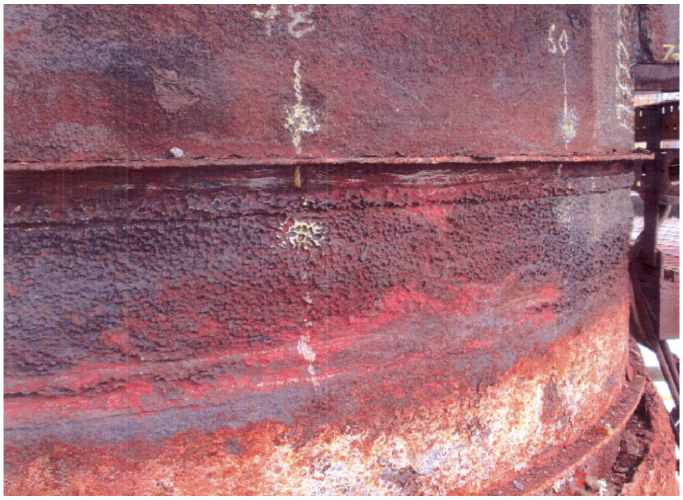


Figure 4. Widespread CUI Near an Insulation Ring on a Vertical Carbon Steel Pressure Vessel.

For austenitic and duplex stainless steel components subject to ECSCC, the damage morphology is usually characterized by surface cracks that have many branches and may be visually detectable by a craze-cracked appearance of the surface [3,4]. These cracks can propagate in service and can lead to leaks, ductile tearing, or fracture. An example of ECSCC is shown in ***Figure 5*** on page 7. Additionally, the material usually shows no visible signs of corrosion. ECSCC occurs under the combined action of tensile stress (often driven by weld residual stress), temperature, and an aqueous chloride environment. In general, the presence of dissolved oxygen increases the propensity for cracking, and operating temperatures between 140°F (60°C) and 400°F (205°C) are most concerning. Austenitic (e.g., 300 series) stainless steels are generally most prone to ECSCC. Duplex stainless steels are typically more resistant, and nickel base alloys are typically highly resistant, but not strictly immune. Nickel content of the alloy has a notable effect on overall resistance. The greatest susceptibility is at a nickel content of 8% to 12%. Alloys with nickel contents above 35% are highly resistant and alloys above 45% are nearly invulnerable. Carbon steels, low alloy steels, and 400 Series stainless steels are not susceptible to ECSCC [3,4].

Expert Tip

Crack growth rates due to ECSCC can be unpredictable and difficult to estimate due to notable scatter in available test data. For this reason, once ECSCC damage is identified, it should be remediated, or the equipment inspection plan should be modified accordingly to routinely check for any significant crack propagation. Additionally, ECSCC can initially appear as separate surface-breaking crack-like flaws, but over time, these isolated flaws can grow and link-up to form larger cracks that could detrimentally affect the load carrying capacity of a stainless steel component.

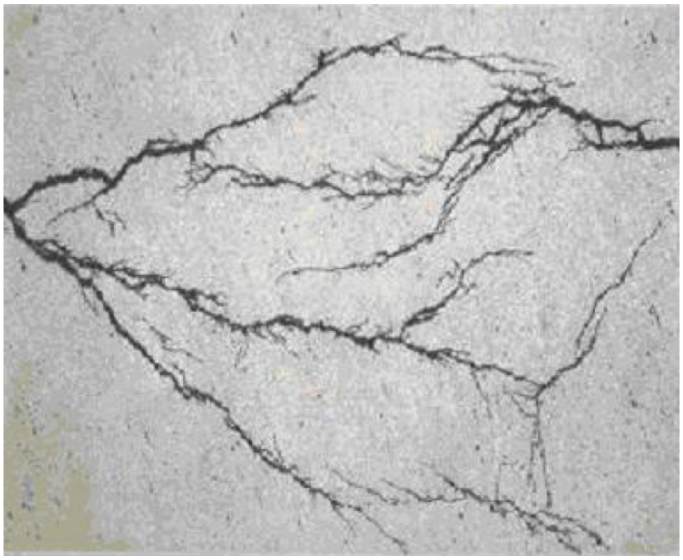


Figure 5. Photomicrograph Showing Fine Branching Cracks Associated with Chloride Stress Corrosion Cracking. (Unetched, 50X Magnification) [3,4].

Locations Prone to CUI Damage

Equipment and structures susceptible to CUI include pressure vessels, piping systems and associated components (e.g., tees, reducers, flanges, and valves), storage tanks, structural support members, pipelines, and instrumentation. Furthermore, CUI has led to many leaks and failures of in-service pressure equipment that have resulted in noteworthy process safety, health, and environmental incidents. Additionally, the worldwide economic impact of CUI is significant due to lost production and the costs associated with CUI mitigation, repair, and replacement of damaged equipment [2]. To this end, all insulated components are susceptible to CUI under the appropriate conditions, even on piping and pressure equipment where the insulation system appears to be in good working condition and no visual signs of corrosion are present. Examples of common locations and equipment prone to CUI include [1-6]:

1. Any equipment with damaged insulation, vapor barriers, external jacketing (weatherproofing), or mastic
2. Areas of protrusions (transition points) through external insulation jacketing at manways, nozzles, lifting lugs, platform clips, brackets, or supports, gussets, stiffening rings, and other components (this includes equipment operating at or below ambient temperatures or in cold/cryogenic service)

3. Insulation jacketing seams located on the top of horizontal piping runs or any regions near improperly lapped or sealed insulation jacketing
4. Areas downwind of cooling towers or any areas exposed to cooling tower mist
5. Regions where caulking is missing, hardened, or separated on external insulation jacketing
6. Areas where the external insulation jacketing system is visibly bulged or stained (this may indicate corrosion product buildup)
7. Areas where banding on external insulation jacketing is missing or damaged
8. Areas where mechanical of flow-induced vibration has caused damage to the external insulation jacketing
9. Regions on equipment exposed to steam vents
10. Areas exposed to process spills, the ingress of moisture, or acid vapors
11. Any region that may be exposed to deluge systems
12. Areas insulated solely for personnel protection
13. Areas under the insulation with visibly deteriorated coatings or wraps
14. Any areas with leaking steam tracing
15. Pipe and flanges on pressure safety valves
16. Systems that operate intermittently above 250°F (120°C)
17. Systems operating below the atmospheric dew point
18. Systems that cycle through the atmospheric dew point
19. Ice-to-air interfaces on insulated systems that continually freeze and thaw
20. Insulation termination points on vessels or piping such as flanged joints
21. Equipment designed with insulation support rings welded directly to the vessel wall (no standoff), particularly around ladder and platform clips, lifting lugs, nozzles, and stiffening rings
22. Piping or equipment with damaged/leaking steam tracing and areas near steam tracer tubing penetrations
23. Localized damage at paint and/or external coating systems
24. Locations where moisture/water will naturally collect (gravity drainage) before evaporating (insulation support rings on vertical equipment) and improperly terminated fireproofing
25. Piping system deadlegs (vents, drains, and other similar items)
26. Pipe hangers and other piping supports
27. Termination points of insulation in a vertical section of piping
28. The first few feet of a horizontal pipe run adjacent to the bottom of a vertical run
29. Bolted-on pipe shoes
30. Low points in piping systems that have a known breach in the insulation system, including low points in long unsupported piping spans
31. Insulation support rings below damaged or inadequately caulked insulation on vertical heads
32. Insulated zone at support skirt-to-shell transition regions
33. Insulated leg supports on relatively small vessels
34. Fireproofed support skirts (CUF)
35. Anchor bolts covered by fireproofing (CUF)
36. Bottom of horizontal vessels (i.e., lower third to half of vessel)
37. Irregular shapes that result in complex insulation installations (e.g., davit arm supports, lifting lugs, body flanges, etc.)
38. Carbon or low-alloy steel flanges, bolting, and other components under insulation in high-alloy piping systems
39. Locations where insulation plugs are missing or have been removed to permit piping thickness measurements on insulated piping and equipment
40. Valves and fittings with irregular insulation surfaces

General Inspection Considerations

An appropriate inspection plan is essential for all equipment subject to CUI damage. Visual inspection for CUI requires insulation removal; however, targeted regions most susceptible to damage can be examined first to potentially minimize the extent of insulation removal. Ultrasonic testing (UT) thickness readings are often crucial to accurately quantify CUI wall loss in carbon and low-alloy steels [7]. Automated UT (AUT), which commonly employs powered, mechanical scanners, is often used to evaluate more widespread pressure boundary CUI damage, where thickness grids (i.e., tabular thickness readings in a spreadsheet or point-cloud) can be developed for efficient use as an input in fitness-for-service (FFS) assessments. While laser scanning techniques can sometimes be used to obtain thickness profiles, careful consideration regarding the margin of error associated with data acquisition is crucial. Furthermore, any FFS assessment should account for this margin of error, and sensitivity to measured thickness should be well-understood [8]. Radiography/x-ray (RT) techniques can be used to obtain digital or real-time wall loss profiles in components like small-bore piping [9]. Additionally, other methods such as neutron backscatter can be used to detect wet insulation, and guided-wave ultrasonics or pulsed eddy-current can also be utilized to detect CUI damage/corrosion, although accurate characterization of localized damage may not be possible with these approaches. Lastly, liquid penetrant surface examination (PT) is often the most effective methodology to identify ECSCC in austenitic and duplex stainless steels [10].

Two general schematics that show commonly recommended locations to inspect for CUI damage are shown in ***Figure 6*** and ***Figure 7*** on page 10 for piping systems and pressure vessels, respectively. Prioritized inspection at these locations reflects a practical means of managing the risk associated with CUI damage and possible failure, including pin-hole leaks. Generally, the consequence of a pin-hole leak should be considered, especially when inspection reveals localized wall thicknesses below 0.100 inches (a typical structural minimum thickness used in FFS assessments) [10]. Ultimately, any thickness readings below minimum design (Code-required) thickness requires qualification via an engineering/FFS assessment, proper repair, or replacement.

Expert Tip

Commonly, external weld build-up/overlay is a repair method utilized to restore component thickness following CUI damage. For widespread CUI, the amount of weld metal and heat input in a specific region during a repair procedure should be carefully considered and monitored. Too much heat input during weld build-up has been known to cause permanent distortion in the pressure boundary of vessels, tanks, and piping. Subsequently, this distortion may then necessitate FFS assessments or costly additional repairs. In some cases, it may be more practical/preferred to repair large areas of CUI using a flush patch (butt-welded insert plate), which may require less welding. Regardless of the method, all CUI repairs need to be properly engineered and executed.

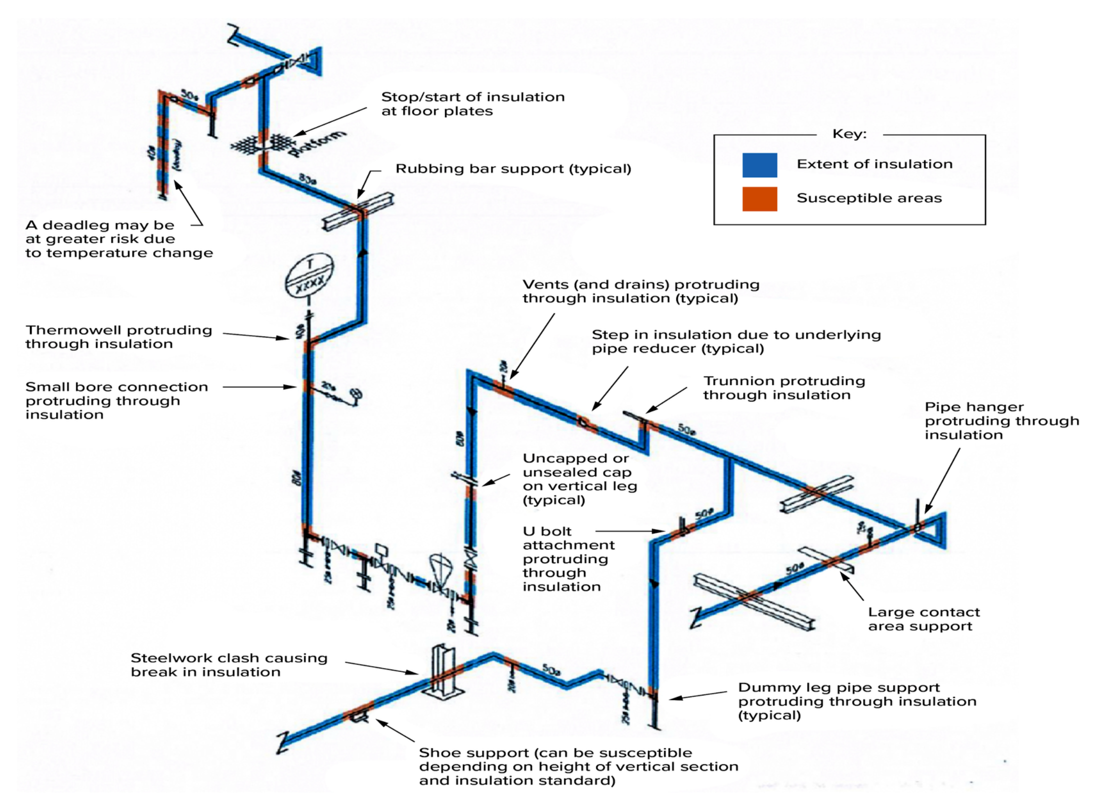


Figure 6. Susceptible Areas for Targeted CUI Inspection on Piping Systems [11].

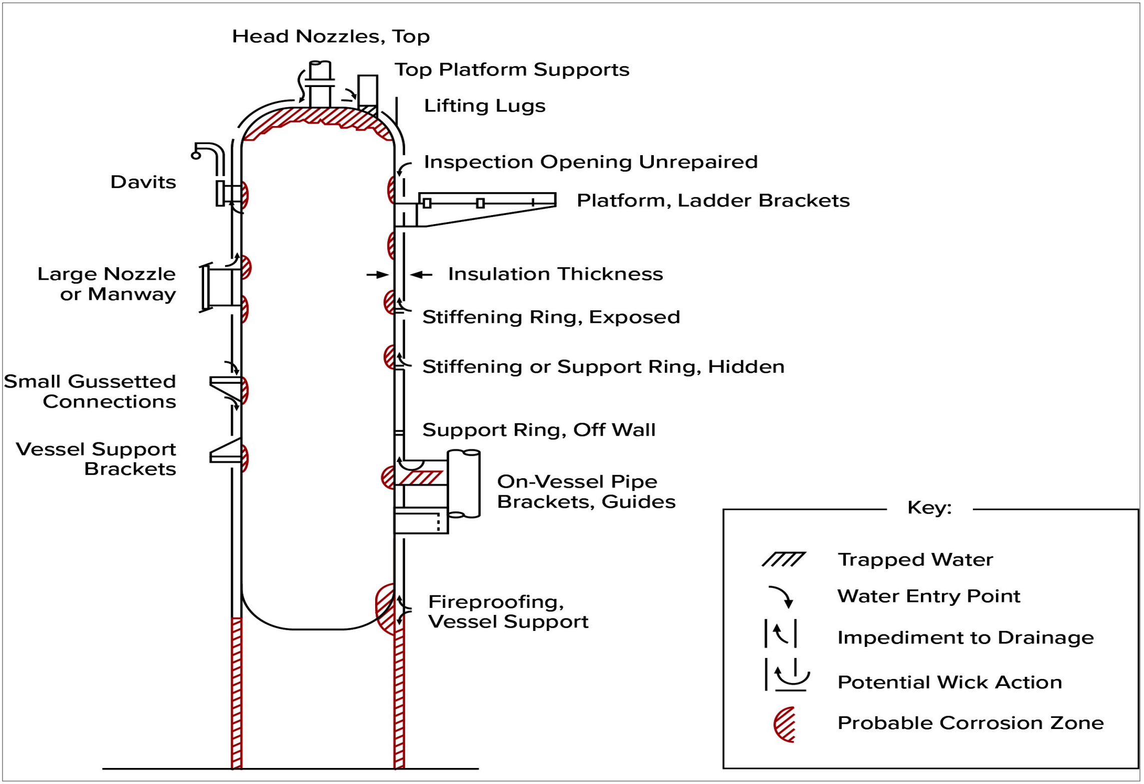


Figure 7. Susceptible Areas for Targeted CUI Inspection on Pressure Vessels [11].

FFS Assessment Methods for CUI

Knowing where to prioritize inspection for CUI on pressure vessels, piping components, and structural members is crucial, but once damage is identified, it is often necessary to qualify observed corrosion using fitness-for-service (FFS) techniques such as those outlined in API 579-1/ASME FFS-1, Fitness-For-Service (API 579). Employing FFS methods is often more economical and can offer an expeditious solution relative to implementing repairs or replacing damaged equipment. When evaluating external corrosion on carbon or low alloy pressure equipment, the following parts of API 579 can be utilized [8]:

- **Part 4:** *Assessment of General Metal Loss*
- **Part 5:** *Assessment of Local Metal Loss*

The assessment methods described in these parts are intended to qualify damaged equipment for protection against plastic collapse; that is, to evaluate the loss of strength (load or pressure carrying capability) due to progressive wall loss, such that loss of containment or gross deformations/plasticity do not occur due to internal/external pressure loading or supplemental loads, such as dead weight or wind/seismic loading (especially important for large vertical columns or towers). Protection against local failure and buckling also needs to be considered in certain cases. It is important to note that for regions of very localized pressure boundary corrosion, as is often the case for CUI damage, small pinhole leaks can occur prior to the onset of gross plastic collapse (see ***Figure 8***). For this reason, it is imperative to understand minimum measured thicknesses associated with localized CUI damage and evaluate the risk of a leak, even if the observed damage can be qualified for protection against plastic collapse via an engineering/FFS assessment.

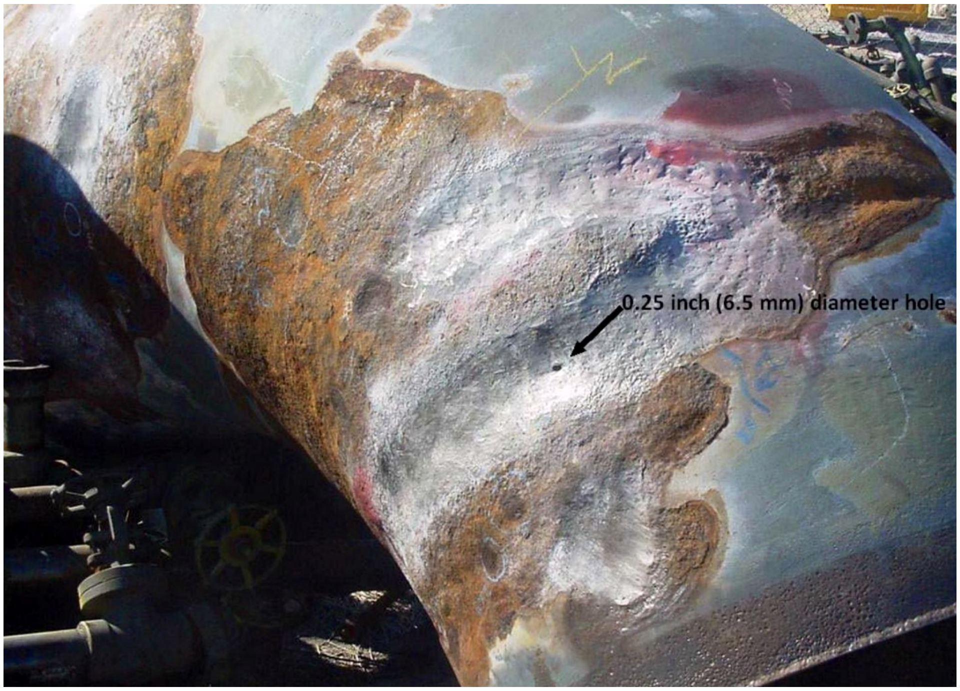


Figure 8. Example of a Small Diameter Hole (Pinhole Leak) in a Carbon Steel Pipe Due to CUI [4].

Level 1 and Level 2 FFS Procedures

The API 579 general metal loss (GML) assessment procedures in Part 4 are based on a thickness averaging approach and can be applied to both uniform and non-uniform corrosion [8]. If local areas of metal loss are found in the component, the thickness averaging approach may produce overly conservative results. Furthermore, the assessment procedures in Part 5, that are based on determining critical thickness profiles (CTPs) and remaining strength factors (RSFs), can be utilized to reduce the conservatism of a Part 4 analysis [13,14]. The exact distinction between uniform and local metal loss cannot be discerned without knowing specific characteristics of the metal loss profile. In most cases, it is recommended to first perform a GML assessment using Part 4. The assessment procedures of Part 5 can qualify local thin areas (LTAs) and can only be utilized in conjunction with detailed thickness profiles because the extent (dimensions) of the region of metal loss, as well as thickness data, are required to carry out the assessment [8]. Furthermore, API 579 defines an LTA as local metal loss on the surface of the component where the length of a region of metal loss is the same order of magnitude as the width [8].

The API 579 Level 1 and Level 2 assessment procedures of both Part 4 and Part 5 employ closed-form solutions to determine acceptability of identified damage [8]. The following limitations and guidelines should be considered for Level 1 and Level 2 calculations:

- The original equipment design must be in accordance with a recognized Code or Standard.
- The component cannot operate in the creep range (see Table 4.1 in API 579[8] for temperature limits).
- The region of metal loss must have relatively smooth contours without notches (i.e., no significant stress concentrations).
- The component is not in cyclic service (i.e., less than 150 total cycles) - more detailed fatigue screening criteria is provided in Part 14.
- The material must have sufficient fracture toughness. If there is uncertainty regarding material toughness or the potential for in-service embrittlement, a Part 3, Level 3 brittle fracture screening evaluation should be completed.
- The component under evaluation cannot contain crack-like flaws. If so, a fracture mechanics assessment per Part 9 is required.
- Special provisions are provided for groove-like flaws, and damage associated with pitting, blisters, and gouges may be evaluated using Part 5 in conjunction with Part 6, Part 7, and Part 12, respectively.

Additionally, to use the Level 1 and Level 2 techniques, the minimum spacing between the region of metal loss and a major structural discontinuity (L_{msd}) shall be as follows:

$$L_{msd} \geq 1.8\sqrt{Dt_c}$$

...where D denotes the inside diameter of the cylindrical vessel and t_c denotes the corroded wall thickness away from the region of local metal loss. If this spacing criterion is not met, a Level 3 assessment is required.

Major structural discontinuities such as stiffening ring-to-shell junctions, support skirt-to-shell junctions, or other pressure boundary attachment locations introduce increased local bending stresses. An example of an LTA near a variety of structural discontinuities on vertical pressure vessels (e.g., columns/towers) is shown in ***Figure 9*** on page 13 for both Part 4 and Part 5. One distinction is that Level 1 and 2 GML procedures per Part 4 can be used near nozzles or conical shell junctions, assuming area replacement requirements are satisfied, whereas LTA procedures per Part 5 cannot be used (that is, a Level 3 assessment is obligatory). For horizontal vessels, the saddle supports constitute a major structural discontinuity and for a spherical storage vessel, the support locations (e.g., shell-to-leg junctions) constitute a major structural discontinuity. Furthermore, for the scenarios depicted in ***Figure 9***, L_{msd} would be taken as the minimum of L^1_{msd}, L^2_{msd}, L^3_{msd}, and L^4_{msd}.

Stiffening/Insulation Ring Classification

The following closed-form methodology can be used to determine if a stiffening or insulation ring attached to the pressure boundary of a vessel should be classified as a major structural discontinuity, thus requiring a Level 3 assessment if damage is within the calculated minimum spacing criteria [15]. A stiffening ring is to be considered as a major structural discontinuity when:

$$\frac{A_R}{A_R + 1.56t\sqrt{Rt}} > 0.38$$

...where A_R represents the cross-sectional area of the stiffening ring in question, R is the inside radius of the vessel, and t is the nominal shell thickness.

The technical basis for this formulation is derived by setting 110 percent of the hoop stress equal to the longitudinal stress on the inside surface of the vessel near the stiffening ring. Additionally, based on this prescribed condition, if the cross-sectional area of a stiffening ring is small enough relative to the vessel, an LTA would not have to be located L_{msd} away from the ring

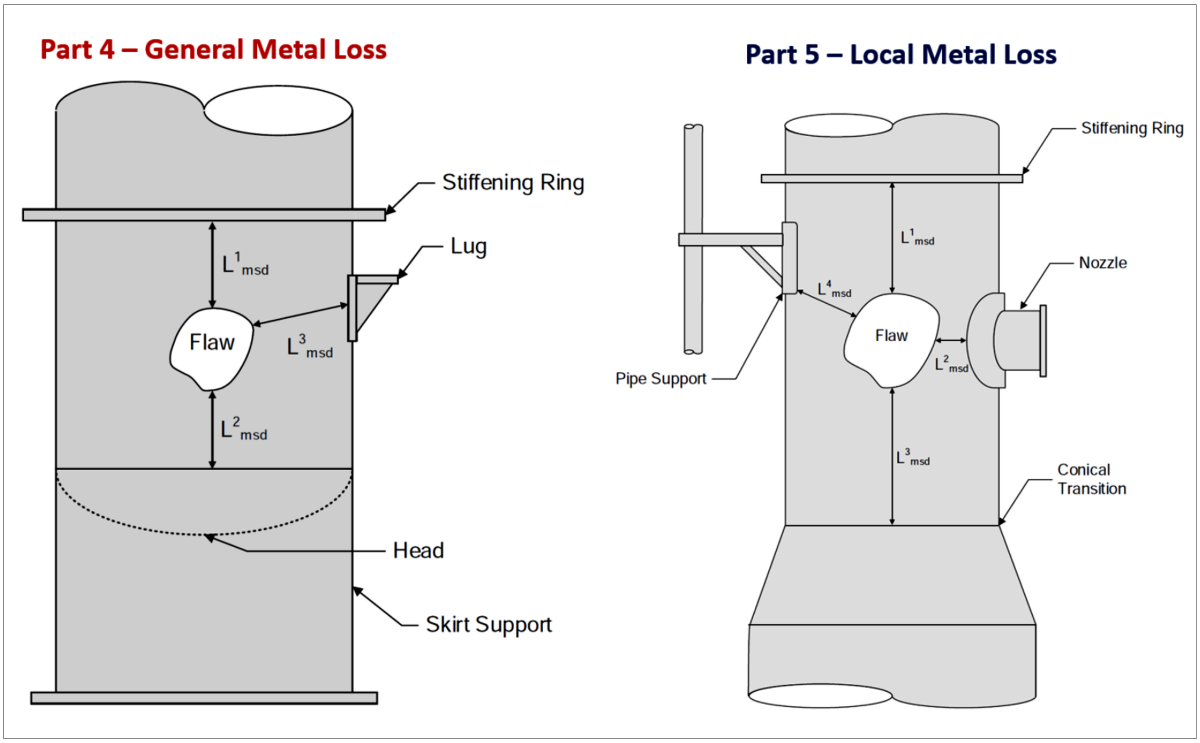


Figure 9. Structural Discontinuity Spacing Requirements for API 579 Part 4/Part 5, Level 1/Level 2 Assessment Procedures [8].

to perform a Level 1 or Level 2 assessment. Leveraging this technically based formulation can be advantageous in that it would potentially eliminate the need for more complex Level 3 assessments and finite element analysis (FEA) for CUI damage near relatively flexible stiffening or insulation rings [15].

Level 3 FFS Procedures

Because CUI damage very often occurs near structural attachments, stiffening/insulation rings, and other major structural discontinuities where moisture tends to accumulate, a Level 3 FFS assessment is often needed to qualify observed corrosion. A Level 3 assessment generally involves the use of advanced stress analysis (e.g., FEA) to model the region of wall loss and to simulate all appropriate loading conditions (load case combinations). In general, some of the advantages of a Level 3 assessment include the following:

- Same procedures and acceptance criteria for Part 4 and Part 5
- No limitations on component geometry
- No limitations on loading conditions
- Required for complex loading (fatigue, buckling, high-temperature creep)
- Most accurate and least conservative method for determining the acceptability for continued operation

Specifically, for vertical columns, it is important to consider supplemental loads beyond internal/external pressure, such as dead weight, wind, and even seismic loading that can potentially cause compressive stresses to govern, which could ultimately lead to buckling. Additionally, for horizontal pressure vessels, mid-span bending stresses due to dead weight and liquid fill can also be significant. These loads can be accounted for directly in the FEA. Annex 2D of API 579 provides guidance on stress analysis procedures, load case combinations (see Tables 2D.1 through 2D.4), and design margins (see Table 2D.5) for demonstrating protection against plastic collapse, local failure, and buckling that are generally consistent with ASME Section VIII Division 2 (ASME VIII-2) [8,16]. All these failure modes may have to be considered when evaluating CUI damage, depending on the equipment geometry and loading scenarios.

When evaluating protection against plastic collapse, three different methods are available to analysts as follows (see ASME VIII-2 for more information) [16,17]:

- **Elastic Stress Analysis Method** – Stresses are computed using an elastic analysis, classified into categories, and limited to allowable values that have been conservatively established such that a plastic collapse will not occur [18-20].
- **Limit-Load Method** – A calculation based on small-displacement theory is performed to determine a lower bound to the limit load of a component. The allowable load on the component is established by applying design factors to the limit load such that the onset of gross plastic deformations (i.e., plastic collapse) will not occur.
- **Elastic-Plastic Stress Analysis Method** – A collapse load is derived from an elastic-plastic analysis considering both the applied loading and deformation characteristics of the component (i.e., nonlinear geometric effects). The allowable load on the component is established by applying design factors to the plastic collapse load.

For limit load and elastic-plastic simulations, acceptability is determined when the numerical FEA model achieves convergence (i.e., an equilibrium solution is attained) at the appropriate maximum factored load cases. Contrarily, plastic collapse occurs when the numerical solution starts to diverge (displacements become large/unbounded and an equilibrium solution cannot be obtained).

Expert Tip

Elastic stress analysis is typically the most conservative method when evaluating CUI damage. Limit load and elastic-plastic methods are often preferred because stress classification/linearization is not required, and simulations can simply be run to non-convergence. Additionally, limit load and elastic-plastic analysis account for the overall stiffening effect of major structural discontinuities. For instance, for CUI damage near a nozzle or stiffening ring, the structural discontinuity will often increase the pressure capacity, although local stresses may still be elevated at such a location. In general, this concept holds true for buckling analysis as well.

Local failure is considered to reflect a fracture or cracking damage mechanism, where local corrosion could result in elevated local strains such that failure due to crack-like flaw initiation/propagation could occur. When evaluating protection against local failure, either elastic or elastic-plastic methods can be used. The elastic and elastic-plastic procedures employ a triaxial stress limit and a local strain limit, respectively. Additionally, for buckling, the following three analysis options are available to analysts (see ASME VIII-2 for more information on design/capacity reduction factors) [16]:

- **Type 1 Buckling Method** – Elastic bifurcation (Eigenvalue) buckling analysis without geometric nonlinearities in the solution to determine the pre-stress in the component. The buckling load is determined after the application of geometric and load-specific capacity reduction factors.
- **Type 2 Buckling Method** – Elastic-plastic bifurcation buckling analysis with geometric nonlinearities in the solution to determine the pre-stress in the component. Again, the buckling load is determined using geometric and load-specific capacity reduction factors.
- **Type 3 Buckling Method** – Elastic-plastic collapse analysis where imperfections are explicitly considered in the analysis model geometry, and the design factor is accounted for in the factored load combinations.

Practical experience suggests that very seldom does the local failure criteria govern for typical CUI damage. In fact, generally, local failure does not tend to govern common design by analysis or FFS scenarios for pressure equipment. Additionally, failure due to buckling usually governs for damage on the lower regions of relatively tall vertical columns, where elevated longitudinal compressive stresses can occur from weight, wind, and seismic loads, or for situations where full vacuum (external pressure) is a viable load case. Failure due to plastic collapse, driven by tensile loading such as internal pressure, governs the rest of the cases where Level 3 assessment methods are used to evaluate CUI damage. Lastly, original weld joint efficiency may have to be accounted for (if less than 1.0) when evaluating the propensity for plastic collapse if the damaged region is near a weld. This can be accomplished by artificially increasing the applied loads to account for potential original weld defects.

Level 3 CUI Evaluation Example

Before any advanced analysis can be performed, it is crucial to make sure all inspection data is valid (e.g., regions of CUI usually need to be cleaned/blasted prior to inspection), the margin of error is known, inspection reports are complete, and the location/orientation of each thickness grid (i.e., set of wall thickness measurements) is easily identifiable. Specifically, dimensions of each thickness grid and distances in the circumferential and longitudinal directions relative to defined and easily identifiable points on fabrication drawings of the vessel, such as nozzles or attachments, are recommended to properly carry out a Level 3 assessment. Furthermore, a sketch or roll-out drawing of the vessel or component is usually helpful. An example of such a sketch is provided in ***Figure 10***, where several different thickness grids are identified on the upper region of a vertical column. This suggestion is intended to ensure the FEA model accurately mimics the location and extent of the actual damage. Additionally, to capture minimum thickness values associated with CUI damage, relatively high-resolution inspection grids are often required (e.g., usually 1-inch by 1-inch grids or even more refined). This may necessitate the use of automated ultrasonic testing (AUT) methods, where thickness readings are acquired from the inside surface of the vessel or component, if possible. To this end, it is also key to confirm that the thickness grid captures all regions of metal loss; that is, the inspection/thickness grid is terminated when approximately nominal thickness (i.e., undamaged material) is observed.

There are several different techniques that can be employed when translating inspection data (e.g., UT thickness readings) onto an FEA model. It is generally conservative to delineate or partition larger regions of the model and assign minimum measured thickness values to entire blocked-out areas, possibly to represent an entire thickness grid. An example of this is shown in ***Figure 11*** on page 17 for three of the inspection/thickness grids depicted in ***Figure 10***. The raw inspection data from each grid is shown in spreadsheet format with color contours applied to the measured magnitudes. Additionally, the minimum overall thickness is identified for each grid.

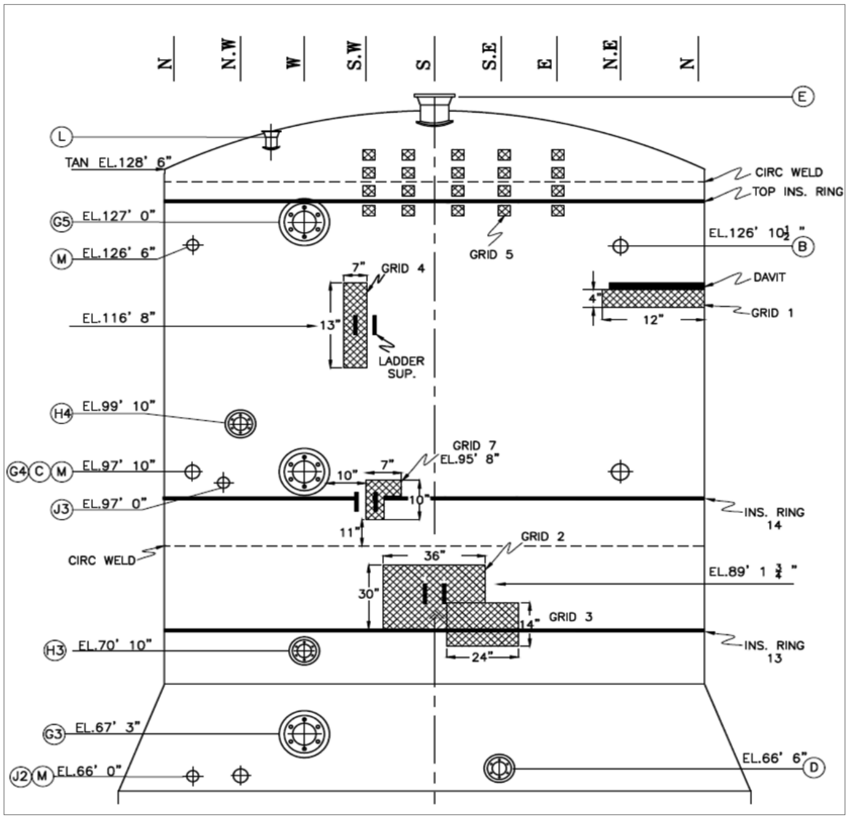


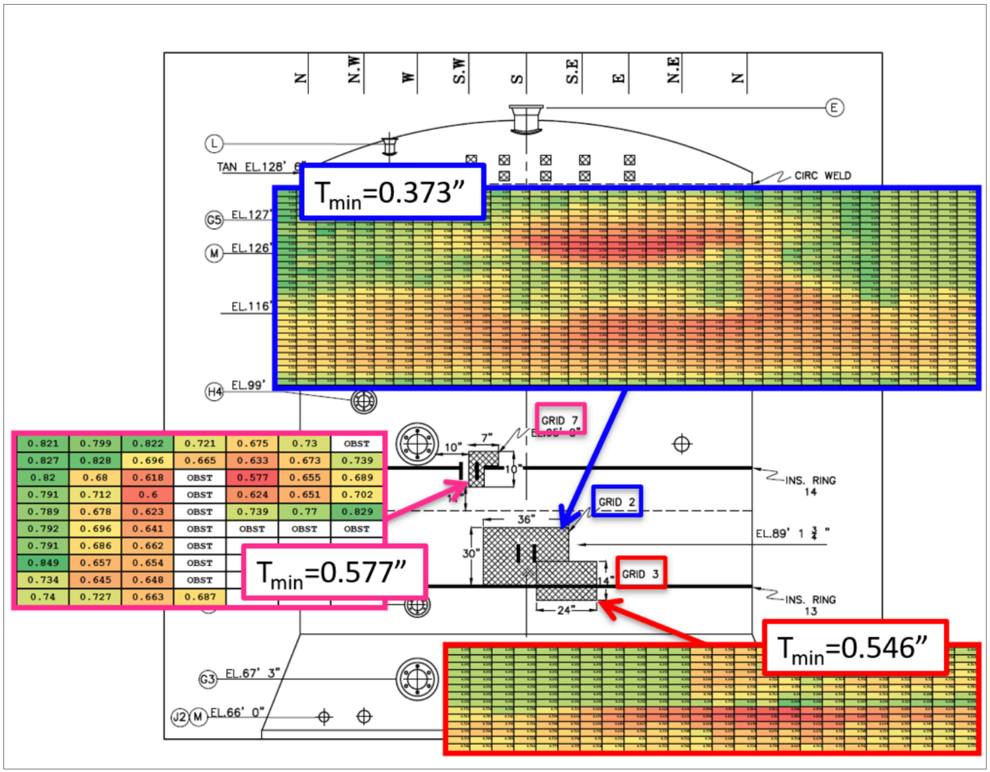
Figure 10. Example of Roll-Out Sketch Showing Thickness Grid Locations on a Vertical Vessel.

Expert Tip

If possible, it is often beneficial for the engineer performing the FFS assessment to communicate and interface directly with the inspector acquiring thickness data in the field. Specifically, thickness reading resolution, desired data format, and an accurate roll-out map of thickness grid locations, are crucial variables and pieces of information. Ensuring engineering and inspection personnel are aligned on required data can save time when performing expedited engineering analysis and FFS assessments.

Figure 12 on page 18 shows these same three grids from ***Figure 11*** conservatively mapped onto the three-dimensional FEA model, where the minimum measured thickness reading is applied to a partitioned region representing the entirety of each grid. In this case, shell elements are used, where the pressure boundary is modeled at the mid-plane and thickness is defined for a given element set. The assigned thickness also accounts for internal/external future corrosion allowance (FCA). The contour scale (STH) shown in ***Figure 12*** represents the wall thickness in inches. Additionally, all major structural discontinuities (e.g., nozzles, stiffening/insulation rings, external/internal attachments, etc.) are included in the model. Structural attachments like this generally stiffen the pressure boundary and offer some benefit for protection against plastic collapse or buckling in a Level 3 FFS assessment [15]. This particular Level 3 assessment resulted in satisfying requirements (i.e., achieving convergence at factored loads) for plastic collapse, local failure, and buckling. For the sake of brevity, these results are not presented herein.

An alternative approach is to map individual point thickness readings directly onto the pressure boundary of the FEA model (constructed with shell elements). Generally, this requires the use of specialized user



0.821	0.799	0.822	0.721	0.675	0.73	OBST
0.827	0.828	0.696	0.665	0.633	0.673	0.739
0.82	0.68	0.618	OBST	0.577	0.655	0.689
0.791	0.712	0.6	OBST	0.624	0.651	0.702
0.789	0.678	0.623	OBST	0.739	0.77	0.829
0.792	0.696	0.641	OBST	OBST	OBST	OBST
0.791	0.686	0.662	OBST			
0.849	0.657	0.654	OBST			
0.734	0.645	0.648	OBST			
0.74	0.727	0.663	0.687			

Figure 11. Contoured Inspection Data and Minimum Measured Thickness Values for Grids 2, 3, and 7.

subroutines, but it can remove the conservatism associated with applying minimum thickness values to larger partitioned regions of the FEA model as shown in ***Figure 12***. This more complex approach is commonly reserved for situations where more conservative thickness definitions, like ***Figure 12***, do not satisfy protection against plastic collapse or buckling, or where significant variability in local thickness readings are observed (e.g., where corrosion resembles sporadic pitting damage). While this approach may require more inspection data processing and manipulation, it can successfully qualify severe localized CUI damage because credit is taken for adjacent material that is still intact.

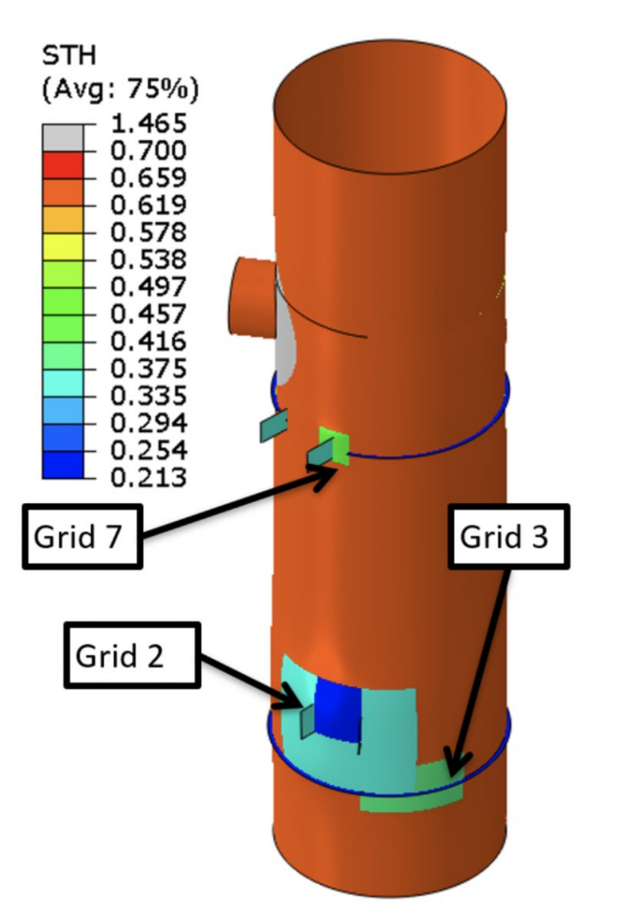


Figure 12. Thickness Contours (inches) for the FEA Model with Grids 2, 3, and 7 Conservatively Mapped (Accounting for FCA).

Practical Considerations and Remaining Life

As previously elucidated, pinhole leaks are often a realistic concern with extensive localized CUI damage. For this reason, adhering to structural minimum thickness values is often recommended, even for cases where a Level 3 assessment can qualify highly localized and severe CUI damage. For Level 1 and Level 2 assessments, API 579 specifies 0.10 inches and 0.05 inches as structural minimum thickness values for pressure vessels/tanks and piping components, respectively [8]. Even if a Level 3 assessment can qualify wall thickness below these values, it is important to understand the risk for pinhole leaks going forward, if small leaks can be readily detectable, and if any loss of containment can even be tolerated given the process conditions.

Lastly, it is also important to consider an FCA in any CUI damage related FFS assessment. Additionally, the above minimum structural thickness thresholds should consider current minimum measured values, plus any internal/external FCA. Understanding likely future corrosion rates can not only help establish meaningful inspection intervals, but it can also guide FFS assessments such that appropriate minimum thickness values are evaluated. Remediating and mitigating CUI damage is preferred, but for cases where CUI damage is suspected or damage can not immediately be remediated, corrosion rate estimates, similar to the trends shown in ***Figure 13*** on page 19, can be leveraged to help engineers estimate remaining life and apply reasonable magnitudes of FCA. ***Figure 13*** shows predicted CUI corrosion rates for carbon steel as a function of service/operating temperature for closed (i.e., where moisture evaporation is limited) and open systems [2].

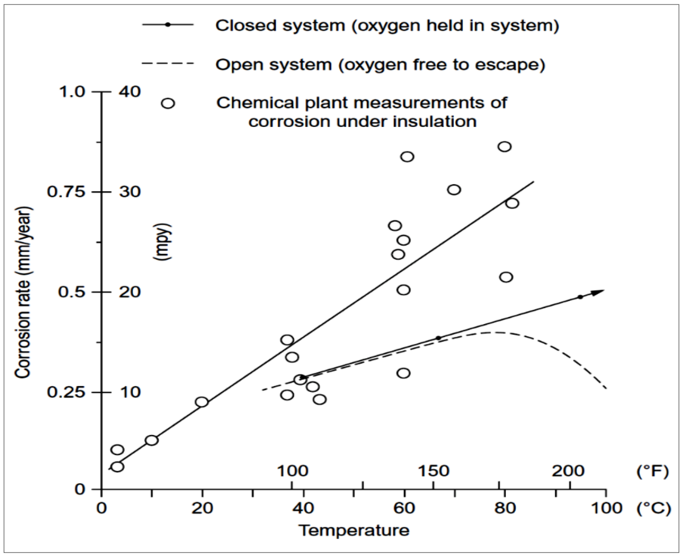


Figure 13. Predicted CUI Corrosion Rates for Carbon Steel as a Function of Service Temperature[2].

CUI Prevention and Mitigation

Proper initial design of insulation systems can dramatically reduce long-term reliability problems and maintenance issues associated with aqueous external corrosion on carbon and low-alloy steels. Furthermore, for in-service equipment, modifications to the existing insulation system and potentially the application of modern external coatings can improve overall damage tolerance going forward. To this end, taking appropriate steps to mitigate CUI can decrease the likelihood of costly equipment downtime that may be necessary to facilitate inspection, fitness-for-service assessments, repairs, or replacement.

In general, CUI can be avoided if moisture ingress into the insulation system is eliminated; that is, if the metal substrate stays dry when the equipment is both operating and out of service. To achieve this, a holistic approach is typically required starting from the design phase, throughout construction and application of the insulation system, and continuing during all inspection and maintenance activities, throughout the life cycle of the component [11]. Careful attention to insulation system design is recommended for critical process conditions that promote CUI (operating metal temperatures between 10°F (–12°C) and 350°F (175°C) for carbon and low-alloy steels [3,4]). Furthermore, several fundamental techniques to prevent CUI have been employed throughout industry, including methodical consideration of the following parameters [2]:

- Insulation selection/specification
- Protective coating selection and application for the metal substrate
- Weather barrier (jacketing/sheathing) selection and design
- Insulation, jacketing, and coating installation conditions and procedures
- Local environment (ambient temperatures, humidity, marine environment, etc.)
- Long-term inspection and maintenance practices
- The cost of unit downtime to facilitate inspection and possibly repairs/replacement

Historically, owner-users have placed the largest emphasis on the type of protective coating on the steel, insulation specification, and weather barrier/jacketing with less focus on installation procedures and maintenance practices [2]. Additionally, damage progression typically starts with a failure (breach) of the weather barrier/jacketing (see ***Figure 14** on page 20*), which leads to moisture ingress/retention and degradation of the insulation itself. Subsequently, localized failure of the metal substrate coating ensues, which tends to cause corrosion and pitting damage. It is important to recognize that damaged or degrading fireproofing can also create an entry point for water retention and can lead to corrosion of the metal substrate (see ***Figure 14***). This can be especially concerning since many fireproofed components are structural in nature (e.g., support skirts for vertical pressure vessels or beams for platform structures, etc.), and as such, widespread corrosion under fireproofing can lead to buckling or structural collapse.

Water can infiltrate the weather barrier or fireproofing from not only rainfall, but drift from cooling towers, steam discharge, condensation from adjacent equipment, process spillage, groundwater, or spray from fire sprinklers, deluge systems, and washdowns [6]. Additionally, fixed pressure equipment or piping systems that are shut down for extended periods of time (mothballed) generally have a relatively high susceptibility to CUI damage. During equipment idle periods, weather barriers and jacketing can deteriorate and may not be part of a regular inspection program. Given this, it may be worthwhile to remove insulation and/or fireproofing on equipment and piping systems that are shut down for substantial periods as part of the mothballing procedure, particularly in humid climates or locations susceptible to water ingress [1].

Insulation and Weather Barrier/Jacketing Selection

There are many types of insulation and weather barrier/jacketing materials available today. For typical refinery and petrochemical applications, API 583 [1] delineates insulation materials broadly into the following three general categories as follows:

- **Granular** – includes calcium silicate, expanded perlite, and silica aerogel;
- **Fibrous** – includes mineral wool and fiberglass; and
- **Cellular** – includes cellular glass, polyurethane, and polyisocyanurate, elastomeric, polystyrene, and phenolic foam.

Cellular insulation materials are typically used for low-temperature applications and normally require a vapor barrier under the outer weatherproofing to minimize the potential for atmospheric moisture condensation. Contrarily, granular and fibrous insulation materials are often selected for high-temperature applications. It is noted that CUI damage has occurred on equipment insulated with all the above materials. While a detailed comparison of these different types of insulation (and their advantages/disadvantages) is not provided herein for the sake of brevity, numerous publications compare CUI susceptibility as a function of insulation material [21-23]. Furthermore, many studies indicate the amount of moisture retention and exposure time are likely the dominant factors in determining the likelihood of damage and estimating corrosion rate [24]. To this end,

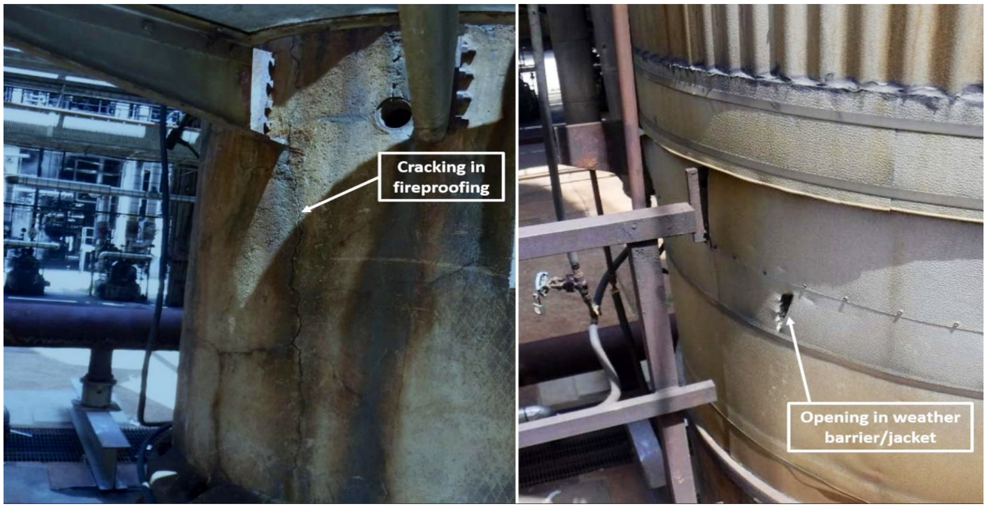


Figure 14. Examples of Degrading Fireproofing on a Support Skirt (Left) and Damaged Weather Barrier/Jacketing on a Vertical Pressure Vessel (Right).

insulation materials that absorb or wick-up water (e.g., calcium silicate or mineral wool) should generally be avoided, particularly for low-temperature applications. Water-repellant insulation materials such as expanded perlite, aerogels, or water-repellent grades of mineral wool are preferred to avoid water retention [23]. Additionally, secondary chemistry effects of the insulation can also contribute to accelerated or inhibited corrosion in some cases, with silicon based hydrophobic treatments and leachable chloride controls generally resulting in favorable corrosion rates [25,26]. Regardless of insulation specification, these trends highlight the importance of mitigating water ingress in the first place through a robust weather barrier/external jacket design.

Weather barriers/protective jacketing are the first line of defense against CUI (to prevent moisture ingress from rain, snow, dew, etc.) and shield insulation from mechanical damage (due to plant personnel or machinery), chemical attack, or fire. Additionally, this barrier serves as a condensate impediment and can generally be inspected quickly and repaired economically [27]. While the primary goal is to prevent moisture from entering the insulation system, if water does accumulate, the design of the underlying component and jacketing should permit evaporation and drainage as much as practically possible (e.g., drainage holes at the system low points). As discussed further below, design features of the jacketing and appropriate seals at any openings or attachment penetrations are crucial.

Jacket materials are generally classified as metallic or non-metallic. Metallic jacketing includes aluminum or varying grades of steels (e.g., aluminum-zinc coated steels, galvanized steels, or austenitic stainless steel) and is most often supplied in thin corrugated, smooth, or embossed sheets that are assembled with stainless steel bands or screws. Non-metallic jacketing includes fiber reinforced plastics and thermoplastics (e.g., PVC). While non-metallic jacketing offers favorable resistance to mechanical damage, it does not offer significant resistance to fire and may require the addition of expansion joints to prevent cracking, particularly in piping systems. Furthermore, non-metallic jacketing materials are usually specified for low-temperature applications, offer generally superior sealing/adhesion compared to metallic jackets, and can be pre-formed or formed-in-place. Pre-formed jacketing is often fabricated from synthetic rubber and may or may not be strengthened with woven glass fiber reinforcement. Formed-in-place jacketing is usually glass fiber reinforced epoxy or polyester applied to the outside of insulation in an uncured state and is cured in place to form a rigid jacket [1]. Both insulation and jacketing materials should be capable of withstanding maximum operating metal temperatures.

Metal Coating Selection

Besides weather barrier design and insulation hydrophobic/water retention properties, selecting the appropriate coating for the metal substrate is perhaps one of the most important design choices for fixed equipment and piping. Furthermore, preventing water from entering an insulation system is not solely a reliable (or realistic) means to completely eliminate CUI damage. Corrosion inhibitors and cathodic protection systems have generally been less effective than metal coatings in mitigating CUI [6]. Thin-film liquid applied coatings, fusion-bonded coatings, thermal spray metallizing, and wax-tape coatings have been successfully used for many different plant applications. Additionally, epoxy coatings are commonly used under fireproofing (galvanizing is regularly used for structural steel under fireproofing), and aluminum foil wrapping is often utilized on austenitic and duplex stainless steels to prevent external chloride stress corrosion cracking (ECSCC). It is essential that the coating for a given application is capable of withstanding the environmental and operating conditions, including maximum metal temperature. Curing time and surface preparation/cleaning requirements may also be an important variable to consider, particularly for recoating of in-service equipment.

Conventional organic coatings/paint systems vary widely in their longevity, depending on surface preparation and application, but can generally provide corrosion protection for approximately 5-13 years [2]. Comparatively, thermal sprayed aluminum (TSA) has a relatively damage-tolerant track record (based on in-service experience and laboratory testing [28]) and is believed to provide corrosion protection for 25 years or more (possibly up to 40 years in some cases) [2,29]. Relative to conventional paints and organic coatings, TSA not only has a longer life expectancy, but it can resist mechanical damage, generally has a greater range of temperature resistance, exhibits durability in cyclic, marine, and chloride environments, and essentially acts as a sacrificial protectant to steels in aqueous environments [2]. Contrarily, higher application costs and difficult field application are potential disadvantages of TSA compared to other coating options. TSA coatings have been used since the 1980s and are applied via a process in which a metal powder, an organic powder, or a metal wire are melted, and the resulting spray is deposited onto the surface of the metal substrate. This process usually requires high-quality surface preparation by blast cleaning [29]. TSA has also been successfully used to avoid ECSCC on stainless steels and is generally preferred to aluminum foil wrapping for sweating service. In certain cases, one or more seal coats (e.g., epoxy sealer) may be beneficial in conjunction with TSA applications [2].

In addition to TSA coatings, other advanced inorganic coatings have also shown promise in meeting many durability and reliability challenges and have demonstrated significant improvement relative to previous generation inorganic zinc (IOZ) coatings [30]. In general, IOZ coatings can be rapidly degraded in cyclic (wet/dry) environments and are typically not specified as a solitary coating for CUI protection, although they may be utilized as a primer with a more CUI-resistant finish coat. Additionally, IOZ coatings (and galvanized steels) should not generally be used in alkaline environments [31]. Epoxy-type coatings (e.g., novolacs, phenolics, fusion-bonded, etc.) can be effective in certain cases, but are primarily specified for relatively low temperature applications [30,32]. While not discussed in detail in this article, some modern coatings that have demonstrated favorable damage tolerance in CUI environments include inert multi-ploymeric matrix (IMM) or inorganic co-polymer (IC) varieties (generally classified as polysiloxane coatings) [30,32]. These coatings are also generally resilient at higher temperature ranges relative to conventional epoxies. Moreover, there are many nuances and special considerations associated with selecting the appropriate coating and specifying cleaning, surface preparation, and application procedures for different components and structures. To this end, typically, it is recommended to consult a coatings engineer/specialist or engineering best practice documents for guidance on maximizing durability of coatings applied as part of a CUI mitigation strategy.

Examples of Inadequate Insulation Details

Several real-life examples of inadequate weather barrier/jacketing design details are presented below. These instances occur at nozzles, transition regions, and structural attachment locations on pressure vessels, where many reliability and maintenance challenges exist for insulation systems. These cases also highlight inadequate water-shedding characteristics and situations that promote insulation degradation due to water absorption, and eventually, CUI damage of the metal substrate. ***Figure 15*** on page 24 shows an example of unsealed metallic jacketing at a platform ladder penetration on a vertical pressure vessel. As depicted, there is an open seam in the jacketing at this location that represents an obvious entry point for water into the entire insulation system. Furthermore, there is no environmental seal or caulking at the jacket-to-ladder support interface. This detail does not reflect current good engineering practices. Similarly, ***Figure 16*** on page 24 shows examples of nozzles and instrumentation (pressure gauge) locations on a pressure vessel that have no environmental seals and improper caulking where the nozzle neck or instrumentation penetrates the insulation jacketing. Additionally, the nozzle necks are exhibiting scale and corrosion indicative of CUI damage. This observation also implies that the pressure vessel shell is likely experiencing similar or even more severe corrosion beneath potentially wet insulation.

The last example shown is a rainwater shield at a support skirt-to-shell junction on a vertical process column (see ***Figure 17*** on page 24). Not only is there an opening in the shield itself, but the design of this junction does not reflect current good engineering practices. Specifically, the rainwater shield at the termination point of the insulation on the vessel is essentially flush with fireproofing on the support skirt below. This detail provides inadequate water shedding and promotes water ingress into the fireproofing below. The shield itself and fireproofing are also visibly damaged at certain locations. Stiffening ring and insulation ring locations are also notoriously improperly designed such that water accumulates on top of the rings and cannot effectively drain away from the pressure boundary (see design recommendations below). All the aforementioned examples of inadequate weather barrier/jacketing configurations should have been avoided at the design phase or identified during routine visual inspections (and ultimately corrected). These simple steps could have prolonged the need to strip insulation for detailed inspections of the pressure boundary and negated costly remediation measures and repairs.

Expert Tip

Special emphasis mechanical integrity (SEMI) programs focusing on CUI are often useful in mitigating unplanned outages due to CUI damage. These programs regularly include many of the insulation system design and inspection strategies offered herein, and generally also incorporate protocols for leveraging inspection data management software (IDMS). Additionally, considerations like proper documentation of equipment materials and operating conditions, appropriate corrosion monitoring location (CML) placement, frequency/accuracy of thickness readings, and preventative maintenance practices are typically also outlined in this type of MI program.

Design Considerations and Good Engineering Practices

In addition to the previously mentioned insulation and jacketing selection contemplations, practical design decisions can dramatically reduce the likelihood of water ingress and CUI damage. Furthermore, the above illustrated design deficiencies on pressure equipment can be avoided if good engineering practices are followed, and all appurtenances, structural attachments, and nozzle/instrumentation penetration locations are properly designed and sealed.

Figure 15. Examples of Unsealed Weather Barrier/Jacketing (Left) and Close-Up of Ladder Support Penetration (Right) on a Vertical Pressure Vessel.

Figure 16. Additional Examples of Improper Insulation System Design at Nozzle and Instrumentation Penetrations.

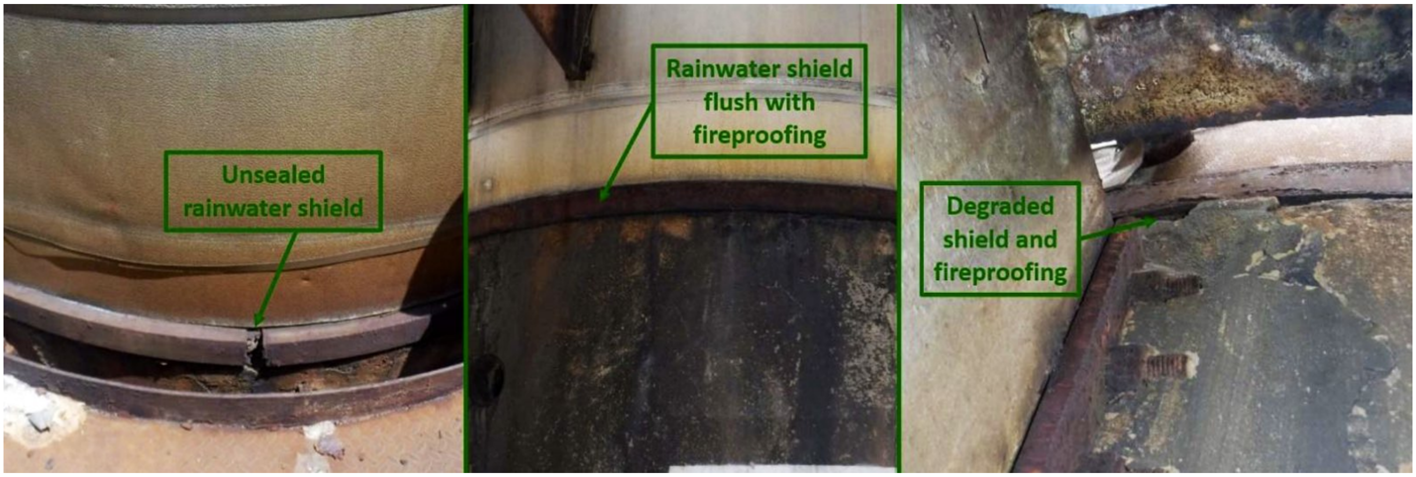


Figure 17. Examples of Poor Design Details, Installation, and Maintenance Practices Near Rainwater Shield at Support Skirt Fireproofing-to-Shell Insulation Junction.

Several practical considerations for both new equipment designs and in-service equipment are suggested below to mitigate CUI damage [1,2,6,11].

General Considerations

- Challenge the need for insulation at the design phase – for example, if insulation is required for personnel protection, consider alternatives such as metal guards or cages in lieu of insulation systems. If insulation is omitted, heat loss and any subsequent detrimental effects on the process should be assessed.
- For new designs, capital projects, or expansion initiatives, consider plant layout to efficiently enable future inspection and maintenance activities – closely spaced equipment and piping can prohibit effective life cycle management activities.
- Steps, walkways, and platforms should be designed such that personnel can traverse pipe racks or other equipment without stepping on insulation.
- Insulation/jacketing materials and coating specifications/procedures for the metal substrate should be carefully selected – this may require consultation with engineering best practice documents or engineering specialists in these fields.
- Free drainage points (such as drainage plugs) should be located at natural low points in the insulated system.
- Inspection ports that are required on insulated systems should be designed to be removed and replaced repetitively while remaining waterproof.

For Pressure Vessels

- Appurtenances and protrusions through the insulation should be designed to effectively shed water. This includes avoiding flat horizontal surfaces and complex shapes like gussets, angle irons, and I-beams, if possible.
- Seal-welded discs or plates should be installed on nozzles, structural attachments, and any other protrusions to divert water away from the opening in the insulation system (see ***Figure 18*** on page 26).
- Attachments supporting ancillary items such as ladders, platform supports, on insulated vessels should be of a sufficient length such that they protrude beyond the insulation thickness by at least 4-inches (100 mm).
- Conventional bucket-type insulation support rings, which could act as a moisture trap, should be avoided. For in-service equipment that does not conform to this recommendation, holes can be drilled in the ring to drain water.
- Insulation support rings should be attached to the pressure boundary via seal-welded brackets, creating a gap between the support clips and the shell to facilitate drainage (see ***Figure 19*** on page 26).
- Structural stiffening rings should be insulated and jacketed/sheathed as shown in ***Figure 20*** to create a water-tight seal.
- Insulation-to-fireproofing interfaces on vertical vessels should be designed to shed water with flashing, and rainwater shields should not be flush and extend beyond the fireproofing below (as shown in ***Figure 17***).

For Aboveground Storage Tanks

- Handrails and other attachments should be installed on the tank sidewall instead of directly on insulated roofs, if possible.
- Ancillary attachments such as ladders, stairways, platforms, level controls, should have a standoff of at least four times the insulation thickness.
- Insulated tank roofs should overhang the shell by at least the shell insulation thickness plus 2-inches (50 mm) to effectively shed water.
- For double-walled tanks, it is crucial to prevent water ingress into the insulated annular space (including during construction).

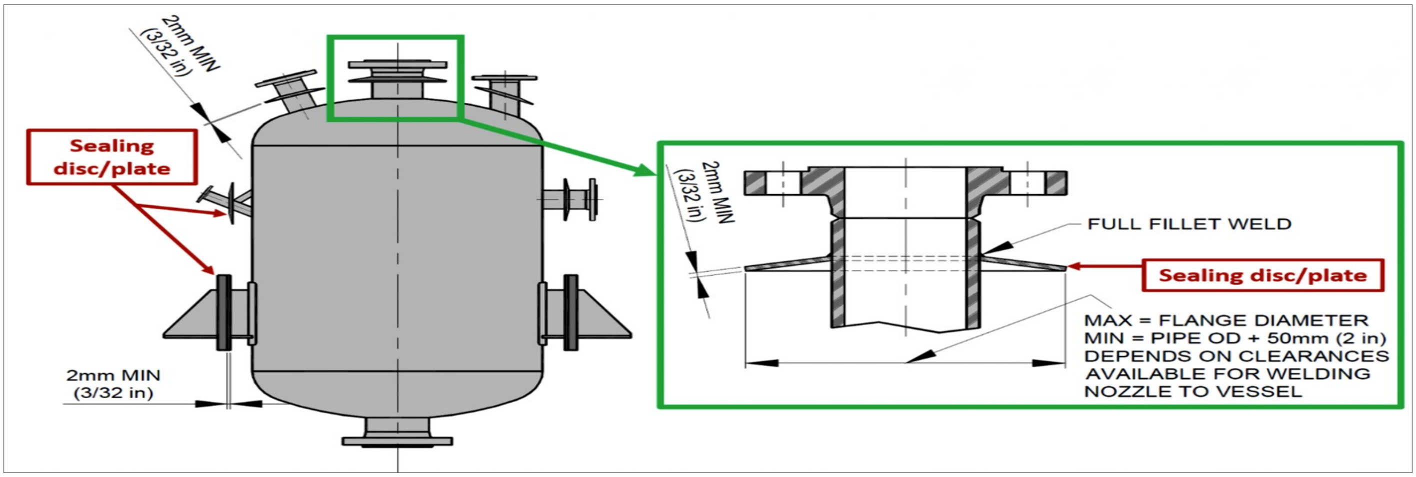


Figure 18. Examples of Recommended Seal-Welded Discs/Plates on Pressure Vessel Nozzles and Other Attachments to Divert Water (adapted from [1]).

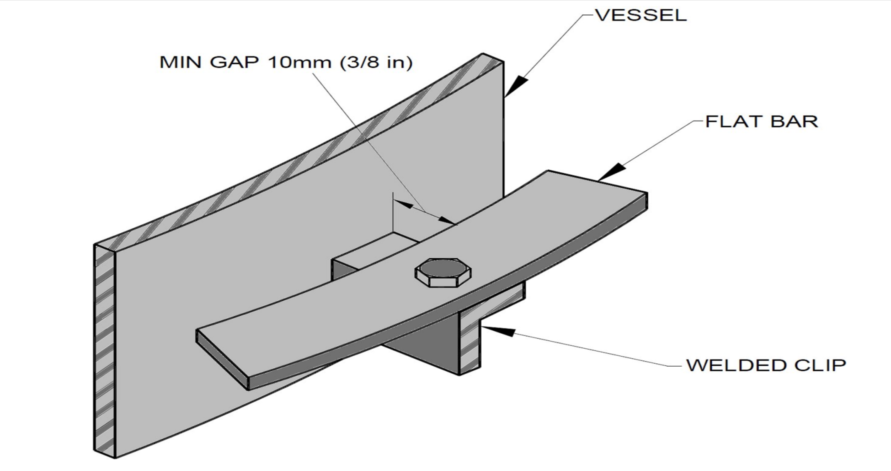


Figure 19. Recommended Insulation Support Ring Detail to Facilitate Water Drainage Between the Vessel Wall and the Ring (adapted from [1]).

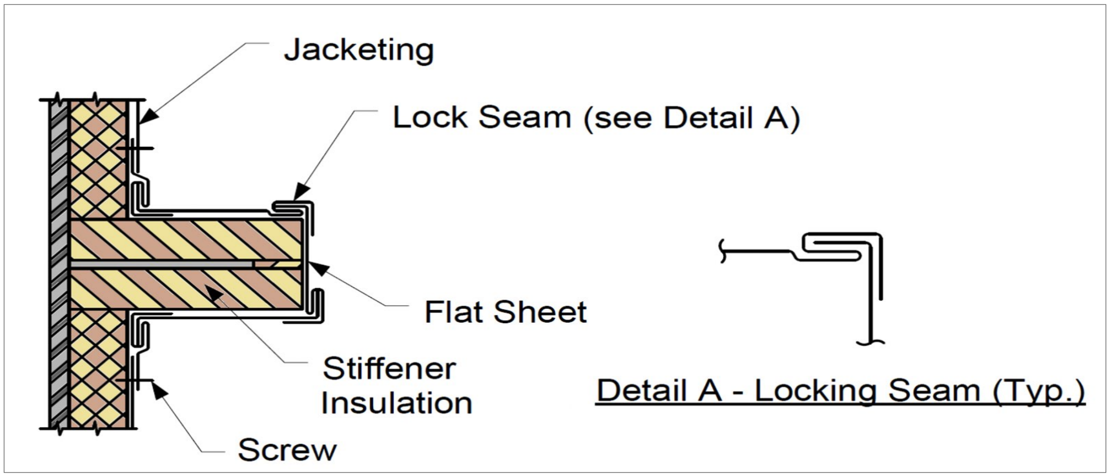


Figure 20. Recommended Structural Stiffening Ring Insulation and Water-Tight Jacketing/Sheathing Detail.

For Piping Systems

- For small-bore piping, consider either increasing the thickness of carbon steel sections to provide more corrosion allowance or implement metallurgical upgrades to stainless steel (with austenitic stainless steel, ECSCC may be a concern and proper coating, or aluminum foil wrapping may be required).
- Locate valves and flanges on horizontal piping runs rather than vertical runs to minimize water penetration and retention.
- Valves and instruments (e.g., pressure gauges) in insulated piping systems should have stems of length equal to at least twice the thickness of the insulation.
- If possible, deadlegs in insulated piping should be avoided.
- Clamped pipe shoes should be avoided because they commonly trap water (welded shoes are preferred).
- Insulated piping should not be placed in trenches or drains below grade due to the risk of water immersion.
- Conical end caps or hoods should be installed on vertical overhead pipe supports to direct water away from potential water entry points.
- Supports for insulated piping should use load-bearing insulation/jacketing to allow the pipe to be supported without the need to penetrate the insulation. If this is not possible, the minimum length of the support should be four times the insulation thickness.

Summary and Conclusions

Corrosion Under Insulation is a prevalent industry problem affecting thermally insulated equipment in many industries. It is one of the most well-researched and understood damage mechanisms in the refining and chemical process industries, and yet it still represents an inordinately large percentage of global plant maintenance expenditures. For this reason, exercising good engineering practices during the design phase and throughout the entire lifecycle of equipment requiring thermal insulation is crucial.

When CUI is properly considered and managed (e.g., special emphasis mechanical integrity programs), long-term reliability can be substantially improved and the need to perform frequent inspections that often require significant time and resources can be negated. Furthermore, taking a holistic approach to insulation system design and reliability that includes systematic selection of insulation materials, weather barrier/jacketing, coating specifications, basic design features at pressure boundary attachments that often act as water entry points, and effective inspection strategies can eliminate the need for costly future maintenance activities, repairs, or equipment replacement [1,6,11].

If CUI is discovered, the assessment methods outlined in this primer offer engineers and analysts a range of technically based methods to qualify CUI damage of varying severity. These FFS techniques, especially Level 3 analysis methods, can justify continued equipment operation, even when extensive CUI damage is identified. Nevertheless, remediation and a proper future inspection plan should be coupled with any FFS assessment to mitigate and monitor any future CUI damage progression.

About the Author

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Phillip E. Prueter is a regular contributor to the "Damage Control" column of Inspectioneering Journal, which offers practical insights into various damage mechanisms affecting equipment in the O&G, petrochemical, chemical, power generation, and related industries. Read more of his work by visiting www.inspectioneering.com/+/prueter.

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