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Recent Experience in Condition Assessment of Boiler Piping Components and Supports

by

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ABSTRACT

This paper provides recent experience in assessment of the current condition of boiler piping components and supports. Besides consideration of the major steam outlet and inlet piping lines, more attention is given to the boiler proper piping, including feedwater, downcomer, and crossover lines.

The boiler piping lines are used to circulate water and steam between the major regions of a unit. Many problems are typically encountered with the piping components and supports and at their terminal connections to the boiler headers and drums.

Examples from recent boiler and piping condition assessment programs are presented which describe problem areas such as cracking in boiler component nozzles, water induction in sloped steam lines, the effects of attemperation on crossover steam piping components, and the impact of malfunctioning supports on boiler headers.

INTRODUCTION

In the performance of boiler and piping condition assessment programs, normally very little attention is given to boiler piping components other than the high energy steam piping leads. However, typical problems with other boiler piping line components and supports have been encountered over the years. These problems are associated with both water- and steam-carrying lines including feedwater, downcomer, crossover, attemperator, and terminal piping components and supports and their connections to boiler drums and headers.

The cause or source of problems or failures encountered with piping line components can generally be attributed to the occurrence of abnormal or unanticipated events, boiler operation in modes other than the original design, and lack of scheduled maintenance, monitoring, or inspection tasks. Historically, a utility fossil-fired unit was designed for thirty years of operation in base-loaded duty. Today, these boilers are being operated well beyond this time, typically in a cyclic mode with frequent load swings to meet shifting demands.

The performance of detailed boiler/piping condition assessment programs and implementation of the reported recommendations is a major reason why owners are now extending the useful life of such units.

Examples of typical piping and related component problem areas are categorized and fully described herein. They are featured under the general headings of Attemperators, Downcomer Piping Systems, and External Piping Leads. Based on the results of the problem component condition assessment studies, recommendations are given for monitoring, maintenance, repair, replacement and retrofit items.

BACKGROUND

A fossil-fired power boiler and its equipment contain a multitude of piping lines and systems. Besides the previously mentioned major piping lines, there are safety valve, chemical feed, spray water, sootblower, and fuel carrying piping systems. Also, there are many items of miscellaneous piping such as vents, drains, surface blow-off, water column, gage glass, and pressure gage lines.

Piping associated with drum type boilers comes under the jurisdiction of the ASME Boiler and Pressure Vessel Code, Section I[1]. The lines are categorized as boiler proper or boiler external piping. The jurisdictional limits are defined in Figure PG-58.3.1 of the code. Construction rules for materials, design, fabrication, installation, and testing of the boiler external piping components are contained in ASME B31.1 Power Piping Code[2]. Non-mandatory Appendix V of this code provides recommended practice for the operation, maintenance, and modification of power piping systems in service.

Not all boiler piping problems are associated with the high energy main steam and hot reheat lines. Problems can be experienced by all boiler piping systems. Low temperature piping lines operating at less than 800°F are not susceptible to creep damage, but can fail due to fatigue, corrosion or erosion, or a combination of the same. Evaluation methods for low and high temperature piping are the same. Low temperature components, if maintained, last much longer than their high temperature counterparts. Typical low temperature systems on a boiler are reheat inlet steam lines and feedwater lines.

Low temperature piping lines can experience the same type of failures as high temperature components. For example, cold reheat piping can experience thermal shock because the reheat steam temperature control is typically an in-line attemperator. Economizer discharge lines, which run from the economizer outlet header to the boiler drum, can be damaged during startup events. If the economizer is steaming and flow is initiated with a water slug, the line can experience severe shocks. Other low temperature piping lines can be damaged by oxygen pitting caused by inadequate water treatment. Also, severe wall thinning can be caused by erosion due to flow cavitation.

Failures in piping systems are not always associated with larger sized components. A recently reported serious failure occurred in a drain line fitting attached to a main steam line. Another source of problems over the years involves the degradation of the threaded connections of radiographic inspection plugs to high energy steam piping components.

ATTEMPERATORS

Attemperators, located in boiler steam piping lines, control the steam temperature by introducing spray water to the steam flow. Typically, the cold reheat steam temperature from the turbine is controlled by an in-line attemperator located in the inlet piping before its connection to the boiler's reheat inlet header. Superheat steam temperatures in the boiler are controlled by attemperators located in crossover piping between the major regions of the superheater, most often between the primary superheater outlet header and the secondary superheater inlet header.

An attemperator assembly is made up of a combination water inlet/spray outlet nozzle, a thermal sleeve or liner, and a series of attachment rings which maintain placement of the assembly in the piping and allow for thermal expansion (see Figure 1). The thermal sleeve or liner is typically about ten feet long and protects the pipe wall from the thermal shock associated with the significant temperature difference between the water and steam. This difference can be as much as 400°F. The water spray events occur on demand in a sporadic or cyclical pattern which over time can introduce fatigue damage to the attemperator components. On many utility boilers, reheat steam sprays do not occur often, so the spray nozzle assemblies are installed in the cold reheat piping without any protective liner.

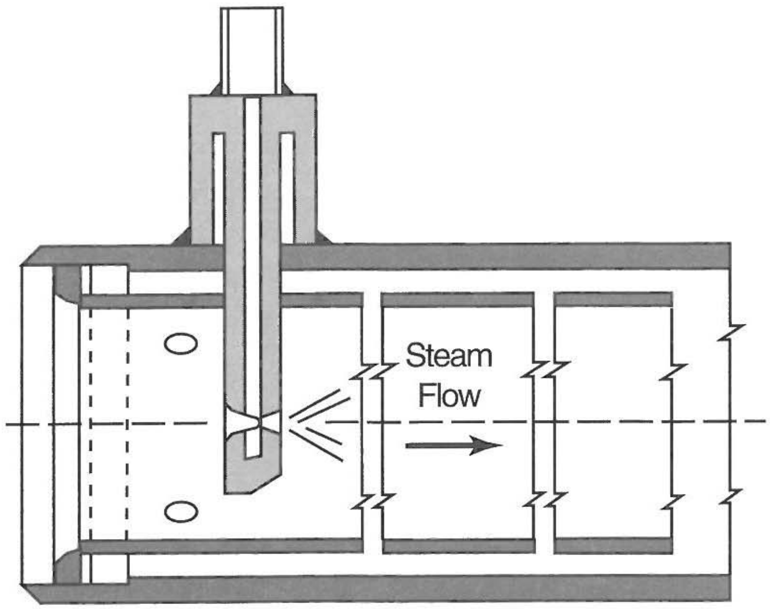

Figure 1 Typical Attemperator Assembly

Attemperator spray stations are locations within boiler piping systems and require scheduled inspection and assessment programs to ensure the component integrity. The spray nozzle assembly is typically removed during an inspection program. This allows for a dye penetrant (PT) check of the exterior nozzle surfaces for evidence of cracking. An inspection with a video or fiberoptic probe through the removed spray nozzle cavity is then performed on the internal components. The spray liner and welds of the attachment ring to pipe are examined for any evidence of deterioration in the form of corrosion, pitting, or cracking. A video recording is made of the inspection for future monitoring purposes. In our experience, attemperator assemblies have been found to be dislodged and relocated downstream in the piping.

Experience with attemperator inspection and assessment programs has shown that the frequency and duration of spray events and the distance of the station from downstream components can have a serious effect on the condition of the attemperator and adjacent piping pressure components.

Another key feature in the protection of the components is the ability to control the water spray, especially during startup, restart, and low load operation of the boiler. Recent retrofit designs for attemperation have incorporated a system with two spray nozzles. The first spray nozzle is a low capacity, variable orifice nozzle which provides excellent spray water atomization at low spray flow rates. In series with this spray nozzle is a high capacity, fixed orifice nozzle with a separate water control valve. The two-nozzle arrangement provides steam temperature control over the entire operating load range of the boiler, with turndown capabilities of 20 to 30:1 or better, depending on the control scheme incorporated into the system.

Some examples of DB Riley experience with problems in attemperators and nearby boiler piping components include:

Power Plant A, Units No. 1 and 2

Both of these identical boilers had a history of problems with downstream cold reheat piping components as a result of excessive, frequent, and poorly controlled spray used to control the inlet reheat steam temperature. The most obvious problem encountered was fatigue cracking in a downstream tee and elbows near the boiler due to severe temperature differentials. The reheat inlet headers also had serious bowing (this subject is addressed later in the paper). An internal video inspection of the inlet headers revealed no internal ligament cracking. The resolution to this problem was to install new piping components and new attemperators with improved controls.

Power Plant B, Units No. 1 and 2

These identical large utility boilers are equipped with twin radiant superheater outlet headers. Each of these headers has two outlet nozzles for crossover to the high temperature superheater inlet headers. Each of the four crossover pipes contains a desuperheater spray station. During a boiler condition assessment program of Unit No. 1, all four spray stations were internally inspected by video imagescope, with access through a removed radiographic plug upstream of the spray nozzle. All four of the spray assemblies were found to have crack indications in the attachment ring welds that anchor the liner to the inside of the pipe. The cracking was attributed to thermal fatigue due to water spray cycles. Also, the radiant superheater had a history of overtemperature conditions. The liners were still in position and the spray nozzles were free from surface cracks. The subject attachment welds were repaired and reinspection intervals were incorporated into the plant's maintenance planning program.

Six months later, the same components were inspected in Unit No. 2, a unit approximately five years newer than Unit 1. The results of the internal fiberoptic inspections of the Unit 2 attemperators revealed no problems with the attachment ring welds. However, one of the four spray nozzles was found to have a severe longitudinal crack on its rear face. This nozzle was recommended for replacement.

Power Plant C, Unit No. 1

This unit had been operated in a cyclic mode for over thirty years. An internal inspection of the attemperator assembly and superheater crossover piping, both upstream and downstream, was performed with a 20 foot long video imagescope. Many cracks were found in an elbow located just downstream of the spray liner. The cracks were confined to the elbow access hole closure assembly. Around the opening in the elbow at the closure, there were many radial shallow cracks approximately " to 1" long (see Figure 2). There were also some partial circumferential cracks inside the attached bullplug nozzle. The inside surface of the closure cap was also pitted and cracked. The inside surface of the liner was found to be heavily pitted. A severe circumferential crack was also found in the attachment (fixed end) ring (see Figure 3). The removed spray nozzle was examined by dye penetrant and found to have extensive cracking and pitting on its surfaces. The cracking, approximately seven inches long, was on both sides of the spray orifice (see Figure 4), and was attributed to cyclic thermal fatigue. No other problems were found in any of the other upstream and downstream components. Recommendations were given to the client for repair or replacement of the subject attemperator and crossover piping components. The access closure was also relocated farther downstream in the piping system.

Power Plant C, Unit No. 2

An extensive condition assessment program was performed on Unit No. 2, which is a different design, larger capacity boiler than Unit No. 1. This boiler had also been operated in a cyclic mode of duty, with over 3,000 startup events. The results of the program showed significant deterioration of many pressure retaining components. Of significance was the presence of internal bore hole and ligament cracking in the economizer inlet header. This type of cracking was also found by internal fiberop-

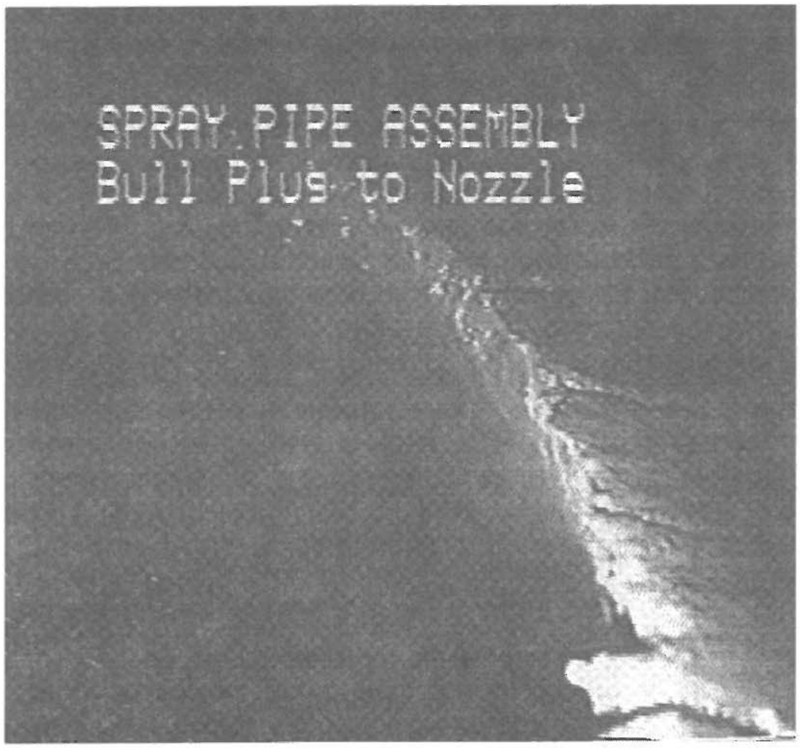

Figure 2 Radial Cracking in Edge of Access Hole Closure Located in an Elbow Downstream of an Attemperator in Crossover Piping

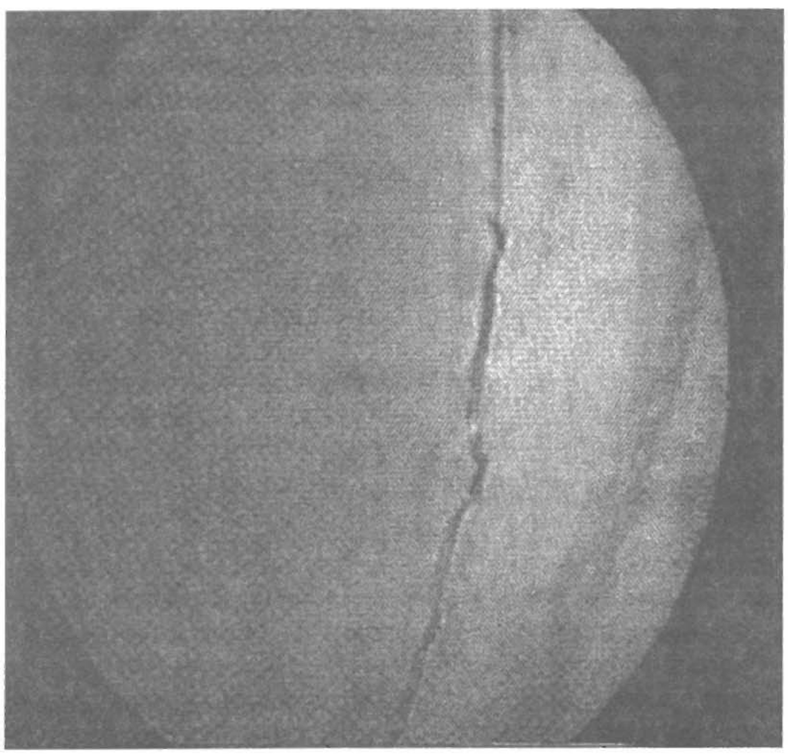

Figure 3 Videoscope Image of Circumferential Cracking in Attemperator Liner Attachment Ring Weld

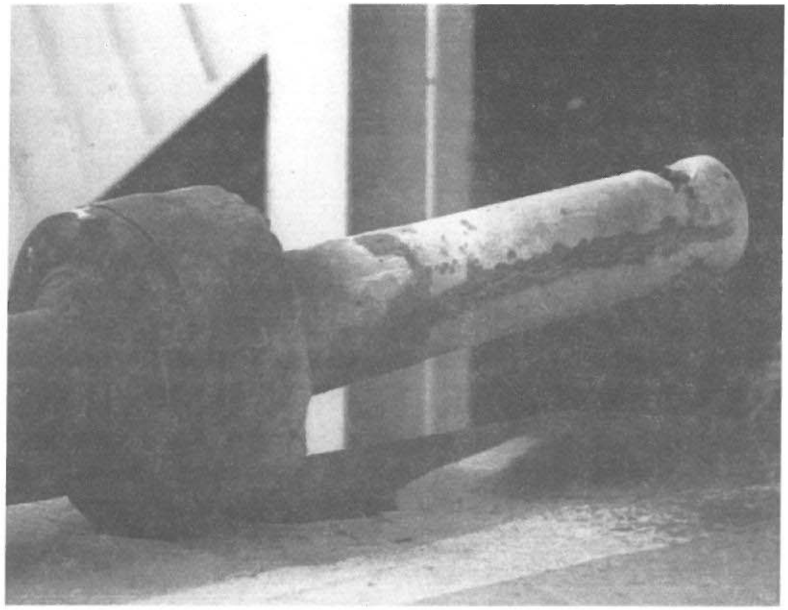

Figure 4 Desuperheater Spray Nozzle with Aligned Pitting and Cracks on Each Side

tic inspection in the high temperature superheater inlet header. This header is located downstream of the superheater spray station. The spray nozzle contained external cracks and the spray liner components were pitted and eroded at the upstream edges.

This type of thermal fatigue cracking found in the components is not uncommon for boilers of this vintage operating in a cyclic mode. Both of these headers were subsequently replaced as part of a major retrofit program for the boiler. In addition, a replacement superheat steam temperature control system was installed, which incorporates the dual spray nozzle design described earlier.

DOWNCOMER PIPING SYSTEMS

For a typical drum type, natural circulation, fossil fired utility boiler, feedwater enters the unit through the economizer inlet header. The flow of water continues up through the economizer tubing, where it is further heated by exposure to the exit flue gases, and then into the steam drum. This water is mixed in the drum with water from the steam-water separators, and then exits the drum through the downcomer pipes. The water flows through these pipes down to the lower water wall headers located at the furnace bottom. The water then rises through the furnace wall tubes, again increasing in temperature by exposure to the furnace gases, and back to the drum as a steam-water mixture. This completes a full cycle of the natural circulation process.

The downcomers are categorized as boiler proper piping and come under the jurisdiction of the ASME Code, Section I1. In the original design of the piping systems, the rules of a piping code such as ASME B31.12 would be used, since such design rules for piping are not contained in ASME Section I. For the inspection, testing, and monitoring of these piping systems in service, the non-mandatory rules of Appendix V of the B31.1 Code are recommended.

The current condition of downcomer piping systems is usually addressed by a cursory visual inspection, as part of hot and cold walkdowns. The visual inspection will note any unusual features in the piping components and support assemblies. These systems do not often have problems, but there are many recorded examples of problems with integral support malfunctions, and anomalies with the piping terminal connections at the steam drum and lower header nozzles.

Some examples of Riley experience with downcomer piping related problems are:

Deteriorated Piping and Support Components

Many fossil fired units are located near the ocean. Consequently, the units experience some additional external corrosive effects. This can be reflected in the condition of the downcomer support assemblies. The major problems which can be found with the piping supports include damaged components, interferences with structures, and twisted attachment plates. These can be due to a lack of scheduled monitoring and maintenance programs for the components, and the effects of abnormal or unaccounted-for unit events such turbine trips. Examples of these problems with constant force supports and their structural attachments are shown in the Figures 5 through 8. Such problems are a result of neglect, but also show evidence of some severe unaccounted-for loadings. The constant force supports shown are obviously not functioning as designed and this can cause problems elsewhere in the piping system.

Lower Water Wall Headers

A common lower water wall header arrangement is called a "raft" design in medium- to large-size utility boilers (see Figure 9). In this header design, cracks have been discovered in the welds joining the side headers to the front and rear headers, as shown in the Figure 9 detail. This cracking has occurred in units in service for ten years or more, and is sometimes accompanied by water wall tube nipple cracking. This cracking has been attributed to a significant amount of cycling or load swings for units originally designed for base loaded operation. There have also been examples where the effects of malfunctioning supports on the attached downcomer piping lines have been found to initiate or aggravate cracking in the header joint welds.

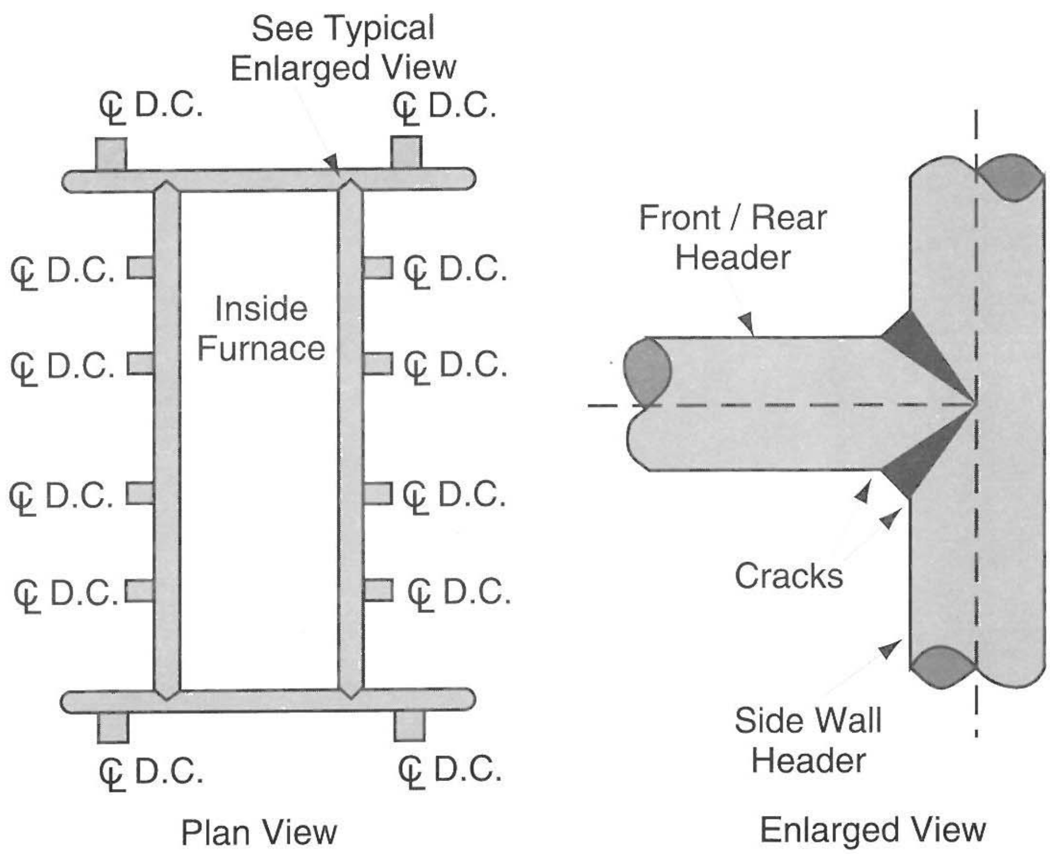

Figure 9 "Raft" Design Lower Waterwall Headers

This cracking can be resolved by grinding and welding, together with an engineering study to determine the effects of differential temperature and stress values for the adjacent components during steady state and transient boiler conditions. In addition, the current functionality of the downcomer support system should be addressed.

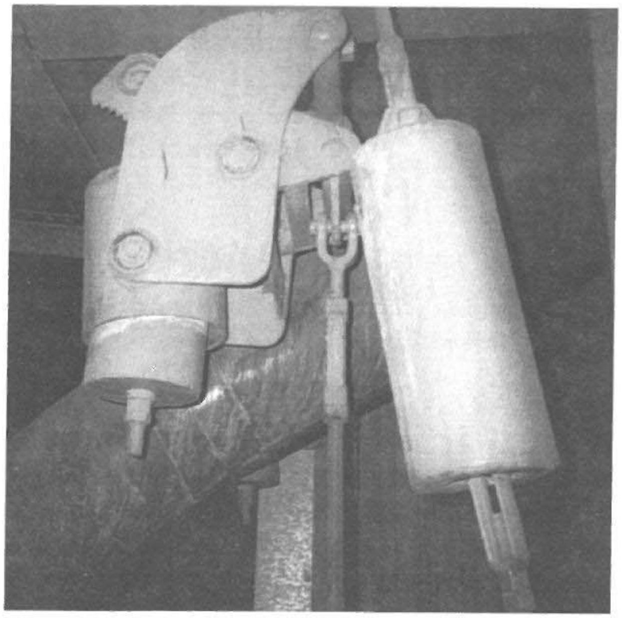

Figure 5 Misaligned Spring Can on Constant Support Hanger on Downcomer Pipe

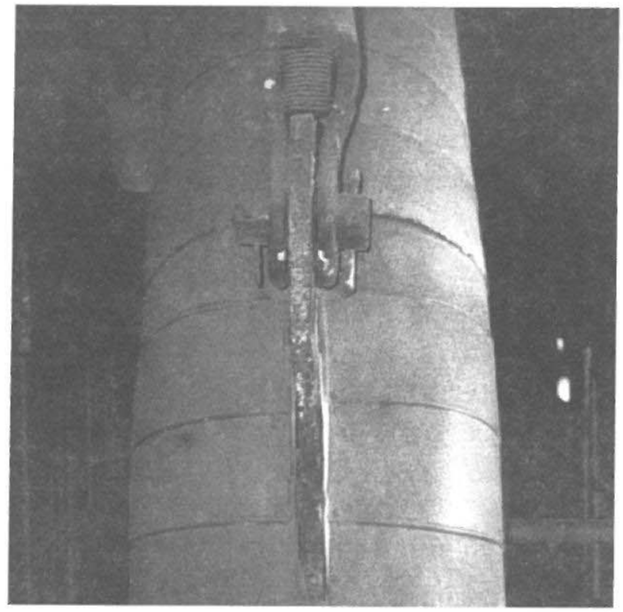

Figure 6 Bent Downcomer Attachment Support Plate

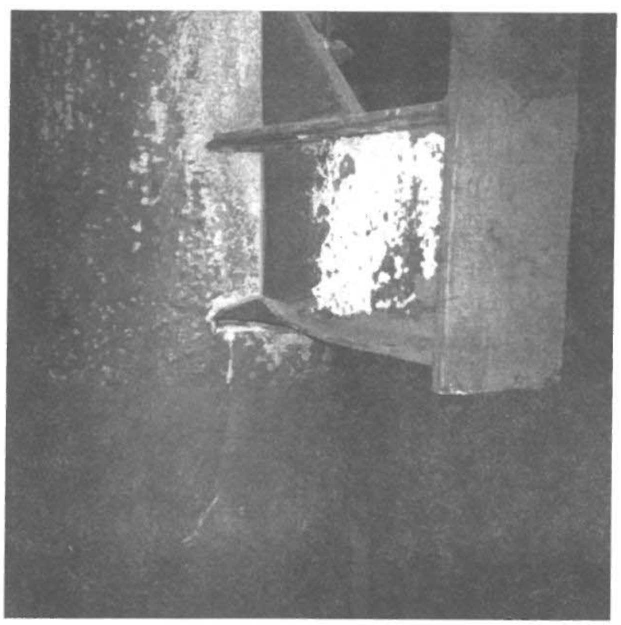

Figure 7 Damaged Beam Support on Downcomer Pipe

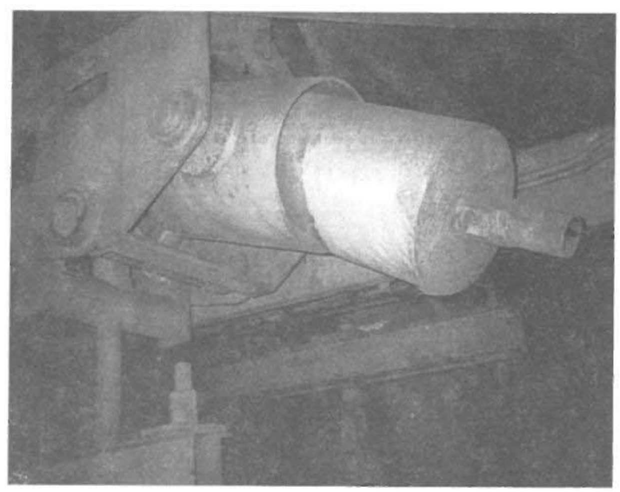

Figure 8 Damaged Spring Can on Constant Support Hanger

Thermal Stratification

Another phenomenon experienced by the lower furnace water wall headers and tubing is called thermal stratification or subcooling. Thermal stratification occurs when a unit is shut down for a short period of time. As the boiler cools down, the colder water sinks to the lower furnace. When the unit is restarted, this cooler water is stagnant until circulation is established. Then the cooler water is replaced by warmer water from the upper boiler, through the downcomers. The lower components experience a sudden thermal shock due to the differential water temperatures. When several hundred of these events occur, such as those produced by cycling or peaking operation, component cracking can result due to accumulated thermal fatigue damage. An example of this fatigue cracking, together with corrosion and deposit buildup, is shown in Figure 10. The monitoring and study of component metal temperatures with thermocouples during transient events can help lessen the effects of temperature shock due to thermal stratification.

Drum Nozzle Cracking

We have seen many examples of crack indications found in the downcomer pipe or nozzles to steam drum shell welds. Depending on the type of welded joints, the indications have been found on both the internal and external drum shell surfaces at the downcomer connections.

Crack indications found on the drum inside surface are typically located in the weld metal, toes of welds, and along the fusion line of the weld to shell metal. These can usually be attributed to original fabrication weld flaws such as lack of fusion or overlap. However, other cases of similar cracking were found to be caused by thermal or corrosion fatigue due to cycles of drum-related steam/water temperature and flow excursions based on the mode of boiler operation. Figures 11 and 12 show examples of internal drum nozzle cracking. Cracking in the external pipe or nozzle-to-drum shell welds are more likely caused by cyclic thermal bending moment loadings, which can be aggravated by malfunctioning supports on the downcomer piping.

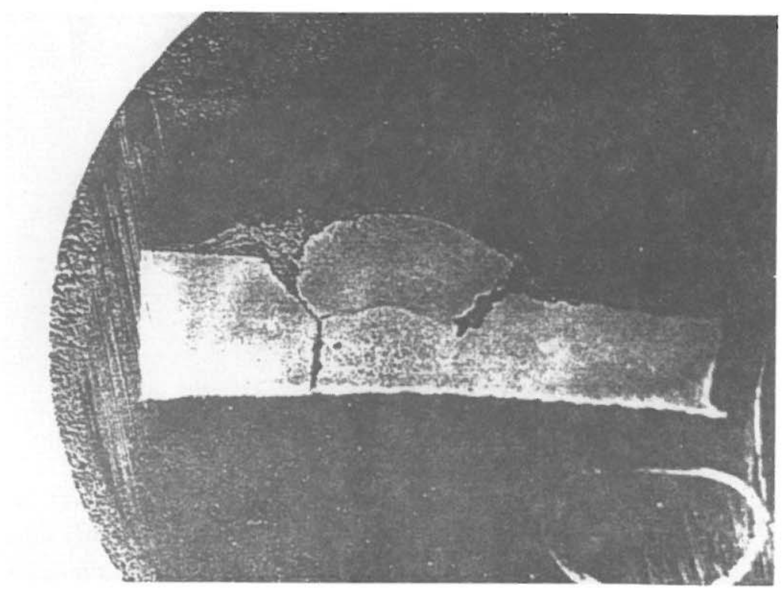

Figure 10 Macroscopic View of Lower Waterwall Header Tube Stub Weld with Backing Ring Showing Thermal Fatigue Cracking, Corrosion, and Deposit Buildup

Scheduled magnetic particle examination of the subject welds is the primary recommended method to determine the presence of crack indications. If indications are found, then a more detailed assessment using ultrasonic shear wave techniques and metallographic replication should be used. The results of an assessment program will provide the appropriate recommendations for monitoring and/or repair.

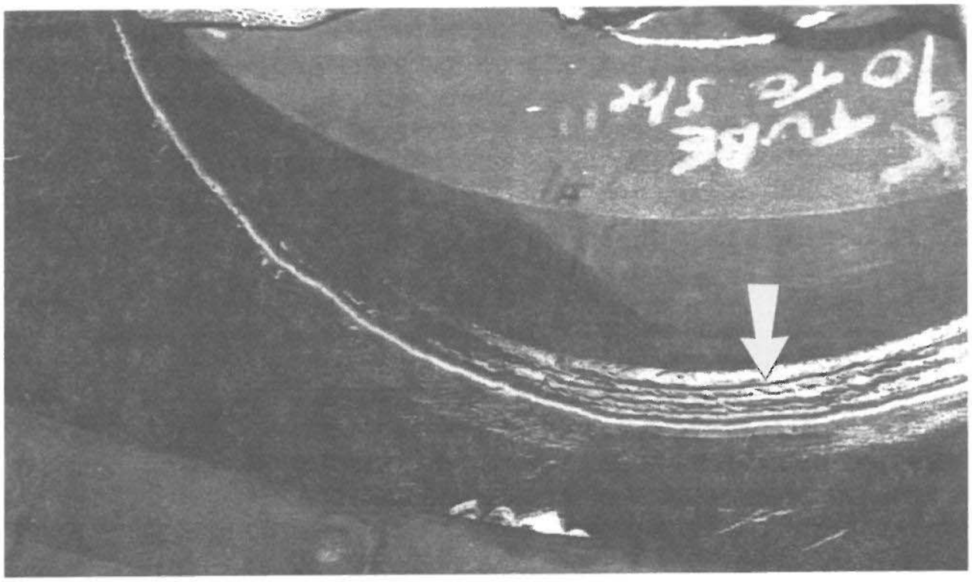

Figure 11 Downcomer Weld at Inside of Steam Drum. Crack Indications are Present in the Weld and Along the Fusion Line at Base of Weld

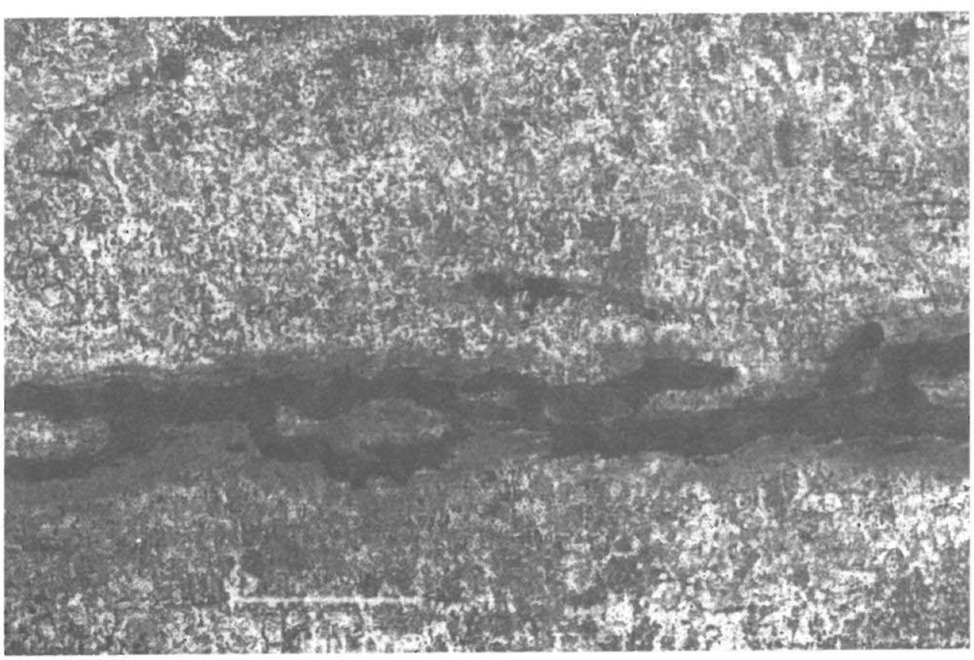

Figure 12 50X Magnification of Replica of Crack Indication in the Weld Metal, as Described in Figure 11

EXTERNAL PIPING LEADS

The primary boiler external piping leads consist of the main steam, hot reheat, cold reheat, and feedwater system connections to the boiler headers. A portion of the lead piping, usually to a first valve, is originally specified as the responsibility of the boiler manufacturer. The subject of the interactions between steam piping and boiler headers is presented in detail in an ASME paper[3]. Damage to high temperature boiler external piping system components is caused by creep, fatigue, creep-fatigue, and erosion-corrosion. Creep and fatigue can occur together and interact to cause more damage than each mechanism by itself. Erosion-corrosion is not as prominent as the creep-fatigue failure mechanisms. It is defined as flow-induced wall thinning. Factors that contribute to erosion-corrosion include bulk fluid velocity, material composition, and fluid percent moisture. The erosion-corrosion mechanism can be more prominent in low temperature feedwater piping systems.

A rigorous condition assessment program is typically performed for high temperature piping system components. The results of such programs have been well documented in recent technical literature. Some equally important external piping lead problems not as widely discussed include:

Reheat Inlet Header Sagging

The cold reheat piping lines reintroduce steam from the turbine to the boiler at relatively low temperatures and pressures as part of the reheating process. Problems encountered with in-line reheat attemperators have been described earlier in this paper. The cold reheat piping connects to the boilers reheat inlet header. DB Riley has had recent experience with several cases of inlet header sagging.

Detailed studies of the problem have concluded that header sagging can be a result of: (1) the header being exposed to overtemperature conditions, especially during boiler startup events when there is no reheat flow and furnace gas temperatures are not properly controlled. (2) A cycling or peaking mode of boiler operation will accelerate the overheating damage to the reheat inlet header. Header sagging problems are resolved by ensuring proper control of flue gas temperatures during startup events and designing and installing additional header support members.

Another cause of the header sagging can be the effects of malfunctioning supports on the cold reheat inlet piping lines. Typically there are two inlet piping leads which are connected to the ends of the reheat inlet header. The nearest outboard constant force supports have been found to be malfunctioning, therefore not carrying the proper load and transferring a portion of the piping forces and moments to the boiler header and its supports. The resolution to this header sagging is to rectify the cold reheat piping support system and provide reinforcement to the boiler header supports if the sagging is permanent.

Water Induction

Water induction from condensing steam can occur in boiler steam piping leads to cause corrosion, pitting, and thermal quenching, with resulting distortions, cracking, and failures.

During a forced cool-down of a boiler with horizontal secondary superheater elements, steam entrapped in the superheater quickly condenses and overflows into the outlet headers and main steam piping lines. Water can also be introduced into the main steam lines from back flow through drains and sample lines. When the condensate comes into contact with the header or pipe bottom section, there is localized thermal quenching. Repeated cycles of the resulting thermal shock can cause excessive bending, permanent distortion, and eventual cracking of the components. This is especially applicable to steam line components where damage to pipe hangers can also occur.

Remedial measures used to prevent or lessen the effects of thermal quenching are adherence to specified boiler cool down rates, temperature monitoring of the top and bottom of components by thermocouples, and nondestructive examinations of components to establish their current condition. Retrofit modifications have included steam line rerouting, enlarging of drain and vent lines, and the addition of valves in these lines to prevent ingress of the condensate.

The subject of water induction and thermal quenching of main steam line components has been addressed in two papers[4,5].

Another area in which condensing steam can cause problems is in the corrosion and pitting of cold reheat piping leads. These piping components are typically made from thinner wall plain carbon steel material based on their specified service conditions. Quite often the pipe fabrication is from rolled plate, which is then longitudinally seam welded. During boiler cool down events, condensation will collect in low spots of the piping. There have been examples of corrosion and pitting in units that have more frequent shutdowns or are off-line for longer periods of time. This can eventually lead to aligned pitting and crack formations, particularly along the longitudinal seam weld if it happens to be on the bottom.

A check for this potential condensate corrosion damage on cold reheat piping lines should be a part of scheduled piping inspection and assessment programs. A visual walkdown will locate potential condensate entrapment regions. Internal video inspections can determine the existence of any corrosion, pitting, or cracking.

SUMMARY

This paper has presented recent experience in problem areas encountered with boiler proper and external piping components and supports. Along with consideration of the major steam outlet and inlet piping leads, attention has been given to the boiler proper piping including feedwater, downcomer, and crossover lines.

Many typical failures and problems found during detailed inspection and condition assessment programs for piping components and supports and their terminal connections at the boiler headers and drums have been described, together with their resolutions. More specifically, the subject components addressed included attemperators, crossover steam piping, downcomer piping, lower water wall headers, steam drum nozzles, external piping leads, and reheat inlet headers. In addition, the effects of phenomena such as attemperation, thermal stratification, and water induction on boiler piping and header components were discussed. Tables 1 and 2 provide detailed summaries for the subject boiler and piping components including the types and cause of damage, the applicable inspection and nondestructive testing tasks, techniques for detecting the damage, and recommendations for remedial action.

RECOMMENDATIONS

Inspection, monitoring, condition assessment, and preventive maintenance programs should be scheduled for both boiler proper and external piping systems as part of each major outage for a unit. A review of available equipment records can provide valuable historical information of problem areas. Hot and cold walk downs should be performed for the external piping lines in conjunction with scheduled outages. These should include readings of hanger and support travel indicators and notations of any abnormalities. During the outage, the minimum of a visual inspection should be performed for the boiler proper piping and supports.

Each of the attemperator assemblies and downstream piping components of a boiler should be examined on a scheduled basis using internal video. Removed spray nozzles should be checked by liquid dye penetrant. In addition, condition assessment tasks should be scheduled for the boiler headers attached to external piping leads. These tasks include visual external and video internal inspections and magnetic particle testing of tube nipple and hanger attachment welds for all such headers. The applicable low temperature headers include the economizer inlet header, the lower water wall headers, the reheat inlet header, and the high temperature superheater inlet header. For the high temperature superheater/reheater outlet headers and the main steam/hot reheat outlet steam leads, metallographic replication and hardness testing should also be performed. Visual and video inspections should be per-

Table 1 Typical Boiler and Piping Water Component Problem Areas

Component	Damage Type	Failure Cause	Inspection/ NDT Technique	Recommendations
Feedwater Piping	Wall thinning	Erosion-Corrosion, Oxygen pitting	UT thickness, Internal video	Monitoring, Feedwater control
Economizer Inlet Header	Ligament cracking, Tube stub thinning	Thermal/corrosion fatigue, Erosion-corrosion	Internal video, UT thickness	Monitoring, Eventual replacement
Economizer Outlet Piping	Internal cracking	Thermal (shock) fatigue	Internal video	Monitoring of components and temperatures
Downcomer piping	Damaged supports and attachments	Corrosion, Abnormal events, Thermal expansion	Visual inspection, Magnetic particle examination	Monitor, Repair
Lower Water Wall Headers	Tee cracking, Tube stub cracking	Thermal expansion fatigue, Thermal/corrosion fatigue	MT examination Internal video	Repair, Replacement
Steam Drum Nozzles	Attachment weld cracking	Fabrication defect, Thermal expansion or erosion fatigue	MT examination, UT shear wave, Replication, Hardness testing	Repair
Attemporator Assemblies	Spray nozzle and liner assembly cracking	Thermal/erosion fatigue	Dye penetrant testing, Internal video	Replacement, Repair, Add dual spray

Table 2 Typical Boiler and Piping Steam Component Problem Areas

Component	Damage Type	Failure Cause	Inspection/ NDT Technique	Recommendations
Cold Reheat Piping	Corrosion/pitting, Internal cracking	Water induction, Thermal fatigue	Visual inspection, Internal video	Monitoring, Relocate components, Replacement
Reheat Inlet Header	Sagging	Overtemperature exposure, External piping loads	Replication, Hardness testing, Inspect cold reheat supports	Review boiler operations, Add support steel
Superheater Crossover Piping	Internal component cracking	Thermal fatigue (attemperation)	Internal video	Monitoring, Relocate components, Replacement
Secondary Superheater Inlet Header	Internal ligament cracking	Thermal fatigue (attemperation)	Internal video	Monitoring, Replacement
Main steam piping	Sagging, External weld cracking	Water induction, Creep	Visual inspection, Internal video, Replication, UT shear wave, MT examination	Monitoring, Replacement, Repair
Hot Reheat Piping	Sagging, External weld cracking	Water induction, Creep	Visual inspection, Internal video, Replication, UT shear wave, MT examination	Monitoring, Replacement, Repair

formed on high temperature steam piping lines to detect any sagged or low points caused by water induction. This phenomenon occurs in boilers with horizontal high temperature superheater/reheater outlet elements.

Tables 1 and 2 show recommendations for each of the boiler and piping components addressed in this paper. These include scheduled monitoring, weld repair, replacement, feedwater control, review of boiler operating procedures, and the installation of dual spray nozzles for improved steam temperature control over a boiler's operating load range. Assessment and subsequent repair of external component cracking is not difficult due to good access. Internal component cracking detection is more difficult, and repair is almost impossible due to a lack of access except inside the steam drum. Recommended solutions for components with internal cracking include monitoring, establishment of the root cause, and eventual replacement.

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