Standard Recommendations for Pressure Part Inspection During a Boiler Life Extension Program

M.N. Hovinga
G.J. Nakoneczny
Babcock & Wilcox
Barberton, Ohio, U.S.A.

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Abstract

Due to the high costs of new boiler fabrication and erection, increasing efforts are being made to extend the life of existing units. The life extension and reliability of these plants is undermined if unscheduled and forced outages occur. Determination of the pressure parts requiring inspection, type of inspections to be performed, and the amount and location of these inspections has always been a major concern in boiler life extension. The complexity of the problem increases when the boiler's age, operating history, and failure history are taken into account. Over the years, The Babcock & Wilcox Company has inspected and provided life extension recommendations on boilers of every style from every manufacturer around the world. These recommendations are based on B&W's accumulated experience. This paper presents Babcock & Wilcox's approach for the recommendations for boiler pressure part life extension inspection requirements to ensure the safe and reliable operation of boilers.

Introduction

The goals of today's condition assessment and life extension programs are to increase the availability, efficiency, and reliability of the existing power plants and ensure safe and cost effective operation. In planning a condition assessment program, it is important to look at both the operating history and objectives for the boiler. Presented in the following paper is the program and methods recommended for the assessment of the boiler pressure parts. The recommendations consider the typical areas of concern. However, they are not intended to address every boiler or be all inclusive of every problem that may be encountered. All inspection plans are unique to the specific unit and should be made based on that unit's history and operating characteristics. The more information known about a specific unit, the more a detailed and cost effective inspection plan can be developed.

Inspection Plan

The inspection scope depends on several factors such as the boiler design type, design temperatures and pressures, materials, fuels, age, unit history, as well as future plans and operating conditions. B&W follows a multi-level approach in the planning of the survey scope.

In Level 1 of a Condition Assessment inspection plan, an evaluation of the plant's operating history and review of historical problem areas is performed. Based on this review, a detailed inspection plan is developed and implemented in Level 2. Nondestructive examination is then used to evaluate the current condition and estimate the remaining life of the inspected components. After the conclusion of the inspection program, the results are used in the planning of re-inspection and regular preventive maintenance to ensure reliable operation. The inspection is centered around the critical components. Generally, the critical components are those whose failure will directly affect the reliability of the boiler. The critical components can be prioritized by the impact they have on safety, reliability, and performance. These critical pressure parts include:

- Drums–steam, lower
- Headers–both steam and water
- Tubing–superheater, generating, waterwall, economizer
- Piping–steam and feedwater
- Deaerator–may have special safety concerns
- Attemperators

The inspection work scope is based on the individual unit's operating history, failure history, and expected failure mechanisms for each critical pressure part.

Following are typical inspection plans for critical pressure parts. These inspection plans are expected to be altered based on any additional unit information. Initially a comprehensive inspection of each pressure component should be made to give baseline data for future reference. Although expensive and time consuming, the advantage to this method is that it determines a time frame when any damage has occurred.

Boiler Drums

Steam drum The steam drum is the most expensive boiler component and must be included in any comprehensive condition assessment program. There are two types of steam drums, the all welded design used predominantly in electric utilities where the operating pressures exceed 1800 psi (124 bar), and drums with rolled tubes. Because of its relatively low operating temperature, the drum is made of carbon steel and is rarely subject to significant creep damage. Creep is defined as increasing strain at a constant stress over time.

Damage is primarily due to internal metal loss. The causes of metal loss include corrosion and oxidation, which can occur during extended outages, acid attack, oxygen pitting, and chelant attack. Damage can also occur from mechanical and thermal stresses on the drum which concentrate at nozzle and attachment welds. These stresses, most often associated with boilers that are on/off cycled, can result in crack development. Cyclic operation can lead to drum distortion (humping) and can result in concentrated stresses at the major support welds, seam welds, and girth welds. The feedwater penetration area has the greatest thermal differential because incoming feedwater can be several hundred degrees below drum temperature. Based on this, these areas should be inspected during any boiler life extension program.

A problem unique to steam drums with rolled tube seats is tube seat weepage (slight seeping of water through the rolled joint). If the leak is not stopped, the joint, with its high residual stresses from the tube rolling operation, can experience caustic embrittlement. In addition, the act of eliminating the tube seat leak by repeated tube rolling can overstress the drum shell between tube seats and lead to ligament cracking.

Lower drum The lower or mud drum is found mostly in industrial boilers. Part of the boiler's water circuit, the lower drum is not subject to large thermal differentials or mechanical stresses. However, as in steam drums with rolled tubes, seat weepage and excessive stresses from tube rolling can occur. In most cases visual inspection, including fiber optic probe examination of selected tube penetrations, is sufficient. Many lower drums are subject to corrosion of the tube-drum interface on the outside diameter (OD). This area of the drum is inaccessible, therefore inspections are conducted from the inside diameter (ID) using standard Ultrasonic Thickness Testing (UTT) and electromagnetic acoustic transducers (EMATs) to check for cracking and wall thinning.

Inspection Typical inspections of the drums during a baseline condition assessment program consist of a thorough visual inspection along with a Wet Fluorescent Magnetic Particle (WFMT) inspection of all welded nozzles and attachments. The drum shell ID longitudinal and circumferential welds should be WFMT and UTT inspected. Selected bore hole ligaments should be WFMT inspected.

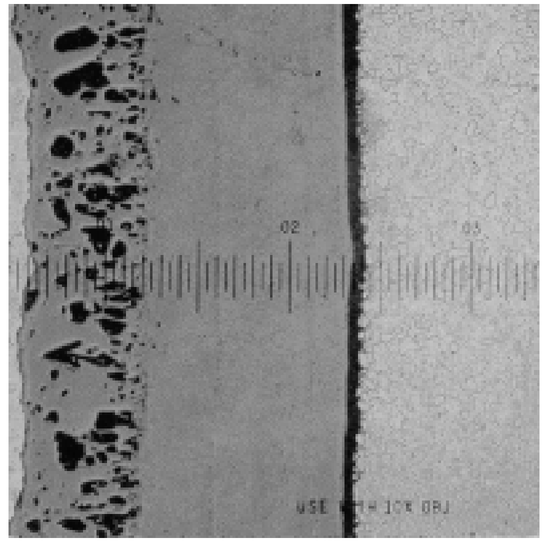

Fig. 1 Steam side oxide scale on ID surface.

Drum Life Assessment In the absence of any significant damage the drum will normally not be life-limited as it is not subject to significant creep.

Boiler Tubing

Boiler tube failures are the primary cause of forced outages. Complete texts are available to address all the problems and damage mechanisms that can lead to failures(1) and we have not attempted to identify or discuss every damage mechanism in this paper.

Steam-cooled Steam-cooled tubing is found in the superheater (high pressure) and reheat superheater. Both components have tubes subjected to the effects of metal creep. Because most boilers targeted for condition assessment are at least 20 years old, superheaters have become critical assessment components. Creep is a function of temperature, stress and operating time. The creep life of the superheater tubes is reduced by a higher operating temperature and by other damage mechanisms, such as erosion and corrosion, causing tube wall thinning and increased stresses. Excessive stresses associated with thermal expansion and mechanical loading can also occur, leading to tube cracks and leaks independent of the predicted creep life.

Over a period of time, superheater tubing exposed to elevated temperatures experiences an ID oxide growth (Fig. 1). This internal oxide interferes with the cooling effect of the steam flow, causing tube metal temperatures to increase. The resultant increase in temperature will drastically reduce the life of the tube. This internal oxide may also exfoliate, causing erosion of valves and turbine components. For certain fuels, the life of the superheater tubing can be greatly reduced by high rates of erosion and corrosion which drives tube degradation more than temperature and oxide growth. Coal ash corrosion is an example of a potentially aggressive damage mechanism.

A typical condition assessment inspection of the superheater tubing would consist of the following:

- Visual Inspection–A visual inspection will generally find areas of severe erosion, corrosion, thermal shocking or expansion problems. Visual inspection is also important to identify failed attachments or rubbing and metal-to-metal wear.

- Ultrasonic Thickness Inspection–UTT should be performed in sootblower lanes and any areas identified by visual examination as potential sites of excessive wall loss.
- Internal Oxide Thickness Inspection–Internal oxide thickness measurements should be taken and remaining creep rupture lives calculated for the alloy tube materials in the hottest regions of the superheater and reheater. A large number of inspection locations should be taken on the initial inspection. Ideally the alloy tube material (SA213T11, SA 213T22) is tested at location where metal temperatures are greatest. A good location is immediately upstream at transition welds to the next grade material. For example, a good location to test T11 material is immediately upstream of the transition to T22 material. In general, the locations are selected based on hottest location but must also consider accessibility. Future inspection locations can be reduced based on results of the initial inspection, history, tube material, dimensional changes, and visual inspections.

Water-cooled Water-cooled tubes include those of the economizer, boiler bank and furnace. The convection pass sidewall and screen tubes may also be water-cooled . These tubes operate at or below saturation temperature and are not subject to significant creep. Modern boilers in electric utilities and many industrial plants operate at high pressures. Because these boilers are not tolerant of water-side deposits, they must be chemically cleaned periodically, which results in some tube material loss. Proper water chemistry control will limit tube inside surface material loss due to ongoing operations and cleaning. The importance of maintaining water quality and keeping ID tube surfaces clean cannot be overly stressed. Extensive damage of waterwall circuits has often resulted from excessive deposition that can lead to aggressive corrosion and hydrogen damage. On cycling boilers a serious problem has also been corrosion-fatigue damage at lower furnace attachment points such as buckstays and windbox attachments. Corrosion fatigue leads to ID initiated cracking that is very difficult to detect by nondestructive methods. Research sponsored by EPRI is currently ongoing to address this NDE need.[2]

Externally, water-cooled tubes are subject to damage. Erosion is most likely to occur on tube surfaces in the boiler or economizer bank from sootblowing or ash particle impingement. Erosion of waterwall tubes can also result from sootblower operation. Corrosion of the water-cooled tubes can result from reducing atmospheres associated with mal-distributed burner air or result from staged combustion on low N0x burner installations. Some types of coal ash can promote corrosion of waterwall tubes as well.

Steam- and/or Water-Cooled–External to Setting Of special concern are some unique problems that have led to failures of tubing that is outside the boiler settings. These type failures have a potential for exposing plant personnel to safety hazards. Examples are supply or riser tubes on units that have had water chemistry control problems when using chelants. Excessive chelant can attack tubing aggressively and lead to thinning and failures. More recently, corrosion-fatigue has been identified on older units (>30 years operation) as the root cause mechanism of riser tube failure in the penthouse. In both instances, whether chelant attack or corrosion-fatigue, the failures tended to be catastrophic with a large piece of tube rupturing.

A typical condition assessment inspection of water-cooled tubes would consist of the following:

- Visual Inspection – A visual inspection will generally find severe erosion, corrosion and thermal shocking, and numerous other problems such as damage from slag falls, local overheat, swelling, etc. Based on the visual inspection, additional methods may be recommended.
- Ultrasonic Thickness Inspection – UTT is by far the most often used inspection method on water-cooled tubes. Initially a comprehensive thickness inspection should be performed. This results in baseline data that may be compared to future, limited scope inspections.
- EMATS Based Inspection – This form of inspection is used to locate tube ID under deposit corrosion, pitting or other tube ID problems such as hydrogen damage. Systems are available for tube thickness mapping[3] and are in development for detection of corrosion-fatigue damage.

Tube Life Assessment

For alloy superheater tubes, life assessment methodologies are well established.[4] Tube remaining life can be determined using creep rupture properties of materials and life fraction analysis methods. A caution when using these life prediction methods is to use the data as a compliment to other data such as tube analysis and failure history. Material creep properties have wide variation from heat to heat. Remaining life predictions should therefore provide a guideline to help establish trends relative to failures and time of replacement and should not be used as an exact life calculation.

For low temperature tubing, life prediction is done by comparing wall loss trends to a predetermined flag or replacement criteria. As a general guideline B&W recommends a flag of 70% original specified wall thickness for water-cooled tubes. For damage mechanisms such as hydrogen damage, cracking or corrosion-fatigue, no attempt is made to predict life – the goal for these tubes is identification of damaged tubes with recommended replacement.

Headers

Headers and their associated problems can be grouped according to operating temperature. High temperature steam-carrying headers are a major concern because they have a finite creep life and their replacement cost is high. Lower temperature water- and steam-cooled headers are not susceptible to creep but may be damaged by corrosion, erosion, or severe thermal stresses.

High temperature The high temperature headers are the superheater and reheater outlets which operate at a bulk temperature of 900F (482C) or higher. Headers operating at high temperature experience creep under normal conditions. In addition to material degradation resulting from creep, high temperature headers can experience thermal and mechanical fatigue. Creep stresses in combination with thermal fatigue stress lead to failure much sooner than those resulting from creep alone. There are three factors influencing creep fatigue in superheater high temperature headers: combustion, steam flow and boiler load. Most manufacturers design a boiler with burners arranged in the front and/or rear walls. Heat distribution within the boiler is not uniform: burner inputs can vary, air distribution is not uniform, and slagging and fouling can occur. The net effect of these combustion parameters is variations in heat input to individual superheater and reheater tubes. When combined with steam flow differences between tubes within a bank, significant variations in steam temperature entering the header can

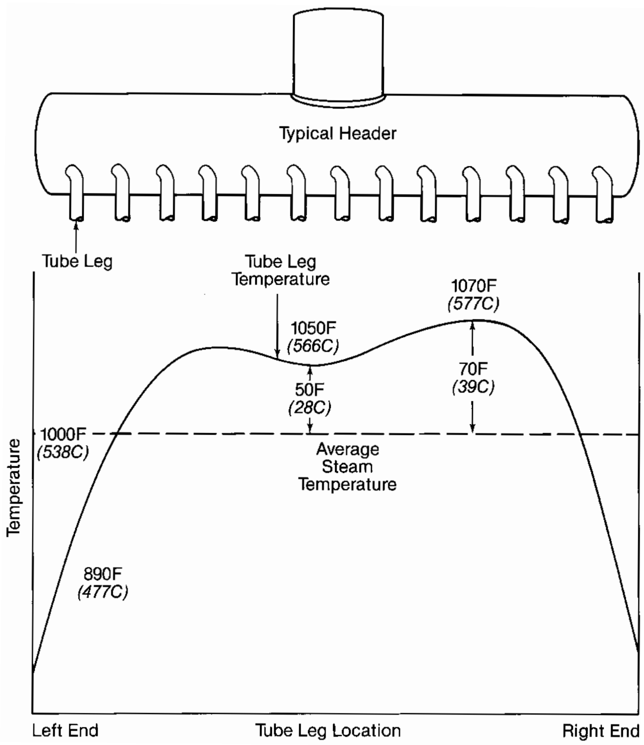

Fig. 2 Steam temperature variation in a header.

occur (Fig. 2). Changes in boiler load further aggravate the temperature difference between the individual tube legs and the bulk header. As boiler load increases, the firing rate must increase to maintain pressure. During this transient, the boiler is temporarily over-fired to compensate for the increasing steam flow and decreasing pressure. During load decreases, the firing rate decreases slightly faster than steam flow in the superheater with a resulting decrease in tube outlet temperature relative to that of the bulk header. As a consequence of these temperature gradients, the header experiences localized stresses much greater than those associated with steam pressure (Fig. 3) and can result in large ligament cracks (Fig. 4).

In addition to the effects of temperature variations, the external stresses associated with header expansion and piping loads must be evaluated. Header expansion can cause damage on cycling units resulting in fatigue cracks at support attachments, torque plates, and tube stub to header welds. Steam piping flexibility can cause excessive loads to be transmitted to the header outlet nozzle. These stresses result in externally initiated cracks at the outlet nozzle to header saddle weld.

Condition assessment of high temperature headers should include a combination of non-destructive examination (NDE) techniques that are targeted at the welds where cracks are most likely to develop:

- Visual Inspection
- Wet Fluorescent Magnetic Particle Inspection–All major header welds, including the outlet nozzle, torque plates, support lugs and plates, circumferential girth welds should be WFMT inspected. Initially, 100% of the tube stub to header welds should be WFMT inspected. After the baseline WFMT inspection, future WFMT inspections may be limited to 10-25% of the tube stub to header welds.
- Ultrasonic angle beam shear wave examination of major welds–This is particularly important if the header has any long seam welds. In general, B&W follows EPRI-established guidelines for examination of these welds.[5]
- Metallurgical Replication–To examine the header for creep damage, metallographic replication should be performed. Typically, between 6-12 replicas are taken on the header tube stubs, header circumferential or longitudinal pipe welds, and nozzle to header welds. Locations for replicas are typically in the areas of highest temperature or stress.
- Ligament and Bore Hole Inspection–The major cause of header end-of-life in the US is creep fatigue. This results in ligament and bore hole cracking. A total of two to three of the hottest or highest stressed areas should be inspected. B&W strongly believes that effective bore hole examination must be preceded by removal of the high temperature oxide. It is important that the base metal of the header be examined for cracking (Fig. 5). B&W developed a unique process for this inspection which is called the Hone & Glow® exam.

Low temperature The low temperature headers are those operating at temperatures below which creep is a consideration. These include waterwall headers, economizer inlet and outlet

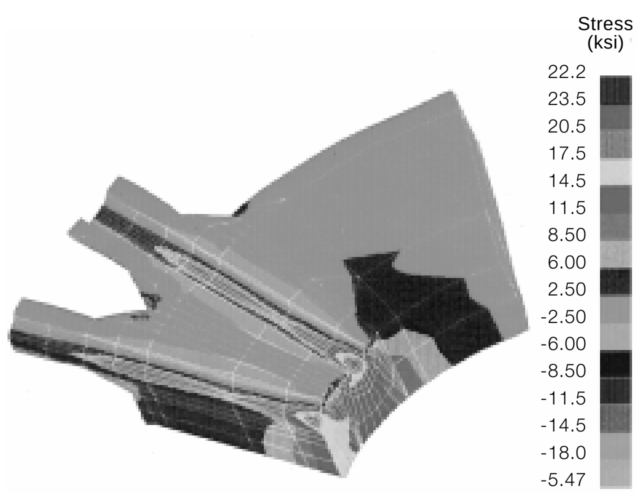

Fig. 3 Localized stresses due to thermal gradients.

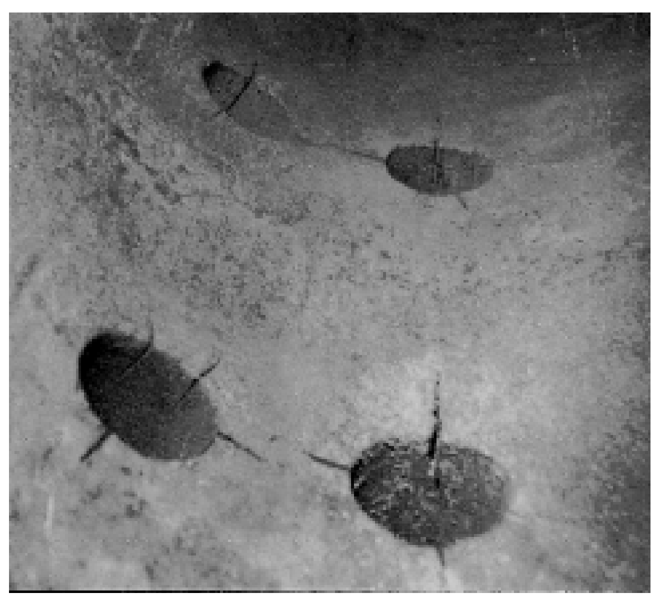

Fig. 4 Large ligament cracks on header ID.

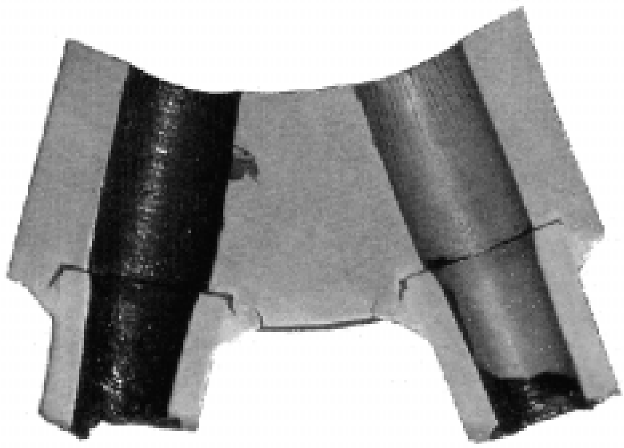

Fig. 5 Header bore hole cracking.

headers, and superheater inlet and intermediate headers. Any damage to the low temperature headers is generally caused by corrosion or, in some instances, erosion or thermal fatigue.

Waterwall headers, found in most electric utility and industrial power generation boilers, are located outside the hostile environment of the combustion zone. An exception is the economizer inlet header; this header is often located in the gas stream and is subject to unique problems associated with cycling. Boilers that are held overnight in a hot standby condition without firing can experience severe damage to the economizer inlet header in a very short time. This damage is typically caused by thermal shock.

The magnitude of the thermal shock is a function of the temperature differential between the unheated feedwater and the inlet header. It is also a function of water flow, which is usually large because the feedwater piping/valve train is sized for rated boiler capacity. The thermal shock is worse near the header feedwater inlet and rapidly decreases as flow passes into the header and tubes. Economizer inlet headers have also experienced damage associated with flow-accelerated corrosion. In general the primary concern with most of the low temperature headers is internal and external corrosion, especially during out of service periods.

Typical inspections of these headers consist of:

- Visual Inspection
- Wet Fluorescent Magnetic Particle–A WFMT inspection should be performed on welded attachments, handhole plugs, header end plate welds, and 10% of tube to header welds.
- Video Probe Inspection–An internal visual inspection can be performed to locate internal problems.
- UTT–Should visual inspection reveal areas of wall loss from either corrosion or erosion, then ultrasonic thickness data may be taken to assess header thickness.

Header Life Assessment

For low temperature headers, the life is not necessarily finite in the normal life spans of the boiler. Replacement of low temperature headers will result from unique damage such as thermal fatigue and cracking. Instances of damage to low temperature headers are very much dependent on the specific plant and operating history. Low temperature headers are more likely to be replaced as part of unit upgrades or as tandem replacement with other components such as wall panels.

As noted previously, high temperature headers on older units were typically made of SA335P22 alloys and will eventually need to be replaced due to reaching their end-of-life. Accurate quantification of header life is difficult since damage is attributed to creep fatigue and is driven by locally high stresses, temperatures and cycles that are not readily measured. Software tools have been developed under projects sponsored by EPRI. The software BLESS(6) which resulted from this work provides for prediction of crack initiation as well as crack growth to predict or quantify life. The difficulty is in accurately defining operating parameters and material properties. Material sampling and testing may be necessary to fully implement the analysis for best results. In general, based on B&W experience, analytical programs such as BLESS have been used as a tool along with other data to help make short term decisions for headers that have already experienced significant cracking, i.e. BLESS can be invaluable to help make a run/repair decision. For most projects, an attempt is not made to quantify remaining life by analysis. From empirical experience and re-inspection programs, sufficient data is normally available to make decisions for life extension projects. Economic analysis of risk and unavailability are a key part of this process.

Attemperators

The attemperator, or desuperheater, is located in the piping of the superheater and is used for steam temperature control. The spray attemperator is the most common type used. In the spray unit, high quality water is sprayed directly into the superheated steam flow where it vaporizes to cool the steam. The attemperator is typically located in the piping between the primary superheater outlet header and the secondary superheater inlet header. Steam exiting the primary header at temperatures of 800 to 900F (427 to 482C) enters the attemperator, where relatively cool water [300F (149C)] is sprayed into the steam and reduces the temperature to the inlet of the secondary superheater. Because of the large temperature difference between the steam and spray water, parts of the attemperator experience thermal shock each time it is used. Over a period of years this leads to thermal fatigue and eventual failure.

Condition assessment of the attemperator requires removal of the spray nozzle assembly. The thermal stresses occurring in the attemperator are most damaging at welds, which act as stress concentrators. The spray head and welds on the nozzle assembly are examined visually and by liquid penetrant PT to ensure there are no cracks. With the spray head removed the liner can be examined with a video or fiber optic probe. For larger attemperators, it may be necessary to remove radiograph plugs before and after the attemperator to better view the critical liner welds.

Attemperator Life Assessment

Spray flow attemperators are critical in the condition assessment program since they are in the closed loop of the superheater. Failures in the attemperator can lead to collateral damage in the superheater leading to tube failures. If left undetected over a long period of time, attemperator failures have the potential to lead to piping failure as a result of thermal fatigue. In general, the attemperator is treated as a preventive maintenance item. They should be periodically inspected following 10 years operation. It is prudent to maintain spares on hand for eventual replacement of the spray head assembly.

Piping and Deaerators

Main steam and hot reheat piping are regarded as critical high energy piping systems in the plant. Because of the operating temperatures and stresses they are subject to creep damage and must be included in any condition assessment program. Seam welded hot reheat piping and seam welds in main steam are of particular concern since the longitudinal seam weld is acted upon by the primary pressure stresses. Catastrophic failures of long seam welds have occurred in numerous instances and are well documented. Extensive research has been sponsored by EPRI and the Materials Property Council and research into more effective inspection methods continues. Full discussion of seam welded piping systems can be found in literature.(5) In general, a full volumetric examination of all critical welds is mandatory for the high energy piping seam welds and circumferential welds. Volumetric examination is done by ultrasonic angle beam shear (UTS) wave methods. More recently ultrasonic time-of-flight diffraction (TODF) and focused array transducers have been used. WFMT, UTT, replication, in-situ material identification, and dimensional creep swell measurements are commonly included in the inspection programs.

Low energy piping such as *cold reheat piping,* and especially *feedwater piping* are also subject to degradation and failure. For cold reheat (CRH) piping, corrosion and fatigue are the primary mechanisms that can lead to damage. In general, visual inspection and NDE of selected welds, bends, and possibly horizontal runs where water can accumulate, are the focus on CRH piping. NDE includes WFMT, internal video probe if accessible, UTT, and UTS.

The feedwater piping system was overlooked for many years. Feedwater piping is of particular concern since it is susceptible to the phenomenon of flow accelerated corrosion (FAC). A full investigation of flow accelerated corrosion was sponsored by EPRI.(7) Of major concern, FAC of feedwater piping can lead to wall loss over a large area of the pipe. Failures resulting from this mechanism tend to be catastrophic since a large area is weakened prior to failure. FAC failures pose a safety hazard to plant personnel. Subsequently, inclusion of this system should be given priority in the assessment program of an aging plant. Assessment programs include NDE to evaluate wall thickness in susceptible areas. UTT is the primary NDE method. Key locations include flow transitions, such as bends, tees and reducers, as well as areas where flow disturbance is possible such as at weld backing rings. Any chemical feed injection points are also susceptible; the downstream piping as well as the location of the connection is included in the scope of examination. UTT is performed on a grid that includes the complete circumference of the pipe in the area of interest.

Deaerators, like feedwater piping, were overlooked for many years. However, catastrophic failure of several DA vessels emphasized the need to include this component in the boiler island assessment program. Guidelines for assessment of deaerators was developed under work sponsored by the National Association of Corrosion Engineers (NACE). NACE Standard RP0590-96 provides a full discussion of the subject. In general, DA problems and failures are associated with corrosion of internal weld surfaces. The recommended NDE method is Wet Fluorescent Magnetic Particle Testing to assess internal vessel welds.

Summary

The recommendations listed are a minimum guideline for inspecting the critical components of the boiler island. Based on the results of any of the above inspections, or problems encountered during the day-to-day boiler operation, additional inspections may be recommended. These inspections will aid in extending the safe, useful operating life of the boiler. During any outage, either planned or forced, a visual inspection should be performed wherever possible. Regular inspections coupled with the appropriate NDE should be performed on a frequent basis and as determined by the re-inspection plan developed during condition assessment. Due to the wide range of reasons that failures may occur in the listed critical components, the type and amount of inspection will be determined on a unit-to-unit basis. A thorough initial inspection, followed by frequent location-specific inspection, should result in increased safety, availability, efficiency, and reliability of the unit.

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