



Guide for Repair of Thinned Piping

1003162

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1003162

December 2001

EPRI Project Manager

Artie Peterson

RRAC Coordinator

Steve McCracken, AmerenUE

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This document was prepared by

EPRI
1300 Harris Blvd.
Charlotte, NC 28262

Principal Investigator
Artie Peterson

AmerenUE
P.O. Box 620
Fulton, MO 65251-0620

Principal Investigator or Author
S. McCracken

This document describes research sponsored by EPRI.

The publication is a corporate document that should be cited in the literature in the following manner:

Guide for Repair of Thinned Piping, EPRI, Charlotte, NC: 2001. 1003162.

ABSTRACT

Numerous piping systems for nuclear power plants were constructed under Section III of the ASME Boiler and Pressure Vessel Code. These systems can suffer from a number of degradation mechanisms, including microbiologically influenced corrosion (MIC), erosion-corrosion (EC) damage or general corrosion.

Inservice repairs to the outside diameter (OD) of piping using weld metal are not usually discussed in codes utilized for construction of ASME III systems.

This document is focused on providing the utility with guidance in developing repair options for use on thinning pipe.

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1

INTRODUCTION

Numerous piping systems for nuclear power plants were constructed under Section III of the ASME Boiler and Pressure Vessel Code. These systems can suffer from a number of degradation mechanisms, including microbiologically influenced corrosion (MIC), erosion-corrosion (EC) damage or general corrosion.

Inservice repairs to the outside diameter (OD) of piping using weld metal are not usually discussed in codes utilized for construction of ASME III systems.

This document is focused on providing the utility with guidance in developing repair options for use on thinning pipe.

Damage mechanisms

The predominant damage mechanisms that lead to thinning of pipe wall, as opposed to a linear indication, (i.e. a crack), are MIC, EC and general corrosion. New materials and design criteria are being evaluated to establish means of resisting most, if not all, forms of corrosion and fouling mechanisms.

System failures have prompted extensive activity to define root cause failure modes and to determine remedial actions which will allow existing systems to continue or extend operation. Failures have been prompted primarily by I.D. corrosion mechanisms.

Microbiologically influenced corrosion

Microbiologically influenced corrosion (MIC) has been identified as a problem in nuclear power plant systems during the past several years. Although recognized over fifty years ago and studied extensively in other industries, the influence of microorganisms, particularly bacteria, on structural materials in nuclear power plants has only recently come to light. The phenomenon has received considerable attention as a result of INPO Significant Event Report (SER 73-84) issued in October 1984, and NRC Information Notice (IN 85-30) issued in April 1985.

Erosion corrosion

Erosion corrosion damage is considered one of the leading causes of wall thinning in piping systems. The abrading (erosion) of the inside surface of a pipe or the chemical degradation (corrosion) are two terms for wall thinning that are almost always placed together. This form of thinning is typically the easiest to argue when justifying the use of a weld overlay.

Fatigue

Fatigue is generally understood as the gradual deterioration of a material which is subjected to repeated loads. In most power plant fatigue failures the driving forces are usually induced by thermal cycling, load changes or mechanical vibration. Most of the fatigue failures are located in an area with either an increased stress concentration or in area with degraded material properties such as the heat affected zone of a weld.

Two other damage mechanisms are described below. Stress corrosion cracking and Creep are two common methods of piping failures. While these two do not typically fall within the boundaries of *thinning* mechanisms they can result in the lost credit for original wall thickness. These two are mentioned purely for information purposes and are not discussed in the repair sections.

Stress corrosion cracking (SCC)

SCC is caused by the interaction of sustained tensile or shear stresses and an aggressive environment which results in delayed cracking at stresses well below the yield strength of the material. The occurrence of cracking is dependant upon the duration and magnitude of the applied stress as well as the aggressiveness of the environment.

Sustained stresses can result from residual stresses, applied loads or both. Residual stresses occur as a result of manufacturing and assembly operations.

Cracking occurs most rapidly for stresses in the material's short transverse grain direction. Conditions leading to SCC include the exposure of copper to ammonia in condensers and heat exchangers and of stainless steels exposed to chloride containing solutions.

Creep

Under the application of a constant load it has been found that materials, both metallic and non-metallic, show a gradual flow or *creep* even for stresses below the proportional limit at elevated temperatures. The deformation which can be permitted in the satisfactory operation of most high-temperature equipment is limited. In metals, creep is the plastic deformation caused by slip occurring along crystallographic directions in the individual crystals, together with some flow of the grain boundary material.

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REPAIR METHODS

The repair methods discussed outline several methods of potential repair techniques. The most common and prominent method of addressing wall thinning is the application of a full weld overlay. Also gradually becoming more acceptable is the use of a localized weld overlay or 'patch weld'. These two methods are discussed extensively in this document in terms of design, application, testing and inspection where applicable.

Other methods discussed, albeit less conventional are non-metallic coatings, liners, sleeve welds, insert plates and leak boxes.

The first section discusses an approach for cracked ferritic piping. Loss of wall integrity due to cracking does not normally fall within the bounds of traditional thinning. The information presented is significant though in that the same basic principles are applied when compared to overlays on austenitic pipe.

Overlay Repairs

Detailed literature searches were performed to determine potential mechanisms that might result in cracking of P1 plain carbon steel materials. The results indicated that potential existed for two possible cracking scenarios. These were stress corrosion cracking and cyclic fatigue. These two phenomena represent a spectrum of material degradation mechanisms that can lead to cracking in most materials. The literature is replete with examples of both mechanisms in a variety of materials. It is useful to attempt to distinguish among candidate mechanisms in order to characterize crack growth rates and specific influences of different parameters. The parameters that control cracking relate to the material composition and microstructure, the environment, and the loading applied to the components. Most technologists view these failure mechanisms as a continuum in that the parameters that influence stress corrosion cracking also influence cyclic fatigue and vice versa. Typically the degree to which the specific parameters are operative will bias degradation towards one mechanism or the other. For example when environmental conditions are aggressive, the corrosion component will be enhanced, or when the cyclic loading components are dominating, fatigue will be enhanced. In some cases, the material itself may provide a mechanistic bias. This would appear to be the case with plain carbon steels.

One requirement for stress corrosion cracking (SCC) is that a critical stress intensity factor must be exceeded, K_{ISCC} . Since stress intensity factor is a function of both load and geometry, both factors important to predicting material degradation by SCC. A key geometrical factor is the acnity of the crack tip. If the crack tip does not

remain sharp, the stress intensity factor will be lowered even if the load remains constant. The SCC mechanism will cease if stress intensity factor drops below K_{ISCC} . This requirement necessarily means that the faces of the crack be much less affected by the corrosion process than the crack tip. This is very difficult for plain carbon steel because general corrosion rates are typically very high. The result is that the crack tip will tend to become blunted and a stress corrosion cracking mechanism will not be favored. As certain alloying elements are added to plain carbon steels such as chromium, nickel, and molybdenum, the general corrosion of the crack faces will be reduced and stress corrosion may be favored. Because of this, low alloy steel materials are generally more susceptible to stress corrosion than are plain carbon material. Records of SCC in carbon steel materials primarily involve LAS.

The SCC mechanism is generally viewed in two stages – crack initiation and crack growth. Crack initiation requires that a geometrical sharp notch tip be developed before a critical stress intensity for growth can be generated. Typically an initiation site might be developed at surface anomalies, corrosion pits, or fatigue cracks. These types of initiation sites also tend to increase the chemical aggressiveness of the environment local to the site. This environmental factor increases the likelihood for SCC. In general the less severe the site geometry the greater the tensile load required to initiate SCC. As a crack begins to extend, a lower load will be required to develop the critical stress intensity factor.

Piping components constructed of higher alloy materials such as austenitic stainless steels are well known to experience stress corrosion cracking of many forms. For example in the boiling water reactor primary system, the stainless steel piping has been plagued with intergranular stress corrosion cracking. Stress corrosion cracking is a common degradation mechanism in piping systems containing aggressive anions. For plain carbon steels, the aggressive environments greatly enhance general corrosion and that form of degradation tends to dominate - thus general corrosion is favored.

However, it should be pointed out that General Electric Nuclear under contract to EPRI studied the potential for stress corrosion cracking of carbon steels in BWR high purity oxidizing environments, and found that under certain conditions, SCC mechanisms may be operative. Laboratory observations of such cracking indicated the existence of a stress and environmental envelope where cracking of carbon steels would be possible. In addition, the widespread cracking of carbon steel PWR secondary feedwater lines in 1979 also suggested a corrosion component of degradation (corrosion-assisted fatigue). The study explored the effects of static, monotonic, and cyclic loading in various oxygenated water environments, and results confirmed that carbon steels can be susceptible to environmentally assisted cracking in high-temperature oxygenated water. The degree of susceptibility of carbon steel is much less than that of sensitized type-304 stainless steel. Full scale pipe testing showed that carbon steel welds would not crack at applied loads up to twice the design stress even in an unrealistically severe environment of high temperature water (288 °C) containing 8 ppm dissolved oxygen.

Further results of the GE study in Reference 2.1 confirmed that environmental effects generally were mild on the fatigue life of carbon steel for exposures at temperatures below 232 °C and for more realistic BWR operating conditions at dissolved oxygen contents of 0.2 ppm or less. This suggested that the widespread cracking of PWR feedwater lines was related more to fatigue than to corrosion parameters. Normal BWR operating conditions (288°C and 0.2 ppm dissolved oxygen) do not approach the boundaries of significant environmental effects. This is consistent with the generally good service performance to date with carbon steel piping in BWRs.

The question to be answered is whether an active crack, regardless how it is initiated, might propagate into carbon or LAS material via a stress corrosion cracking mechanism. Several case histories (incidents) are known to the authors that may suggest potential for the extension of an existing crack into low alloy steel material (LAS). Three of these incidents involved the potential extension of cracks that had formed in Alloy 182 welds and weld butter material located on the ends of LAS nozzles in BWR vessels. In all three cases cracking initiated in the HAZ of the Alloy 182 weldment, and propagated into the Alloy 182 nozzle butter material. It appeared that the crack may have propagated a short distance into the LAS nozzle material. One of the incidents occurred in the N1 nozzle of the Pilgrim facility. A metallurgical investigation suggested that the cracking phenomenon may have been related to shrinkage cracking during solidification in the diluted HAZ on the LAS side of the weld. Defective material was removed and the nozzle was repaired.

The other two incidents reported involved the potential for extension of a growing IGSCC defect progressing into LAS nozzle material. These later two cases involved Carolina Power and Light's Brunswick Unit 1 and Taiwan Power Company's Chinshan Unit 2. In both cases the potential crack extension into LAS material was the result of an IGSCC initiated in the Alloy 182 HAZ of the weld (safe-end side) joining the austenitic stainless steel safe-end to the nozzle butter. The crack grew across the weld and propagated towards the nozzle. At Brunswick the ultrasonic test information indicated significant penetration into the nozzle. To confirm the propagation of the flaw into the LAS and investigate the metallurgical characteristics, a boat sample was removed from the end of the nozzle. The metallurgical investigation revealed no flaw. A full circumferential ring was then sectioned to remove the defect and restore the piping system. The ring was submitted for detailed metallurgical examination and this too failed to unambiguously identify the crack extension. It was considered likely that the UT indication of crack extension into the LAS may have been the result of a "field" metallurgical forging artifacts inherent to the LAS nozzle and not in-fact extension of an IGSCC initiated flow.

UT identified the cracking indication at Chinshan Unit 2 as had been done at Brunswick 1. Analysis indicated that a crack-like defect extended from the Alloy 182 weldment slightly into the end of the nozzle. In this case the safe-end was severed at the weldment/butter interface. Additional material was removed at the location of the UT indication. A procedure was used whereby small amounts of material would be removed in a "step-wise" manner and the surface examined for the existence of a crack. It appeared that a very small crack was present and penetrated the LAS nozzle material approximately 0.10 inches. The UT methodology was

faithful in identifying the correct location; however it was deficient in identifying the correct flaw profile. The defect was much smaller than predicted by NDE interrogation. In this case the defect appeared to be skewed towards the nozzle ID cladding. No metallurgical examination was performed, but a qualitative map of the defect was generated from defect measurements each time material was removed prior to repair. The intent was to fully remove the defect (indicated by a clear PF examination) but removing as little material as necessary. It was noted that the laboratory experiments performed in the EPRI study identified previously suggested that such crack extension would be possible if the stress field were sufficiently high.

Perhaps the most dramatic documented case histories of SCC extension in LAS material were observed in pressure vessel components. The first incident discovered was cracking of the lower steam generator head at Garigliano a BWR Model 1 configuration having a secondary steam generator located in Italy. The lower head was fabricated of A302 Grade B material (LAS) clad with NiCu Alloy 190. The fabrication sequence called for a field installation of the head. The clad head was manually welded in-place and the weld root region was manually "back" clad from the ID using the SMAW process. Extensive cracking was seen in the lower head closure weld region. Cracks were typically 30 to 50% throughwall and open to the I.D. surface. A large 360-degree inner surface crack pattern was identified through-wall at one location. A 4-inch diameter through-wall plug sample was removed and examined for root cause characterizations. The subsequent metallurgical examination revealed a SCC crack that initiated in the manual clad alloy steel interface from a network of solidification cracks. The investigators suggested that a combination of the creviced crack initiator with the high residual stress from the manual field weld led to SCC in the LAS that penetrated the LAS wall. Again this is consistent with the laboratory results from the EPRI study.

Another LAS cracking incident occurred in 1990 involving the RPV head at Quad Cities Unit 2. Cracking was discovered during the normal outage ISI by visual inspection, followed by PT and finally UT from the outside surface. Many discontinuous cracks were identified on the ID cladding surface of the head at an elevation where the dome is welded to the head flange. These defects which were associated with a geometric discontinuity of the flange to head dome weldment were determined to penetrate into the LAS material (SA533-B-1) to distances no greater than 0.25 inches. A metallurgical evaluation was performed on several boat samples removed from the head ID surface at locations measured by UT to be a maximum depth. Results indicated that the cracking initiated on the ID surface (cladding), and propagated towards the LAS material and into the HAZ of the vessel head weld. The stress intensity factor, K_I , at the cladding – LAS interface exceeded the threshold for crack propagation into the LAS material. Cracking was determined to be SCC along the dendrite boundaries through the cladding and propagated along prior austenitic grain boundaries in the LAS HAZ material. Fabrication records indicated weld buildup at this location to accommodate mismatch of the plates and flange forging. Consequently, additional welding cycles were applied and the stainless steel cladding was applied manually with SMAW procedures. This produced a low ferrite cladding deposit known to be susceptible to IGSCC in oxidizing conditions. Note that the upper head region of a BWR is a highly oxidizing 2-phase water-steam environment.

Heavy grinding of the clad buildup was clearly identified in the metallography, and is believed to be a major factor in crack initiation. As the cracking formed in the cladding a creviced condition was produced and SCC occurred in the LAS material. The rework operations on this head were believed to produce the special residual stress conditions that led to the cracking. Three sister units were inspected and none exhibited the cracking condition. Again these cracking conditions are consistent with the laboratory results from the EPRI study.

It should be noted that all of these materials were LAS and thus contained a small amount of alloying elements that were capable of minimizing general corrosion at the crack tip that would lead to crack tip blunting. Applied to pre-existing fabrication cracks or cracks in susceptible cladding material led to a stress intensity that exceeded K_{ISCC} , SCC became active. Because the combined residual and applied loads plain carbon steel (P1 material) does not have this chemistry and thus it would be much more difficult to extend an existing SCC defect by a SCC mechanism in the pure water primary system of a reactor. However, the environment to which a material is exposed can alter behavior for materials like plain carbon steel. For example the presence of nitrates in an aqueous environment has been shown to result in a special form of stress corrosion cracking in plain carbon steel. Two nuclear power stations have reported this phenomenon for their secondary service water system. In both of these cases nitrites had been added to the service water as an inhibitor to general corrosion. Unfortunately certain bacterial species present in these service water systems were capable of converting the inhibiting nitrites to corrosion causing nitrates and SCC resulted. The mechanics of these specific failures involved built in crevices attendant to the use of backing rings during welding. While these conditions are capable of producing SCC degradation in plain carbon steel, neither of these situations would be present for primary water applications - the topic of this study. Therefore, stress corrosion mechanisms are considered unlikely for P1 material applications. Regardless, a stress corrosion cracking scenario has been evaluated. Results are discussed in the crack growth section.

Cyclic fatigue is a potential mechanism for degradation common to all structural materials. There are many parameters known to characterize cyclic fatigue but in principle it is damage caused by repetitive flexure. The flexure can be load driven or displacement driven, and the material response is normally a function of the mean load around which the member is cycled. Loads are generated from a variety of sources including fabrication residual stresses, operational loads (mechanical, pressure or thermal), and from the interaction with nearby equipment.

Typically the fatigue performance is characterized by a power law relationship of the changes in stress intensities factor versus cracking rate. Different relationships are given for different stress R-ratios. This is the method used by the ASME Code to predict crack growth. The environment is known to strongly influence the power law characterization and separate curves are given for aqueous environments as opposed to air environments. If particularly aggressive environments were present, different relationships would have to be used. In primary nuclear environments, the standard code relationships are sufficient.

The technical literature is filled with case histories of fatigue in all kinds of materials and components. For BWR LAS applications, the most widely known incidents of cracking are the feedwater nozzle cracks and cracks in the CRD return lines were initiated by thermal fatigue and driven by operational pressure cycling in BWR 2 - 5 plants, and the CRD return nozzles in several plants. In PWR carbon steel and LAS applications the most widely known are thermal fatigue cracking incidents of the steam generator feedwater inlet lines, and thermal fatigue cracking of the vessel wall inside the steam generators.

In reality most cracking is seldom solely fatigue or entirely SCC, but rather a synergistic combination to some degree of both mechanisms. For example, cyclic loads are known to exacerbate SCC and aggressive environments are known to exacerbate fatigue. Therefore knowledge of the material behaviors and the design parameters utilized are employed to determine the parameters used to predict crack extension.

For plain carbon steel piping materials (P1) applied in nuclear primary systems the most likely crack extension mechanism is fatigue potentially exacerbated by the environment. Since the environment is pure water, it is concluded that the ASME Section XI procedures for predicting fatigue crack growth are appropriate.

Overlay Specifics – Carbon Steel

This Section presents the design of the weld overlay for ferritic piping. Currently there is no basis for the design of a weld overlay on ferritic piping. However, ASME Code Case N-504-1 (using NUREG-0313, Rev.1) does provide guidelines for application of weld overlays on austenitic steel piping. For purposes of this analysis the guidelines provided in ASME Code Case N-504-1 will be used for the design and design criteria of the weld overlay. This is justified also since the weld overlay will be made from Alloy 52 material which is an austenitic steel. The residual stress induced by the original weld followed by the weld overlay are described in Section 4.0.

The weld overlay was designed as a full structural overlay in accordance with the requirements of NUREG-0313, Revision 2 (which was implemented by Generic Letter 88-01), ASME Code Case N-504-1, Section XI of the ASME Boiler and Pressure Vessel Code, Paragraph IWB-3640. The overlay will extend around the full circumference of the pipe for the required length. It was designed by assuming the weld to be completely cracked through the original pipe wall and the first layer of the overlay. In effect, credit was not taken for the first overlay layer conservatively assuming that this layer remains susceptible to degradation due to possible dilution of the Alloy 52 weld overlay material from the underlying weld and base material. Thus, the first overlay layer is considered part of the original wall. The thickness of the overlay was determined by comparing the weld overlay strength for a combination of dead weight, internal pressure, seismic stresses, and other loads such as water hammer, jet impingement, and safety relief valve discharge with the criteria contained in Paragraph IWB-3641. Both normal operating and emergency/faulted conditions were considered in the evaluation. Note that the criteria above is for austenitic piping but is being used as a guide to provide a starting weld overlay design for analysis.

Per Code Case N-504-1, the overlay design must also meet the ASME Code, Section III stress limits for primary local and bending stress and secondary peak stress.

Specifically, Tables IWB 3641-1 and IWB 3641-2 or the equations in Appendix C of ASME Code Section XI can be used to initially size the overlay. These tables and the appropriate equation will be used for the gas tungsten arc welding (GTAW) process, which will be used to apply the overlay. The overlay material will be IGSCC-resistant Alloy 52 and will be deposited using the GTAW process. The results of this calculation must be compared against the other requirements to finalize the weld overlay thickness.

In summary, the weld overlay design must address the determination of the overlay thickness and length such that structural integrity is assumed. This includes consideration of the applied loads, crack growth into the overlay and behavior of pre-existing flaws covered by the overlay. The following section evaluate all of these items to assure the acceptability of the overview.

Design Criteria

This section presents the design of the weld overlay for a 12 inch schedule 80 pipe. Currently, weld overlay repair of austenitic steel is permitted and is specified in ASME Code Case N-504-1 and NUREG-0313, Rev.2 (under “standard weld overlay”). The overlay material selected for this evaluation is Alloy 52 which is an austenitic steel.

Stress Calculation

The loads for the overlay design using the piping analysis were obtained from a typical piping weld. Only the primary stresses are considered in the design of the weld overlay. This is per Appendix C of the ASME Code Section XI since a GTAW process will be used. The stresses are typically calculated as shown below:

Pressure Stress $\sigma = P[ID^2]/[OD^2-ID^2]$

Dead Weight, Seismic Bending Stress

$$\sigma = F_a / A + \frac{\sqrt{(M_b)^2 + (M_c)^2}}{Z}$$

$$F_a = \text{Axial Force}$$

$$M_b, M_c = \text{Bending Moments}$$

$$Z = \text{Section Modulus}$$

F_b , F_c (shear forces) and M_a (torsion moment) are not included since they do not contribute to the normal stress at the weld cross-section.

The membrane stress, P_m is equal to the stress due to pressure and axial loads. The bending stress, P_b is equal to the bending stress caused by deadweight and seismic stress and other primary loads.

The design stress intensity for the Alloy 52 material is taken as the limiting S_m value for the base material. In this case, the overlay is being applied on to SA-508, Cl.1 pipe weld filler. The S_m for this material corresponds to that of the SA-508 Cl.1 material. The S_m at 550°F is 18.6 ksi [3-4]. This value will be used for the weld overlay calculations.

The flow stress is taken as $3S_m$ based on IWB-3600 criteria for austenitic steels. Alloy 52 is an austenitic steel. The length of the overlay is determined using the guidance from ASME Code Case N-504-1.

Weld Overlay Thickness Calculation

The determination of weld overlay thickness must satisfy the following criteria:

- Use of the source equations in Appendix C, Section XI of the ASME Code.
- Use of 75% maximum allowable flaw criteria (per IWB-3640 of ASME Code Section XI).
- Use of ASME Code Section III stress limits (per Code Case N-504-1).

The bounding thickness (maximum) of these three approaches will be taken as the overlay thickness. The first two items are summarized below. The third item above, assures that the weld overlay length and placement with respect to the crack location is acceptable. Since this evaluation applies the overlay symmetrically about the weld and meets the length recommendations of ASME Code Case N-504-1, the third item is not a concern. The overlay thickness was calculated using the pc-CRACK computer program .

Use of Equations in Appendix C, Section XI of the ASME Code

The weld overlay thickness, per ASME Code Case N-504-1, is designed using the equations provided in Appendix C of the ASME Code, Section XI. These equations are based on net-section plastic collapse. At the point of collapse, the equations, which describe the equilibrium condition, are:

$$\beta = [(1-d/t-P_m/\sigma_f)\pi]/(2-d/t)$$

$$P_b' = (2*\sigma_f/\pi)*[(2-d/t)\sin(\beta)]$$

where:	β	=	angle of neutral axis
	P_m	=	primary membrane stress
	σ_f	=	flow stress of material = $3S_m$
	S_m	=	design stress intensity
	α flaw	=	half angle of crack = 180° for fully circumferential
	d	=	crack depth
	t	=	thickness

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P_b = primary bending stress

P_b' = primary bending stress at collapse

P_m and P_b are determined from the applied primary loads at the location of the crack for the original uncracked condition. The condition based on equilibrium, which must be satisfied, is:

$$P_m + P_b' = SF (P_m + P_b)$$

where SF = safety factor = 2.77 for normal or upset condition

1.39 for emergency or faulted condition

Based on typical stress values for piping systems, the following values of stress were used in the weld overlay thickness calculations:

<u>Normal or Upset</u>	<u>Emergency or Faulted</u>
------------------------	-----------------------------

P_m = 5 ksi	P_m = 6 ksi
---------------	---------------

P_b = 5 ksi	P_b = 9 ksi
---------------	---------------

A summary of the inputs for the weld overlay calculation are shown below:

Upset Case

t = 0.687 inch

S_m = 18.6 ksi

$3S_m$ = 55.8 ksi

P_m = 5 ksi

P_b = 5 ksi

SF = 2.77

Faulted Case

t = 0.687 inch

S_m = 18.6 ksi

$3S_m$ = 55.8 ksi

P_m = 6 ksi

P_b = 9 ksi

SF = 1.39

Using the inputs shown above, **pc-CRACK** was used to determine the weld overlay thickness. A maximum weld overlay thickness of 0.21-inch was determined in order to meet ASME Section XI IWB-3640 requirements.

Use of 75% of Wall Maximum Criteria

The ASME Code Section XI, IWB-3640 does not allow for an a/t greater than 0.75, where a is the crack depth and t the combined thickness of the original pipe and weld overlay. The calculated weld overlay determined using **pc-CRACK** does not satisfy this requirement.

To satisfy this requirement, the weld overlay thickness can be calculated as below:

$$(a+0.075)/[(a+0.075) + t_{wo}] = 0.75$$

where: 0.075 = assumed thickness of weld overlay first pass (not counting

structural portion of overlay).

a = thickness of original pipe

t_{wo} = thickness of weld overlay (structural portion)

This results in a weld overlay thickness of 0.25 inch which does not include the first layer (0.075 inch).

Use of Section III Stress Limits

Since the weld overlay is being placed symmetrically over the weld centerline, meeting this criteria is not an issue. There may be some instances when the overlay will not be symmetric or may not meet the length guidance provided in Code Case N-504-1. If that is the case, finite element analysis may be required to demonstrate that the ASME Code Section III stress limits are met.

Weld Overlay Length

Per ASME Code Section III Code Case N-504-1, it is suggested that the length of the overlay be at least $0.75\sqrt{Rt}$ from the crack location in order to support meeting the ASME Code Section III stress limits. Note that this is not a requirement and that shorter lengths may satisfy the Section III requirements which may requires the use of finite element analysis. For this location, $R = 12.75$ inches and $t = 0.687$ inches.

$$L = 0.75*\sqrt{[(12.75/2)*0.687]} = 1.6 \text{ inches}$$

This is measured from each weld to pipe interface. Using typical weld prep dimensions result in a weld crown of approximately 0.9 inch. Thus the total length of the overlay is:

$$L = 1.6 + 1.6 + .9 \cong 4.1 \text{ inch}$$

Note that the 4.1 inch length corresponds to the full thickness portion of the overlay. Beyond this, a 45 degrees taper is used.

Crack Growth Considerations for Overlay Material

ASME Code Case N-504(g)(2) requires that the repair consider potential flaw growth due to fatigue and the mechanism believed to have caused the flaw. The flaw will be considered to grow through the original pipe wall via fatigue and stress corrosion cracking. Fatigue and stress corrosion crack growth on considered in the following discussion.

Stress Corrosion Cracking

The weld overlay material is Alloy 52 (UNS N06052, Alloy 52, ASME Code Case 2142) applied over the Alloy 182/Alloy 82 weld and carbon steel safe end. Generic Letter 88-01, which addresses stainless steel weld overlays, discusses a dilution layer when welding over austenitic stainless steel, which requires that the first layer not be considered as IGSCC resistant if it does not have a ferrite level of 7.5% (or 7.5 FN). This situation does not exist in nickel base alloys (such as Alloy 52) since there is no ferrite and the IGSCC resistance comes generally from the high level of chromium in the alloy. Consequently, the initial layer can be retained as IGSCC resistant provided the chromium level is sufficient. It is believed that a chromium level of approximately 25% is required to provide outstanding IGSCC resistance for austenitic materials in the BWR environment. Note for example, that XM-19, a very resistant material, has nominally 22% chromium. As a reference point, Alloy 82, an alloy identified by the NRC as IGSCC resistant in Generic Letter 88-01, contains a nominal chromium level of 18 to 22% and Alloy 182, a susceptible material, contains a nominal chromium level of 13 to 17%. In contrast, the nominal chromium level of Alloy 52 is 30%.

When diluted with Alloy 182, it is anticipated that the chromium level of the diluted first layer produced by an Alloy 52 weld overlay would at least be equivalent to that in Alloy 82, and would most likely approach 25% chromium, since more filler metal is typically mixed with the "bite" taken from the base material (which in this case would be Alloy 182) to form the weld puddle. Consequently, the diluted "first layer", or 0.075-inch (nominal), should be resistant to IGSCC and therefore can most likely be counted as an IGSCC resistant layer. In any case, even if the chromium level did

not reach the "resistant" composition, this layer can be considered as part of the structural reinforcement, independent of the chromium level, since the weld procedure qualification (which will be performed) qualifies this as a structural weld overlay. In the event of a chromium poor initial layer, the first layer may not qualify as fully IGSCC resistant, but always would be considered structural, as long as the IGSCC is observed not to penetrate this layer. This is accomplished by performing a surface examination of the original surface, determining it to be free of IGSCC and performing a second surface examination following the application of the initial overlay layer. If the second PT shows no indications, the overlay layer is acceptable.

Note that the recommended first layer thickness is a nominal value. A first layer less than 0.075-inch is acceptable as long as the first layer passes the inspection discussed above. However, if the measured first layer exceeds 0.075-inch, the difference between the measured thickness and 0.075-inch must be added to the 0.25-inch weld overlay structural thickness. This assures that the 0.75 maximum a/t ratio is met.

In summary, welding with the chromium rich Alloy 52 generally provides an IGSCC resistant first layer even when diluted with Alloy 182. This layer is always a structural layer, since it will be qualified as such. If the dilution is severe, the initial layer may not have the IGSCC resistance of the subsequent undiluted layers, but should at least match the IGSCC resistance of undiluted Alloy 82, a material considered IGSCC resistant in Generic Letter 88-01.

Fatigue Crack Growth

As discussed earlier, the overlay material is highly resistant to IGSCC. However, the weld material is not inherently immune to fatigue crack growth. Thus, fatigue crack growth must be considered in evaluating the long-term integrity of the weld overlay. The amount of fatigue crack growth is dependent on the number and magnitude of the stress cycles. Calculations performed as a part of weld overlay design efforts have historically predicted crack extension due to fatigue to be insignificant over several operating cycles, using plant specific stress and design cycle information, with no credit taken for residual stress benefits. Based upon results of this type, it has generally been concluded that flaw extension by a fatigue mechanism would not be significant but if it did occur, would be detected by ISI prior to degradation of the design.

To demonstrate the small amount of crack growth expected for the overlay, following is a simplified conservative calculation. Note that at this time, the ASME is considering a Code Case to define fatigue crack growth rates for austenitic stainless steel material in the light water reactor environment. Although the weld overlay material is Alloy 52, the use of stainless steel fatigue crack growth rates is considered conservative since they are both face centered cubic materials and similar crack growth rates to those of stainless steel have been reported in Alloy 600 and Alloy 182 in the BWR environment. The impact of the environment on fatigue crack growth is an issue being considered in the industry.

For purposes of this calculation, a factor will be applied to the fatigue crack growth rate for stainless steel in an air environment. The ΔK for a 360° crack (with depth

equal to original pipe wall), subjected to the normal operating stresses is approximately 30 ksi $\sqrt{\text{in}}$. Analyses have been performed for similar weld overlays with and without stagnant water on the inside surface. Results of the evaluation have demonstrated compressive stresses on the inner portion of the pipe. This results in essentially no crack growth. The R-ratio ($K_{\min}/K_{\max}$) is therefore taken as low. For these values, the crack growth rate in air is approximately 1.2×10^{-5} in/cycle.

It should be noted that the ASME is considering a Code Case regarding austenitic stainless steel fatigue behavior. Applying the factor of 10 to the air environment fatigue crack growth rate results in a crack growth rate of 1.2×10^{-4} in/cycle.

Most of the loading in the piping is associated with startup-shutdown cycles. Other operational transients occur much less frequently or at lower stresses. For purposes of this evaluation, 120 startup-shutdown cycles will be used. This is conservative since Perry has been operating for several years and the 120 cycles is equivalent to the allowable number of startup-shutdown cycles for the entire 40-year original license period.

Based on these conservative assumptions, the crack growth resulting from fatigue is estimated to be:

$$\Delta a = (120 \text{ cycles})(1.2 \times 10^{-5} \text{ in/cycle})(10) = 0.014\text{-inch}$$

This confirms that the amount of fatigue crack growth is expected to be small. Note also that the first 0.075-inch of Alloy 52 material is not considered as the load carrying portion of the overlay to meet sizing requirements. The 0.075-inch (nominal) layer is applied to compensate for possible stress corrosion cracking due to dilution effects. However, SCC is expected to be minimal, well below the allotted 0.075-inch. The first 0.075-inch of weld overlay material could be used to compensate for both fatigue crack growth and SCC. Therefore, it is not considered necessary to add additional material to the 0.25-inch load carrying overlay material for fatigue crack growth consideration.

Based on the discussion above, this design meets the ASME Code Section XI safety margins and the ASME Code Section III stress limits for primary local and primary bending stress.

3

LOCALIZED OVERLAY WELD REPAIRS

The United States Nuclear Regulatory Commission (USNRC) issued Generic Letter 90-05 (GL90-05), "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping." This document provides guidelines for evaluating relief requests for performance of temporary, non-Code ASME Class 3 repairs to piping while a plant is operational. GL90-05 currently requires that all permanent repairs be conducted in accordance with ASME Code requirements. Non-Code approaches must be submitted for review and evaluation to the USNRC on a case-by-case basis for consideration before a relief request is granted. Application of weld overlays to low carbon steel systems or components, on either a temporary or permanent basis, is not addressed for systems installed to ASME III or repaired under ASME XI.

The ability to perform localized weld overlay-type repairs on low carbon steel ASME III Class 2 and 3 systems as "Code repairs" is desirable. In order to support applicable code case work efforts, the ASME Section XI "Task Group on Alternative Rules for Repair of Erosion-Corrosion Damage" determined that in addition to analytical studies, data obtained from actual burst testing on selected pipe diameters and weld overlay repair configurations were needed. In response to this need, utilities and members of EPRI's Repair & Replacement Application Program supported the analysis and burst testing of piping mockups.

PREPARATION AND WELDING

Test Specimens

A total of 28 weld overlay repairs were installed on 12 carbon steel (A106 Grade B) pipe coupons. Three pipe coupons (4A, 4B, and 8H) had been removed from the Service Water System of an operating nuclear plant. These three coupons exhibited numerous areas of localized wall thinning -- the cause of which was determined, by chemical analysis, to be microbiologically influenced corrosion (MIC). For these three coupons, representative thinned locations were selected for repair. The remaining nine coupons consisted of new piping. One coupon (8E) from this group of nine was selected as a control specimen. This control specimen was tested without creation of any thinned areas and without installation of any weld overlay repairs. Simulation of internal wall thinning in the eight remaining coupons was accomplished using one of the following three methods:

- 1) Cut and Patch Method - A through-wall rectangular hole was created in the pipe wall. This hole was subsequently closed using a 1/8" thick backing plate. This

backing plate was welded in place using ER70S-2 filler material. The weld overlay was installed over the backing plate and adjacent pipe.

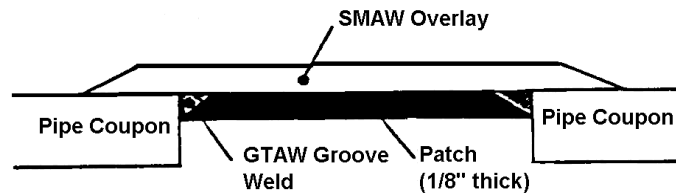


Figure 1. Cut and Patch Method

- 2) Electrical discharge machining (EDM)--EDM was used to remove base material from the pipe ID surface.
- 3) Mechanical metal removal -- milling or other machining was used to remove base material from the pipe ID surface.

These three methods to simulate wall thinning were selected to provide utilities several demonstrated approaches for qualification. Each method provided similar results. The length and width of each thinned area were recorded. Ultrasonic wall thickness examinations were performed to document the wall thickness in each thinned area prior to weld overlay installation. Pipe caps were butt-welded to both ends of each coupon to facilitate simulation of water backing during weld installation, and to provide for burst testing upon welding completion. Repair areas were cleaned as necessary to remove paint, rust, scale, and other foreign matter. Coupons were placed in pipe stands, and remained stationary throughout the installation of each weld overlay repair.

Overlay Installation

Weld overlay installation was accomplished in accordance with guidelines developed by the ASME Task Group on Alternate Repair for Erosion and Corrosion. All weld overlay repairs employed the following installation guidelines:

- Welding was performed by qualified welders using qualified welding procedures, standard welding equipment, and E7018 electrodes.
- With the exception of coupon 4A, all coupons were filled with cold, flowing water throughout the installation of the overlay repair. Coupon 4A, which contained extensive corrosion products (MIC deposits), was saturated with water and subsequently drained immediately prior to welding, to simulate a piping system which had been recently drained.
- External preheat was not applied. Preheat temperatures, which were directly related to water temperature, averaged approximately 70F.
- Final grinding was performed only to the extent necessary to prepare completed repair areas for final nondestructive examinations.

The final thickness of each repair area (i.e., the thickness of the weld deposit plus the thickness of the underlying base material) was equal to or less than the nominal pipe wall thickness.

In addition to the preceding requirements, the instructions developed by the Task Group also provided for simulation of several “worst case” scenarios. Unique conditions included:

- 1) Burn-through of water-filled piping. The weld overlay operation caused complete, through-wall penetration of the underlying base material during installation of four overlay repairs (coupon 4B repair 2, coupon 8H repairs 5 and 9, and coupon 24B). In each instance where burn-through occurred, the area(s) of burn-through were repaired using E7018 electrodes. The affected coupon was not drained to facilitate burn-through repair, nor was the flow of water interrupted at any time during the repair.

Subsequent destructive testing of burn-through repair areas demonstrated that each through-wall repair was mechanically and structurally sound. Subsequent nondestructive testing of burn-through repair areas demonstrated that these repairs were free of defects, indicating that repair of through-wall leakage may be acceptably accomplished using shielded metal arc welding, without isolating and draining the leaking component.
- 2) Welding over existing welds. Coupon 8G involved installation of a weld overlay on a circumferential girth butt weld. This girth weld was located in the center of the test coupon, and the weld overlay was centered on the girth weld.
- 3) Heat input variation - Both low and high heat inputs were used in distinct locations on specific repairs, to permit assessment of heat input effects.
- 4) Untempered welding - To simulate a situation where water-backed welding was performed without a temperbead weld layer, a final, circumferential weld bead was installed around the perimeter of two completed overlay repair areas (coupon 8H repairs 2 and 9). Subsequent metallurgical examination identified that, as predicted, this final untempered weld bead created high hardness levels in the adjacent heat affected zones.
- 5) Shrinkage monitoring - Punch marks were installed on pipe O.D. surfaces adjacent to selected overlay repair areas. These punch marks were used to monitor shrinkage resulting from overlay installation. Circumferential shrinkage monitoring yielded the following dimensions:

Table 1. Shrinkage Measurements

<i>Coupon</i>	<i>Coupon Diameter</i>	<i>Maximum Longitudinal Shrinkage</i>	<i>Maximum Circumferential Shrinkage</i>	<i>Overlay Dimensions Longitudinal</i>	<i>Overlay Dimensions Circumferential</i>
4A	4"	0.06"	0.06"	--	--
4B	4"	0.10"	0.10"	--	--
8A	8"	Not Measured	0.125"	5.8"	3.8"
8B	8"	Not Measured	0.125"	3.8"	5.8"
8C	8"	Not Measured	0.125"	5.8"	3.8"
8D	8"	Not Measured	0.125"	3.8"	5.8"
8F	8"	.015"	0.044"	2.8"	3.8"
8H	8"	0.10"	0.10"	--	--
24B	24"	Not Measured	0.540"	9.2"	15.2"

Note that the circumferential shrinkage associated with coupon 24B (0.540") resulted from an overlay repair area that was 9.2 inches in length and 15.2 inches in width -- the corresponding shrinkage is commensurate with these repair dimensions.

Coupons 4A, 4B, and 8H, and were field removed samples and were repaired with multiple overlays (4A: 6 overlays, 4B: 3 overlays, 8H: 11 overlays).

- 6) Multiple repairs in a single location - Initial overlay repairs were installed in two separate locations (coupon 4A repair 6 and coupon 8H repair 1) to restore nominal wall thickness. Upon thickness restoration, grinding was performed on the underlying, internal pipe surfaces to reduce the repair area thickness to a value below design minimum wall. A second overlay repair was then installed on the O.D. surface of each of the initial overlays to restore nominal thickness.
- 7) Pitting simulation - To simulate pitting, three holes of varying diameters (1/16", 3/32" and 1/8" diameter, respectively) were drilled on the pipe I.D. surface beneath two separate overlay repair areas (coupon 8H repairs 2 and 11). These holes did not penetrate through the overlay - remaining overlay thickness, after drilling, was approximately .125".

OVERLAY TESTING

Nondestructive Examination

After welding, all overlay repair weld surfaces were prepared by grinding to achieve a surface suitable for ultrasonic thickness measurement. Thickness measurements were performed to verify that the combined thickness of the overlay and the underlying base material was approximately equal to the original nominal pipe wall. Weld metal was added or removed as necessary to obtain the desired thickness.

Magnetic particle examination was performed on all completed overlay repairs, and on adjacent base materials for a minimum of 1/2" in each direction. No defects or relevant indications were detected in either the weld material or in the adjacent base material.

Radiographic examination was performed on all overlay repairs on coupons 4A, 4B, and 8H. No defects or relevant indications were detected in either the weld material or the adjacent base material. The areas where burn-through had occurred (coupon 4B repair 2, coupon 8H repairs 5 and 9) were also free of defects.

Burst Testing

Hydrostatic burst testing was performed on all coupons. Strain gauges were attached and strain levels recorded at several pressure levels for coupons 4A, 8C, 8D, 24A, and 24B. Pressure was increased until plastic deformation occurred. Maximum pressure values were recorded, and the coupon was depressurized. Outside diameter dimensions were then measured, and repeated at incremental pressure levels. After failure, a final set of diameter measurements were recorded, the failure location was photographed and characterized, and the coupon was prepared for subsequent testing and evaluation.

Burst pressures, both calculated and actual, are as follows:

Table 2. Burst Test Pressures

<i>Coupon</i>	<i>Max. Allowable Working Pressure (Note 1)</i>	<i>Design Burst Pressure (Note 2)</i>	<i>Actual Burst Pressure</i>	<i>Approx. Test Temp.</i>	<i>Factor of Safety (Note 5)</i>
Coupon 4A (4" Sch. 80)	2,075	10,234 psi (Note 3)	9,100 psi	75F	3.39
Coupon 4B (4" Sch. 80)	2,075 psi	11,008 psi (Note 3)	9,100 psi	75F	3.39
Coupon 8A (8" Sch. 40)	1,007 psi	5,568 psi	6,000 psi	55F	4.96
Coupon 8B (8" Sch. 40)	1,007 psi	5,568 psi	6,000 psi	55F	4.96
Coupon 8C (8" Sch. 40)	1,007 psi	5,568 psi	5,900 psi	62F	4.85
Coupon 8D (8" Sch. 40)	1,007 psi	5,568 psi	6,000 psi	62F	4.96
Coupon 8E (8" Sch. 40)	1,007 psi	5,569 psi	5,750 psi (Note 4)	41F	4.71
Coupon 8F (8" Sch. 40)	1,007 psi.	5,568 psi	5,750 psi	41F	4.71
Coupon 8G (8" Sch. 40)	1,007 psi	5,568 psi	6,000 psi	62F	4.96
Coupon 8H (8" Sch. 40)	1,007 psi	5,390 psi (Note 3)	4,900 psi	72F	3.87
Coupon 24A (24" Sch. 20)	415 psi	2,248 psi	2,425 psi	36F	4.84
Coupon 24B (24" Sch. 20)	415 psi	2,248 psi	2,245 psi	37F	4.41

Note 1: Maximum allowable working pressures were calculated using ASME III, 1992 Edition through 1993 Addenda, NC-364 1. 1, Equation 5.

Note 2: Design burst pressures were calculated based on ANSI B16.9 requirements.

Note 3: Coupons 4A, 4B, and 8H were MIC-damaged sections of piping that were removed from the Service Water System in an operating nuclear plant. All three coupons exhibited significant MIC damage along the entire length of each coupon. Pitted areas were typically 1/2" to 1" in diameter, with depths ranging from 40% to 50% of nominal wall thickness. Initiation of the burst fracture occurred, for each of these three coupons, in a MIC-induced pit which had not been weld overlay repaired.

Note 4: Coupon 8E was a control coupon. No repairs were performed.

Note 5: Factor of Safety = Actual Burst Pressure/MAWP-1.

Burst pressures for coupons 8A, 8B, 8C, 8D, 8F, 8G, 24A, and 24B exceeded calculated design burst pressures. Burst pressures for 8" diameter coupons 8A, 8B, 8C, 8D and 8F equaled or exceeded the burst pressure of the control sample (coupon 8E). These burst pressures demonstrate that these weld overlays did not degrade the pipe material or adversely affect structural performance. Burst pressures for coupons 4A, 4B, and 8H were, as expected, below the design burst pressures calculated using nominal wall thickness values. As explained in Table 2 Note 3, these thinned areas had been previously identified as MIC damage sites, but overlay repairs were not installed since design minimum thickness requirements were satisfied. Normal operating conditions for these three pipe spools, while in service, were 60 psi and 95°F --maximum design operating conditions were 200 psi and 100°F. Burst pressures were on the order of 25 to 45 times higher than maximum design conditions. Substitution of the actual failure location wall thickness for "t" yields design burst pressures that are significantly lower than the actual burst pressures.

At the request of the ASME Section XI "Task Group on Alternative Rules for Repair of Erosion-Corrosion Damage," the EPRI Repair and Replacement Applications Center (RRAC) has completed additional testing of Class 2 & 3 high energy piping to

include burst testing of long radius elbows. Supplemental testing, included localized overlay repairs on 4-, 8- and 24-inch diameter elbows. Coupon designs were based on predictive finite element analysis (FEA) models generated by Altran Corporation.

Flaw development was typical of that used in the straight pipe. The practice of using a shaped insert to represent the thinned area provided the ability to set an exact pre-weld thickness. Post-weld ultrasonic examinations of the defect area ensured that the cumulative repair thickness (thinned wall plus the overlay height), did not exceed 87½ % of the nominal wall thickness. This allowed a design to be based on the absolute minimum nominal wall thickness possible as produced by the manufacturer.

Three coupons were made for each of the diameters in the matrix. The first sample was a control coupon with no defect. Second, a thinned coupon was repaired with the defect centered on the extrados of the elbow and centered about the arc at an azimuth of 45°. The third coupon had its flaw centered about the arc, but with the toe of the weld overlay located on the center of the extrados as shown in Figure 2.

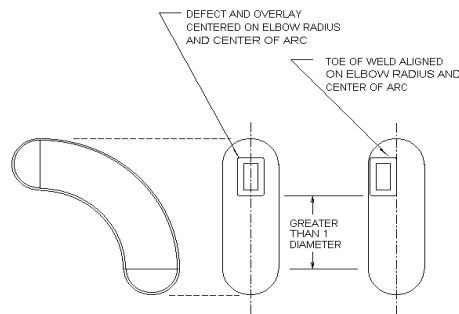


Figure 2. Elbow Overlay Alignment

Pressurization was done hydro-statically in uniform increments. Outside diameter and axial dimension changes were recorded in conjunction with these pressures.

Failures in the control coupons occurred along the extrados of the elbow. The outside radius offers a larger bending moment due to the greater span between the restraints created by the end cap welds. It should be noted that this region also has a thinner wall relative to the intrados as a result of the manufacturing process.

Failures in the flawed coupons occurred either along the intrados or on the sides 90 degrees from the intrados. The overlay weld metal offers a structural reinforcement thereby “driving” the failure to another location.

Burst pressures, both calculated and actual are as follows:

Table 3. Elbow Burst Pressures

<i>Mechanical</i>		<i>Max. Allowable Working Pressure</i>	<i>Design Burst Pressure</i>	<i>Actual Burst Pressure</i>	<i>Factor of Safety</i>	<i>Testing and</i>
	<i>Coupon</i>					
	Coupon 4L1 - control	2,075 psi	7,040 psi	7,800 psi	3.76	
	Coupon 4L2	2,075 psi	7,040 psi	7,600 psi	3.66	
	Coupon 4L3	2,075 psi	7,040 psi	7,800 psi	3.76	
	Coupon 8L1 - control	1,007 psi	5,568 psi	6,000 psi	5.96	
	Coupon 8L2	1,007 psi	5,568 psi	5,900 psi	5.86	
	Coupon 8L3	1,007 psi	5,568 psi	6,000 psi	5.96	
	Coupon 24L1 - control	415 psi	2,248 psi	2,425 psi	5.84	
	Coupon 24L2	415 psi	2,248 psi	2,600 psi	6.27	
	Coupon 24L3	415 psi	2,248 psi	2,425 psi	5.84	

Microstructural Examination**Side Bend Testing**

Side bend specimens were cut from coupon 4A repairs 1 and 6, coupon 4B repair 1, and coupon 8H repairs 1, 2, 8, and 9. These side bends included a cross-section through the weld overlay repair area, and were bent so that the convex surface of the bend specimen was centered on the interface between the edge of the overlay and the adjacent base material. All side bend specimens behaved in a ductile manner. No splits, tears, or other defects were visually observed in any of the side bend specimens.

Microhardness Testing

HAZ hardness values for coupons 8A and 8B provided some indication that lower HAZ hardness may be obtained in locations of lower weld heat input (21 KJ/in) than in areas of high heat input (31.5 KJ/in). This minor difference in hardness values, however, is considered insignificant with regard to weld repair acceptability, since all values fall within the range normally considered acceptable for the materials tested.

HAZ hardness values for coupons 8C and 8D were slightly higher than those recorded for coupons 8A and 8B. This difference in hardness values is attributed to the method of preparation for overlay weld repair. Coupons 8A and 8B were prepared using the cut and patch method, while coupons 8C and 8D used EDM. The cut and patch approach appears to provide a degree of tempering, as a result of installation of the groove weld used to install the patch plate. This tempering benefit was not available when EDM was used.

HAZ hardness values for coupon 24B were slightly lower than those of coupon 24A. This difference in hardness values is attributed to the multiple through-wall repairs on coupon 24B. Although these repairs were performed in the presence of water, a measurable tempering benefit appears to have been achieved.

Microstructural Evaluation

Evaluations were performed to assess the microstructure at the interface between weld toe and the underlying base material. Martensite was apparent in all locations;

however, all heat affected zones (except for coupon 8H repairs 2 and 9) demonstrated that this martensite had received some degree of tempering as a result of weld installation. Examination of this zone in welds installed with higher heat input values revealed a coarse martensitic structure. This coarseness was reduced in areas where lower welding heat input values had been used. Martensite generally extended a distance of 0.25mm/0.5mm beyond the weld toe. Immediately beyond this range, the martensitic structure began to dissipate into a predominately bainitic structure. This bainitic structure extended to the outermost edges of the heat affected zone. The microstructure of the adjacent, unaffected base material was a mixture of ferrite and pearlite.

The microstructure adjacent to coupon 8H repairs 2 and 9 (the two repair locations which incorporated a final, untempered perimeter pass) clearly lacked the tempering effects of adjacent weld beads. The heat affected zones adjacent to these perimeter passes contained acicular transformation products which, as previously stated, demonstrated high hardness values.

Toughness Testing

Charpy tests were performed at 70°F on coupons 8C, 8D, 24A and 24B. Notch locations for all Charpy specimens were within the weld overlay heat affected zone. Specimen notches were, to the greatest extent possible, centered at locations that were 1, 3, and 5 mm from the weld fusion line, with notches aligned in the through-wall orientation.

Average Charpy values for coupons 24A and 24B were equal to or greater than 60 ft-lbs. Average Charpy values for coupons 8C and 8D were equal to or greater than 45 ft-lbs. All values are consistent with expected toughness values for A106 Grade B base materials. The differences in absorbed energy between the 8-inch and 24-inch coupons are attributed to the differing properties of the respective heats of base material.

ENGINEERING ANALYSIS

Finite Element Analysis (FEA)

A finite element model was developed using data obtained from both ultrasonic thickness measurements and burst testing. Burst test data included recorded output from strain gauges installed on coupons 8C, 8D, 24A, and 24B, as well as the sequential diameter measurements recorded during the incremental pressurization of all burst coupons. A three-dimensional model of the weld overlay area was developed using ANSYS 5.OA software.

Modeling was performed on various pipe sizes, including piping 4", 8", 12", 16", 20", and 24" NPS. Burst test results obtained from coupons 8B, 8C, 8D, 8F, 24A, and 24B showed strong correlation between burst results and FEA predictions. The majority of the rupture initiation sites in these coupons were axially oriented, and

these initiation sites were located a short distance outside the weld overlay heat affected zone. These ruptures occurred in locations which were identified, by FEA, as locations of maximum stress intensity.

One test coupon (coupon 8F) was prepared with a 1" by 2" thinned area. This repair size duplicated the repair size predicted, by FEA, to result in an overlay stronger than the original pipe. This coupon, during burst testing, failed at a location 180° opposite the weld overlay location, supporting the accuracy of FEA results. The elbow models evaluated by Altran showed an increase of the stress intensification factor from 2.1 for piping to approximately 2.4 for a repaired elbow. These results were under further study at the time of preparation for this paper.

All burst test comparisons provide reasonable demonstrations of FEA modeling accuracy. Based on these results, this FEA model is considered a viable tool for predicting stresses in the region of weld overlay repairs under internal pressure and bending loads.

CONCLUSIONS

Test results from this project have shown that weld overlay repairs are feasible for thinned Class 2 & 3 ferritic piping. The following conclusions were developed:

- The structural integrity of a thinned pipe can be restored by localized weld overlays, provided the combined thickness of the overlay and remaining pipe wall is equal or greater than the nominal pipe wall thickness.
- Localized weld overlays can be applied with water backing and over existing welds.
- Defects such as wall thinning due to erosion-corrosion damage, pitting, burn-through, and multiple repairs did not adversely influence pressure retention.
- Burst pressures of overlaid samples were typically 4 times the maximum allowable working pressure, and 25 to 45 times the actual service conditions.
- All of the burst samples failed outside of the weld overlay area.
- Burst pressures for elbows were identical to pipe coupon results.
- All burst test comparisons provide reasonable demonstrations of FEA modeling accuracy.

4

ALTERNATIVE REQUIREMENTS FOR WALL THICKNESS RESTORATION OF ASME CLASS 2/3 CARBON STEEL PIPING COMPONENTS

Configuration of The Weld Overlay Repair:

The thinned wall area is bounded by the rectangular area $A = L \times C$ (where L is axial and C is circumferential length) and the minimum remaining thickness is designated u . Figure 1 illustrates a typical partial sectional view of a thinned wall pipe with proposed weld overlay. The weld overlay is required to extend beyond the thinned area in all directions a minimum overlap length of S , have a minimum thickness of w , and an edge angle a .

Pipe components without any defects are herein referred to as *virgin* coupons. The defect orientation in straight pipe components, is aligned with the pipe longitudinal axis or perpendicular to it. For elbows, there are two defect locations. The first, Patch A is centered axially and circumferentially to the elbow. The second, Patch B is off-centered circumferentially. The location of Patch A and B are illustrated in Figure 2. Figure 3 shows the defect positions for tees and reducers.

The following relations define the limiting parameters and design variables of the thinned area and the required weld overlay repair. The maximum axial dimension and area of base metal predicted to degrade below minimum design wall thickness over the remaining life of the repair shall not exceed that defined by the equations:

$$L_{\max} = k_1 D_o + k_2$$

$$A_{\max} = 0.455 D_o - k_3 \quad \text{where:}$$

$$C_{\max} = \frac{A_{\max}}{L_{\max}}$$

$$u_{\min} = 3/8 t$$

$$w_{\min} = 1/2 t$$

$$S_{\min} = 3/4 \sqrt{R t}$$

$$k_1 = 0.21 \text{ for pipe smaller than NPS 12}$$

$$= 0.11 \text{ for pipe NPS 12 to NPS 24}$$

$$k_2 = 0.55 \text{ inch for pipe smaller than NPS 12}$$

$$= 1.84 \text{ inch for pipe NPS 12 to NPS 24}$$

$$k_3 = 0.9 \text{ inch}^2 \text{ for pipe smaller than NPS 8}$$

$$= 0.8 \text{ inch}^2 \text{ for pipe NPS 8 to NPS 24}$$

$$D_o = \text{nominal pipe outside diameter (inch)}$$

$$t = \text{nominal pipe wall thickness (inch)}$$

$$R = \text{pipe outer radius (inch)}$$

$$\text{NPS} = \text{nominal pipe size}$$

The expressions for $L_{\max}$ and $A_{\max}$ were developed based on stress analysis of straight pipes with weld overlay which is described below. The same equations were used to define the maximum degraded areas for elbows and other fittings.

RRAC Burst Pressure Testing:

Burst pressure testing were performed on virgin components (i.e. without thinned wall thickness) as well as components with thinned walls and weld overlay repair. Tested components included straight pipes and elbows. Some of the test coupons were obtained from piping systems in operating nuclear plants. The remaining test components were full size mock-up components.

RRAC Burst Pressure Testing of Straight Pipe:

EPRI RRAC burst pressure testing of straight pipe components were conducted in two phases, Phase I and Phase II. Two 4 inch schedule 80 and one 8 inch schedule 40 pipe with weld overlay repair were selected for the Phase I pressure test. These test coupons were removed from an emergency service water system and exhibited numerous area of wall thinning away from weld repair. The Phase II test coupons are six 8 inch schedule 40 and two 24 inch schedule standard pipes with simulated wall thinning and weld overlay repair. Table 1 summarizes the repair parameters, the tested (actual) burst pressure and the computed design burst pressure using Code equations. These tests showed that the repaired areas did not impact the burst pressure. No failures were observed in the area of the weld overlays.

RRAC Burst Pressure Testing of Elbows:

Burst pressure testing of elbows were conducted on virgin as well as coupons with Patch A and Patch B repairs. Two elbow sizes were tested, 8 inch schedule 40 and 24 inch schedule standard. The elbows are long radius and are supplied with short straight pipes with end caps. The elbows were subjected to an incremental pressure loading of 1000 psi for the 8 inch coupons and 600 psi for the 24 inch. After each loading increment, the pressure was relieved and measurements of deformation were taken. The pressure was then increased and the process repeated until the pipe ruptures. On rupture, the pressure was noted and is tabulated below in Table 2 along with the design Code burst pressure and the repair geometries. Additional 8" Sch.40 elbows with $\frac{1}{2}D \times \frac{1}{2}D$ patch were also tested and results are presented in Table 2.

Stress Analyses of Repaired Components Using FEA:

The purpose of these analyses was two fold. First, the applicability of the ASME Code stress equations in Sections NC/ND to Class 2/3 piping with weld overlay repair had to be investigated. Proposed modifications, if any, to the Code equations were to be developed based on the analysis results. These modifications required good understanding of the mechanical behavior and stress distributions throughout repaired components. Second, simulations of the EPRI RRAC burst testing were performed to raise confidence in the analyses methods and justify their use for other component and fitting sizes. These simulations and analysis methods are then used to justify and develop a "cookbook" type guideline for weld overlay repair.

Finite element analysis (FEA) methods were selected to perform the stress analysis of pipe components. These methods are versatile, accurate, and provide detailed solution (stresses, strains, displacements) by refining the mesh as needed. The reliability and benefits of the FEA in modeling and analyzing piping components and other mechanical components is well established in the nuclear industry. Accuracy of the FEA in this study was established by comparing the FEA stresses versus the benchmark Code stresses for virgin straight pipes, elbows, tees, and reducers and by simulations of the RRAC burst tests.

In assessing the impact on the Code equations, linear elastic material modeling was used. Simulation of burst pressure testing of elbows incorporated elastic-plastic material simulation to closely model post-yielding material behavior.

FEA of Straight Pipes:

FEA investigations of straight pipe components were conducted previously by Southern California Edison. This study consisted of two phases that paralleled the

two phase EPRI RRAC tests described above. Table 3 summarizes the pipe sizes and weld repair geometries used in the analysis. Additional FEA for ½D x ½D Patch were performed by Altran and are documented in Ref. 6.

Calculated burst pressures showed good agreement with the RRAC burst test results. Based on the analyses of pressure and moment loads, the maximum acceptable thinning areas (L_{max} , C_{max}) were calculated and the proposed weld repair parameters (S, w, a) were developed. The results of the study recommends the use of a stress intensification factor (SIF) of $i = 2.1$ in the ASME Code equations to account for the higher stresses obtained by the FEA in the weld overlay areas.

FEA of elbows:

FEA methods were also utilized to obtain stresses in virgin (no thinning) elbows as well as elbows with Patch A (centered) and Patch B (off-centered) repairs. Figure 2 illustrates the layout of these patches. Details of the finite element models are shown in Figures 5A and 5B. For conservatism, the thinned areas were not included in the FEA models. The FEA included internal pressures, in-plane moment, and out-of-plane moment loads using linear elastic pipe material. FEA simulations of the RRAC burst pressure testing were also conducted. A summary of the defect size parameters and the analysis performed are presented in Table 4.

The FEA stress results for the virgin elbow coupons were comparable to the that of Code calculated stresses. However, results for Patch A and B coupons obtained by FEA were higher than that of the Code calculated stresses. Thus, changes to the Code equations are needed to reflect the increase in stresses. The ratios of the FEA stresses for elbows with weld repair to the Code stresses for virgin elbows were computed to obtain the required stress increase factors (considering Class 1 stress equations) as follows:

- Pressure stress increase factor, $C_{1P} = S_{FEA} / (\text{Code Pressure Stress})$, where the Code pressure stress was calculated according to Equation 10, Paragraph NB-3653 as follows:

$$\text{Code Pressure Stress} = C_1 \frac{PD_o}{2t}$$

where:

C_1 = pressure stress index

P = internal pressure

D_o = outside diameter of pipe

t = thickness of pipe

EPRI Proprietary Licensed Material

- In-Plane moment stress increase factor, $C_{2PIM} = S_{FEA} / (\text{Code Moment Stress})$, where the Code bending stress was calculated according to Equation 10, Paragraph NB-3653 as follows:

where:

$$\text{Code Moment Stress} = C_2 \frac{D_o M}{2I}$$

C_2 = moment loading stress index

M = bending moment load

I = moment of inertia

- Out-of-Plane moment stress increase factor, $C_{2POM} = S_{FEA} / (\text{Code Moment Stress})$, where the Code Moment Stress is as defined above.

- To simplify the process, a single increase factor, C_{2P} , for moment is proposed in the modified Code equations which is the envelop of C_{2PIM} and C_{2POM} .

The above increase factors, C_{1P} and C_{2P} , are labeled similar to the corresponding Code stress indices, C_1 and C_2 , for pressure and moment stresses, respectively. A summary of these stress increase factors is given in Table 5. Graph representations of these factors is also given in Figure 6.

The results of this FEA stress evaluation indicate the following:

- (a) The out-of-plane moment stresses are enveloped by the in-plane moment stresses.
- (b) The moment stress intensification factor for Class 2/3, $i=C_2K_2/2$, should be increased (by multiplying by C_{2P}) depending on the repair location (Patch A or Patch B) and the value of the flexibility characteristic, h , for the elbow.
- (c) The pressure results show an increase in the Code Class 1 stresses. Although Class 2/3 equations do not include stress indices for pressure stresses, the C_{1P} factor can be conservatively incorporated into the pressure stress of Class 2/3 equation 11 to account for increases resulting from the defect.
- (d) Review of stress results shows no change is required in the Code primary stress index, B_2 , and the Code peak stress index K_2 .
- (e) Review of deflection results show no change is required in the elbow flexibility factor, k .

FEA of Fittings:

Finite element analysis of reducers and tees were also performed to evaluate the increase in stresses due to wall thinning and weld repair. The postulated thinning

locations are shown in Figure 3. General isometric views of the finite element mesh in the repaired areas are shown in Figure 7. The tee model was of the un-reinforced fabricated tee (UFT) type.

FEA results showed that the pressure stress increases for the reducer are bounded by the increases determined for elbows (Table 5). No stress increases are required for moment stresses.

For Tees, no stress increase factors are required since the stress concentration for a repaired specimen does not change from that of a virgin specimen. However, for small ratios of branch to header sizes, the virgin tee stress concentration decreases. As the branch to header size ratio decreases, the problem converges to a straight pipe for which the stress intensification was recommended to be 2.1. Therefore, no change is recommended for the existing Code stress intensification index for tees except that a lower bound is set at 2.1 for this index.

Other fittings such as miter bends and corrugated bends were not analyzed and are considered outside the analysis scope. Further evaluations will be required for these components.

FEA Simulations of RRAC Burst Testing of Elbows:

Non-linear material models of the Patch A and B elbow repairs were generated using the FEA program to simulate the RRAC burst pressure testing of elbows. A bilinear kinematic plasticity model was specified for the pipe/weld material behavior. The material properties at yield and at ultimate stress were based on actual tensile test data. An equivalent failure stress strain was calculated based on the strain energy consumed in a more realistic stress-strain model with strain softening.

Rupture of the pipe was postulated to occur when the maximum stress at any point reaches the equivalent failure stress. The minimum pressure when rupture occur is taken as the burst pressure.

The results of the analysis showed close agreement with the RRAC test results given in Table 2. Thus, the use of FEA to predict actual burst pressure is justified.

ASME Code Cases:

Code Cases N-561 and N-562 presently address application of weld overlays to straight pipe - including use of the 2.1 stress intensification factor. Those Code Cases are currently undergoing revision to expand the provisions to elbows and tees, utilizing the data obtained and factors developed under the ALTRAN Finite Element Analyses and EPRI RRAC Burst Tests.

Stress Attenuation Length for Use with Weld Overlay Repairs:

A letter report provides the following stress attenuation lengths.

The following results are based on 4", 8", 16" & 24" size elbows, 16" x 8" size reducer, 20" x 20" x 10" Tee, 8" & 24" size straight pipes and can be generalized for other different size of fittings and pipes at this time. The stress attenuation length can be summarized as shown below:

Elbow Patch A:	$1.33 \sqrt{Rt}$
Elbow Patch B:	$1.75 \sqrt{Rt}$
Reducer with Patch:	$1.83 \sqrt{Rt}$
Tee with Patch:	Insignificant - use $0.75 \sqrt{Rt}$
Straight pipe with Patch:	Insignificant - use $0.75 \sqrt{Rt}$

Where R is inside radius

t is wall thickness

Table 1**Straight Pipe Burst Pressure Test Results Versus Code Design Values**

Phase	Test Coupon	Geometry of The Repair ⁽¹⁾ (inch)					Test Burst Pressure (psi)	Design Burst Pressure (psi) ⁽³⁾
		C	L	u	w	S		
Phase I ⁽²⁾ [1]	4A						9100	8990
	4B						9100	8990
	8H						4900	4480
Phase II [1]	8A	4	2	1/8	0.2	0.88	6000	5568
	8B	2	4	1/8	0.2	0.88	6000	5568
	8C	4	2	1/8	0.2	0.88	5900	5568
	8D	2	4	1/8	0.2	0.88	6000	5568
	8E	Virgin coupon with no thinned area					5750	5568
	8F	1	2	1/8	0.2	0.88	5750	5568
	24A	12	6	1/8	0.25	1.59	2425	2248
	24B	6	12	1/8	0.25	1.59	2425	2248
Additional 8" Sch.40 Piping [8]	Coupon C (Virgin)	N/A	N/A	N/A	N/A	N/A	6000	5568
	Coupon D (Repaired Pipe)	2	4	0.125	0.155	0.88	6200	5568

where:

L = axial length of defected area, [in.]

C = circumferential length of defected area, [in.]

u = remaining wall thickness at defected location, [in.]

w = weld overlay thickness, [in.]

S = weld overlap length, from defected boundary to weld overlay boundary

Notes:

(1) Weld edge angle, α , is 45° for coupon 4B and all Phase II coupons except for 8F for which it is 30°

(2) See Ref. 1 for defect/repair information.

(3) Burst pressure = $2 S_u t/D_o$ per ANSI B16.9. Values are adjusted to incorporate the actual material ultimate strength except for 4A and 4B which are based on $S_u = 60,000$ psi. t is the nominal thickness and D_o is the outside diameter.

Table 2**Pipe Elbow Burst Pressure Test Results Versus Code Design Values**

Test Coupon	Patch Location ⁽¹⁾	Geometry of Repair ⁽²⁾ (inch)					Test (actual) Burst Pressure (psi)	Design Code Burst Pressure (psi) ⁽³⁾
		L	C	u	w	S		
Long Radius Elbow Coupon (8" SCH 40) [4]	Virgin	N/A (No Weld Repair)					6000	5759
	Patch A	4	2	0.125	0.155	0.88	6000	5759
	Patch B						6100	5759
Long Radius Elbow Coupon (24" SCH STD) [8]	Virgin	N/A (No Weld Repair)					2425	2248
	Patch A	12	6	0.125	0.320	1.59	2600	2248
	Patch B						2425	2248
Additional 8" Sch.40 Elbow Testing	Coupon A (Virgin)	N/A	N/A	N/A	N/A	N/A	6300	5756
	Coupon B (Virgin)	N/A	N/A	N/A	N/A	N/A	5200	5756
	Coupon D Patch A (Repaired Elbow)	4	4	0.125	0.155	0.88	6400	5005
	Coupon E Patch B (Repaired Elbow)	4	4	0.125	0.155	0.88	5500	5005

where:

L = axial length of defected area, [in.]

C = circumferential length of defected area, [in.]

u = remaining wall thickness at defected location, [in.]

w = weld overlay thickness, [in.]

S = weld overlap length, from defected boundary to weld overlay boundary

Notes:

(1) See Figure 2 for locations of Patch A and Patch B

(2) Weld edge angle, $\mu = 45^\circ$

(3) Per ANSI B16.9 using the nominal pipe thickness and actual material ultimate strength

Table 3**Pipe Sizes And Patch Geometry for FEA Analysis of Straight Pipes**

Pipe Size NPS	Schedule	Removed Area L X C	Weld Overlay Thickness, w	Weld Overlap, S	Wall Degradation	Ref.
4"	80	4.7 x 4.2	0.17"	0.65"	Part Wall	Phase I [1]
4"	80	2.2" x 2.6"	0.26"	0.65"	Part Wall	Phase I [1]
4"	80	1.6" x 2.2"	0.19"	0.65"	Part Wall	Phase I [1]
4"	40	1 1/2" x 3/4" 3/4" x 1 1/2"	0.237"	0.55"	Through Wall	Phase II [1]
4"	80	1 3/4" x 7/8" 7/8" x 1 3/4"	0.337"	0.65"	Through Wall	Phase II [1]
6"	40	2" x 1" 1" x 2"	0.28"	0.72"	Through Wall	Phase II [1]
8"	40	2 1/2" x 1 1/4" 1 1/4" x 2 1/2"	0.322"	0.88"	Through Wall	Phase II [1]
12"	Std.	3 1/4" x 1 5/8" 1 5/8" x 3 1/4"	0.375"	1.16"	Through Wall	Phase II [1]
16"	Std.	3 1/2" x 1 3/4" 1 3/4" x 3 1/2"	0.375"	1.30"	Through Wall	Phase II [1]
20"	Std.	4" x 2" 2" x 4"	0.375"	1.45"	Through Wall	Phase II [1]
24"	Std.	4 1/2" x 2 1/4" 2 1/4" x 4 1/2"	0.375"	1.60"	Through Wall	Phase II [1]
8"	Std.	4" x 4"	0.161"	0.87"	Part Wall	Phase I [6]
16"	Std.	8" x 8"	0.188"	1.28"	Part Wall	Phase I [6]
24"	Std.	16" x 16"	0.188"	1.58"	Part Wall	Phase I [6]

**ALTERNATIVE REQUIREMENTS FOR
WALL THICKNESS RESTORATION OF
ASME CLASS 2/3 CARBON STEEL
PIPING COMPONENTS**

**Technical Report No. 96167-TR-01
Revision 0
Volume 1 of 1**

**Table 4
Weld Overlay Repair Evaluation Matrix For Elbows**

Size D _{nom}	Pipe Sch	Virgin			Patch A				Patch B				Defect Size Parameters (in)				
		PRES	MIP	MOP	PRES	MIP	MOP	BURST	PRES	MIP	MOP	BURST	L	C	S	U	W
4	STD	yes	yes	yes	yes	yes			yes	yes			1.5	.75	.53	.089	.119
8	20	yes	yes	yes	yes	yes			yes	yes			2.5	1.25	.77	0.94	.125
8	STD	yes	yes	yes	yes	yes			yes	yes			2.5	1.25	.87	.121	.161
8	STD	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes		7.76	2	.87	.121	.161
8	STD				yes							yes	4	2	.87	.121	.161
8	80	yes	yes	yes	yes	yes			yes	yes			2.5	1.25	1.07	.188	.25
8	160	yes	yes	yes	yes	yes	yes		yes	yes	yes		2.5	1.25	1.40	.34	.453
16	STD	yes	yes	yes	yes	yes			yes	yes			3.5	1.75	1.28	.141	.188
24	STD	yes	yes	yes	yes	yes	yes		yes	yes	yes		4.5	2.5	1.58	.141	.188
8	STD								yes	yes			4.0	4.0	0.87	0.121	0.161
16	STD								yes	yes			8.0	8.0	1.28	0.141	0.188
24	STD								yes	yes			12.0	12.0	1.58	0.141	0.188

Where:

D_{nom} = Nominal pipe diameter, in
 Sch = Pipe weight schedule
 STD = Standard pipe weight
 Virgin,
 Patch A, B = Elbow configuration
 PRES = Pressure loading
 MIP = In-plane moment loading
 MOP = Out-of-plane moment loading
 Burst = Elastic-plastic burst pressure

S = Defect overlap = $0.75 (r_m t)^{1/2}$
 U = Remaining pipe wall = $0.375 t$
 W = Weld overall thickness = $0.5 t$
 U+W = $0.875 t$
 t = Nominal pipe wall thickness, in
 r_m = Pipe mean radius, in

Note that the mean radius is conservatively used in the above expression for S instead of outer pipe radius.

Elbow D_{nom}	Pipe Sch	$h^{(4)}$	r_m/t	Stress Factor ⁽³⁾					
				Pressure C_{1P}		In-Plane Moment C_{2PIM}		Out-of-Plane Moment C_{2POM}	
				Patch A	Patch B	Patch A	Patch B	Patch A	Patch B
4	STD	0.313	8.99	1.24	1.33	0.89	0.91	—	—
8	20	0.171	16.8	1.27	1.33	1.04	1.20	—	—
8-x ⁽¹⁾	STD	0.224	12.9	1.24	1.30	0.94	1.03	—	—
8	80	0.364	8.1	1.23	1.25	0.91	0.93	—	—
8	160	0.730	4.3	1.11	1.14	0.85	0.89	0.63	0.80
16	STD	0.147	20.8	1.28	1.30	1.00	1.25	—	—
24	STD	0.097	31.5	1.24	1.24	1.01	1.34	0.54	0.64
8-y ⁽¹⁾	STD	0.224	12.9	1.57 ⁽²⁾	1.72 ⁽²⁾	0.94	1.07	0.60	0.56
8-z ⁽¹⁾	STD	0.224	12.9	1.57 ⁽²⁾	1.72 ⁽²⁾	0.94	1.07	0.60	0.56
8 ⁽⁵⁾	STD	0.224	12.9	1.62	--	0.98	--	--	--
16 ⁽⁵⁾	STD	0.147	20.8	1.79	--	0.91	--	--	--
24 ⁽⁵⁾	STD	0.097	31.5	1.88	--	1.03	--	--	--

Notes:

(1) x, y, and z indicate 8" standard patch sizes, length (L) x width (C) as follows:

x = 2.5" x 1.25"

y = 7.76" x 2"

z = 4" x 2"

(2) These high factors are due to surface stresses on the inside of and close to the sharp end of the defect area.

(3) C_{2P} = Maximum (C_{2PIM} , C_{2POM})

(4) h = elbow flexibility characteristic = $t R/r_m^2$, where R is the bend radius = $1.5 D_{nom}$

(5) Patch size is $\frac{1}{2}D$ x $\frac{1}{2}D$.

5

COATING/LINING RESTORATION

Failures in SWS piping are typically repaired by replacing the failed section with the like-materials or upgraded materials, localized repair (e.g. welding), or by lining degraded components, although lining materials are not intended to stop leaks or re-establish structural integrity of failed components. Short sections of piping with flanged spool pieces can be easily removed and replaced with pre-lined components or like-materials, but other less accessible components need to be repaired in place. Through-wall failures must be repaired (welding or replacement) and component integrity restored prior to coating / lining. Coatings are primarily utilized for :

- Eliminating existing corrosion problems.
- Minimizing replacement cost and extending the service life of degraded components.
- Nullifying galvanic couples by obstructing the cathodic or anodic reactions (i.e. cathodic protection).
- Protecting carbon steel components, with no corrosion allowance, in aggressive environments (e.g., seawater).

Coating/lining materials selection for restoration of uncoated and components with failed liners, should be consistent with existing system materials and operating conditions. Repair applications should consider the surface finish requirements, methodology of applying the coating, accessibility, etc. Typically, coating/lining materials are applied under wet and inferior surface conditions, due to corrosion degradation, high humidity and poor draining / drying capabilities. Surface preparation is generally achieved by chemical cleaning to a white metal finish followed by an abrasive cleaning to provide a textured finish or anchor pattern for the coating materials.

Lining materials commonly utilized for SWS applications include:

- Cement-Mortar Linings (carbon steel components).
- Fusion Bonded Coatings (e.g., epoxy, polyethylene, PVC).
- Solvent-Type Polymeric Coatings (e.g., epoxy phenolic, coal-tar epoxy).
- Sheet Applied Elastomers (e.g., rubber, neoprene).

Cement-mortar linings are typically used in carbon steel SWS components and piping, without a corrosion allowance. Seawater, brackish, and soft waters are highly aggressive to carbon and cast irons and are generally not used without a corrosion barrier in these

environments. Cement lining is limited to large diameter pipe due to the required coating thicknesses and accessibility.

Cavitation, erosion, leaching, and/or mechanical damage can cause failures in the concrete lining, resulting in exposed base materials. Degraded cement liners typically fail in large sections causing a potential for severe damage and blockage problems of downstream components. Failed areas of concrete-mortar liners are easily repaired by patching and/or total replacement. In either case, the surface should be cleaned utilizing a high pressure water jet and all loose debris removed and flushed from the system. Surface preparation is of less importance when applying mortar compared to fusion bonded and solvent type coating applications.

The mortar can be applied with a spinning/spray head, for complete coverage, or manually applied for localized repairs. Both techniques can be utilized for field or shop applications, depending primarily on the extent of damage and accessibility. Manual repair applications are typically limited to pipe diameters greater than 20 inches. Once the mortar is applied, a spring loaded trowel assembly spreads the mortar flush with the existing lining and/or to desired thickness, and produces a smooth surface finish. ACI Standard C-602 establishes guidelines for field applications for cement-mortar lining of water pipelines.

Weld Filler Metal Specifications

AWS Specification	Specification Title
A5.01-87	"Filler Metal Procurement Guidelines"
A5.1-81	"Specification for Covered Carbon Steel Arc Welding Electrodes"
A5.4-81	"Specification for Covered Corrosion-Resisting Chromium and Chromium-Nickel Steel Welding Electrodes"
A5.5-81	"Specification for Low Alloy Steel Covered Arc Welding Electrodes"
A5.6-84	"Specification for Covered Copper and Copper Alloy Arc Welding Electrodes"
A5.7-84	"Specification for Copper and Copper Alloy Bare Welding Rods and Electrodes"
A5.9-81	"Specification for Corrosion-Resisting Chromium and Chromium-Nickel Steel Bare and Composite Metal Cored and Stranded Welding Electrodes and Welding Rods"
A5.11-83	"Specification for Nickel and Nickel Alloy Covered Welding Electrodes"
A5.14-89	"Specification for Nickel and Nickel Alloy Bare Welding Electrodes and Rods"
A5.16-90	"Specification for Titanium and Titanium Alloy Welding Electrodes and Rods"
A5.18-79	"Specification for Carbon Steel Filler Metals for Gas Shielded Arc Welding"
A5.20-79	"Specification for Carbon Steel Electrodes for Flux Cored Arc Welding"
A5.22-80	"Specification for Flux Cored Corrosion-Resisting Chromium and Chromium-Nickel Steel Electrodes"
A5.28-79	"Specification for Low Alloy Steel Filler Metals for Gas Shielded Arc Welding"
A5.29-80	"Specification for Low Alloy Steel Electrodes for Flux Cored Arc Welding"
A5.30-79	"Specification for Consumable Inserts"

Standards for Evaluating Lining Materials

Tensile Properties /Elongation	ASTM D638 and ASTM D522
Coating Permeability	ASTM E96 AND ASTM G9
Lining Absorption	ASTM D471 AND ASTM D3491
Abrasion Resistance	ASTM D968 AND ASTM G6
Flexibility	ASTM D1737 AND ASTM D790
Impact Properties	ASTM G14, ASTM G13 AND ASTM G17
Coefficient of Expansion	ASTM D696
Chemical / Corrosion Resistance	ASTM G20, ASTM G18 AND ASTM D1654
Cathodic Disbondment and Blistering	ASTM G8, ASTM G42, ASTM G95, ASTM G89, ASTM G80, ASTM D870, AND ASTM D714
Quality Assurance	ASTM D3843

Fusion Bonded Polymeric Coatings are typically not applied in the field due to accessibility (e.g., buried pipe, hangers, etc.) for uniform heating. In shop applications the resins can be applied by either spraying dry powder or rotating resin beads on a preheated surface. Thermosetting epoxies or thermoplastic pvc resins are catalyzed or melted into a continuous coating.

Field repairs can be accomplished, where accessible, by externally heating the pipe with thermal wraps or electromagnetic heaters. Field weld locations and liner flaws have also been repaired with plastic sleeve tubes. The sleeves are inserted into the pipe and adhesively bonded to the I.D. surface. The pipe is then heated externally with a torch or thermal wrap, expanding the sleeve to the contour of the surface.

Solvent-Type coatings are commonly used to refurbish SWS pipelines, protecting components susceptible to galvanic corrosion, and protecting tube ends degraded by erosion. Epoxy resins similar to fusion bonding materials are dissolved in a diluent, allowing coating to be applied as a paint type coating. The coating is applied, cured, and dried on the surface to provide a continuous corrosion barrier.

Low flash point and health concerns of the solvent fumes are the major drawback of applying solvent-type coating. Fumes concentration and ventilation must be maintained to assure air quality is sufficient and that explosive hazards are eliminated. New non-solvent emitting (NSE) epoxies have been developed to minimize the hazards of applying coating materials. NSE have been utilized with the same effectiveness as the solvent-emitting coatings.

Sheet applied elastomers are applied /installed in flanged spool pieces are typically not repaired in the field. Rubber lined pipe can fail as a result of mechanical damage, cavitation, etc. and if left unrepaired, disbonded areas can propagate (sheet delamination).

Failures can cause blockage of downstream heat exchanger tubes and/or small diameter pipe, impeding the operation of safety related systems. Inaccessible (<20 inch diameter) elastomeric lined pipe is considered unrepairable without being removed from the system. Subsequently, elastomeric lining material is limited to accessible pipe diameters and short lengths of flanged spool pieces.

The most effective way of removing the lining material is with high pressure water jet cleaning. Accessible pipe can be repaired with sheets of matching lining material while inaccessible pipe are limited to patching of failed areas with a neoprene type putty. Rubber lining degradation can be accelerated if material experiences intermittent dry lay up conditions and is best maintained under continuous immersion. Due to the limitations of rubber type liners, they are not considered an appropriate coating material for most applications.

Process for Lining/Coating SWS Components

Lining (sleeving) or coating a degradation piping system is considered a temporary repair, which allows for long-term remedies to be evaluated. Depending on the quality of applying the lining materials, e.g., cleaning, maintenance, etc., and coating/lining selection, the SWS life can be extended from three to ten years. Liners are applied as a continuous sheet and are adhesively bonded to the surface. Coatings are typically applied by swabbing, spraying, or spreading the material over the surface area. Linings are typically preferred over coatings to assure holiday free applications are achieved.

Lining/coating selection criteria should consider final surface roughness, friction factors and diameter reduction which may cause pressure drop and/or reduce flow rates. The lining process should also consider:

- percentage bonding required
- accessibility for inspection
- surface cleaning requirements
- reparability

Sandjet cleaning/coating process is an abrasive cleaning process utilized to clean the pipe I.D. Nitrogen gas is used in the cleaning process to produce a clean, dry surface preparation which resists flash corrosion. The coating material is immediately applied while the system remains under the same dry inert atmosphere. One method of applying the coating material (UCISCO process) utilizes nitrogen to propel two spheres (balls) and the coating material through the system. The coating material is injected between the diameter of the spheres. The process requires two access areas; one to inject the excess coating material and spheres. The process is limited to one diameter of pipe per application, and all tees, valves, etc. must be removed and replaced with a flanged spool

piece. The process requires a minimum of one week drying time at 70⁰ F and is typically applied off-line.

Coating materials can be applied with a rotating head or nozzle utilizing centrifugal forces. This technique evenly applies the coating material and regulates the coating thickness by monitoring the flow rate and travel speed. The process is limited to one diameter per application and tees and valves must be removed and replaced with a flanged spool piece. Due to traveling mechanisms, the process is also limited by elbows.

Insituform coating process (Insituform Mid-America, Inc.) utilizes a polyester fiber felt tube permeated with a liquid thermosetting resin . The tube is inserted through an access port and inverted into the piping system. A vertical stand pipe of cold water is used to force the tube into the system and press the tube against the pipe wall. The tube is cured into place by heating the water. The wall thickness and resin (e.g., epoxy, polyester, vinyl ester resins) are designed or specified per application. The process can accommodate pipe diameter between 3 and 96 inches. The advantages of Insituform are:

- The tube and resin have the ability to fill cracks, cover voids.
- The process can accommodate elbows.
- The liner conforms to the surfaces, resulting in a minimal reduction in inside diameter.
- The process provides a superior surface finish and improves flow capacity.
- Curing temperatures (app. 170⁰ F) kill man MIC organisms.
- The liner can be solvent patched
- The liner can be mechanically or chemically cleaned (chemical compatibility should be tested).

PALTEM (Ashimori Industry Company, Ltd. And Tokyo Gas Company, Ltd.) is an inversion lining system which forms an I.D. pipe seal. The process consists of a woven canvas (for reinforcement) with a felt sealed with epoxy resin. The liner is inverted with air, which limits the distance a liner can be inverted. The epoxy is cured thermally with steam or non-thermally with air. The process can accommodate pipe diameter between 20 and 1000 mm. The PALTEM process may produce wrinkles at the short radii of elbows limiting lining to straight sections.

Swageling is a process which utilizes a polyethylene pipe to refurbish the I.D. of degraded pipe. The polyethylene pipe is thermally treated to reduce its outside diameter, then drawn through the degraded pipe. The pipe expands back to its original size against the I.D. of the pipe. The process does not required curing (e.g., steam) and can accommodate long radius bends up to 22-1/2 degrees. Up to 2000 feet of pipe can be

lined continuously by butt fusion welding 40 foot sections together. The overall length is dependent on the I.D. conditions and bends.

Localized Repair

Condenser and heat exchanger component failures include leaks, erosion corrosion, vibrationally induced degradation, etc. Repairing the tubes, tubesheets water boxes, etc. is accomplished by coating/lining, plugging, staking, or by component replacement.

Coatings. 100% catalyzed epoxies, epoxy phenolics, and polyesters have been utilized to eliminate existing corrosion mechanisms, repair leaks in tube/tubesheet joints and to reestablish structural integrity of condenser tubesheets. These types of coatings fail as chips instead of sheet delamination, eliminating the risks of downstream blockage. Epoxy lining in conjunction with cathodic protection has been utilized to protect waterboxes, tubesheets, etc., when upgrade materials such as titanium are used to replace less noble materials e.g., aluminum bronze.

Coating materials are typically not used to re-establish structural integrity or for sealing leaks, although a cladding technique can be utilized to produce a sufficient coating thickness to restore failed components. The PLASTOCOR process developed in Germany (5), utilizes a 200 mil molded epoxy overlay or clad to restore tube/tubesheet degradation where structural integrity has not been compromised (Figure 3-2). This cladding process offers a long-term repair where erosion, corrosion, and mechanical damage is a concern. The protective cladding also provides a surface finish which reduces flow resistance and fouling.

Many copper based alloys are susceptible to inlet-end erosion due to high turbulence and as a result of macrofouling e.g., clam shells, etc. Maintaining flow rates in an attempt to minimize turbulence is usually insufficient in controlling erosion corrosion of susceptible materials and typically results in increased fouling problems. In lieu of replacement tube materials, such as titanium and highly alloyed stainless steels, inlet-end erosion can be controlled by erosion resistant inserts or coatings. Inserts and coatings are typically designed to create a feathered transition within the tubes to minimize the potential for fouling and turbulence, and to increase flow efficiency.

Inserts are typically made of highly alloyed stainless steels (6Mo stainless steel), erosion resistant copper alloys (90-10, 85-15, 70-30 Cu-Ni), or polymeric materials (nylon). Insitu coating materials are usually a polymeric material such as epoxy. When utilizing more noble materials for inserts there is a potential for galvanic attack of less noble

components e.g., waterbox, tubesheets and tubes. Cathodic protection is often necessary to prevent galvanic attack of these components.

The effectiveness of the insert material is a factor of:

- The erosion-corrosion resistance of the insert material.
- The galvanic compatibility of the insert materials with the existing materials.
- Insert wall thickness, downstream taper, surface finish and length.
- Effectiveness of tube cleaning practices and water treatment.

Inserts are fastened with a bonding cement and/or roller expanded at both ends of the insert to minimize crevice conditions. The entire length of the insert should also be sealed with a non-metallic anaerobic sealant to assure a continuous dry, contact between materials. The length of the insert is determined by the extent of erosion; typically inserts range from six to ten inches in length. A downstream taper is necessary to allow appropriate drainage during lay up, preventing turbulent flow conditions at insert/tube interface, and to minimize fouling.

Staking is utilized to eliminate vibrationally induced failures (fretting) in condenser and heat exchanger tube bundles. Stakes are designed to be wedged between the vibrating tubes, anchoring them into position. Most stakes are designed to be self-securing to eliminate further movement once installed. If not self-securing stakes must be tied off to eliminate further movement. Stainless steel is a common stake material, although any stake material should be compatible with system materials or consist of a non-metallic material.

Plugging is used to block off the leaking tube or tubesheet, until a permanent repair/replacement can be assessed. The design and material selection of tube plugs vary significantly per application. Considerations in applying and designing a plug include:

- Material selection – Galvanic complications, welding computability, and acceptable corrosion resistance.
- Temperature – Plug should have same thermal expansion as the tubes or should be able to compress or swell to maintain tight seal.
- The plug should be able to conform to the surface conditions of the degraded tube.

Plugs can be either tapered, compression type, or tube stub type. Tapered plugs are made from metallic, wood, or other non-metallic materials which will swell in place. The tapered plugs are forced into the tube end, similar to a wedge. Compression type plugs are expanded in place to conform to the shape of the tube surface. Compression type

plugs are typically made from rubber, silicon, or other flexible materials. Tube stub type plugs are utilized for plugging holes in tubesheets as well as tubes. The tube stub consists of a piece of tubing sealed at one end by an expanding tool. The tube stub is inserted into the hole or tube and expanded to conform to the opening.

Spool piece replacement material selection can be assessed through accelerated testing and evaluation of acceptance criteria (e.g., code acceptance criteria, longitudinal and girth welds, etc.). Subsequent, long term evaluations, typically greater than one year, can then be designed to determine spool piece compatibility with plant specific conditions e.g., seasonal water chemistry changes, environmental conditions, etc. Spool pieces should be tested under worst case scenarios including stagnant, low and high flow conditions, and under increased temperatures. Material selection criteria and testing are discussed in section 2.0, Replacement Materials.

Valve Repair. The ability to maintain valves in-line is desirable since many valves are welded in-line. Common repairs include sealing surface repair (e.g., bonnet, flanges, seat surface, etc.) packing restoration, seat ring and disc replacement. Seat hardfacing materials improve the life of the seat and disc surfaces. Cobalt-chromium alloys are typically used for hard surfacing. Seat surfaces can be repaired by cutting out (grinding) the original seat hardfacing, rewelding and grinding the surface to the original configuration. If replaceable, rewelding a new seat in place. In most cases, SWS valves are replaced and repair is not considered a practical option.

6

ALTERNATE BEST PRACTICES FOR REPAIR

The following methods describe new processes for general piping repairs. These methods have not been accepted as standards nor have they been approved for use on Code piping systems.

Repair Method for Fillet Welded Patches With Reinforcing Plug Welds

Description

This repair method describes the selection criteria, application limitations, design, fabrication, examination and testing of fillet welded surface patches applicable to pressure retaining components. This repair method is based on sound engineering and construction practices. Application of this repair method is subject to approval of those authorities having jurisdiction over the affected component.

The fillet welded patch repair method can be generally described as the application of a replacement pressure boundary which is mounted to the surface of the affected pressure retaining component by fillet welds and reinforcing slot or plug welds. This repair method has performed satisfactorily in vessel shells experiencing degradation from local wall-thinning mechanisms.

This repair method consists of fitting a repair plate to closely match the original shell exterior surface. The repair plate is sized to cover the areas exhibiting degradation, both at the time of repair and that anticipated for the repair's design life. The repair plate must be large enough to fully encompass the damaged area and assure that the attachment welds will not be undercut in the future.

Where required due to repair plate size or access/interference considerations, split sections may be used when joined by full penetration welds. The repair plates are attached to the existing shell using single fillet lap welds reinforced with adjacent plug welds. The repair plate and weld filler materials are the same or similar to those used in the original vessel's construction.

The repair method is typically applied to pressure retaining shells that have suffered local wall thinning degradation due to erosion, corrosion and other wastage mechanisms.

Limitations

This repair method is best suited for repairs to vessels and tanks larger than two feet in diameter. The repair method is typically applied to pressure retaining shells that have suffered local wall thinning degradation due to erosion, corrosion and other wastage mechanisms.

This repair method should be limited to those applications where the degradation mechanism is non crack-like and the extent of deterioration is well characterized, including future growth behavior. It is applicable to cylindrical or spherical vessels and pipes 24 inches and larger in diameter that are subject to temperatures not greater than 750°F.

In applying this repair method, consideration must be given to material compatibility, operating conditions both during repair installation and for the component's remaining life, thermal and shrinkage effects of welding, and other application limits such as examination and testing constraints.

Design

The design basis for this repair method is derived from provisions of the ASME BPVC, Section VIII. Although the original qualification of this repair was based in part on detailed stress characterization using finite element methods, application restrictions imposed by the methods described herein significantly simplify design considerations such that the governing load case is internal pressure. However, if the component to be repaired is subject to bending, the design approach must include consideration of these loads.

The following design methods are derived from standard pressure vessel design calculations and various provisions from ASME Section VIII, Division 1. The thickness of the patch plate is dependent on material mechanical properties and the calculated attachment weld sizes. As a general rule, for patch plate materials that are the same as the original shell material, the patch plate thickness (T) should be in the range of $t + 1/8$ in. to $t + 1/4$ in. The size (length and width) of the patch plate is governed by the requirement to assure all attachment welds (both perimeter and plug/slot welds) will be located on sound base metal completely encompassing the degraded areas (see Figure 1).

Internal Pressure Loads

D_i = Inside diameter of vessel or pipe, in.

D_o = Outside diameter of vessel or pipe, in.

D_m = Diameter at mid-wall of vessel or pipe, in.

R = Outside radius of vessel or pipe, in.

R_m = Radius at mid-wall of vessel or pipe, in.

t = Wall thickness of vessel shell or pipe, in.

T = Thickness of the patch plate, in.

t_{min} = Weld leg based on minimum leg dimension, in.

p = Internal pressure based on 1.5 times design pressure, pounds per in.²

F_c = Circumferential force due to internal pressure, pounds per in.

F_l = Longitudinal force due to internal pressure, pounds per in.

F_T = Total force due to internal pressure (acting at patch plate corner), pounds per in.

FA = Allowable force on fillet welds, pounds per in.

S_a = Allowable base metal stress (ASME Section VIII or Section II Part D), pounds per in.²

L_{min} = Shell set-back distance, in.

E = Weld joint efficiency factor (0.50)

Circumferential Load

$$2 F_c = p D_m$$

Force in hoop direction:

$$F_c = \frac{p D_m}{2}$$

Longitudinal Load

$$p A = p \frac{\pi D_m^2}{4} = \pi D_m F_l$$

Force in longitudinal direction:

$$F_l = \frac{p \pi D_m^2 / 4}{\pi D_m}$$

$$F_I = \frac{p D_m}{4}$$

Structural Discontinuity Evaluation

For stresses near a nozzle or other structural discontinuity to be insignificant, the distance between the fillet welded patch plate and the existing discontinuity should be:

$$L_{\min} = 2 (R_m t)^{1/2}$$

The factor of 2 accounts for both the existing nozzle (or other similar structural discontinuity) and the patch plate.

Allowable Weld Load

$$F_A = t_{\min} E S_a$$

$$F_T = (F_c^2 + F_I^2)^{1/2}$$

If $F_T < F_A$, the fillet weld will be adequate for the design loads. Note that although plug/slot welds are used for this repair method, the perimeter fillet weld shall be sized such this criteria ($F_T < F_A$) is met.

Effective Plug Area

The allowable working load on a circular plug weld in either shear or tension shall be:

$$P = 0.63 S_a (d - 1/4)^2$$

where

$P =$ total allowable working load on the plug weld, pounds

$d =$ the bottom diameter of the hole in which the weld is made, in.

The slot welds are used in lap joints to increase joint efficiency and provide resistance against bending at the root of the fillet weld due to the shell discontinuity at the patch plate. They shall be set back from the edge of the patch plate by not less than 2T nor

more than 4T, and shall be spaced to carry their proportion of the load. As indicated earlier, the perimeter fillet weld shall be designed to be adequate for the entire load; however, these welds may be considered to take up to 30% of the total load to be transmitted, if required.

Plug weld holes shall have a diameter not less than $T + \frac{1}{4}$ in. and not more than $2T + \frac{1}{4}$ in.

Plug weld holes shall be completely filled with weld metal when the thickness of the patch plate (T) is 5/16 in. or less; for patch plates where $T > 5/16$ in., the holes shall be filled to a depth of at least $\frac{1}{2}T$ or 5/16 of the hole diameter, whichever is larger, but in no case less than 5/16 in.

Cold Forming Limits

Carbon steel and low alloy patch plates fabricated by cold forming shall not exceed 5% extreme fiber elongation. The extreme fiber elongation shall be verified as follows:

For double curvature
$$\frac{f}{R_f} \left(1 - \frac{f}{R_o} \right) \leq 5\%$$

For single curvature
$$\frac{f}{R_f} \left(1 - \frac{f}{R_o} \right) \leq 5\%$$

where

R_f = Final center line radius of patch plate, in.

R_o = Original center line radius of patch plate (equals infinity for flat plate), in.

Fabrication

Plate edges may be cut to shape and size by mechanical means such as machining, shearing, grinding, or by thermal means such as flame or arc cutting. Plug/slot holes may be fabricated by punching, drilling, machining, or flame/arc cutting. If thermal means are used, a minimum of 1/16 in. additional material shall be removed by grinding or machining.

Forming to the required shape may be performed by any process that will not unduly impair the physical properties of the patch plate material.

Parts to be fillet welded shall be brought together as close as practical and in no event shall be separated by more than 3/16 in. If the separation is 1/16 in. or greater, the size of the fillet weld shall be increased by the amount of the separation.

Welding procedures and operators shall be qualified in accordance with Section IX of the ASME Boiler and Pressure Vessel Code.

Field erection activities should conform to the following sequence:

- Paint, scale, rust and other foreign material must be removed from an area not less than 1½ in. on either side of an attachment weld. Grinding of existing seam or girth welds flush with the vessel or pipe O.D. is required only in those areas that will be covered by the new patch plate.
- The new patch plate may be slid into place using any suitable method.
- Plug/slot welds between the new patch plate and the existing vessel/pipe should be made first. The perimeter fillet weld may then be completed. Clamps or wedges may be used to assure proper joint alignment and fit-up.

ASME or ASTM materials may be used as applicable to the Code fabrication requirements of the original vessel/pipe. Certified material test reports shall be supplied with patch plate and weld filler materials and shall remain traceable throughout the fabrication/installation process.

Exposed metal surfaces shall be re-coated at the discretion of the equipment owner.

Examination

All installation welds shall be examined by either the magnetic particle (MT) or dye penetrant (PT) methods in accordance with Appendix 6 or 8 as applicable in Section VIII of the ASME Boiler and Pressure Vessel Code.

If lifting lugs are used and left in place, the welds shall be MT or PT examined. If lifting lugs are removed after installation, and at locations where temporary clamps and/or wedges were attached by welding, removal areas shall be MT or PT examined.

Testing

If the vessel/pipe can be isolated for pressure testing, it shall be tested at the design pressure for one hour and inspected for leaks. Alternatively, a pre-service inspection shall be performed of all weld joints when the vessel/pipe has returned to normal operating pressure and temperature. Testing and inspections should be performed prior to re-application of insulation or jacketing, if applicable.

Full-Encirclement Steel Sleeves for Pipelines

Description

This repair standard applies to the design and installation of full-encirclement welded steel sleeves for piping. The sleeves may be designed for reinforcement only or pressure containing. Full encirclement reinforcement sleeves have proven effective in the repair of

a wide variety of internal and external defects and have been successfully used for many years by the pipeline industry.

Full encirclement steel sleeves consist of a cylindrical shell-placed around the pipe section to be repaired and welded along the two longitudinal seams, as illustrated in Figures 1 and 2. There are two Types of sleeves, often referred to as “Type A” and “Type B”. Sleeves may be made from pipe or rolled plate material.

In a Type A sleeve the sleeve ends are not welded circumferentially to the carrier pipe, as shown in Figure 1. The sleeve is not pressure containing and only functions as reinforcement for a defective area. It is only used for non-leaking defect repairs.

In a Type B sleeve, the sleeve ends are welded circumferentially to the carrier pipe, as shown in Figure 2. A Type B sleeve is pressure containing because the ends are fillet welded to the carrier pipe. This Type may be used to repair leaking defects and to strengthen circumferentially oriented defects. A properly designed and installed Type B sleeve must be as strong as the carrier pipe.

Cautions and Limitations

Section I of *Repair of Pressure Equipment and Piping* contains additional requirements and limitations. This article shall be used in conjunction with Section I.

Refer to pipeline regulations and to the pipeline design codes for restrictions regarding repair techniques.

When used to repair a pipeline subjected to significant cyclic pressurization, all Types of sleeves are likely to have a finite time to failure. In the case of a reinforcing sleeve, the useful service life will most likely be controlled by the repaired defect. For a pressure containing sleeve, the sleeve itself, and most critically the end welds, will be the controlling elements. If a sleeve repair is applied to a system subjected to frequent pressure cycles an evaluation of the fatigue resistance shall be made and the results shall be used to establish a suitable life limit.

When subject to cyclic through-wall thermal gradients, a fatigue evaluation of the shear stress in the sleeve-to-pipe fillet welds should be conducted to establish the fatigue life of the repair.

Local wall thinning defects weaken the carrier pipe shell and typically bulge outward prior to failure under increasing pressure. The effectiveness of repair sleeves relies on their capability to restrain the outward bulging of a pipe defect prior to its failure. To achieve this objective, it is often necessary (a) to use a hardenable filler material under the sleeve, particularly when the defect is external, and (b) to reduce the line pressure at time of installation.

For Type A sleeves, it is necessary to achieve the tightest fit-up possible between the pipe and the sleeve, to assure that the sleeve will provide the desired reinforcement.

Type A sleeves are not appropriate for the repair of circumferentially oriented defects because they will not prevent full separation.

For Type A sleeves, corrosion resistance of the open un-welded ends should be taken into account. Coating and/or tape wrapping should be considered.

If either sleeve Type is intended to cover an existing butt-weld or longitudinal weld, the fit between the sleeve and the carrier pipe is very important. There are sleeves fabricated with a circumferential bulge to bridge the weld, as shown in Figure 3. If it proves prudent to remove the weld cap by grinding, the weld shall be NDE examined, RT or UT, prior to grinding. This examination is particularly important when the line is in service.

Areas of major thinning should be fully covered by the repair sleeve. In the case of a Type B sleeve, the end fillet welds should only be made in areas where sufficient wall thickness exists to prevent burn through, or the formation of unacceptable weld and HAZ metallurgical properties.

Past Type B sleeves failures have been related to problems with the end fillet welds. It is essential that the welds be installed to qualified procedures reflecting the field conditions and by qualified welders. It must always be kept in mind that these welds are being made to the pressure membrane and are not just structural welds. In particular, the qualification of the welding process must take into account (a) the potential for hydrogen induced cracking in the heat affected zone as a result of accelerated cooling rate and of hydrogen in the weld environment, and (b) the risk of forming an unacceptably hard heat affected zone.

Type B sleeves may be considered for longitudinal cracks only when it is determined by an engineering evaluation that the crack will not propagate from under the sleeve.

Design

A full-encirclement welded split sleeve shall have a design pressure at least equal to that required for the maximum allowable operating pressure of the pipe being repaired. If conditions require that the sleeve carry the full longitudinal stresses, the sleeve shall be at least equal to the design strength of the pipe being repaired.

The pressure design calculations of the applicable construction code shall apply for calculating the required sleeve strength. Sleeve material and allowable design stress shall comply with the applicable construction code requirements.

Full encirclement sleeves must be at least 100 mm (4 in.) long and extend beyond the defect by at least 50 mm (2 in.). The maximum length of a single sleeve shall be no longer than that which can be fabricated and installed and still provide the proper fit.

If the sleeve is thicker than the pipe being repaired, the circumferential ends shall be chamfered at approximately 45 degrees, down to the thickness of the carrier pipe.

If external damage is repaired with a Type A sleeve, the damage shall be filled with a hardenable filler material with compressive strength adequate to transfer the load to the sleeve. With a Type B sleeve, the damage may be protected either by the filler previously mentioned or by intentionally pressurizing the sleeve by hot tapping the pipeline under it. In the latter case, it must be verified that the stagnant fluid between the sleeve and the carrier pipe will not cause corrosion, and that the fluid viscosity is sufficiently low to penetrate the narrow space between the sleeve and the carrier pipe.

Fabrication

For installation of a Type A or Type B sleeve the entire circumference of the carrier pipe in the area to be covered by the sleeve shall be cleaned to bare metal. If hardenable fill material is to be used, the filler shall be applied to the indentations, pits, voids, or depressions. The sleeve shall be fit tightly around the carrier pipe. Mechanical clamping means should be used to assure fit. A “no gap” fit should be generally achieved; however, a radial clearance of up to 2.5mm (3/32in.) maximum may be allowed in some areas.

If a filler material is used between the pipe and sleeve, care should be exercised to assure that it does not extrude out into the weld areas. Burning of the filler material during welding will compromise the quality of the weld. Excess filler material must be removed prior to welding. If necessary, a pre-heat torch may be used to burn the excess away from the weld area.

For a leaking defect, the defect area should be gasket sealed. A vent valve may be provided. One sleeve half should be centered over the defect and the sleeves compressed together adequately to cause the gasket to seal. For lines with flammable contents, purging the sleeve with nitrogen or other inert gas maybe done to prevent the formation of a combustible mixture under the sleeve.

If the defect is not leaking, the circumferential fillet welds are optional. If circumferential fillet welds are made, the sleeve’s longitudinal welds should be butt welds, as shown in Figure 2, Type B Sleeve. The welding procedures for the circumferential fillet welds shall be suitable for the materials and shall consider the potential for underbead cracking. The use of low hydrogen consumables is recommended. Backing strips are recommended. If the circumferential welds are not made, Type A, the longitudinal welds may be butt welded or fillet welded to a side bar, as shown in Figure 1.

Consider reducing the carrier pipe operating pressure or taking it out of service while the repair is being made. This will simplify the welding process and will decrease the pipe-sleeve gap when the pipe is repressurized. This action will depend on the normal and extreme operating conditions of the pipe being repaired and the physical characteristics of

the sleeve repair. Recommended maximum repair pressures for pipelines operating above 40% of the specified minimum yield strength (SMYS) are as follows:

“Type A”

- 0.8 Po, if hardenable filler material is used.
- 0.67 Po, if no filler is used
- 0.90 Po, filler with mechanical clamp to compress sleeve into place.

“Type B”

Lowest of:

- 0.8 Po
- pressure for hoop stress to equal 30% SMYS
- Pressure at which a leaking defect can be safely vented or contained.

Po=Maximum anticipated normal operating pressure.

Examination

All sleeve fit-ups and welds shall be visually examined.

For Type A sleeves the longitudinal welds shall be dye penetrant, magnetic particle, or ultrasonically examined after completion. The weld root area may be examined during welding to verify proper penetration and fusion.

For Type B sleeves, the base material shall be ultrasonically examined for thickness and possible lamination in the area where the circumferential welds are to be applied. If a backing strip is not used under the longitudinal weld, the area under it shall also be ultrasonically examined. Sufficient wall thickness must exist to prevent burn through or the formation of unacceptable metallurgical properties in the weld and HAZ. Longitudinal welds shall be dye penetrant, magnetic particle, or ultrasonically examined after completion. The weld root area may be examined during welding to verify proper penetration and fusion.

If a Type B sleeve has been used to join together replacement pipe sections, instead of pipe to pipe butt welds, all sleeve welds should be radiographically examined.

Owner may require full “in-process” visual examination, as described in ASME B31.3, para.344.7 of the sleeve weld installation. Such examination will be visual and the results shall be documented. Inspectors shall meet qualification requirements specified by the Code.

Testing

Owner may require hydrotest of a Type B sleeve by pressurizing the annulus between the sleeve and the carrier pipe, in accordance with the applicable construction or post-construction code. The test pressure shall be selected such that the inner pipe will not collapse due to external pressure. A Sensitive Leak Test as described in ASME B31.3, para.345.8 may be used.

REPAIR METHOD FOR BUTT WELDED INSERT PLATES IN PRESSURE COMPONENTS

Description

The repair of pressure components by butt welded insert plates generally can be described as the replacement of pressure boundary material in a cylindrical, spherical, conical, or a flat pressure component with an insert plate attached by a full penetration butt weld. It is applicable to single and double curvature shells. Replacement of an entire component, or a complete shell course of a cylindrical shell, or a complete head, or a section of a pipe is not considered in this repair method.

This repair method is typically used to replace parts of pressure retaining vessel shells or pipe walls that have been damaged due to cracks, local wall thinning from erosion, corrosion and other damage mechanisms, or to replace an existing nozzle/[manway](#), or install a new nozzle/[manway](#) with an insert plate containing the nozzle/[manway](#).

Limitations

This repair method is applicable to cylindrical, spherical and conical shells and to flat pressure components. It may also be used on other pressure components (such as formed heads) as long as the curvature of the replaced section matches the curvature of the original pressure part. It is not limited by the size of the pressure component, except where practical considerations preclude the use of an insert, such as on small diameter pipe or tube. It may also be used on small diameter pressure components provided special care is taken to ensure a close fit of the insert plate and the existing pressure component and that the repaired pressure component meets the tolerance requirements of the applicable code of construction.

In applying this repair method, consideration must be given to compatibility of materials, operating conditions for the intended life of the component, fitting and welding to minimize the shrinkage [residual stresses](#) and distortions, and any limitations on non-destructive examination and pressure testing.

This method may be used for equipment subject to either internal or external design pressure. If the pressure component is subject to external pressure, additional consideration should also be given to any loss of buckling strength as a result of permanent distortions [or misalignment](#) in the repaired component.

This repair method may also be used in vessels that are either clad with corrosion resistant lining or weld overlaid. The insert plate cladding or weld overlay shall be compatible with the existing materials and suitable for the intended service. Consideration shall also be given to the use of weld details and welding procedures suitable for the intended service.

Insert plates and welds should be of the same material as the existing pressure component, or of another material that has at least equal notch toughness and allowable stress, and conforms to the requirements of the applicable code of construction,[and is](#)

[suitable for the intended service](#). Where ASME materials are used, the replacement material shall preferably have the same ASME P-number designation as the pressure component material into which the insert is being installed.

Use of dissimilar materials is not prohibited, but must meet the required minimum mechanical properties for the pressure component and must be carefully evaluated for compatibility between the dissimilar materials and with the service environment, both internal and external.

Design

The insert plate thickness, material and welds shall meet the design requirements in the applicable code of construction for the existing pressure component into which it is being installed and shall be consistent with the joint efficiency or joint quality factors used in the original design. The allowable stresses shall be the same as in the applicable code of construction for the existing component.

The insert plate thickness shall not be less than the nominal thickness of the material it welds into. [If a thinner insert plate than the nominal thickness of the material it welds into must be used, it shall be evaluated for the intended service, using the rules in the applicable code of construction for the pressure component, or the applicable post-construction code, and it must be acceptable to the User and the Authorized Inspector. See 4.1.5.](#)

The insert plate may be circular, oblong, square with rounded corners or rectangular with rounded corners.

Rectangular and square insert plates must have corners rounded to a radius, except when the entire shell plate is replaced. Rectangular and square insert plates 13 mm (½ in.) thick and up to and including 25 mm (1 in.) thick shall preferably have a 75 mm (3 in.) or a larger corner radius. Insert plates less than 13 mm (½ in.) thick may have smaller corner radii. Insert plates over 25 mm (1 in.) thick shall preferably have a 150 mm (6 in.) or a larger corner radius.

The insert plate shall be of sufficient size to replace the entire area of the existing pressure component that has been assessed as not being fit for continued operation of the pressure component and to ensure that all welds are in sound material.

The minimum diameter, or length and width dimensions of [non-postweld heat treated, butt welded carbon and low alloy steel](#) insert plates shall be 12t (where t is the thickness of the parent material), [however the maximum diameter need not exceed 15 in. \(380 mm\)](#). See 3.6 and Fig. 2 and 3.

For large cutouts where structural stability and distortion of the unsupported plate edges of the opening may be of concern, structural analysis should be performed to assess the need for temporary stiffening around the cut edges of the opening [during removal of the shell section to be replaced with an insert plate](#). The analysis shall consider all loading conditions that may occur on the vessel and the component during the repair.

Flush inserts in pipe or tube may be round or oblong cutouts, as shown in Fig. 1, or rectangular cutouts with rounded corners.

The nozzle/manway reinforcement in insert plates with nozzles shall meet the design requirements and weld details of the applicable code of construction for the pressure component. The minimum diameter of insert plate with a nozzle shall be the larger of the following:

- a) For all nozzle/manway assemblies, the diameter of the nozzle penetration plus the width needed for nozzle reinforcement and any edge bevels,
- b) For non-postweld heat treated carbon and low alloy steel nozzle/manway assemblies, the diameter needed to maintain a minimum distance of 150 mm (6 in.) between the nozzle attachment weld and the nearest edge of the insert plate butt weld, however, the diameter of the insert plate need not be larger than two times the outside diameter of the nozzle. (See Fig. 2 and 3).

Fabrication

Cutting and Forming.

Edge bevels in the insert plate and in the vessel shell may be prepared by thermal cutting, arc gouging, machining or grinding. The method should be appropriate for the material and welding process(es) used.

All edges prepared for welding shall be examined to the requirements of the applicable code of construction for the pressure component being repaired. All unacceptable indications shall be repaired to the requirements of the applicable code of construction.

Forming the insert plate to the desired shape may be accomplished by any process that does not impair the properties of the plate material. It may be rolled or pressed to the proper curvature such that it conforms to the same curvature of the vessel shell after it has been installed and welded into the vessel shell or pipe or tube. For pipe or tube inserts, the insert may also be cut from another piece of pipe or tube of the same diameter and thickness as the pipe or tube to be repaired. Thicker pipe or tube inserts may be used provided they meet the requirements of 4.1.5.

Carbon steel and low alloy steel insert plates shall be heat treated subsequently when the resulting extreme fiber elongation during cold forming is more than 5% from the as-rolled condition, determined by the following formulas:

a) For single curvature shells (cylinders),

$$\% \text{ extreme fiber elongation} = \frac{75t}{R_f} \left(1 - \frac{R_f}{R_o} \right)$$

b) For double curvature (heads and spherical shells),

$$\% \text{ extreme fiber elongation} = \frac{50t}{R_f} \left(1 - \frac{R_f}{R_o} \right)$$

where t = plate thickness, mm (in.)

R_f = final center line radius, mm (in.)

R_o = original center line radius, mm (in.). (Radius equals infinity for flat plate)

Cold forming strains (e.g. from bending) in materials other than carbon and low alloy steel shall not exceed the limitations in the applicable code of construction without a subsequent heat treatment.

The maximum offset at the edges of the insert plate weld shall be within the limitations of the applicable code of construction for the pressure component. If the insert plate thickness exceeds these limitations, the edge(s) of the insert plate shall have a tapered transition having a length not less than three times the offset between the adjacent surfaces of abutting sections.

Welding

The weld between the insert plate and the existing pressure component shall be a full penetration butt weld. Where possible, double welded butt joints should be used.

The welded joints (weld metal and heat affected zones) shall meet the minimum strength⁽¹⁾ and toughness requirements and other requirements in the current edition of the applicable code of construction for the pressure component.

Note (1): Matching strength filler metal as noted in the AWS 5.X filler metal specifications should be used for welding pressure components. Use of as-deposited weld metal with substantially greater strength shall be avoided.

Welding procedures, welders and welding operators shall be qualified in accordance with the current requirements of the applicable code of construction or the applicable post construction code. [Welding procedure qualifications shall include impact tests and heat affected zones \(HAZ\) when required by the current edition of the applicable code of construction for the pressure component. Vessel \(production\) impact tests are not required.](#)

Welding materials and processes shall be as currently permitted by the applicable code of construction for the pressure component. Welding of carbon and low alloy steels shall be with low hydrogen [electrodes and](#) processes.

All welds between the insert plate and the existing shell shall be in sound material. In some cases, the welds may be in a damaged area, provided any damage is considered in the design of the repair, and the damage has been evaluated and is acceptable by the rules of the applicable post construction code.

Detrimental oil, grease, paint, scale and other foreign material shall be removed from the area adjacent to the weld and sufficient distance away from the weld to avoid contamination.

Fit-up of insert plates is important to the integrity of the weld. The weld details and welding procedures shall be such as to minimize distortion and flat spots due to weld shrinkage and the risk of weld cracking due to the restraint provided by the surrounding material.

For flush inserts in pipe or tube or other pressure components that do not allow two sided welding, gas tungsten arc welding, [or another welding process that provides an acceptable weld on the opposite side](#), shall be used for the initial pass joining the insert to the pipe wall. Subsequent passes may be completed by gas tungsten arc or another welding process. [Gas Metal Arc, Short Circuit Mode, is not recommended for these types of welds.](#)

The accessible surfaces of insert plate butt welds shall preferably be ground⁽²⁾ to a smooth contour, or flush if warranted by the service conditions. The weld toe regions shall blend smoothly with the base material. The reduction of thickness due to grinding shall not exceed 0.8 mm (1/32 in.) or 10% of the nominal thickness of the adjoining surface, whichever is less. In no case shall the final thickness be less than the required thickness.

Note (2): Grinding welds to a smooth contour reduces stress concentrations at weld discontinuities and the risk of crack initiation.

Weld Spacing Between Non-Intersecting Adjacent Butt Welds in Carbon Steel and Low Alloy Steel Pressure Components.

Non-post-weld heat treated butt welds around periphery of insert plates shall be spaced no closer to existing non-post-weld heat treated butt welds or reinforcing plate attachment welds than the following:

- a) $t_w \leq 13 \text{ mm}$ ($\frac{1}{2} \text{ in.}$): 150 mm (6 in.)
- b) $t_w > 13 \text{ mm}$ ($\frac{1}{2} \text{ in.}$): The greater of 250 mm (10 in.) and $8 t_w$

t_w is the thickness of the thicker of the two adjacent butt welds, mm (in.)

The spacing between adjacent non-postweld heat treated carbon and low alloy steel butt welds may be reduced to the lesser of $8t_w$ or 200 mm (8 in.) for $t_w \leq 40 \text{ mm}$ ($1\frac{1}{2} \text{ in.}$), provided both butt welds are ground smooth, 100% RT or UT examined and either 100% MT or PT examined after completion of welding in areas where the spacing between the adjacent butt welds is less than that specified in 4.3.1. As an alternative, the root pass and the weld after half of the groove is filled may be either MT or PT examined in place of the 100% RT examination requirement. The butt welds with thicknesses less than 13 mm ($\frac{1}{2} \text{ in.}$) need only be MT or PT examined. See 5.1.

The spacing between the adjacent butt welds shall not be less than $2 t_w$ if the first butt weld is stress relieved before making the second butt weld.

Intersecting Butt Welds in Carbon and Low Alloy Steel Pressure Components.

Intersecting insert plate and existing butt welds should be avoided where possible. Where it is impractical for the insert plates to avoid an existing non-stress relieved butt weld, the insert plate butt weld should be placed such that it intersects the existing butt weld at an angle not less than 30° , as shown in Fig. 2. Alternatively, the insert plate may be sized such that it intersects the existing butt weld at a 90° angle, as shown in Fig. 3.

Unless 100% RT or UT examination is required by the applicable code of construction, the insert plate butt weld and 100 mm (4 in.) of the existing butt weld, on both sides of the intersection, shall be 100% MT or PT examined after completion of both welds, as shown in Fig. 2. In case of the “doghouse” type insert plate butt weld shown in Fig. 3, this examination shall be performed on the full length of the new weld along the existing shell butt joint. See 5.1.

Postweld Heat Treatment

The butt welds between the insert plate and the existing pressure component shall be postweld heat treated (PWHT) when required by the original code of construction, [or for process reasons](#), except as permitted by the applicable post-construction code.

Insert plate assembly that includes a nozzle shall be postweld heat treated after fabrication when required by the applicable code of construction. Proper precautions should be taken during the PWHT to avoid distortion of the welded assembly.

For the repaired pressure parts that require PWHT (either Code-mandated or dependent upon service conditions), the PWHT shall be performed in accordance with the applicable code of construction, unless process reasons require a more stringent PWHT (e.g. higher PWHT temperature or longer hold time).

Repairs to pressure equipment that require PWHT dependent upon service conditions shall be postweld heat treated, unless other means are provided to ensure that the as-welded joints will be suitable for the service conditions, [or permitted by the applicable post-construction code](#).

Examination of Welds

All insert plate welds to the existing pressure component in pressure vessels shall be examined by radiographic (RT) [or ultrasonic \(UT\) examination](#) methods to the extent required by the applicable code of construction for the pressure component. Where UT is [used](#) examination of the root pass by either magnetic particle (MT) or liquid penetrant (PT) methods is recommended. The procedures, [personnel qualifications](#), and acceptance criteria shall be in accordance with the applicable code of construction or the applicable post construction code.

Unless 100% radiographic (RT) [or ultrasonic \(UT\)](#) examination is required, all finished welded surfaces shall be examined by magnetic particle (MT) or liquid penetrant (PT) methods. [Examination by the magnetic particle \(MT\) or liquid penetrant \(PT\) methods is recommended for the root pass of one-sided welds and for the backgouge of two-sided welds](#). No crack-like indications, incomplete fusion or lack of penetration are permissible.

For piping, all nondestructive examination requirements shall be in accordance with the current requirements in the applicable code of construction.

Additional Examination Requirements for Carbon and Low Alloy Steels

For rectangular or square insert plates, the welds around the rounded corners, as a minimum, shall be either spot RT or UT examined. As an alternative, the root pass, the weld after half of the groove is filled, and the completed weld shall be either MT or PT examined.

See Sections 4.3 and 4.4 for additional examination requirements for closely spaced welds and intersecting welds.

Pressure Testing

If the vessel or pipe can be isolated for pressure testing, all insert plate welds should be pressure tested as required in the applicable post-construction code. Alternatively, non-destructive examination may be performed in place of pressure testing, if permitted by the applicable post-construction code and by the local jurisdiction at the location of the pressure equipment, when contamination of the pressure retaining item by liquids is possible or when pressure testing is not practical.

A safe distance shall be maintained from the pressure component when the pressure is increased for the first time. Special safety precautions shall be taken in case of a pneumatic test to reduce the risk of accident.

Consideration should be given to any hazards that might be associated with the test medium (toxicity, flammability, explosiveness, etc.).

A separate leak test (visual, bubble-forming solutions, sniffer, etc.) may be desirable to check for leaks before pressurizing the component to the maximum test pressure. Such a leak test should be performed at a safe pressure that is substantially less than the maximum test pressure by pressurizing the component to a desired pressure and reducing the pressure to the leak test pressure before performing the leak test.

All testing and inspections shall be performed prior to application of insulation or coatings.

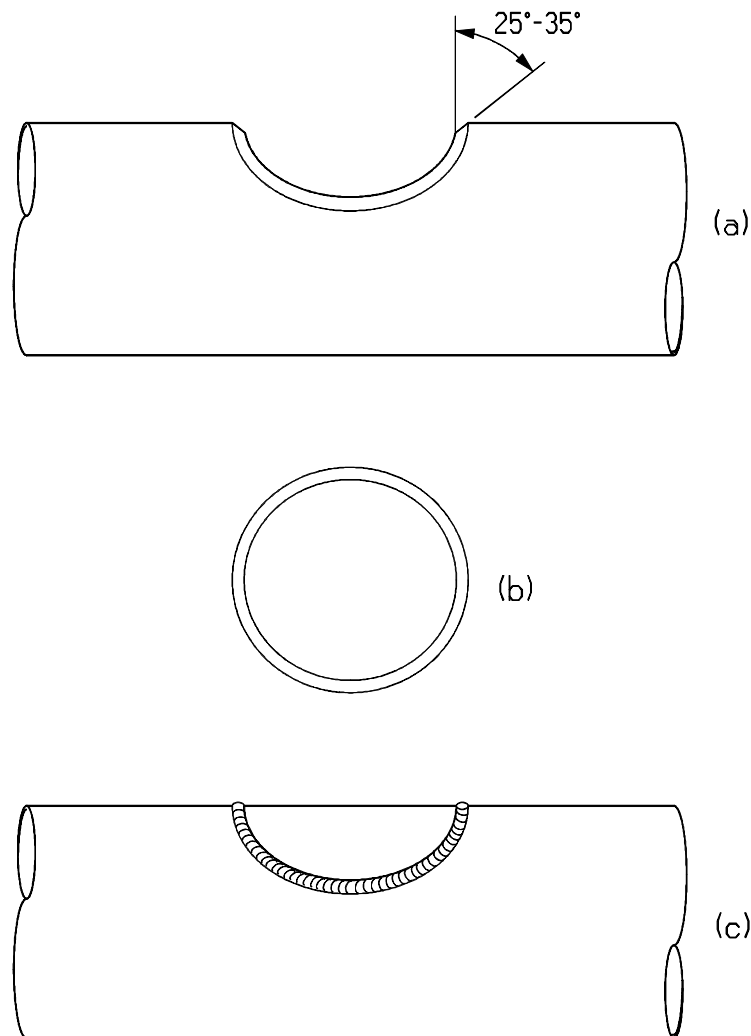


Figure 1 - Flush Insert in Pipe or Tube

a) Side view of cutout in pipe or tube with edge bevels.

(Fig. 1 shows one-sided joint detail with 25° to 35° edge bevel. Other joint details and edge bevels may be used, as appropriate for a particular weld joint).

b) Insert with edge bevels. (Fig. 1 shows an insert with one-sided joint detail).

c) Welded insert in pipe or tube.

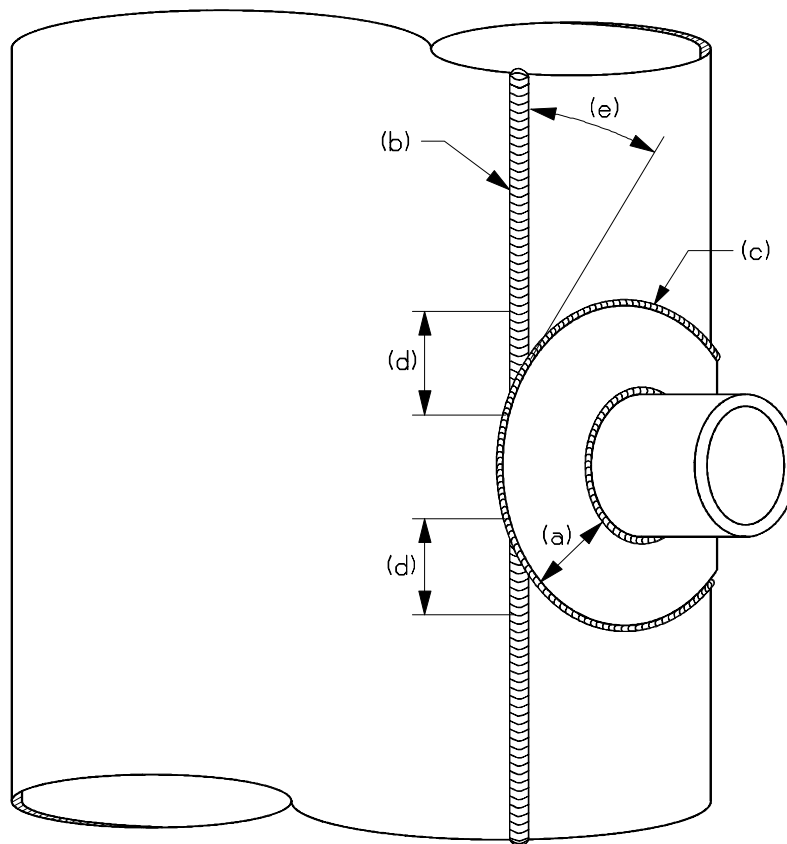
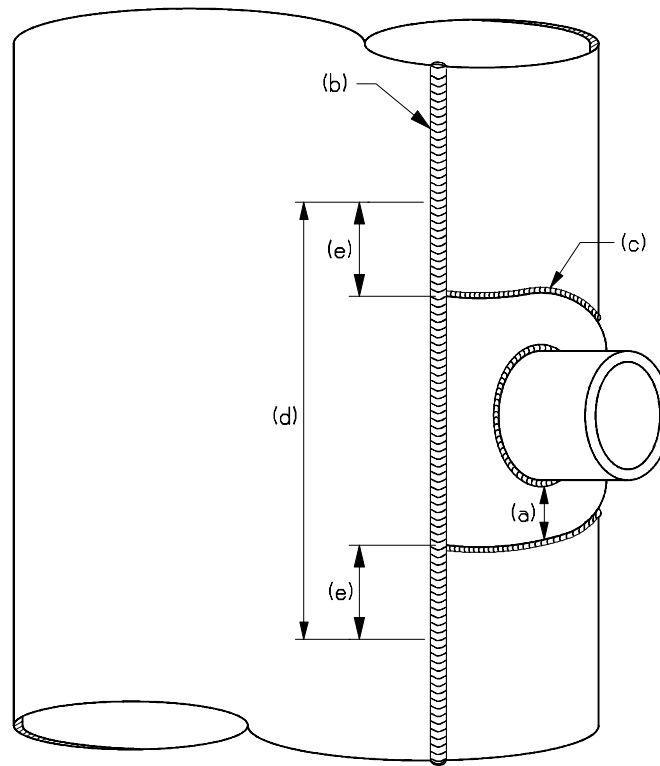


Figure 2 - Flush Insert Plate (With or Without Nozzle/Manway) With Its Butt Weld Intersecting Existing Butt Weld in Shells or Heads

- a) For non-postweld heat treated carbon and low alloy steel nozzle/manway assemblies, 150 mm (6 in.) minimum between the toe of the nozzle fillet weld and the nearest edge of the insert plate butt weld.
- b) Butt weld in vessel shell or head, welded before insert plate butt weld. (Fig. 2 shows butt weld in cylindrical vessel shell).
- c) Insert plate butt weld; weld after completion of shell butt weld. Full RT or UT, or MT or PT both sides of weld.
- d) Full RT or UT, or MT or PT both sides of existing butt weld, 100 mm (4 in.) min. each side of intersection with insert plate.
- e) 30 degrees minimum angle.



**Figure 3 - Intersecting “Doghouse” Type Insert Plate Butt Weld
(with or without Nozzle/Manway)
With Shell Butt Weld in Vessel Shells and Heads**

- a) For non-postweld heat treated carbon and low alloy steel nozzle/manway assemblies, 150 mm (6 in.) minimum between the toe of the nozzle fillet weld and the nearest edge of the insert plate butt weld.
- b) Existing butt weld in vessel shell or head. (Fig. 3 shows butt weld in a cylindrical vessel shell).
- c) Insert plate butt weld.
- d) Cut existing shell butt weld to 150 mm (6 in.) minimum on each side of intersecting insert plate butt weld and bevel edges (or arc gouge edges) to the desired edge bevels. Weld after completion of insert plate butt weld. Full RT or UT, or MT or PT both sides of new weld.
- e) Length of cut in shell butt weld, 150 mm (6 in.) minimum on each side of intersecting insert plate butt weld.

WELDED LEAK REPAIR BOX

Description

A welded leak repair box consists of an enclosure with end pieces, placed around the pipe, equipment or component being repaired and welded, leaving a clearance space between the repaired pipe or equipment and the leak repair box. Examples of leak repair box for a pipe are illustrated in Figures 1, 2 and 3. Should the component leak, the fluid would be contained within the enclosure. A leak detection drain, vent or gage may be attached to the enclosure. This section addresses welded repair boxes. Boxes that are assembled by other means, such as bolting or clamping, are not addressed in this section.

Leak repair boxes may have a variety of shapes, usually following the contour of the pipe, pipe component or equipment being repaired. Leak repair boxes may also be used to enclose components such as flanges and valves or fittings, branches, nozzles or vents and drains. Leak repair boxes may have several configurations; for example, they may be cylindrical, rectangular, with flat or dished heads

The annular space between the leak repair box and the repaired component may be left empty, or may be filled with epoxy, sealant, fiber, or refractory linings.

Limitations

Normally, leak repair boxes are used to contain leaks at packings, flange and gasket joints, or to contain leaks due to local corrosion. The leak repair box will not prevent the propagation of a crack in the pipe or equipment. Therefore, leak repair boxes must be used advisedly where there is a potential for a propagating crack. They may be used with local cracks provided

- (a) the conditions that lead to crack formation and propagation have been eliminated so that the crack will not grow during the planned life of the repair, or
- (b) a fitness-for-service assessment shows that the crack growth during the planned life is acceptable, and that the crack will not propagate into the leak repair box closure weld, or
- (c) the leak repair box and its welds are designed for the case of complete rupture of the cracked component.

The design should avoid welding the leak repair box to the knuckle region of end caps or formed heads.

The design should avoid enclosing parts that could significantly corrode if in contact with the leaking fluid, such as flange bolts. Because the leak repair box will typically be at a lower temperature than the component, condensation of leakage gases should be considered for their corrosive effects.

Design

Leak repair boxes and attachment welds should be designed for normal operating conditions and occasional loads, and to the design pressure and range of temperatures of the repaired pipe or equipment, unless means are provided to limit the pressure in the leak repair box. Designing the box for a lower range of design and operating temperatures than the component is acceptable if justified by heat transfer analysis. The leak repair box materials should satisfy the minimum temperature and, where applicable, minimum toughness requirements of the construction code.

Normal operating conditions include the maximum and minimum pressures and coincident temperatures of the system, the load imposed by the weight of the leak repair box including the entrapped leaking fluid on the enclosed pipe or equipment, and the stresses due to expansion, including differential expansion, and flexibility of the pipe or equipment.

Occasional loads include thrust loads in case of circumferential rupture of the pipe or equipment, wind, earthquake or fluid transients (water hammer) as applicable.

The calculation of minimum wall thickness should conform to the applicable construction code, with the applicable joint efficiency or joint quality factor. The wall thickness should include a corrosion/erosion allowance appropriate for the projected time in service.

The leak repair box should be designed to restrain the maximum load in case of rupture of the component, including the full axial thrust load, unless the remaining strength of the degraded component, including future corrosion in service, is known and can be accounted for by detailed analysis.

Additional restraints may be added to the pipe or equipment to reduce the loads on the leak repair box.

The rules and formulas used to design the leak repair box should comply with the applicable construction code of the pipe or equipment being repaired. In cases where there are no design formula, the principles of the applicable construction code must be followed. Components of the leak repair box that are fabricated by machining standard fittings (such as cutting-out an opening in standard pipe caps to make the leak repair box end pieces) should be qualified by analysis or testing, as provided in the applicable construction or post construction code. The cut-outs in the leak repair box end pieces should be designed following the rules for openings or by analysis or proof testing, and be reinforced if necessary.

The leak repair box should be sufficiently long to extend to sound base metal for the box-to-pipe or equipment weld. This should be verified by non-destructive examination, such as ultrasonic testing.

The design of the leak repair box should include sizing of the box and box-to-pipe or box-to-equipment welds. Welds between leak repair box subassemblies (such as the sleeve-to-cap welds or welds between two halves of a sleeve) should be full-penetration welds. Welds between the leak repair box and the repaired pipe or equipment should be a full penetration groove weld in combination with a cover fillet weld. Partial penetration welds may be used, provided the weld is sized by design to safely sustain the normal operating conditions and occasional loads.

The design should consider the potential for differential expansion between the component and the leak repair box.***Fabrication***

The leak repair box may be fabricated from standard pipe and pipe fittings, or from flat or rolled plate of material permitted in the applicable construction or post construction code. The leak repair box components are then cut or machined to permit their installation around the component. Weld bevels should be consistent with the applicable construction code and the welding procedure specification.

The material should be compatible with the enclosed pipe or equipment in chemistry, weldability, mechanical properties, coefficient of expansion, modulus of elasticity, and notch toughness.

The leak repair box may be installed and welded to the pipe or equipment when in service or during a shutdown. For welding in service, the weld procedure qualification should properly address preheat temperature, weld cooling rate the risk of burn-through and the effect of the welding temperature on the strength of the metal under service stresses. A vent or drain should be provided. The vent or drain should include a threaded cap, a flange or a valve that will be opened during welding to preclude pressure build-up, and closed after welding, inspection and testing. This same vent or drain may be used to vent or drain the leak repair box in the future.

The weld procedure and welder shall be qualified to perform the repair under the applicable construction or post-construction code.

Pre- and postweld heat treatment should conform to the applicable construction or post construction code. The need for pre- and postweld heat treatment beyond the requirements of the applicable construction or post-construction codes and dependent upon service conditions should be considered.

Examination

The examination of welds should be in accordance with the applicable construction code, and be consistent with the joint efficiency or joint quality factors used in design. The

method(s) of examination selected should be that (those) which is (are) deemed most suitable to the need.

The method of examination, the certifications of examiners, the acceptance criteria and documentation should be in accordance with the applicable construction or post construction code.

Welds that can not be examined by radiographic or ultrasonic techniques because of weld geometry, should be examined by liquid penetrant or magnetic particles. NDE confirmation of full penetration may be omitted if justified for the service conditions such as in case of low stresses and low risk of crevice corrosion at the box-to-component weld joint.

Testing

Pressure testing should be conducted in accordance with the applicable construction or post-construction code. However, when it is established that the pipe or equipment being repaired can not sustain the test pressure (e.g. may buckle), a sensitive leak test or an in-service leak test may be applied in place of a pressure test such as hydrostatic or pneumatic test.

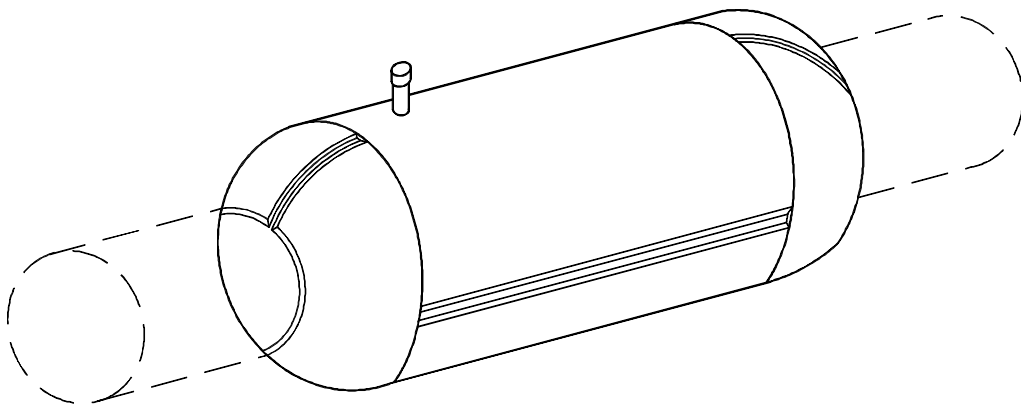


Figure 1 Example of a Welded Leak Repair Box for Straight Pipe

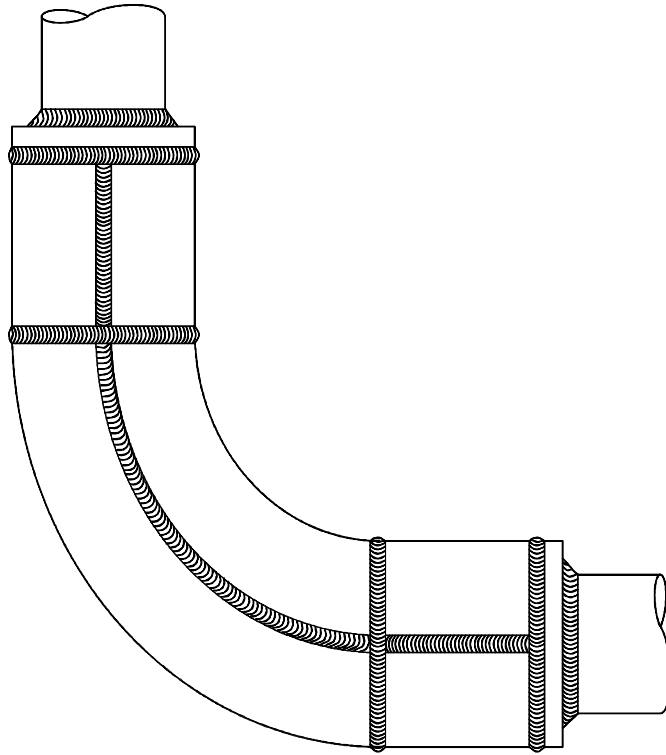


Figure 2 Example of a Welded Leak Repair Box for Pipe Elbow

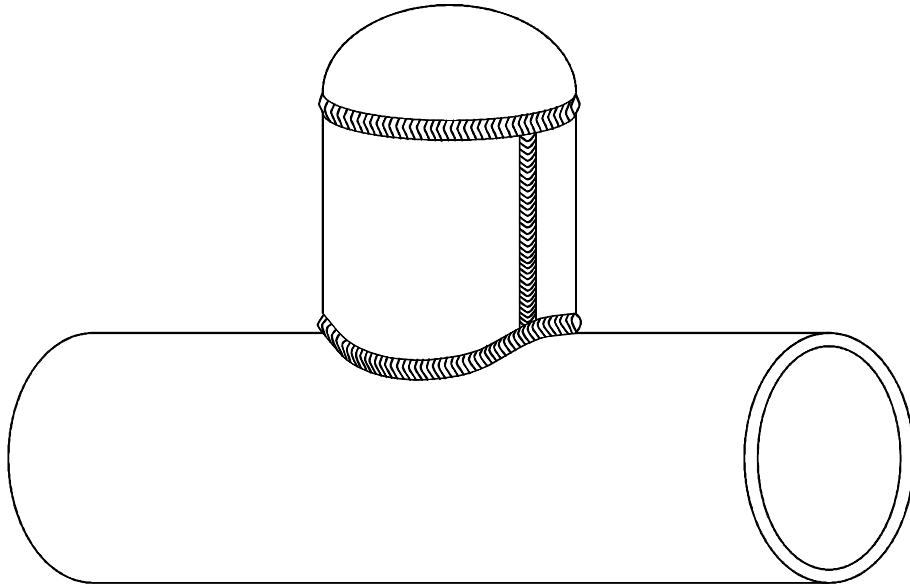


Figure 3 Example of a Welded Leak Repair Box used to Cover a Leaking Vent

Non-metallic Internal Lining for Pipe (Sprayed Form for Buried Pipe)

Description

Background

This standard is for use of thermo-setting resins as protective or structural lining for buried pipe when applied in a sprayed form. The pipe can be steel, cast iron, concrete, or other less common materials, located below ground / buried, and with / without liners (e.g., cement, paint). The thermo-set resins also have a sub-set of materials called epoxy resins. The use of these thermo-setting resins is commonly called Cured-In-Place Pipe. This repair standard section does not apply to above ground piping, pumps, valves, tanks, or pressure vessels.

Use of CIPP repair methods can provide added structural strength, increased chemical and abrasion resistance, reduced infiltration and exfiltration, reduced pipe line flow resistance, and rapidly executed repair projects. This repair method is particularly useful for buried piping greater than 24-inch diameter.

Advantages

One major advantage of the epoxy resin that is sprayed onto the inside of the host pipe, is that it adheres to the pipe and becomes part of a composite system (epoxy lining plus the host pipe). A second advantage of the epoxy resin is that it can be reinforced with chopped fiber (glass or carbon), pre-impregnated carbon, or pultruded carbon, thereby making the composite pipe much stronger. Third, the epoxy spray form system can be used for patching portions of the buried pipe instead of the entire buried pipe. Fourth is the speed of application, which can easily be accomplished well within short outage windows in the plant. In addition the epoxy resin is mixed and applied in the field, so it is very accommodating to the normal outage schedule perturbations. Compared to the inserted form its cost effectiveness increases with pipe diameter especially in lines 36 inches in diameter and larger.

Disadvantages

The disadvantage of the sprayed form is for buried pipe less than 24 inches in diameter, since manned pipe entry and spraying is practically impossible for normally sized individuals. There is the possibility of robotic applying the sprayed form for small pipes. This is now available in highly specialized applications.

Cautions and Limitations

Application Temperature & Humidity Limitations

Some thermoset resins, including epoxies, may have application maximum and minimum temperature and humidity limitations.

Operating Temperature Limitations

Thermoset resins, including epoxies, have a maximum design operating temperature that depends greatly on the ingredients or additives. Beyond that temperature, this repair method may be substantially degraded. The curing time for thermoset resins may be extremely long for lower temperatures or may require auxiliary heat.

Operating Humidity Limitations

For thermoset resins that use solvents for the application process, humidity may affect the process. Thus humidity control of the application area may be needed.

Design

General Design Considerations

The design application categories of this repair standard are for the CIPP to be used as a:

- A - pipe corrosion protection liner from the contained fluid;
- B - load bearing member for a system within a partially deteriorated buried pipe;
- C - load bearing member for a system within a fully deteriorated buried pipe.

For design application category A, the CIPP application is assumed to carry no system loads.

For design application category B, this repair standard applies to continuously supported buried piping systems (conservative boundary condition).

For design application category C, this repair standard applies only when the buried host pipe has sufficient structural capacity to carry the pressure of the installation process and serve as a form for CIPP application.

The sprayed form application of non-metallic internal lining may be considered the in-place formation of a composite pipe.

Types of Sprayed Form

The sprayed form consists of epoxy resin spray without reinforcing fiber, spray with reinforcing fiber, spray with reinforcing cloth, spray with partially cured materials, and spray with pultruded carbon. The sprayed form can use a variety of reinforcing fibers (i.e., glass, carbon). Typically the epoxy resin is mixed on site, pumped through a spray nozzle, and applied directly to the internal pipe surface being protected or reinforced.

The major factors influencing the design applications for CIPP are system exposure (i.e., acids, solvents, water), operating temperatures (maximum, minimum, and range), coefficients of thermal expansion, modulus of elasticity, and tensile strength.

Piping Degradation Cases

Case #1 is where internal corrosion has not yet occurred or has penetrated less than the depth of the accepted corrosion allowance. In this case the host pipe meets all of the necessary design and safety requirements. The application of a protective CIPP lining will likely allow the host pipe to remain satisfactory for the life of the plant. This Case is a good application of Design Application Category A.

Case #2 is where internal corrosion is localized in either pits, around welds, or in other small areas. Some pin hole leaks may be evident. With the exception of these small areas, the host pipe has not lost all of its corrosion allowance. The losses in these small areas do not affect the general overall strength of the host pipe and do not indicate any near term impending failure. The repair of these small areas will allow the host pipe to remain satisfactory until the next required inspection. The repair could be with weld overlays or reinforced CIPP. This Case is a good application of Design Application Category B.

Case #3 is where there is severe generalized corrosion, but it is limited to short lengths or sections of host pipe. This general corrosion might have been caused by loss or damage to the original liner, flaws in the host pipe, or loss of cathodic or anodic protection. The losses due to this generalized corrosion are greater than the corrosion allowance and some degree of failure of the host pipe might be eminent. This Case is a good application of Design Application Category B.

Case #4 is where there is significant generalized internal corrosion. The host pipe has lost all or most of its corrosion allowance. The host pipe still maintains the majority of its required strength and is under no immediate danger of catastrophic failure. This Case is a good application of Design Application Categories B or C.

Case #5 is where there is severe generalized corrosion, either internal, external, or a combination. The host pipe is in immediate danger of failure. The host pipe can no longer be expected to carry the majority of the design loads. The host pipe may continue to undergo external corrosion even if a CIPP liner is installed. This Case is a good application of Design Application Category C.

Material Considerations

This repair standard applies typically to epoxy resins (a sub-set of thermosetting resins), that may have reinforcing fiber (i.e., glass, carbon).

The thickness of the applied thermo-setting resins (and amount / type of reinforcing fiber) depends on whether the resin is to provide protective coating to pipe (design application category A), to structurally augment the partially deteriorated host pipe (design application category B), or to carry all the design loads of the pipe (design application category C).

Epoxy resins are perhaps the best of the thermo-setting resins for buried pipe rehabilitation due to their versatility, strength, adherence to the host pipe, low coefficient of friction, and chemical and abrasion resistance. However mixture ratios, setting time, and curing time must be managed with proper selection of curing agents and well designed application equipment to insure the best product and set times.

Material Property Determination

The design life and the maximum temperature to which CIPP will be exposed over its design life for all anticipated loading conditions shall be specified.

A time-temperature-corrected flexural modulus of elasticity shall be determined in accordance with ASTM D790 and ASTM D2990 using the maximum temperature and design life from above.

A time-temperature-corrected ultimate tensile strength shall be determined in accordance with ASTM D638 and ASTM D2990 using the maximum temperature and design life from above.

The coefficient of thermal expansion for the maximum temperature from above shall be determined in accordance with ASTM D696.

Specific Design Requirements

The design thickness of the CIPP is a function of the resin, reinforcing material, and condition of the host pipe. The anticipated or postulated loads in the Design Specification for the modifications on piping system shall be specified.

The Design Specification shall address the following loads:

Design for Internal Fluid Pressure

Internal pressure is typically the first design consideration for buried pipe. Having selected a pipe material and diameter compatible with the required flow, the designer calculates the minimum wall thickness required to safely sustain the design pressure at the design temperature. The equation used to calculate the wall thickness of buried piping is specified in the Code or Standard applicable to the service (see Appendix IV for

references). In all cases, the intent of the equation for wall thickness is to limit the hoop stress in the host pipe (original design), composite pipe, or CIPP to a fraction of the material's specified minimum yield or ultimate strength. The form of the equation for the original design varies with the applicable Code and pipe material, but it is not different than the above ground pressure design equation (pipe wall is sized the same way for underground and above ground service). See Appendix I for applicable equations for CIPP.

Design for Soil Loads

Soil loads are an important consideration for pipes made of rigid and non-ductile materials such as concrete or cast iron and pipes with large D/t such as encountered in civil engineering applications. Conversely, earth loads are rarely quantified for pressure piping made of ductile materials such as steel or polyethylene. See Appendix I for applicable equations for CIPP.

Design for Surface Loads

It has been established for many decades that the pressure applied to the pipe wall from a concentrated surface load decreases as the square of the height of soil cover. Therefore, the effect of heavy surface loads, such as highway traffic, railroad, or structures built above the buried pipe, is often controlled in design practices by providing a minimum depth of cover above the pipe. Minimum depth of covers are specified by Codes and Standards and should be checked by analysis for particularly heavy surface loads (see Appendix I).

Design for Temperature Change

Buried pipelines are often operated at temperatures that are not significantly above the surrounding soil temperature. If there is no differential expansion between the soil and the pipe, then a thermal analysis is not required. In cases where the fluid is hot, compressive and bending stresses are generated as the pipe expansion is restrained by the surrounding soil, unless a mineral fiber cushion (or equivalent) has been wrapped around elbows and bends to permit thermal expansion.

Design for Waterhammer

The response of a buried pipe to waterhammer differs from the behavior of above ground piping, since restraint by soil limits its movements and bending moments. Under the excessive hoop stresses from the pressure pulses that accompany waterhammer, fitting, valve, or pipe rupture is possible.

Design for Seismic Loads

In practice, the design of buried pipe for seismic loads is limited to critical applications in earthquake prone areas. An earthquake may affect the integrity of a buried pipe in two possible ways: through wave passage (transient ground deformation) and through

permanent ground deformation. Failures are more often due to soil failures (liquefaction, landslides, fault movement) rather than the transient passage of seismic waves.

Fabrication (Installation)

Host Pipe Examination

An examination shall be performed to determine the design condition of the host pipe, i.e., partially or fully deteriorated.

The host pipe shall be cleaned of loose rust, scale, and biofouling. For best adhesion of the thermosetting resin to the host pipe, the inside pipe surface shall be near “white” condition.

Epoxy Mixing

Resin and curing agent batches and mixture proportion shall be verified.

Epoxy Application

Epoxy shall be applied in even and over lapping patterns until design thickness is achieved.

When chopped fibers or cloth are added, they shall be evenly disbursed, wetted, and rolled / compressed to remove voids. Then top layer of epoxy is applied over the chopped fibers to provide smooth, monolithic liner.

If protruded or pre-impregnated carbon is being utilized, then first apply adhesive layer, second press the carbon into the adhesive epoxy, and third top coat to the design thickness to provide smooth, monolithic liner.

Examination

Test Sample Retrieval

For each CIPP batch installed, samples may be taken in accordance with the following:

Samples may be taken on coupon specimens identical to material sprayed onto the host pipe (similarly cured).

Samples may be large enough to provide ten specimens for each of the test procedures required in material testing below.

Samples should be identified to provide traceability.

Material Testing

The test samples obtained in accordance with the above requirements for test sample retrieval may be tested to confirm the design basis material property values, i.e.,

- time - temperature - corrected flexural modulus of elasticity for CIPP (E_F in psi from Appendix I),
- time - temperature - corrected ultimate tensile strength of CIPP (S_T in psi from Appendix I),

and the coefficient of thermal expansion used in the analysis required by Appendix I.

CIPP Installed Geometry Verification

In accordance with approved procedures by qualified personnel, the minimum installed CIPP wall thickness shall be verified using ultrasonic or other examinations to meet the design requirements.

A set of four measurements, equally spaced around the circumference of the CIPP, should be taken at each end and at one intermediate point.

Additional sets of measurements should be taken in areas of significant host pipe degradation.

Documentation of CIPP As-Installed Condition

A visual examination shall be performed.

Voids, surface flaws, and areas of improper curing shall be evaluated, as required.

All inspection / examination and corrective action shall be in accordance with Appendix II.

Monitoring Plans

A plan for monitoring a partially deteriorated host pipe's corrosion rates should be prepared . No monitoring plan is required for a fully deteriorated host pipe. A plan for monitoring CIPP for degradation due to environmental conditions, erosion, or thermal expansion and contraction should be prepared .

Testing

A system pressure test shall be performed on the CIPP as follows:

Isolable Pipe

The system pressure test for buried components that are isolable by means of valves should consist of a test that determines the rate of pressure loss. Alternatively, the test may determine the change in flow between the ends of the buried components. The acceptable rate of pressure loss or flow should be established.

Nonisolable Pipe

The system pressure test for nonisolable buried components should consist of a test to confirm that flow during operation is not impaired.

Pressure Loss Test

If practicable, a pressure loss test should be conducted, at a test pressure specified by the design.

DESIGN CONSIDERATIONS FOR BURIED PIPE

Wall Thickness of CIPP

The required CIPP design wall thickness, t_r , for a partially deteriorated host pipe shall be at least the greater of the thickness determined by Eqs. (1) and (3). This minimum thickness shall be increased to provide for all applicable manufacturing-specific installation or carrier tube constructability tolerances and shall be referred to as the nominal CIPP wall thickness, t , and shall be used in the analysis required by analysis equations below.¹

The t_r for a fully deteriorated host pipe shall be at least the greater of the thickness determined by Eqs. (1) and (2). This minimum thickness shall be increased to provide for all applicable manufacturing-specific installation or carrier tube constructability tolerances and shall be referred to as t_n and shall be used in the analysis required by analysis equations below.¹

Design Equations

Equation (1) shall be used to determine the t_r required due to internal pressure on CIPP contained in a partially or fully deteriorated host pipe.

$$t_r = \frac{D_o}{\left[\left(\frac{2S_T}{P_D N_S} \right) + 1 \right]} \quad \text{Equation (1)}$$

where

t_r = required CIPP design wall thickness, in.

P_D = internal design pressure, psig

D_o = outside diameter of CIPP (inside diameter of host pipe), in.

S_T = time-temperature-corrected ultimate tensile strength of CIPP, psi

N_S = design safety factor (typically 2)

¹ Although the partially deteriorated host pipe assumption could result in a thinner wall thickness than a fully deteriorated host pipe, it will require future monitoring of the host pipe whereas the fully deteriorated pipe will not.

Equation (2) shall be used to determine the t_r required due to applicable external pressures on CIPP contained in a fully deteriorated host pipe.

$$t_r = 0.721 Do \left[\frac{(N_E q_t / C)^2}{E_F R_w B' E'_s} \right]^{1/3} \quad \text{Equation (2)}$$

where

q_t = total external pressure on CIPP, psi

R_w = water buoyancy factor (0.67 minimum) = $1 - [0.33(H_w/H)]$

H_w = height of groundwater above top of host pipe, ft.

H = height of soil above top of host pipe, ft.

B' = coefficient of elastic support = $1/(1+4e^{-0.065H})$.

C = ovality reduction factor =

$$C = \left[\left(1 - \frac{q}{100} \right) / \left(1 + \frac{q}{100} \right)^2 \right]^3$$

q = ovality (%) of host pipe

$$= 100 \chi \frac{(\text{Maximum measured diameter} - \text{Minimum measured diameter})}{\text{Average measured diameter}}$$

N_E = 2 (Design Factor)

E'_s = modulus of soil reaction, psi

E_F = time-temperature-corrected flexural modulus of elasticity for CIPP, psi

Equation (3) shall be used to determine the t_r required due to applicable external pressures on CIPP contained in a partially deteriorated host pipe.

$$t_r = \frac{D_o}{\left[\frac{2K E_F C}{q_t N_E (1 - \nu^2)} \right]^{1/3} + 1} \quad \text{Equation (3)}$$

where

K = buckling enhancement factor of the soil and host pipe adjacent to CIPP. A value of 7.0 shall be used.

ν = Poisson's ratio = 0.30; or Poisson's ratio may be determined using the test method of ASTM D2105.

Analysis Equations

To validate CIPP design, the analysis shall consider the effects due to applicable thermal expansion, weight, other sustained loads, and other occasional loads specified in the Owner's Requirements.

Stresses due to sustained and occasional loads shall meet the requirements of Equation (4) below.

$$\frac{P_{mo} D_o}{4t_n} + 0.75i \left[\frac{M_A + M_B}{Z} \right] + \frac{S_\alpha}{A} \leq \frac{kS_T}{4} \quad \text{Equation (4)}$$

where

D_O = outside diameter of CIPP, in.

M_A = resultant moment loading on cross section due to weight and other applicable sustained loads, in-lb. Because CIPP is continuously supported by the existing soil system or the partially deteriorated host pipe, the M_A term can usually be neglected.

Z = section modulus of CIPP, in³.
 $= \pi r_m^2 t_n$

r_m = mean radius of CIPP, in.

t_n = nominal CIPP wall thickness, in.

P_{mo} = maximum operating pressure, psig

M_B = resultant moment loading on cross section due to applicable occasional loads, such as thrusts from relief and safety valve loads,

from pressure and flow transients, and seismic inertia, in-lb. For seismic inertia, use only one-half of the range. The effects of seismic displacements may be excluded from Equation (4) if they are included in Equation (5).

- S_{α} = axial loading on cross section due to seismic displacements or other applicable occasional loads, lb.
- A = cross-sectional area of CIPP, in.²
- k = occasional load factor = 1.2
- i = stress intensification factor (SIF). The SIF for sprayed form CIPP in a straight or curved host pipe shall be taken as 1.
- S_T = time-temperature-corrected ultimate tensile strength of CIPP, psi

Stresses due to thermal expansion loads shall meet the requirements of Equation (5).

$$\frac{iMc}{Z} + \frac{S}{A} \leq \frac{S_T}{2} \quad \text{Equation (5)}$$

where

- M_C = resultant moment loading on cross section due to thermal expansion, in-lb. Also includes moment effects of seismic displacements if they were omitted from Eq. (4).
- S = axial loading on cross section due to seismic displacements, if included, and thermal expansion, lb.

Determination of Resultant Moment

For Equations (4) and (5), the resultant moments for straight and curved piping members shall be calculated as follows:

$$M_j = (M_A^2 + M_B^2 + M_C^2)^{1/2}$$

where

- j = A, B, or C, as defined in Equations (4) and (5)

INSPECTION / EXAMINATION AND CORRECTIVE ACTION REQUIREMENTS FOR CIPP

General

All required corrective actions to the CIPP due to voids, surface flaws, and areas of improper curing shall be in accordance with this Appendix.

Epoxy Mixture Control

Mixture control shall be confirmed by color of the epoxy.

Color chip should be used to compare epoxy to the proper mixture of epoxy.

Epoxy Thickness Sampling

Measure epoxy thickness based on minimum design calculations.

Thickness may be measured with UT or magnetic instruments.

Epoxy Hardness

Measure hardness of epoxy for quality control of the mix ration installed.

Hardness sample points may be determined at random approximately every three feet on installed length and at approximately four circumferential points.

Hardness sample points should also be where ever the installed visual color looks bad.

Epoxy Coverage

Measure coverage of epoxy to identify “pin holes” and imperfections.

Use “holiday test” as specified by the manufacturer to identify pin holes and thin spots in the coating.

Surface Defect Corrective Actions

Grind away the epoxy around the surface defect to create adhesive bonding sites.

Mix the components of the epoxy in accordance with manufacturer's recommended proportions.

Spray or trowel the epoxy over the surface defect.

Inspection of the epoxy system, applied to the surface defect in accordance with the CIPP epoxy manufacturer's recommendations, shall be the determining factor in judging cure completion.

Grind away, as required, the excess epoxy so that the corrective action follows the contour of the existing CIPP. Note this excess epoxy only affects the flow surface of the pipe, not the structural aspects of the CIPP.

Corrective Action for Areas of Insufficient Curing

Areas of insufficient curing shall be completely cured by steps identified in II-6.0 above. Inspection in accordance with the CIPP epoxy manufacturer's recommendations shall be the determining factor in judging cure completion.

Glossary of Terms and Acronyms

Glossary of Terms

Cured-In-Place Pipe	- (CIPP) The buried piping modification method with a thermosetting resin into a host pipe
Curing	- The changing of properties of a polymeric system by the application of heat or other means into a more stable and usable condition
Epoxy Resin	- These are usually a two component system primarily composed of epichlorahydrin and Bisphenol A combined with an amine-based curing agent
Fully Deteriorated Host Pipe	- A host pipe that is not relied upon to support soil, surcharge, or groundwater loads
Host Pipe	- The old existing pipe to be modified
Partially Deteriorated Host Pipe	- A host pipe which is relied upon to support soil and surcharge loads throughout its design life
Reinforcement	- A high strength filler imbedded in the plastic resin, resulting in mechanical properties superior to those of the base resin
Resin Filler	- A relatively inert material added to a plastic resin to modify its strength, permanence or working properties
Thermoset Resin	- These are plastic resins that cannot be re-softened following polymerization (include Bakelite, epoxy, polyurethane, polyesters, vinyl esters, and paints)
Surcharge	- Loading on a buried host pipe produced by ground transportation traffic, e.g., truck or railway

Glossary of Acronyms

ASME	- American Society of Mechanical Engineers (ASME International) New York, NY
ASTM	- American Society for Testing and Materials Philadelphia, PA
AWWA	- American Water Works Association Denver, CO
CIPP	- Cured-In-Place Pipe

REFERENCES

Codes and Standards References

<u>Standard or Specification</u>	<u>Title</u>	<u>Revision Date or Indicator</u>
ASTM F 412	Standard Terminology Relating to Plastic Piping Systems	1994b
ASTM D638	Standard Test Method for Tensile Properties of Plastics	1994b
ASTM D696	Standard Test Method for Coefficient of Linear Thermal Expansion of Plastics Between -30°C and 30°C With Vitreous Silica Dilatometer	1991
ASTM D790	Standard Test Method for Flexural Properties of Unreinforced and Reinforced Plastics and Insulating Materials	1992
ASTM D903	Standard Test Method for Peel or Stripping Strength of Adhesive Bonds	1993
ASTM D2105	Standard Test Method for Longitudinal Tensile Properties of “Fiberglass” (Glass-Fiber-Reinforced Thermosetting-Resin) Pipe and Tube	1990
ASTM D2837	Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials	1992
ASTM D2990	Standard Test Method for Tensile, Compressive, and Flexural Creep and Creep-Rupture of Plastics	1993a
ASTM D 1763	Standard Specification for Epoxy Resins	1994
ASME B&PV Code Section III ND-3672.6(a)	Piping Design / General Requirements / Expansion and Flexibility / Stresses / Stress Range	1992 Edition or later
ASME B&PV Code Section III ND-3611.2	Piping Design / General Requirements / Acceptability / Stress Limits	1992 Edition or later
ASME B31.1	Power Piping	1998
ASME B31.3	Process Piping	1996
ASME B31.4	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids	1998
ASME B31.5	Refrigeration Piping	1992
ASME B31.8	Gas Transmission and Distribution Piping Systems	1995
ASME B31.9	Building Services	1996
ASME B31.11	Slurry Transportation Piping Systems	1989
AWWA C-150/A21.51	Standard for Thickness Design of Ductile Iron Pipe	1991

AWWA C-151/A21.51	Standard for Ductile Iron Pipe, Centrifugally Cast, for Water or Other Liquids	1991
AWWA C-200	Standard for Steel Water Pipe 6 in and Larger	1997
AWWA C-300	Standard for Reinforced Concrete Pressure Pipe, Steel-Cylinder Type, for Water and Other Liquids	1997
AWWA C-301	Standard for Pre-stressed Concrete Pressure Pipe, Steel-Cylinder Type, for Water and Other Liquids	1999
AWWA C-302	Standard for Reinforced Concrete Pressure Pipe, Non-cylinder Type	1995
AWWA C-303	Standard for Concrete Pressure Pipe, Bar-Wrapped Steel-Cylinder Type	1995
AWWA C-900	Standard for Polyvinyl Chloride (PVC) Pressure Pipe, 4 in Through 12 in, for Water Distribution	1997
AWWA C-905	Standard for Polyvinyl Chloride (PVC) Water Transmission Pipe, Nominal Diameter 14 in through 36 in	1997
AWWA C-906	Standard for Polyethylene (PE) Pressure Pipe and Fittings, 4 in through 63 in, for Water Distribution	1999
AWWA C-950	Standard for Fiberglass Pressure Pipe	1995
AWWA M-11	Steel Pipe - A Guide for Design and Installation	1989
AWWA M-23	PVC Pipe - Design and Installation	1980
AWWA M-45	Fiberglass Pipe Design	1996

Weld Overlay Repair Methods for Thinning Steel Pipe

Description

Preface

This standard is intended to detail the weld overlay repair application criteria, design criteria, as well as appropriate overlaying procedures and testing methods to be used as an alternative to piping replacement or weld repair methods for piping experiencing wall thinning or degradation. This standard documents weld overlay repair methods and standards for use on steel piping. The repair methods described in this article are based upon extensive testing and analysis performed for the development of ASME Code Case N-561 which covers alternative repair rules for Class 2 and high energy Class 3 carbon steel piping, and Case N-562 which covers the requirements for the alternative repair of moderate energy Class 3 carbon steel piping. The objective of these Code Cases is aimed at providing an engineered, reliable repair method that can be readily applied to these classes of piping without the need for plant shutdown or piping replacement.

The repair methods described herein should be reviewed and approved by the appropriate jurisdiction prior to implementation. These repair methods are subject to the appropriate construction or post construction codes for the affected component and are not considered to be all inclusive.

Description

Weld metal overlay has been successfully implemented in industry as both temporary and permanent repair for the restoration of thinning or degraded steel piping. Piping systems suffer from numerous degradation mechanisms. The primary causes of damage in austenitic piping is stress corrosion cracking (SCC), fatigue, and general corrosion. The degradation mechanisms for ferritic piping include microbiologically influenced corrosion (MIC), erosion-corrosion damage (EC), fatigue, and general corrosion. The magnitude of the damage induced in the pipe determines whether a weld overlay repair can be successfully applied to restore the pipe's integrity. This standard addresses the repair of piping degraded by wall thinning due to corrosion, erosion-corrosion, MIC and other mechanisms. It does not address the repair of cracked piping.

When appropriate, applying a weld overlay repair to thinning pipe will provide the necessary structural reinforcement and will eliminate the need for either total replacement of the pipe or the need for an internal weld repair. Specifically, a weld overlay procedure can be used to structurally restore steel piping to the appropriate wall thickness without resorting to replacement efforts. Utilizing a weld overlay repair for piping experiencing wall thinning is desirable due to the fact that the repair can be implemented without any breach to the system and will significantly minimize the cost and time which would

otherwise be necessary for total piping replacement. Application of a weld overlay repair is also possible in a liquid-backed environment, which further eases implementation of the repair. In some cases, it may be possible to effect a repair while the piping system is in operation.

Limitations

- Section I of *Repair of Pressure Equipment and Piping* contains additional requirements and limitations. This article shall be used in conjunction with Section I.
- Application of the weld overlay remedy for steel piping is strictly prohibited under two conditions for this standard. Namely, a weld overlay can not be used for structural reinforcement when 1) there is suspicion any form of cracking (in the current or as-repaired condition) and 2) the minimum thickness of deposited weld metal necessary to satisfy the design requirements is greater than the original nominal thickness of the pipe.
- Refer to pipeline regulations and to the pipeline design codes for restrictions regarding repair techniques.

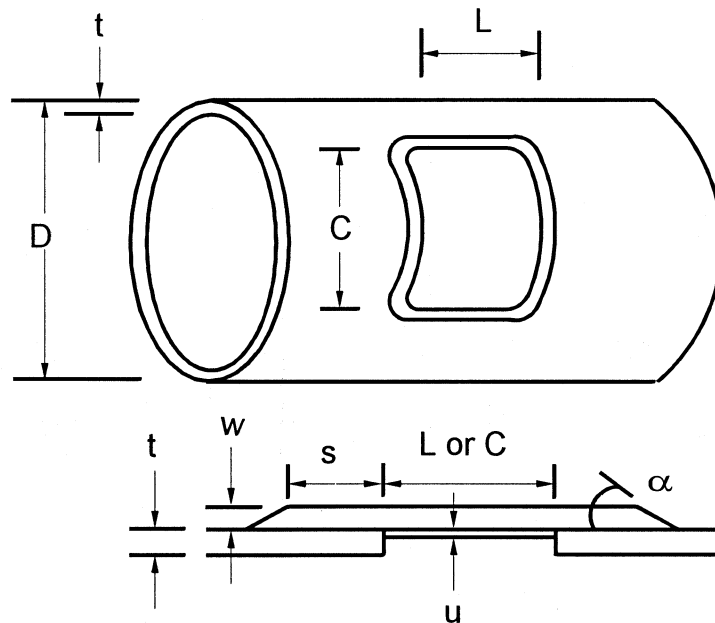
The user is cautioned to ensure that these repair techniques are appropriate for the specific damage mechanism to be repaired and the intended service conditions. A proper engineering review and root cause analysis may be required prior to application of this, or any other, repair method.

In all cases, the user should evaluate the flammability, volatility, or potential reactions of the media within the pipe prior to application of any welding process. In no case should welding be performed without a thorough understanding of the media transmitted within the pipe. This should also include an evaluation of the media for potential reactions with the base material due to the heat from welding.

Examples of process media that should be properly flushed from the system prior to repair may include hydrogen, hydrogen cyanide, oxygen, caustic materials, butadiene, acetylenic compounds, chlorine and others. In some cases, decontamination procedures may be necessary to prepare a piping system for repair.

Design

The following figure depicts the weld overlay dimensions referred to in this section.



Overlay Design

When steel piping experiences wall thinning or pitting as a result of conditions such as, but not limited to, general corrosion, flow- assisted corrosion, and microbiological corrosion, a weld overlay procedure can be performed as an alternative to replacement or internal weld repair subjected to the following requirements:

Weld Metal Requirements

- The nominal chemistry of the deposited weld metal shall match the base material. If the nominal chemistry of the weld metal does not match the chemistry of the base metal, then a welding/materials engineer should be consulted to assure that the weld metal is compatible with the process.
- The tensile strength of the weld metal shall be at least that of the base metal to which it is applied.

Overlay Geometry Requirements

- The design of the overlay shall be as such that post-repair examinations and evaluations or any pre-service examinations will not be hindered.
- The full thickness of the weld shall extend a full distance S_{min} in each direction beyond the affected base metal (unless otherwise established by theoretical or

experimental analysis).

$$S_{\min} = \frac{3}{4} \sqrt{R t_{\text{nom}}}$$

R = outer radius of the component

t_{nom} = nominal wall thickness of the component

- The edges of the weld overlay shall be tapered to the existing piping surface at a maximum angle of 45 degrees.
- The thickness of the overlay shall be uniform except for the tapered edges.
- The thickness shall be sufficient to maintain the predicted life of the repair.
- All corners of the overlay should have a minimum radius not less than the overlay thickness.
- In addition, overlays should not be spaced any closer than $\frac{3}{4} \sqrt{R t_{\text{nom}}}$, between the toe of each overlay. Configurations not meeting these requirements must be established based on theoretical or experimental analysis.
- The minimum required thickness of deposited weld metal necessary can not exceed the nominal size and schedule of the piping.
- The total thickness of the filler metal applied over multiple repairs shall not exceed the original nominal thickness.
- Any corrosion allowance that is determined to be necessary should be added to these dimensions. The predicted maximum degradation of the overlaid piping, and the overlay, over the design life of the restoration should be considered.

Overlay Qualification Requirements

- The weld overlay can be considered *pre-qualified* in which case no qualification procedures will be necessary prior to the application of the overlay, otherwise the overlay will need to be qualified through a *proven engineered design*, or through a *proof test*.
- The weld overlay can be qualified by a proven engineered design . If the weld reinforcement is not prequalified and is considered an integral part of the piping (not as a weld), then the allowable stress values of the base metal shall apply to the design of the weld metal and the following factors must be considered in the design:
 - 1) the effects of 3-dimensional shrinkage,
 - 2) the effects of flexibility, stress concentration, and section properties,
 - 3) stress concentrations from the piping internal surface configuration, and
 - 4) the effects of differing thermal expansion coefficients between the base and the weld metal.
- As an alternative to the design by analysis of weld overlays, a proof test qualification

may be performed through a satisfactory burst test mock-up. The details of the mock-up configuration and considerations can be seen in subsection 3.3, titled “Burst Test Procedures”.

- Application of the weld overlays on straight pipe and associated welds to correct limited degradation can be considered a *prequalified* design and will be exempt from a design qualification or a proof test qualification given that all of the following conditions are met:
 - 1.) The pipe material has allowable stress, S_m of at least 103MPa (15,000 psi).
 - 2.) The maximum design temperature does not exceed 340°C (650°F).
 - 3.) The specified thickness of the existing base metal shall be at least Schedule 40 or Standard Wall, whichever is less.
 - 4.) The maximum angle of the taper shall not exceed 30 degrees.
 - 5.) The finished overlay shall be circular, oval, full circumferential, or rectangular in shape.
 - 6.) For each repair, the maximum dimension compensated by a circular or oval overlay shall not exceed the lesser of $\frac{1}{2}$ the nominal outside diameter of the piping or 200mm (8 inches).
 - 7.) Rectangular overlays shall be aligned parallel with or perpendicular to the axis of the piping, and corners shall be rounded with radii not less than the overlay thickness.
 - 8.) The distance of the toes of adjacent overlays shall not be less than $\frac{3}{4}\sqrt{Rt_{nom}}$.
 - 9.) The maximum axial dimension and area of base metal predicted to be below the required thickness shall not exceed that defined by:

$$L_{max} = k_1 D_o + k_2$$

$$A_{max} = 0.455 D_o - k_3$$

Where

L_{max} = maximum axial dimension of base metal predicted to degrade below the required thickness over the remaining life of the repair, in.

A_{max} = maximum area of base metal predicted to degrade below the required thickness over the remaining life of the repair, mm² (in²).

D_o = piping nominal outside diameter, mm (inches).

K_1 = 0.21 for pipe smaller than DN 300 (NPS 12)
= 0.11 for pipe DN 300 (NPS 12) to DN 600 (NPS 24)

K_2 = 14mm (0.55 in.) for pipe smaller than DN 300 (NPS 12)

= 46.7mm (1.84 in.) for pipe DN 300 (NPS 12) to DN 600 (NPS 24)

K_3 = 581mm² (0.9 in.²) for pipe smaller than DN 200 (NPS 8)

$= 516\text{mm}^2$ (0.8 in.²) for pipe DN 200 (NPS 8) to DN 600 (NPS 24)

- 10.) If flexibility analysis was required by the original Construction Code, the effect of the weld overlay shall be reconciled with the original analysis. In this case, for rectangular-shaped overlays on straight pipe, a Stress Intensification Factor (SIF) of 2.1 shall be applied to the overlay.

Burst Test Procedures

This section describes the methods and equipment used for burst testing of samples for qualification of weld overlay repairs for ferritic piping. It should be clearly understood that burst testing of any component can be very hazardous and specialized equipment and safety procedures must be used. It is highly recommended that testing be performed within a containment structure or in an isolated location. Personnel must be protected from debris/shrapnel that may result from over-pressurization of a component.

Please refer to Figure 1 below for the dimensions stated in this repair standard.

Proof Test Qualification Requirements

As an alternative to the *Engineered Design* approach, a burst test of a mock-up overlay can be performed to qualify the weld overlay design.

A satisfactory mock-up burst test shall qualify the weld overlay design for application in the same orientation on the same type of item, and the same location on fittings, when the following conditions are met:

- 1.) The base metal is of the same P-No and Group number as the mock-up base material tested.
- 2.) The specified minimum tensile strength of the item does not exceed that of the mockup base material tested.
- 3.) The average thickness of the overlay areas is at least the thickness of the mock-up plug, u in Fig. 1.
- 4.) The overlap on the full thickness of base metal, s , is at least that of the mock-up.
- 5.) The transition angle at the outer edges of the overlay, α , is not greater than that of the mock-up.
- 6.) The overlay surface is similar to or smoother than that tested.
- 7.) The maximum proportionate axial dimension, L/D , is not more than that tested.
- 8.) The maximum proportionate circumferential dimension, C/D , is not more than that tested.
- 9.) The nominal diameter is not less than one-half nor more than two times the diameter tested.
- 10.) The nominal thickness/diameter ratio, t/D , is not less than $\frac{1}{2}$ nor more than 3 times the t/D ratio tested.

- A rounded-corner segment of the base material of the mock-up, shall be removed to represent the maximum proportionate size (axial dimension of L and circumferential dimension of C) and location of thinning or pitting to be compensated for by the weld overlay. A plug of the same base material and of uniform thickness u, which shall not exceed the smallest average thickness on which the overlays will be permanently applied, shall be full-penetration welded around the opening and flush with the outside surface of the piping. Alternatively, an equivalent volume of base metal may be removed from the inside surface of the mock-up by machining or grinding, without the need for welding in a closure plug.
- Overlay section thickness (deposit + base metal), represented by the dimension 'U' and 'W' in figure 1, for the thinned area of the mockup shall be not greater than 87.5% of the nominal wall thickness. This is intended to provide a conservative thickness for the qualification of the overlay design. Because pipe manufacturers have up to a 12.5% wall thickness tolerance to work with, under many specifications, the maximum 87.5% nominal wall thickness requirement for the thinned portion of the overlay qualification will account for this possible deviation in manufactured thickness.
- To qualify a repair design for general application (on piping in the same orientation or at the same location on fittings), burst pressure shall not be less than:

$$P = \frac{2 t S_{act}}{D}$$

Where:

P= minimum acceptable burst pressure

t = minimum specified thickness (excluding manufacturing tolerance) of base material tested, mm (inches).

S_{act} = reported actual tensile strength, MPa (psi), of the base material tested.

D = outside diameter of the pipe, mm (inches).

Burst Testing Method

A significant concern for any hydrostatic testing program is safety of personnel, and to a lesser extent - equipment.

A recommended approach would be to perform burst testing in a location as remote as possible from other personnel and equipment. Other recommendations include:

- Consider the calculated burst pressure for the component, assuming no defects or repairs, to ensure that the proposed containment is sufficient in size and strength to

contain burst parts and water. A pit in the ground is an appropriate test site if other facilities are not available.

- Clamp, chain or otherwise secure the component being tested to a heavy steel/iron table or platen to limit travel of large parts, during proof testing.
- Control potential damage that may be caused by debris (including water), through use of sufficient pit depth, remote location, and strength or design of containment.
- Keep all personnel out of the test area. Personnel should be located where there is a substantial (concrete block) wall between themselves and the test area.
- All viewing of the test should be with closed circuit television or other method that does not require personnel in the test area.
- All pressure parts used for proof testing, such as hoses, hydraulic fittings, gauges, etc., shall be rated with working pressures at or above the working pressure of the testing pump.

WARNING: *Hydrostatic Burst Testing is extremely dangerous and can cause loss of life and damage to property. All tests should be thoroughly evaluated for safety and control of debris from component failure.*

Pump Selection

The pump station used for burst testing should be equipped with a pump capable of exceeding the maximum calculated burst pressure. It is recommended that the pump provide a minimum of 25% overpressure to allow for changes in pressure from wall thickness variation, weld reinforcement, etc.. In most cases, the actual burst pressure will exceed the calculated value by a small margin. Appropriate pumps include air driven hydraulic pumps that are low-volume, high pressure systems. Gauges must be rated at, or above the working pressure of the pump, and calibrated to provide accurate readings for qualification purposes.

Burst Test Fittings and Gauges

All fittings, hoses and gauges shall be rated for working pressure equal to or greater than the pump rating. Fittings attached to the pipe mockup were threaded into the end bells of the mockup and then seal welded to prevent leakage. Fittings suitable for this service are available from a number of manufacturers. Gauges must also be rated for working pressures at or above the pump pressure rating and should be calibrated to a pressure standard, traceable to the National Institute of Standards and Testing (NIST), by a reputable laboratory.

Fabrication

This section describes application methods and techniques for applying weld overlays on degraded or thinning steel piping. This section should be considered as a general guideline for overlaying and should be used in compliance with the requirements of the applicable new construction or post construction code.

Pre-Repair Inspection Requirements

- The material beneath the surface to be repaired should be evaluated to establish the average wall thickness and the extent and configuration of degradation to be reinforced by the weld overlay. Consideration should also be given to the cause and rate of degradation. (If the cause of the thinning is not known or understood, then a materials engineer should be consulted to approve the repair techniques and procedures to assure that the repair will not cause a change in damage mechanism.)
- The entire surface area to which the weld overlay is to be applied, shall be examined using the liquid penetrant method or the magnetic particle method. Acceptance criteria shall be in accordance with the applicable new construction or post construction code.

Pre-Repair Surface Preparation

- It is important to ensure that the surface to be overlaid is free from rust, scale, paint, coatings, or other contaminants. Grinding or wire brushing will probably be necessary to remove surface oxides or protective coatings.
- Immediately prior to welding, the final weld surface should be thoroughly cleaned using a solvent, such as acetone, to remove any traces of oil or grease. This procedure will also help in removing traces of moisture.
- These contaminants can lead to porosity and other welding defects, which can adversely affect the welding quality. A clean surface will also assist in permitting more accurate nondestructive evaluation assessment of the pipe wall degradation.
- In some cases, it may be necessary to repair existing leakage prior to performing a weld repair. If sufficient material is available, peening may be used to close off the leakage and permit seal welding (1). Another option is application of weld metal immediately adjacent to the leakage with a series of overlapping weld beads. Once sufficient material is available, peen to close off the leakage and perform final seal welding.

Weld Overlay Placement

- The area that is determined to be degraded below the allowable wall thickness should be clearly mapped out on the pipe surface, using a scribe or other suitable marking technique.

Electrode Size and Filler

- The required weld metal should conform to sub-section 3.1.1.
- Prior to initiation of welding, the remaining wall thickness should be determined to ensure that the proper electrode size is used to prevent burnthrough of the pipe wall.
- Typical welding practice is to use the largest electrode that is practical for the available welding conditions.
- In the case of weld overlays for repair of wall thinning, it is necessary to minimize penetration during the first layer, thus smaller diameter electrodes are recommended. If in doubt about the accuracy of the wall thickness, such as in the case of pitting, the smallest possible, 1.6mm (1/16-inch) or 2.4mm (3/32-inch) diameter, electrode should be selected.
- Based on burnthrough testing of a carbon steel overlay performed under EPRI studies, the electrode size should not exceed the remaining base material wall thickness (1).

Welding Process and Techniques

- Overlay welding should be performed using a qualified groove welding procedure, in accordance with ASME Section IX, or as required by the applicable new construction or post construction code.
- Typical welding processes used, but not limited to, include SMAW, GTAW, and FCAW.
- Piping with wall thickness less than the diameter of the electrode shall be depressurized before welding.
- Vapor systems shall be depressurized before welding.
- Temperbead techniques, as permitted in the applicable post-construction codes, can be used on carbon steel piping for liquid-backed conditions and on low-alloy steel piping to avoid the need for high temperature heat treatments.
- A 50% bead overlap should be maintained.
- The following techniques can be used:
 - 1.) Once the area to be repaired has been mapped and the pipe surface cleaned, welding may be initiated on the first layer. As noted above, caution should be maintained on the first layer to minimize the potential for burnthrough. Welding parameters should provide as low a heat input as possible while maintaining fusion. This not only reduces the potential for burnthrough but reduces the width and hardness of the finished heat affected zone. Again, the use of small diameter electrodes is beneficial for welding the first layer to minimize the potential for burnthrough.
 - 2.) The first weld pass(es) should follow the outer perimeter of the weld overlay location to provide 1) an outer gage for the welder, 2) assists in improving the heat affected zone quality by eliminating the potential for a final, untempered weld pass on the base metal surface for carbon and low alloy steel materials. After completion of the perimeter weld pass, the first layer may be welded in accordance with the qualified weld procedure.

- 3.) Subsequent welding passes may be completed in a normal fashion, however care should be taken with the weld passes at the edges of the overlay to maintain the edge angle, or taper, to equal or less than that qualified. An edge angle of 30 degrees is recommended and meets one of the provisions for a pre-qualified design. The taper angle is important as it minimizes the stress intensifying effect of the overlay, due to the changes in surface geometry. The maximum allowable edge taper angle is 45-degrees.
- The surface of the completed weld overlay shall be prepared by machining or grinding, as necessary for required surface and volumetric examination.

Typical Welding Parameters Used

The welding procedures needed to perform repair of thinned piping can be based on existing procedures for piping fabrication. An EPRI test program used a conventional shielded metal arc welding procedure for P1, Group 1 & 2 base materials (1).

Examination

It is critical to ensure pipe integrity, prior to service, after any repair to ensure personnel safety and online service capability. This is particularly true with any high pressure, high temperature piping system. There is always a risk of immediate and catastrophic failure in steel piping if degradation or flaws within a repair are not detected properly. Proper examination and nondestructive testing will greatly diminish, if not eliminate, these risks. Pre-repair, interim repair, and post-repair inspection should be a corner stone of any repair program.

The following inspection requirements apply to weld overlay repairs:

- The completed weld overlay and existing piping beneath the overlay shall be examined using the liquid penetrant or magnetic particle method and shall satisfy the surface examination acceptance criteria of the applicable new construction or post construction code.
- The weld overlay and relevant existing piping shall be inspected to verify adequate wall thickness.
- The weld overlay shall be volumetrically inspected except under the following conditions:
 - 1.) Weld overlays not exceeding 6450mm² (10 in².) surface area.
 - 2.) When the applied thickness (w in Fig. 1) does not exceed
 - a.) $\frac{1}{3}t$ for $t \leq 19\text{mm}(\frac{3}{4}\text{in.})$

b.) $6.4\text{mm}(\frac{1}{4}\text{in.})$ for $19\text{mm}(\frac{3}{4}\text{in.}) < t \leq 63.5\text{mm}(2\frac{1}{2}\text{in.})$

c.) The lesser of

$9.5\text{mm}(\frac{3}{8}\text{in.})$ or 10% of t for $t > 63.5\text{mm}(2\frac{1}{2}\text{in.})$

Where

t = finished full section thickness of compensated area
(e.g. “w + u” in Fig.1)

- When volumetric examination is required, the full volume of the finished overlay, excluding the tapered edges, but including the volume of base metal required for the design life of the overlay, shall be examined by either the ultrasonic or radiographic method, and shall, to depth at the surface of the existing piping, satisfy the acceptance criteria for welds of the applicable new construction or post construction code.
- Grinding and machining of the as-welded overlay surface may be used to improve the surface finish for such examinations, when the overlay thickness is not reduced below design requirements.

Testing

If the pipe can be isolated for pressure testing, all repair locations should be pressure tested as required by the applicable post-construction code. Special safety precautions should be taken in case of a pneumatic testing in order to minimize the risk of accident. Alternatively, non-destructive examination may be performed in place of pressure testing, if permitted by the applicable post-construction code and by the local jurisdiction at the location of the pressure equipment, when contamination of the pressure retaining item by liquids is possible or when pressure testing is not practical.

All testing and inspections must be performed prior to application of insulation or coatings.

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0000000000001003162



*Printed on recycled paper in the United States
of America*

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com