ELECTRIC POWER RESEARCH INSTITUTE

Boiler Tube Failure Program Best Practices

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United Dynamics Corporation

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

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ABSTRACT

The challenge to do more with less is faced industry wide. As the performance demand for clean power increases, the ability to identify potential problems surfacing between planned outages escalates, as well. The need for in-house expertise and solutions is critical. The focus for development of best practices is needed to provide solid, standardized solutions for boiler maintenance practices that will result in optimized boiler efficiency, reliability, and availability, as well as minimized environmental impact, which are required as we move forward. These best practices will provide a collective, comprehensive reference that is formulated to assist power generation maintenance management industry wide.

This report presents the results of a survey of utilities to gather industry best practices for boiler tube maintenance. The survey received responses from 23 utilities, which are included in the report. It is intended to serve as a reference for those involved in boiler maintenance programs across the industry. It presents a collective effort of various proven applications of maintenance solutions currently used in boiler systems. These best practices include solutions for inspection tools and techniques, methods to avoid recurring damage mechanisms, and recommendations for maintenance and repair. The purpose is to achieve a proactive approach for maintaining systems.

Keywords

Best practices
Boiler reliability
Boiler tube failures
Inspections
Outage preparation

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1 INTRODUCTION

The challenge to do more with less is faced industry wide. As the performance demand for clean power increases, the ability to identify potential problems surfacing between planned outages escalates, as well. The need for in-house expertise and solutions is critical. The focus for development of best practices is needed to provide solid, standardized solutions for boiler maintenance practices that will result in optimized boiler efficiency, reliability, and availability, as well as minimized environmental impact, which are required as we move forward. These best practices will provide a collective, comprehensive reference that is formulated to assist power generation maintenance management industry wide.

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Conversion Factors

Table 1-1 lists the measurements used in this report, along with conversion factors to convert them between U.S. measurements and International System of Units measurements.

Table 1-1
Conversion Factors

Measurement	Conversion
Distance	1 in. = 2.54 cm 1 ft = 0.3048 m 1 mm = 0.039 in. 1 mil = 25.4 µm
Heat transfer	1 BTU/hr/ft^2 = 0.003 kW/m^2
Pressure	1 psi = 6.89 kPa
Temperature	°C = (°F - 32) × 5/9 °F = (°C × 9/5) + 32

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PLANNED OUTAGE PREPARATION

Planning and preparation for an outage is vital to a successful experience. All relevant information should be easily available to all team members in the team work area. The boiler inspection team should prepare by reviewing the following items:

- **Boiler operating environment.** Relevant information can be extrapolated from the yearly boiler operating environment. This can include management decisions on operational procedures such as soot blowing and load management.
- **Cycle boiler water chemistry.** If a chemical problem develops during the cycle, it is important that the team leader examine the potential impact on the boiler and its inspection. Conclusions might warrant additional or more detailed inspections.
- **Effects of boiler operation.** The team leader must be cognizant of operational problems, such as high/low temperatures, high/low loads, fuel changes, ash pluggage, and soot blower problem areas.
- **Corrective and preventive programs that might be in place.** Experience might show that certain corrective programs are more successful than others. It is in the best interest of the boiler to repeat and optimize relevant programs.
- **Remaining life assessment results from previous outages.** The purpose of remaining life assessments is not simply to generate data for one-time analysis. By consulting previous assessment data, the team leader can follow up and track the progress of items uncovered during each assessment.
- **Inspection results from previous outages.** By reviewing results of previous inspection efforts, the team leader can follow up and track the progress of items identified during each inspection cycle. It is not uncommon for many items slated for repair to remain outstanding. Based on the inspection results and documentation of previous outages, the team leader can develop a scope of work for an upcoming outage before the boiler is removed from service. In many instances, lower-priority maintenance items become higher-priority repair items.
- **Inspection methods.** Every boiler has unique characteristics. Identically designed boilers in a plant might prove to be less similar than expected by design. Specific inspection and repair methods might prove more successful than those generally accepted as the industry standard. This fact lends credence to the philosophy that team leaders must examine relevant boiler histories in aggregate to maintain a proactive posture.
- **Boiler tube repair and replacement.** It is vital to know exactly when and where boiler tubes have been replaced. This awareness helps to preserve the quality of tube thickness histories and can alert the team leader to a potentially catastrophic event while it is still in its genesis.

- **Known boiler-specific failure mechanisms.** The boiler history might reveal specific failure mechanisms that are prominent. If the team leader remains cognizant of these failures, the failure mechanisms can be addressed from a preventive maintenance standpoint during the inspection. With this information, past areas of concern can be focused on and inspected with greater scrutiny.
- **Recommended actions.** Historically successful inspection and repair techniques should be applied to the current outage, as appropriate. Individual equipment needs vary, and identification of the most advantageous inspection and repair methods rests with the team leader. He or she must be prepared to take advantage of methods that proved most successful in the past. This does not necessarily preclude considering other possible repair methods.

Achieving High-Quality Repairs with Minimum Outage Duration

The team leader should take an active role in the planning process. This is especially true if financial issues and schedules heavily influence the status of the identified scope of work. It is essential that parties work closely toward a common goal to utilize scarce resources effectively. The following activities and resources are needed to implement a successful total outage:

- **Boiler operating environment.** Post the written management philosophy regarding boiler operations, which can include soot blowing and load management policies. Some inspection findings could be affected by these policies.
- **Boiler water chemistry.** If there were water treatment events in the past operating period, they should be recorded and made available to the team for review. This knowledge might demand that additional or more detailed inspections be conducted.
- **Effects of boiler operation.** The team should be aware of operational anomalies, such as high/low temperatures, high/low load, fuel changes, plugging occurrences, and soot blower problem areas.
- **Existing corrective and preventive programs.** Any corrective or preventive maintenance programs should be in writing and available to the inspection team. Preventive maintenance program documentation should be filed or attached to the component that is affected.
- **Past outage remaining life assessment results.** By reviewing a previous inspection effort, the inspection team can follow up and or track the progress of a problem uncovered during the previous inspection. It is not uncommon for identified work to remain not done.
- **Inspection methods.** Inspection procedures should be in writing and available to the inspection team.
- **Boiler tube repair and replacement.** Have drawings available with tube replacement information for each component. It is vital to know exactly when and where boiler tubes have been replaced.

- **Known boiler-specific failure mechanisms.** History of the unit might involve specific failure mechanisms that are prominent. The team should be up to date on these failures so they can be addressed during the inspection.
- **Recommended actions.** Historically successful repair techniques should be applied to the current outage; they should be posted in writing and filed or attached to the individual component information package. They should include the repair criteria for various action levels and guidelines for thickness or tube condition for classification as various priority ratings, such as priorities 1, 2, and 3. Guidelines should be clear and recalculated for each component area.

Staffing and Scheduling

If you are going to cover multiple shifts with inspection team members, have a plan for shift coverage. Group team members that complement each other on each shift. Always schedule less-qualified inspectors with experienced boiler inspectors. The inspection effort is also best served by grouping local inspectors with visiting inspectors. Spread out experienced team members for optimal coverage. Inspectors should always be paired for efficiency and safety.

The team leader is most abreast of all available resources. The team leader should brief each inspection team before the inspection. This usually occurs after the team has examined all the available documentation. The team leader can impart information that is hard to glean from the printed record, including the following:

- The leak history of the area
- Upgrade or replacement components and materials
- Special repair techniques
- Safety and access concerns
- Special tools required for the inspection

This is also a good time to review repair criteria and priorities that are currently in use. The inspection team can approach the inspection with new insight that could not be gained without this briefing.

Best Practice—Great River Energy

Great River Energy provided the following information:

> We purchased a tube bender to bend our own tubes.
>
> **Outage boxes.** We have boxes that have tools and equipment that are staged in different areas around the boiler for both planned and emergency outages. For example, we have one light box that contains all the portable lights that are used during both the cleaning and repair of the boiler, and we have different boxes for the different corners of our boiler, with each box containing equipment to make repairs specific to that corner of the boiler. This has saved us many hours in the cleaning and repair process.

Pre-Outage Planning

Establish outage inspection/test plan evaluation procedures, such as the following:

- Alloy analysis (nuclear alloy analyzer instrument)
- Boat sample
- Borescope
- Dimensional measurements
- Dye penetrant testing
- Eddy current testing
- Magnetic particle testing
- Metallographic replications
- Oxide thickness inspection
- Radiographic testing
- Ultrasonic testing
- Visual examination

In outages, a boiler planner often lacks advance knowledge of what new tasks will arise and what specific actions will be needed to make progress on known tasks. With "when" and "what" uncertain, boiler planners must instead reactively prioritize currently eligible tasks based on the information that is available. The approach is designed to make best use of whatever priority-relevant information is available at decision time. Boiler planners must decide priority among competing tasks. An ideal priority determination process should use whatever information is available, even it becomes so just before a decision is required or after a task has been awarded priority and begun executing. Which tasks should be deferred, interrupted, or aborted?

We all are subject to budget and time constraints. We use a comprehensive plan supported by inspections, laboratory results, or other scientific results. This plan must have a financial component, indicating the return on investment in the repairs. Data-driven decision making is the only consistently effective method to support budgets. In many cases, the data are best supported by good photographs of the problem areas and a statistical analysis of failures or near failures that will likely be avoided. Lost generation scenarios at different times of the year usually work well to support budget requests. Simple, concise, supported data are always more effective than any technique that is not supported by sound data. We recommend required repairs by strict application of the criteria shown in Figure 2-1.

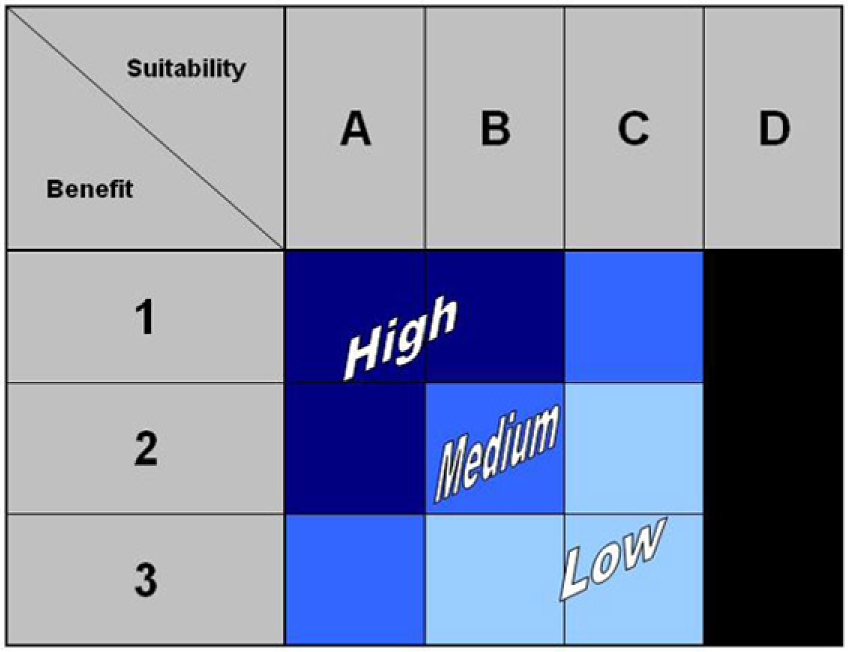


Figure 2-1
Priority model

The historical approach to making such decisions is to identify all tasks to be carried out and all the constraints on those tasks, and then search for the best possible order. The following definitions have been used with reasonable success:

- Priority 1 problem
  - Safety or loss-of-life issue
  - Certain forced outage before the next planned outage
- Priority 2 problem
  - Probable but not guaranteed forced outage before the next planned outage
  - Performance issue
- Priority 3 problem
  - Low-grade performance issue
  - Long-range mechanical optimization
  - Information or documentation issue

Risk Assessment Matrix

To provide more detailed information as it pertains to risk, the risk matrix shown in Table 2-1 is being adopted.

Table 2-1
Risk Assessment Matrix

Factors	**Extreme >90%**	**Likely >70%**	**Moderate >50%**	**Fair >30%**	**Low >10%**
Safety	Multiple deaths	Major injury	Lost time from workplace	Minor injury	
Property	Destruction or complete loss of >50% of the inspected asset	Extensive damage or loss <50% of the inspected asset	Damage or loss of <20% of the inspected asset	Minor damage or loss of <5% of the inspected asset	Minor damage
Cost of repair	>30% of project or asset annual budget	>10% of project or asset annual budget	>5% of project or asset annual budget	>5% of project or asset annual budget	>2% of project or asset annual budget
Loss generation	>144 hours	<72 hours	<48 hours	<36 hours	<24 hours
Accessibility	Penthouse access required	Scaffold needed	Sky climbers needed	Limited impact	No impact

The matrix has been further refined for use a boiler model, as shown in Figure 2-2.

UDC Priority Assignment Analytics Matrix™					
Assessment Factors	Probability of Occurrence				
	Extreme (>90%)	Likely (> 70%)	Moderate (>50%)	Fair (>30%)	Low (>10%)
Injury or Loss of Life / Failure / Restricted Accessibility	20	19	18	16	13
Environmental Impact / Failure / Moderate Accessibility	19	18	17	13	9
Failure / Satisfactory Accessibility	18	17	14	12	7
Failure / Performance Issue / Good Accessibility	17	15	13	8	6
Possible Failure / Preventative Measures Needed	15	13	11	6	4
Some Impact	10	7	6	2	1
Limited or No Impact	5	4	3	1	0

Priority 1	(FRIN > 13)
(FRIN >13) Countermeasures should be implemented immediately	

Priority 2	(FRIN ≥ 8)
(FRIN ≥8) Countermeasures should be implemented as soon as practical	

Priority 3	(FRIN < 8)
(FRIN <8) Countermeasures should be planned for future implementation	

Initial Risk Index Number (IRIN: 1 to 20)
0

Weighted Adjustment Reference Chart	
Waterwalls	3
Superheaters	2
Reheaters	-1
Remaining Wall Thickness ≤ 35%	7
Remaining Wall Thickness ≤ 45%	3
Remaining Wall Thickness ≤ 55%	1
Variable Adjustment	
	0

Final Risk Index Number (FRIN: 1 to 30)
0

Figure 2-2
Risk matrix refined for use as a boiler model

3
DATA COLLECTION

Because the boiler system was designed for a specific outcome, the initial design must be the basis for any alteration, update, or upgrade. Capacity, temperature, efficiency, and expected life must be examined. To this matrix, we must add current conditions (if different from design) and the expected result. It is important to understand the methodology of the boiler designer at the point of design conception. This is the starting point for all subsequent improvements. It is likely that the system design fundamentals—fuel type, emissions considerations, load swing dynamics, and firing techniques—have changed.

All the pertinent data will be located in the boiler manufacturers owner's manual or drawings supplied with the original purchase of the boiler system. The original owners specifications used for the procurement of the boiler system will also yield much useful information. The equipment supplied might or might not actually meet the owner's specifications. The principal data that you will be interested in are the following:

- Coal specified (BTU, ash content, ash fusion)
- Design pressure (water, superheat, and reheat)
- Design temperature (steam, furnace exit gas temperature, economizer outlet)
- Gas velocity
- Heat release rates (BTU/hr/ft^2)
- Pressure drops (flue gas, steam, and water)
- Thermal/combustion efficiency

Operating, Maintenance, and Inspection History

Operating History

The issues for the older boiler plants that operate at temperatures well into the creep range for low-alloy steels are fatigue and creep damage, the latter of which is influenced greatly by the operating hours experienced by the older coal-fired units that have exceeded their design lives. The following questions must be answered:

- What were normal operational parameters?
- What were the extremes in operating parameters?

This provides a specific plant history input, so we complete the design data with operating and maintenance events, which are the following:

- For the operating history
  - The operating parameters, such as pressure and temperature
  - Incidents, events of failure, and repair statistics
  - Condition of the plant facility by number of starts/stops and service hours

- For the maintenance history
  - Component replacement and repair history
  - Component geometry (slag traps)

- For the inspection history, test results, the most important of which are the following:
  - Destructive material testing, such as failure analysis and creep testing
  - Metallographic examination by field replication
  - Ultrasonic tube wall and internal oxide thickness measurement
  - Visual inspection

The results of the visual inspection, nondestructive testing, and destructive testing provide essential inputs for the component integrity evaluation and life assessment.

Maintenance History

For the maintenance history, the following questions must be answered:

- Is this component original or has it been replaced?
- Why was the component replaced or upgraded in the past?
- Was the original design maintained in the past updates?
- What improvements were made in past updates?
- What was the success of the previous updates?

Inspection History

For the inspection history, the following questions must be answered:

- What have the historical condition assessments revealed?
- What has the inspections revealed?
- What are the chronic areas requiring inspection and repair?

Justification for Replacement

The justification for replacement should consider the following costs:

Cost to maintain + cost of lost generation + cost to repair + cost of startups

Failure and Repair History

Boiler pressure parts can account for a significant proportion of unplanned availability losses and are often limiting factors on plant load flexibility. Knowledge of component life status in relation to future plant utilization is required to achieve the most favorable performance. The management of integrity of the boiler tubes, elements, and headers is an essential element of this approach.

Header failure, in particular, would be a serious safety concern, as well as forcing long and expensive outages. They are, however, more predictable than tube failures and can be prevented through careful planning of inspection and assessment. Flexible operating ability is primarily defined by the following parameters:

- Maximum number of startup/shutdown cycles without incurring unacceptable material degradation.
- Minimum time from barring speed to full megawatt load for a range of initial high-pressure and intermediate-pressure casing temperatures.
- Maximum rates at which the megawatt load can be increased and reduced.
- Where the failures are physically located within the component?
- What were the lost generation costs due to these tube leaks?
- What were the actual repair costs due to these tube leaks?
- What proactive repairs have been implemented to improve or maintain availability?
- What has been the cost for maintaining availability over a 10-year period?

4

OUTAGE AND POST-OUTAGE TESTING AND ANALYSIS

Outage

Outage testing and analysis entails the following:

- Implement the inspection/test plan.
- Perform root cause analysis as needed to ensure all necessary data are obtained during the outage. Install instrumentation to support on-line testing if required by the phase I plan or for root cause analysis.

Post-Outage Testing and Engineering Analysis

Post-outage testing and engineering analysis entails the following:

- Perform the final remaining life analysis.
- Conduct operational testing and analysis, as required.
- Develop recommendations for follow-up—repair, replace, or reinspect, based on the analysis.

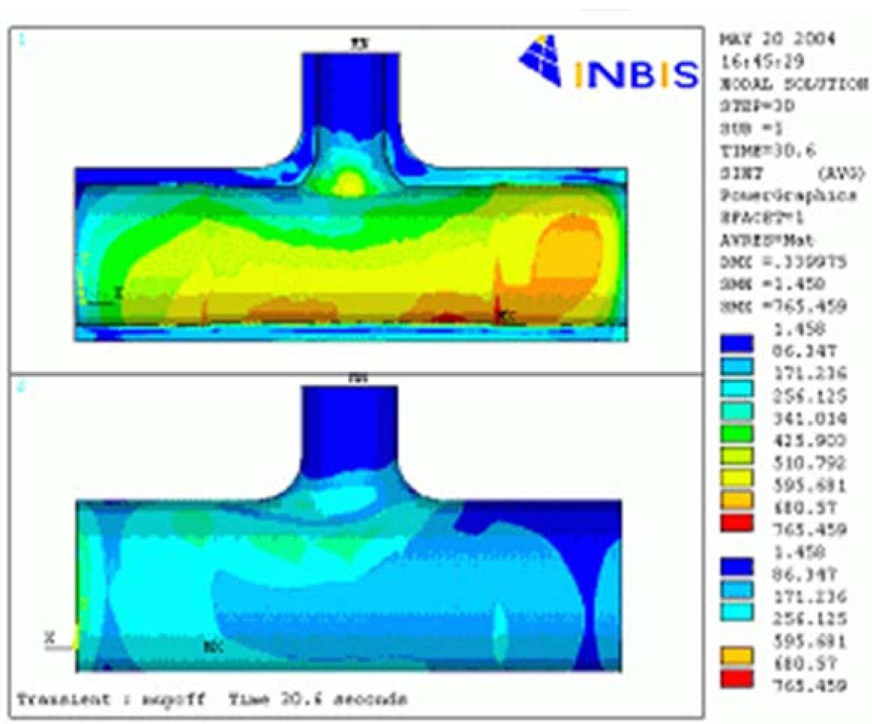


Figure 4-1
Engineering analysis

Scientific Approach

Based on the information gathered, it is possible to calculate the remaining life of the component. This can be done by two different scientific approaches:

- Theoretical lifetime consumption calculations
- Qualitative lifetime assessment based on metallographic investigations

Life Assessment

The aging of the boiler and piping components is mainly manifested by various mechanisms that must be considered:

- Carburization
- Corrosion
- Creep
- Dissimilar metal weld failure
- Stress corrosion cracking
- Thermal fatigue

Degradation mechanisms other than creep and fatigue are less accessible to useful life prediction by calculation.

5

USING SOFTWARE SYSTEMS TO IMPROVE BOILER RELIABILITY

Photographs allow easy identification and classification of new tube leaks. Digital cameras should be used liberally. A drawing used as a key for the location of the problem aids in assessing new problems. A complete text dialog is required to describe the problem in detail (see Figure 5-1).

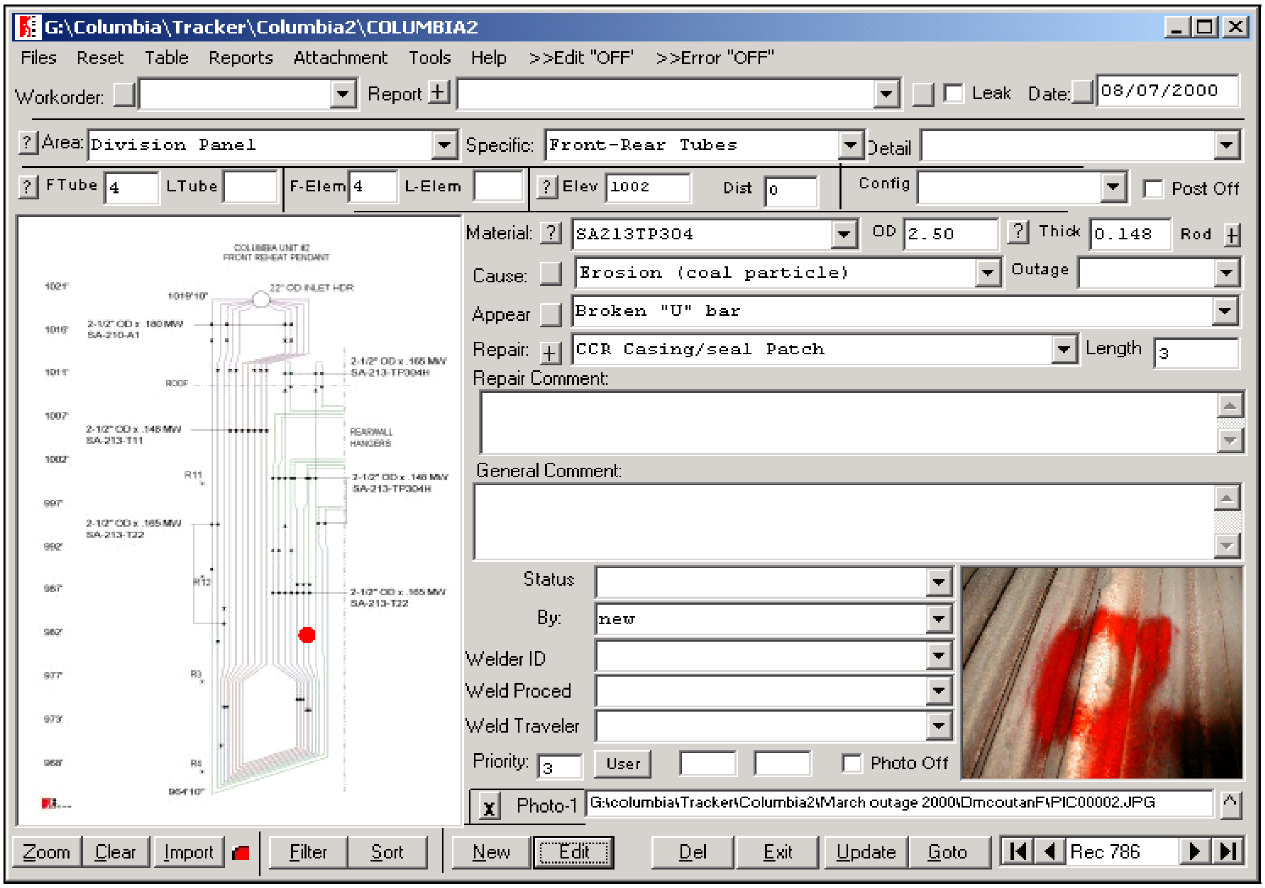


Figure 5-1
Boiler reporting software screenshot

Through the use of available software, potential problems can be readily identified before failures occur, allowing the plant to target effective predictive maintenance. This concept places the team leader in control and allows him or her to focus maintenance dollars when and where they are needed. Software can be used in real time during outages, generating inspection reports and documents that are currently prepared by more manual means. These systems can save precious outage time while increasing productivity, efficiency, and accuracy. This can be done without increasing the time required for existing methods.

Over a period of time, plants typically catalog leaks. This can consist of handwritten documentation or integrated software systems. Regardless of the system used, there are minimum requirements that must be included.

Best Practice—Midwest Generation

Midwest Generation provided the following information:

> Enter data in the corporate data base which everyone can access to track failures and action items. Use action items to prepare future inspections and tube replacements. Use this data along with all other failure tracking and inspection methods to identify areas of each furnace to concentrate visual and NDE inspections for scheduled outages. Search other similar fleet boilers for areas of concern and incorporate these areas into scope for Crawford.

Quality Assurance

Preparation and Use of Technical Information

In every plant, technical information is available to the boiler inspection team, even if it is limited to the boiler manual. The boiler manual will have pertinent information, including tube materials and nomenclature. In many cases, it will also include part numbers and welding information. Small drawings showing pressure parts as well as details of insulation and refractory are usually available. Copy all relevant sections for use during the outage, or scan them for use in your software systems. Drawings might be scarce, but an attempt should be made to copy, scan, and reduce these for outage use. It is important that the boiler inspection team have quality drawings for use in the boiler during the inspection (see Figure 5-2).

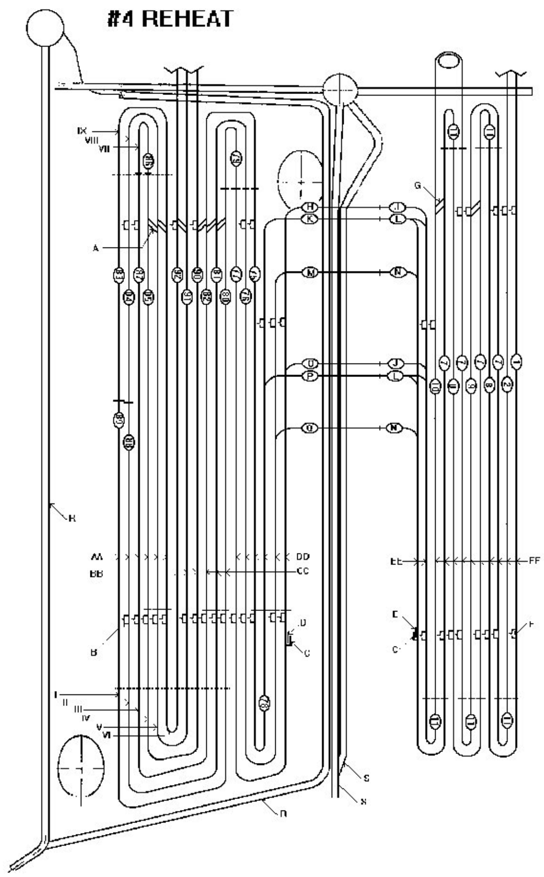


Figure 5-2
Example of scanned reheat layout drawing

Ideally, color-coded computer-aided design drawings will be available for reproduction in color. Regardless of the type of drawings, they should be used by the boiler inspection team. Effort is expended simply to find the correct tube material. This should be done before the actual inspections. Time is precious during the outage; potential confusion must be minimized proactively. Errors made in materials selection and identification is a significant cause of tube leaks. Therefore, identifying materials and including this identification in the inspection report become essential. The inspection team should, and most likely will, be the most familiar with the materials in any given component. This single step reduces the possibility of mistakes in material selection.

The designers of the boiler equipment were quite specific as to the application of materials (see Figure 5-3). We must not change or modify these materials without careful consideration of the effects. In some cases, it is acceptable to upgrade a material or increase the thickness of a material. A good rule of thumb is to replace materials according to the original design—in other words, replace with exactly what was installed new. Use the drawings and documentation as a guide when selecting replacement material.

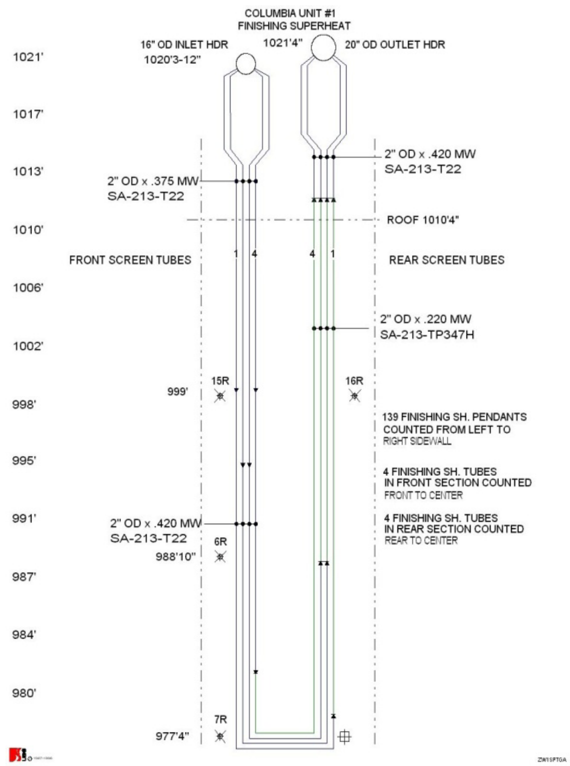


Figure 5-3
Detailed drawing providing additional needed information

Data Forms

As a continuation of drawings and documentation, check lists and inspection data forms should be used by your inspection team. Forms can range from basic printed forms to a complete software system. Figure 5-4 shows a typical inspection data form. No matter what kind of data form you use, it must contain the following elements:

- Tube numbering system must be clear and concise.
- Elevations must be included where relevant.
- Material identification should be color coded. Data forms must include outside diameter, thickness, minimum wall, and grade as specified by the original manufacturer. Be careful to incorporate all relevant changes from design into the data sheets. If you do not have color capability, encourage management to authorize a color printer. Color is now affordable and easy to use.
- Counting references must be clear and easy to understand. Not all plants count the same way; however, your regular people will likely be familiar with the method you have used. This is an essential element for visiting or supplemental personnel.
- Make a grid which has the principal elements required for this specific inspection. Items such as assembly, tube, elevation, length, problem description, repair, and action required should be the minimum information required on the data sheet.

Note: Above all else, make the data sheet easy to use in the boiler while inspecting. Filling out the data sheet in the office is the wrong thing to do.

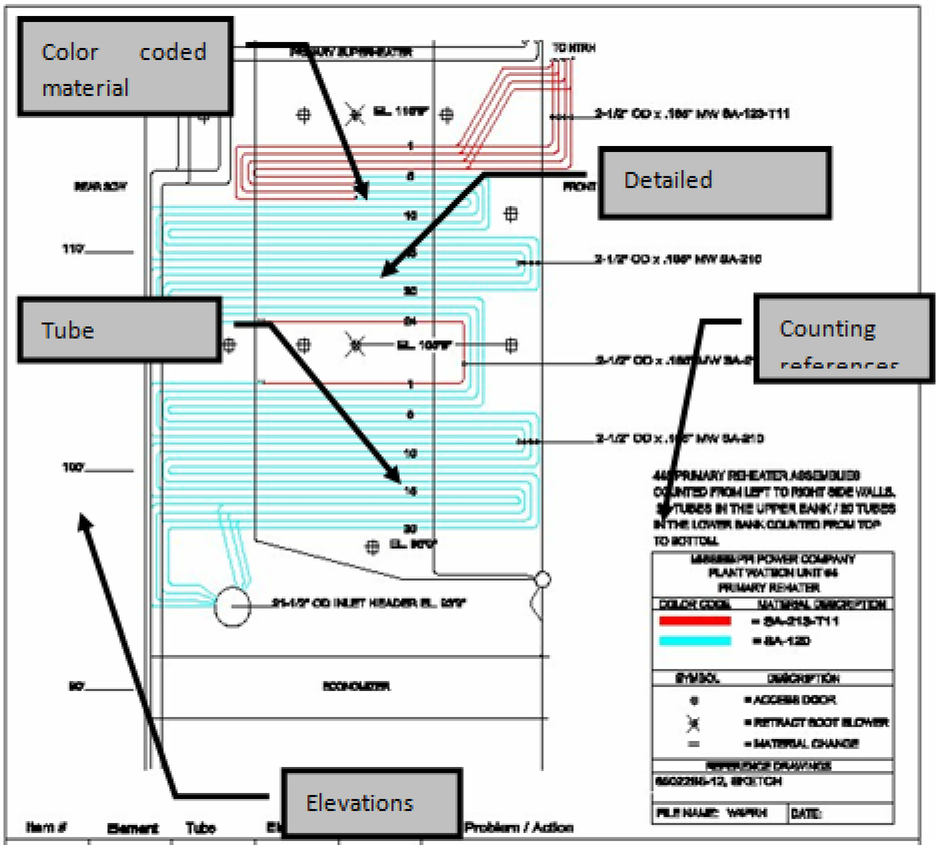


Figure 5-4
A typical inspection form with the essential elements

6
INSPECTION CHECKLISTS AND TECHNICAL PROCEDURES

Over a period of time a boiler inspection team will identify problem areas that are specific to the subject boiler. These should be recorded so that the specific experience can be shared with inspectors that follow. The checklist system can range from a handwritten and copied piece of paper with attached drawings or sketches to a complete software system. Figure 6-1 shows the framework for a technical procedure required to complete an inspection and required repairs. Figure 6-2 shows the detailed inspection procedure.

Primary Superheater inspection before debris removal
(278 elements, 2380 PSI, 1000 degrees F). (Vertical tubes)

GENERAL:

Elements are numbered from 1 to 20, from the left side wall to the right side wall.

Tubes are numbered 1 to 20 , top to bottom, with O.D.s
Vertical tubes are numbered 1 to 20 , from front to rear.

Primary Superheater inspection before debris removal
Inspect:

[] 1. Tubes. Record percent free area and tubes deep for plugging of gas lane. Record general areas of possible tube erosion.

[] 2. Bundles. Identify gas lanes with spacing greater than 6 inches. Sketch fly ash, bridging. Estimate percent free, area lost, and areas of bridging between tubes within bundle.

[] 3. Flow baffle. Indicate plugging resulting in flow area of mesh reduced > 50%, worn or eroded screen locations > four square inches. Sketch configuration including dimensions and angle of baffle.

Figure 6-1
Framework for a technical procedure

Primary Superheater inspection after debris removal

Inspect:

[] 1. For overheating. Record excessive sagging of tubes, blackened appearance, elephant hide, bulging, and burnt shields, tube, element, cause of overheat, and measure tube outside diameter.

[] 2. Fly ash erosion of tubes or fins. Record tube, element length of eroded area (spot "UT" thickness examine), cause (misdirected flow), and wall loss > 20%.

[] 3. For misalignment. Record misalignment into gas lanes > 1/4 diameter, erosion, rubbing, bundle, tube, and element.

[] 4. Pad welds. Record cracking, erosion, proper metal, tube, and element.

[] 5. Existing shielding. Record holes, bent, loose (redirection of flow), overheated shield conditions, missing (if missing "UT" thickness examine), tube, element, and wall.

[] 6. Gas lanes. Measure distances (center to center), record debris (shields lodged, any blockage redirecting gas flow), bundle, tube, and element.

[] 7. Bends. Record polishing, erosion (rear bends), tube, element, tube wall loss > 20%.

[] 8. Convection pass side walls. Inspect side walls for missing refractory, fly ash erosion, record tube # that erosion is adjacent to, and wall.

[] 9. Gas baffles. Record holes in mesh > 4" square, missing angles, and measure baffle (include height, width, angle).

[] 10. Hangers tubes (if existing). Record bowing, rubbing, cracked welds, missing pins, erosion, hanger, and element #.

[] 11. Inlet header (if accessible). Record condition (spot "UT" thickness examine), low temperature corrosion, nipple cracking, tube, and element #.

[] 12. Left and Right Convection Wall peg fins. Inspect peg fins especially and corners. Record missing, cracked, or broken fins, adjacent tube, elevation, and refractory.

[] 13. Front and rear wall to element support brackets, and attachment welds.

[] 14. For retract blower erosion. Tubes are worn flat. Spot "UT" thickness examine erosion. Record tube, retract blower, elevation, and tube wall loss > 20%.

Figure 6-2
Detailed inspection procedure

Inspection Photography

Select a durable, digital camera that can withstand the rigors of the boiler inspection environment. Keep moving parts to a minimum because the fly ash can foul a camera's internal components. The team should use cameras during all inspections, without exceptions. Not all photographs might be used in the report; however, it makes the process of report generation much easier. Communication is key, and photographs can convey an area's condition with a minimum of words. If you discover a problem in the field, complete the following:

- Paint the problem brightly for location in the future; include the repair.
- Mark the tube/element number clearly on the problem area with a paint stick.
- Take a photograph that clearly shows the problem and the identification you have marked with a paint stick.
- Take extra photographs at different angles and positions.
- Identify in your notes what each photograph represents and which photograph number pertains to specific items.
- Select the best photo for the report if more than one picture is available. Add as many as might be required. Archive all photos, and include them in an appendix at the end of your final report. Include captions with each photo for easy identification. Captions are important because hundreds of pictures will be taken during a typical outage.

Figure 6-3
An inspection photograph

Best Practice—Crawford and Fisk

Crawford and Fisk provided the following information:

> Whenever the boiler comes off line, inspect as much of the boiler as time allows. Constant, continued surveillance of the secondary super heater, reheater, and back pass will identify problem areas sooner and mitigate failures in these areas. Minimizing steam tube failures results in fewer outages because these are the type of failures that take the unit off quickly.

Problem Identification in the Field

One of the most difficult problems in the inspection process is the repair crew finding the specific area to be repaired. We can aid this process by clearly and uniformly marking the problem areas. This can be accomplished by using simple techniques, such as the following:

- When beginning any inspection, count and number all the elements and tubes in the inspection area. Identify soot blowers and other landmarks that might be of use during the inspection/repairs. Write on every fifth element for easy reference during the inspection and subsequent repairs.
- Brightly mark the area of concern with either bright paint or a tag (see Figure 6-4). If painting, do not paint into an area that will require overlay. This makes the preparation process more difficult for the repair person. We suggest that you circle the area to be pad welded. If using paint, use a bright color in contrast with the fly ash you are encountering. Mark the repair and tube identification on the tubes with a paint stick.
- Tags are the preferred method for identification. Prepare about 300 tags at the beginning of the outage. Give each boiler inspection team member a group of consecutively numbered tags. Record the numbers given to each team member. The tags should be consecutively numbered 1–300. Each tag should have a rubber band or a metal wire to hang the tag on the repair area.
- Use a single tag for each repair item. On the tag, mark the identification (tube number, element, and so on) and the required repair. Record the tag number as part of your notes. If you are inspecting an area in which tag attachment is not possible, such as a furnace wall, write the tag number on the wall and destroy the tag bearing that number.

Figure 6-4
Marking a problem area

7
REPORT PREPARATION

The boiler inspection team is in constant competition with other teams for the pool of available budget. It is a process of convincing management that the boiler team needs the money more than another area of the plant does. Although overall system availability is important to everyone, if forced outages due to tube leaks rise, the inspection team will likely bear the responsibility. Therefore, we must protect our areas of responsibility. Experience has shown that a well-done inspection report will help convince otherwise passive management. Developing a high-quality report is more efficient, and overall more cost effective, even though it requires more time to complete than does a lesser effort. You will find in time that the extra effort is well spent.

Some obvious advantages are the following:

- A high-quality report communicates more effectively with management.
- The repair crews will have fewer questions and less confusion.
- Less time will be required during the planning stages of the repairs because materials specifications and quantities are listed in the report.
- Fewer mistakes are made on material selection.
- Higher quality welds are made because the welders know exactly what they are welding to and how thick it is.

Figure 7-1 provides an example of a detailed report.

AREA: Reheat inlet pendant.

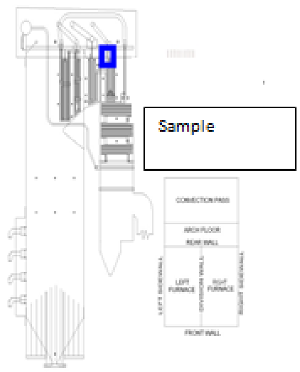
By:

The area was numbered from boiler left side to boiler right side.

Items were marked with white paint stick and orange paint.

The total number of repair items for this area is 9

P R I O R I T Y # 1   R E P A I R S   T O T A L = 6



==

Repair item #: 17   Priority #: 1

Area: Reheat inlet pendant

Action: PAD WELD.

Repair #: 17-a Record:# 41 (PAD WELD).

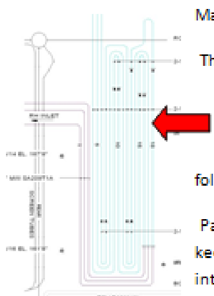
General location is Reheat inlet pendant Rear.

Specific location: Tube #: 18 Element #: 2 Elevation= 169'.

Length= 1.5'

Cause = Erosion (soot blower).

Appearance= a flat on tube.



Material= 2.5" OD x 0.165" MWT x SA-178A Electrode= 7018.

The UT Reading is .120.

These tubes are below 75% of MWT and above 65% MWT. They are also located at the following locations; 7, 8, 9, 17, 19, 23, 46, and 58.

Pad weld using vertical stringers. Do not horizontal weave pad weld. Down hand is suggested to keep the temperature as cool as practical. Do not pad weld if copper deposition is present on the internal surface of the tubing. Use TIG if the tube remaining wall is less than .125".

Figure 7-1
A detailed boiler inspection report

Best Practice—Duke Energy

Duke Energy provided the following information:

> All inspection reports from the last 10–15 years are stored on corporate and plant servers. The history is easy to find because the index and format are largely the same.
>
> Reports are created in Microsoft Word for ease of use by all plant staff.
>
> Reports are submitted each day before leaving the station. The plant engineer is kept up to date.

8
HUMAN RESOURCES

Selecting the Boiler Inspection Team Leader

The most important constituent of the boiler inspection team, whether it is an in-house endeavor or a contracted effort, is the team leader. The team leader is ultimately responsible for all inspection activities and is the consistent element of the total inspection effort. The key is consistency. Team support personnel can come from a number of resources, including plant operations, laboratory, coal yard personnel, and so on. Support personnel can also come from other plants within your system. Participation by personnel who are not intimately involved with the subject boiler or are not schooled in the discipline of boiler inspection technology can lead to inconsistencies in the inspection philosophy. In addition, their primary duties might take precedence over their temporary inspection team assignment. The team leader must consider these factors and act accordingly to ensure consistency of the total inspection program.

Best Practice—Duke Energy

Duke Energy provided the following information:

> **Training:** Inspectors need some training before becoming productive boiler inspectors. A three-day class is taught each year to train new inspectors. The class covers boiler design, boiler failure mechanisms, safety, and inspection and reporting practices.
>
> **Repeatability/Ownership:** The SME that leads the inspection at a particular plant has shared ownership with the plant boiler engineer. This ownership includes a reliability index in their annual performance goals.

Organizing an In-House Boiler Inspection Team

Forced Outage Team Members

During forced outages, it is important that members of the repair crew also be boiler inspection team members or observers. During a typical forced outage, there is limited warning. In most instances, the people involved are welders and mechanics who are trained to locate and repair the leak or problem. Further training of repair personnel as boiler inspection team members adds technology, knowledge, and quality to the forced outage repair process. The forced outage responder is the best possible choice to assist in the inspection, repair technique, documentation, and final repair methods. Remember, when the boiler has a leak, it is an opportunity to gain insight into lurking problems that have not been addressed during planned outages.

Even though we are in a forced outage scenario, we must inspect all the areas in and around the leak event, as well as other areas that can be easily accessed without impacting the timing and duration of the original event. We suggest that we inspect our way in to the leak and then back out. This is why the inspector should have all the tools and techniques to determine any collateral damage as well as similar damage in the suspect areas.

Planned Outage Team Members

The boiler inspection team is commonly composed of representatives from diverse areas of the plant. Utilization of personnel from different departments can add an element of diversity that is beneficial to the inspection team. It is suggested that personnel who do not have a heavy work focus during the outage period be used. These might include operations, technicians, environmental, and laboratory personnel. Technically trained plant personnel are ideal candidates for inspection team members. Utilization of maintenance workers as planned outage boiler inspection team members is not recommended; in many instances, their normal job duties interfere with the inspection effort.

Note: A major mistake that inspection teams make during a planned outage is to release inspection team members too early. This reduces the effectiveness of the technical surveillance and follow-up inspections. Many problems, such as additional items found, can be resolved in the time from the end of the initial inspections until hydro. The cost of maintaining the inspection team until hydro is significantly offset by the increase in the overall quality of the outage.

It is important that the team members maintain consistency from unit to unit and from year to year. This will require incentives from management. An ongoing training program is essential to keep everyone up to date.

Training Regimes of Inspection Personnel

It is essential that all inspection team members have formal inspection technology training. Insufficient boiler inspection training is the primary contributing factor to poor performance of a boiler inspection team. Having a background that well equips an inspection team member for boiler inspection, in itself, is not sufficient. This includes engineers, managers, welders, and mechanics; no one involved with the inspection process should be exempt.

Physical Capability

Boiler inspection is physically demanding. Team members must be capable of climbing and crawling in unpleasant environments and able to enter small openings with limited access. It is not recommended that individuals with fear of heights or confined spaces be part of the inspection team. Excellent vision, natural or corrected, is essential.

Team Player

Most importantly, every team member must be a team player.

Technical Expertise

A good boiler inspection team member need not be a degreed engineer; however, the team member must have a fundamental understanding of some basic concepts in physics, metallurgy, mathematics, and strength of materials. Intelligent individuals with a strong work ethic and desire to learn make great boiler inspector candidates.

Note: Consistency is the primary ingredient in a successful in-house inspection team.

Best Practice—American Electric Power

American Electric Power provided the following information:

> UDC provides training classes two times per year for AEP. The core UDC team provided continuity that was lost when AEP downsized and lost their experienced personnel or they moved into other positions.

Supplemental Boiler Inspection Team Members

Intra Company

Personnel from other plants within your system are usually team leaders or members of their respective plant boiler inspection teams. This is a popular planned outage concept, as plants within the same system typically remove equipment from service at different times. A wide range of experience is enjoyed with such a compilation of talent; however, their boilers and equipment might be of a different model and manufacture. In addition, management policy can vary from plant to plant, potentially confusing the relationship.

The team leader can address these problems by pairing the supplemental personnel with local boiler inspection team members. Local pairing of human resources ensures that the policies and interests of the subject plant are best served. Pairing is also important in combining various levels of experience. Pairing experienced inspectors with trainees or less-experienced inspectors promotes camaraderie and on-the-job training, benefiting both the current inspection effort and the collective level of expertise of the entire company. It is incumbent on the team leader to take advantage of highly trained and experienced personnel in this manner to ensure optimal performance of the inspection effort.

Best Practice—Crawford and Fisk

Crawford and Fisk provided the following information:

> During scheduled outages, bring in outside inspectors to assist with boiler inspections. The reason is twofold: first, the inspections are more thorough due to the number of experienced inspectors inside the boiler, and second, the punch lists are issued more quickly, which gives the mechanical contractor more time and allows the BPS to prioritize better.

Best Practice—Duke Energy

Duke Energy provided the following information:

> The majority of Duke boiler inspections are performed by internal labor. The labor is almost always from a visiting station and is led by a boiler SME.
>
> **Benefits:**
>
> This process creates a large number of engineers with a good level of boiler knowledge. Most managers at Duke inspected boilers at some point in their career.
>
> Because labor comes from other plants, there is a huge amount of relationship building and tech transfer from plant to plant. This may be the biggest advantage of using internal labor for inspections.
>
> The host plant can focus on execution and does not have to inspect or check up on the inspection team.
>
> The SME leading the inspection usually has a long-term relationship with that plant. They know that boiler and have inspected it several times. This also improves long-term planning because many station engineers rotate jobs every 2–5 years.

Contracted Professionals

There are many advantages to contracting experts in the field of boiler inspection technology. Professional boiler inspection team members work together during many outages each year. A well-traveled professional brings a wealth of expertise and experience to the outage. He or she is a valuable source for vital technical information. Professional consultants should be used extensively to conduct on-the-job training during the inspection period. Effective pairing will facilitate this goal.

The selected inspection contractors should bring experience and knowledge of your specific equipment and the industry in general. They should be knowledgeable in all aspects of team activity as it pertains to your inspection program. They should be skilled, efficient, competent, and able to easily adapt to your inspection program. If you use specific software as part of your inspection program, your contracted inspectors should be knowledgeable in those areas, as well. It is important to research prospective inspection contractors thoroughly to ensure that your technical requirements are met.

Best Practice—TransCanada Ravenswood

TransCanada Ravenswood provided the following information:

> Boiler inspections: Yearly internal and external boiler inspection by in-house engineering or OEM (Alstom). Results are documented and executed when possible. Every outage (3–5 years) an NDE inspection of selected headers/links/leads susceptible to creep damage. Reinspection intervals are based on the inspection results and recommendations. Desuperheater liners are inspected every 3–5 years

Best Practice—American Electric Power

American Electric Power provided the following information:

> Utilizing UDC designated boiler inspection; independent of the AEP inspectors.

Forced Outages

Ultrasonic thickness measurements should be used to determine remaining wall thickness of tubes that have received secondary damage. It might be necessary to replace thinned tubes, even though no through-wall holes are present, if the remaining wall thickness is too thin to sustain additional service loads during the next operational period. Immediate tube replacement in these situations can prevent repeat failures. The following guidelines should be followed:

- Personnel responsible for reporting boiler tube failures should be trained in all aspects pertinent to reliable reporting of tube failures—that is, exact designation of failure location, standard mechanism cause codes, probable root causes, verification of root cause, type of repair, and so on. This is typically the welder or mechanic who is performing the actual repair, which is why welders and mechanics should be well-trained team members.
- Standard report forms should be used for all boilers and should be required documentation for every tube failure and repair.
- All boiler tube failure reports should be processed through the boiler inspection team leader for continuous tracking and trending on a specific unit, plant, and system.
- Monthly and annual reports should be issued and formatted, specific to the need-to-know and action requirements of the inspection team.

9
FAILURES AND NEAR FAILURES

Boiler tube failures occur in fossil-fired plants throughout the world. Failures differ only in the failure mechanisms experienced and the magnitude of the associated availability loss. Tube failure experiences among utilities are usually treated as unique incidents in individual boilers, rather than as recognized common occurrences that can benefit from detailed knowledge and shared information about failure mechanisms and root causes. This rationale results in consideration of each unit's boiler tube failure problem as a special case that requires extensive failure cause analysis, special testing, and outside technical support. Generally, U.S. utilities take this approach to solve boiler tube failure problems primarily because they 1) tend to accept tube failures as normal maintenance activity, 2) have tremendous pressure to return the efficient units to service quickly, and 3) seldom have the required technical expertise at the plant to study the problem and implement optimum correction or prevention solutions.

The following guidelines apply to failures and near failures:

- Every boiler tube failure should be recognized as an indicator of a potentially serious problem. Too often, repeat tube failures are considered normal maintenance, and serious problems go undetected until high costs or generation losses get the attention of senior management. Comprehensive information should be recorded and reported for every tube failure, describing the specific boiler and tube location, failure mechanism, and root cause. Repeat tube failures result when the tracking and trending process that is necessary for early problem detection is not performed.
- Early warning signals of potential problems in similar boilers cannot be recognized if information on boiler tube failures is not documented and cataloged. Figure 9-1 shows an example of a problem that can be detected during an inspection, before a failure occurs.

Figure 9-1
A "golden tube." Finding this problem during an inspection prevents a tube leak that could result in a forced outage.

- Every failure problem should be analyzed by a responsible, trained, full-time boiler inspection team to define the location, extent, failure mechanism, and most probable root cause, and to perform a cost–benefit analysis of alternative corrective or preventive actions for management approval and boiler inspection team implementation.
- Every failure requires a pre-repair inspection to determine the extent of damage to the failed tube, the tubing in close proximity of the failed tube, and the tubing in other locations subject to the same root cause. This inspection should also determine sample specimens that are appropriate for root cause failure analysis. A trained and experienced boiler inspection team member should conduct this inspection.
- Personnel responsible for reporting boiler tube failures should be trained in all aspects pertinent to reliable reporting of tube failures—that is, exact designation of failure location, standard mechanism cause codes, probable root causes, verification of root cause, type of repair, and so on.
- Standard report forms should be used for all boilers and should be required documentation for every tube failure and repair.
- All boiler tube failure reports should be processed through a central focal point for continuous tracking and trending on a specific unit, plant, and system.
- Monthly and annual reports should be issued and formatted, specific to the need-to-know and action requirements of the team functional groups.
- Implementation of a formalized boiler tube failure correction, prevention, and control program, incorporating these four critical program elements, should virtually eliminate repeat boiler tube failures and significantly improve the availability of fossil plants.

Best Practice—American Electric Power

American Electric Power provided the following information:

> Review all tube leaks per the EPRI program.

Failure Identification and Cataloging Techniques

Boiler tube failures have been the primary availability problem for all utilities with fossil plants for as long as reliable statistics have been kept. Figure 9-2 shows an example of a failed boiler tube. The majority of boiler tube failures have been repeated failures, indicating that returning a unit to service has traditionally been more important than understanding the mechanism and root cause of each boiler tube failure. Failures have emanated from poor initial design, environment, and lack of proper management support.

Figure 9-2
A failed boiler tube

Boiler failure libraries are expert systems used to diagnose boiler tube failure mechanisms from information on the tube location, appearance, and possible initiating events. When the failure mechanism is known, the expert system provides a list of potential root causes along with recommendations for root cause verification, repair and inspection procedures, and guidelines for preventing future failures.

Repeat Boiler Failures

There are four primary reasons for repeated boiler tube failures. Repeat failures are defined as multiple failures in a single boiler having the same failure mechanism and root cause. Repeat boiler tube failures occur for the following reasons:

- Failure to follow state-of-the-art practices
- Improper failure analysis
- Improper choice of corrective or preemptive action
- Failure to develop a problem definition

Failure to Follow State-of-the-Art Practices

State-of-the-art practices are defined as operation, maintenance, and engineering practices demonstrated by experience to be necessary in the prevention of repeat boiler tube failures.

State-of-the-Art Operating Practices

Major operating practices that can influence boiler tube failures are cycle water chemistry; boiler, superheater, and reheater temperature control; combustion control; and layup, both waterside and fireside.

State-of-the-Art Maintenance Practices

Many cases of repeat tube failures caused by poor or improper tube repairs are common and well documented. It is not uncommon to hear that a weld that was made as a repair failed 24 hours later. The reason behind the root causes—tube overheating due to blockage by welding debris and incomplete fusion of the weld—is the failure to take proper tube repair quality control preventive actions that follow proven state-of-the-art maintenance practices.

These repeat boiler tube failures can also be eliminated by establishing and using plant tube repair maintenance procedures that clearly define not only the repair method and materials to be used but also proper quality control actions to prevent repeat failures.

Maintenance practices include the maintenance of chemical treatment equipment for the makeup system and condensate polishers (where installed), maintenance of cycle components to prevent ingress of impurities into the feedwater, and maintenance of chemical sampling equipment and analytical instrumentation. It is imperative to maintain tight condensers, to seal the areas through which air leaks into the vacuum section of the cycle, and to maintain efficiency of the air removal equipment. Appropriate chemical cleaning practices are also a part of a complete maintenance program.

State-of-the-Art Engineering Practices

Many repeat failures occur due to neglect in determining the remaining life of tubes, with loss-of-life damage from the same failure mechanism that caused the initial tube failure. Even though the root causes were properly diagnosed and corrected, tubes that experienced loss-of -life damage from the same mechanisms and root causes of previous failures are now beginning to fail. The root cause of these repeat failures is the neglect to take state-of-the-art engineering preventive action, which is to perform a residual life evaluation of tubes that have suffered loss-of-life damage. These repeat boiler tube failures can also be eliminated by establishing and using plant boiler tube inspection procedures that clearly define both the method for verifying the integrity of the tube repair, such as radiography or hydrostatic testing, and proper residual life preventive action to be taken to ensure against loss-of-life-damage repeat tube failures.

Proper engineering practices also include design and material selection for the boiler and preboiler cycle components. This includes compatibility of all cycle materials with the selected water treatment; capacity of the deaerating equipment; design of the chemical treatment equipment, boiler drum steam separators and blowdown; and design of the temperature, pressure, and water chemistry monitoring equipment

Improper Failure Analysis

When a forced outage results from a boiler tube failure, there is considerable pressure on plant personnel to complete the repair and return the unit to service as quickly as possible. Many times, expeditious repairs result in inadequate problem analysis, which leads to repeat failures. Analysis of a tube failure incident should include the following:

- Inspections to determine the extent of primary and secondary tube damage
- Identification of the failure mechanism
- Determination of the root cause
- Verification of the root cause
- Determination of residual life and predictive maintenance.

A primary tube failure can cause secondary failure or damage to other tubes in close proximity of the primary failure. Lack of careful inspection of all tubes damaged during the failure incident, with appropriate wall thickness measurements, will result in future repeat tube failures.

It is important to identify the correct failure mechanism of every tube failure because, for each mechanism (such as fireside corrosion, fly ash erosion, and so on), there will be unique root causes. Incorrect failure mechanism determination will usually result in taking the wrong corrective or preventive action and in having subsequent repeat tube failures.

To protect against repeat tube failures from incorrect root cause analysis or determination, verification of the most probable root cause should be obtained as soon as practicable. Appropriate measurements and tests should be conducted to support the assumptions and postulations made in the root cause analysis.

A tube failure can result from either a corrosion or erosion failure mechanism in which the tube wall thickness is reduced to the point of tensile rupture. These failure types have a high probability of producing repeat tube failures unless a residual life determination of other tubes experiencing similar degradation is performed. To prevent repeat tube failures before the next scheduled boiler outage, wall thickness measurements and residual life determinations should be made of all tubes adjacent to or in the close proximity of tubes that have failed due to these mechanisms.

During an analysis of corrosion failures (waterside and fireside), identification of the chemical species at the tube and crack surfaces can help in determining chemical root causes of a failure. Involvement of the water chemist in failure analysis and a review of chemistry history are also helpful.

Improper Choice of Corrective or Preemptive Action

Repeat tube failures can occur because a temporary rather than permanent solution is applied to correct or prevent the tube failure problem. An example of a temporary action is the use of sacrificial shields or metal/plasma sprays to inhibit fireside corrosion or erosion. A permanent solution would be based on determining the root cause, such as a reducing atmosphere in the furnace and excessive flue gas velocity, and taking appropriate engineering or maintenance preventive action. An example of a temporary action is the use of a window or pad weld to make a tube leak repair. Best practice would be to immediately replace the damaged tube with a new tube section or to replace the window or pad welded section at the next scheduled boiler outage. Unfortunately, many temporary solutions are not replaced with permanent actions, and therefore fail again within a short time interval.

In relation to corrosion failures, the corrective or preventive actions should include a reduction of impurity ingress, establishment of proper water chemistry practices, and a determination of tube life reduction by the corrosion damage. For example, hydrogen damage of boiler tubes cannot be reversed, and a replacement of the severely damaged tubes will prevent annoying continuation of tube failures.

All scheduled major boiler inspections should include boiler tube wall thickness measurements in areas experiencing erosion or corrosion damage, until erosion or corrosion rates are established. In areas experiencing damage, root cause analysis will be performed, and corrective, preventive, and control actions should be taken to inhibit forced outages due to these mechanisms. Problem definition and root cause analysis of waterside corrosion failures is usually more difficult because of the need to review water chemistry history and data over an extended period of time.

Proper corrective and preventive action requires correct mechanism identification, root cause analysis, and verification. A formalized boiler tube failure prevention program satisfies these requirements through management mandates and support.

Failure to Develop a Problem Definition

Root cause analysis of every tube failure is a prerequisite mandate for an effective, formalized tube failure prevention program. Before the actual root cause of a boiler tube failure problem can be determined, it is essential that the problem be clearly defined in terms of the failure mechanism.

A Multidisciplined Approach

Activities associated with boiler tube failures— that is, mechanism identification, root cause analysis and verification, and appropriate corrective or preventive action—are complex and usually require the expertise of several technical and experience disciplines. For example, mechanism identification can require knowledge of the metallurgical characteristics of boiler tube steels at high temperature over time.

Root cause analysis might require knowledge of feedwater and boiler water chemistry, boiler tube wall temperature, scale thickness, and heat flux. Verification might require a stress analysis of complex tube assemblies that are subjected to expansion restraints. Short-term, extensive water chemistry monitoring preventive action might require a change in operation or maintenance practices. Effective boiler tube failure prevention programs recognize this complexity and address it by mandating and supporting a team approach to solving boiler tube failures.

Severe duty on both the fireside and the water or steam side of the various heat transfer surfaces in the boiler or steam generator cause frequent unplanned outages and lengthening of planned outages to repair failures to these critical components of the power plant.

Utilities have opportunities to increase electrical output at existing units without increasing fuel burn or carbon footprint by focusing on the boiler system in the following three areas:

- Improving combustion and thermal efficiency
- Reducing forced outages and extending time between outages
- Improving the effectiveness of the clean-up equipment (environment)

These three areas are well known and routinely controlled by plant management. Unfortunately, the historical standard has been that the management team is acting as the final distiller of information for use in management decisions. They combine the input they receive from the burner group, the maintenance group, and the environmental group. With this information, plans are formulated and executed. This places the full responsibility for overlaps directly on management. This is inequitable, as the management team is not expected to be expert in every field and operation in the plant. Experience has shown that, with this model, the overlap areas are usually overlooked.

During our discovery inspection process, we look for the ingress of outside air that enters the boiler from nonproductive sources. We refer to this leakage of air as *tramp air* because it contributes nothing to the combustion process. It comes in around burned soot blower housings, holes in the casing, and other locations. We mark, record, and report these items with a low priority. The tramp air is not a direct risk to a forced outage; therefore, it is not considered essential for repair during that specific outage. It is flagged for optional repair, if time and money allow. This category rarely gets any attention due to the budget pressures that exist in most plants. Due to reducing budgets and time frames, many utilities are interested in repairing only priority 1 problems. In this case, the inspection team devotes little time to priority 2 and none on priority 3 items.

If air enters the boiler and is not used for combustion, the following sequence of events occurs. The additional volume of flue gas increases the overall gas velocity. This increase in velocity has two dramatic effects. The erosion of tubing by fly ash increases at the square of velocity, so fly ash erosion is increased dramatically. The increased gas velocity through the pressure parts—that is, the superheater, reheater, and economizer—cause a reduction of heat absorption and a decrease in thermal efficiency of all of these components (see Figure 9-3). The additional volume of flue gas increases the loading on all of the flue gas equipment.

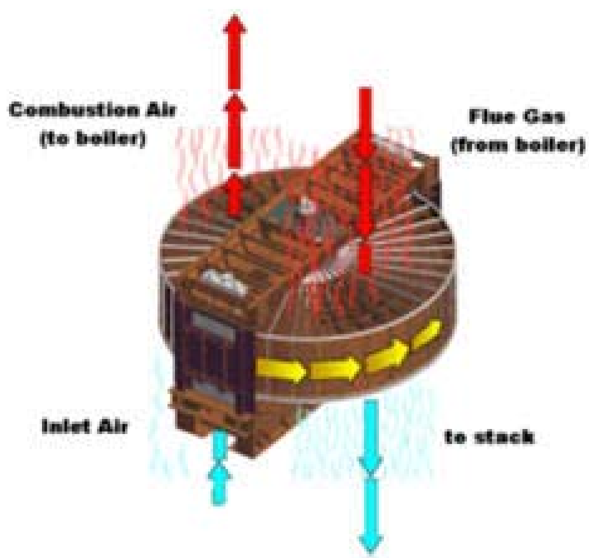


Figure 9-3
Air heater has reduced performance due to high gas velocity
Courtesy of Storm Technologies

The following conditions exist in this scenario:

- The ID fan is drawing additional amps to handle the increase. In many cases, the boilers are load limited due to lack of ID fan capacity.
- The air heater is operating at a greater pressure loss, reducing its efficiency and increasing erosion in the air heater itself.
- The electrostatic precipitator operates on the principle of balanced gas flow of a specific velocity. When these parameters are violated by excess volume, the efficiency of the electrostatic precipitator is compromised (see Figure 9-4). This increases the opacity and particulate output from the system.

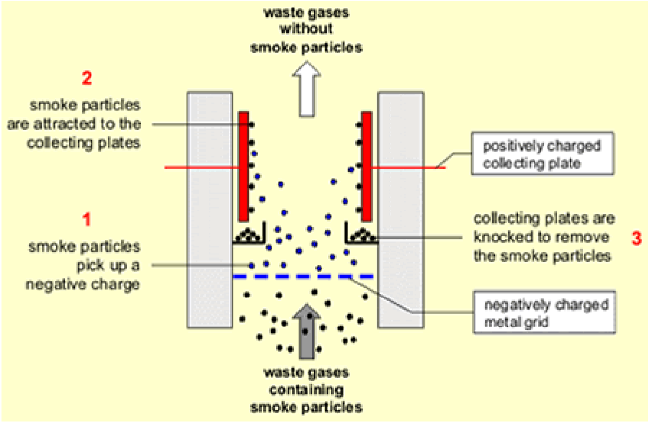


Figure 9-4
When gas speeds up through the electrostatic precipitator, the collection efficiency decreases
Courtesy of Nuendorfer Particulate Knowledge

- When oxygen enters the boiler not contributing to the combustion process, it increases the measureable O_2 concentration. The combustion process uses oxygen sensors at the economizer outlet to calculate the proper fuel air mixture.
- If these readings are incorrectly measured high, the air flow is reduced at the burners. This miscalculation results in extremely low oxygen concentrations. This has been referred to as a *reducing condition*. This reducing condition process usually results in soot and high corrosion rates on water wall tubes.
- The low oxygen flue gas contributes to several failure mechanisms (see Figures 9-5 and 9-6):
  - Soot blower erosion due to increase carbon (soot) removal
  - Localized high heat flux, resulting in the potential for overheat and exacerbation of waterside deposit corrosion
  - Water wall fireside corrosion is caused by corrosive conditions in the combustion zone due to inadequate oxygen supply, high concentration of sulfur and/or increased chlorides in the fuel, improper alignment of the fuel burners, and formation of molten ash on the water wall tube surface.

Figure 9-5
Accumulation and erosion to boiler tubing

Figure 9-6
Severe corrosion
Courtesy of David N. French Metallurgists and Engineers

What was originally considered a small, insignificant, priority 3 item has a deep and complex effect on many areas not considered. This is repeated outage after outage. Consideration of all the parameters and how they interact throughout the system is required to achieve a reliable, efficient, and environmentally friendly power generating facility.

Residual Life and Predictive Maintenance

Most repeat tube failures (that is, failures in the same boiler with the same mechanism and root cause) occur not because the mechanism or root cause is not known and understood but because the remaining life of other damaged tubes was not determined, Most failure mechanisms deplete tube life that cannot be restored even though the root cause has been corrected. Good examples are fireside and water side corrosion, where the tube strength has been diminished due to wall thinning (fireside corrosion) or changes in microstructural properties (hydrogen damage). When failures resulting from these or other mechanisms that deplete tube life occur, residual life of other tubing in areas that are influenced by the same root cause should be determined as soon as practicable.

This will expose other damaged tubing that is prone to failure before the next scheduled boiler outage and establish corrosion/erosion rates for predicting maintenance requirements to inhibit future failures. Formalized boiler tube failure prevention programs satisfy this requirement, by mandating residual life determination as an integral part of the program's correction, prevention, and control processes.

Permanent Engineered Solutions

In many tube failure problems, temporary rather than permanent engineered solutions are used to solve the problem, with the result that the remedy is a continuing and costly maintenance burden. A good example might be where tubing is damaged by soot blower erosion because the blower is located too close to a corner or wall protrusion, yet rather than relocate the soot blower, the tubing is pad welded or shielded. Another example might be where water wall fireside corrosion damage due to a reducing atmosphere in the furnace is repaired with metal or plasma sprayed coatings, rather than providing curtain air along the walls.

In most cases, temporary repairs should be used only in emergencies, with engineering fixes being the permanent solution. A formalized boiler tube failure prevention program with a team approach to permanent solutions satisfies this requirement.

Root Cause Analysis and Verification Methods

Boiler tube failure root cause analysis and verification methods include 1) gathering physical evidence or data and 2) the studying available facts through systematic problem analysis. In most cases, combining both methodologies is necessary because gathering all the necessary data might be impossible or too time-consuming and costly. Important, relevant parameters that might require determination by calculation, observation, or measurement are as follows:

- Boiler water and feedwater chemistry
- Boiler water flow
- Flue gas flow pattern and velocity
- Flue gas temperature
- Fuel constituents
- Fuel fouling and slagging characteristics
- Tube deposit constituents and thickness
- Tube metal material properties
- Tube metal microstructure
- Tube metal stress
- Tube metal temperature
- Tube metal thickness

On-line monitoring, periodic sampling, and laboratory testing are three ways in which to quantify these critical parameters. Determination of the failure mechanism and probable root causes is the key to minimizing data gathering requirements. Information on probable root causes should be used to minimize the data needed to verify the actual root cause. This approach will expedite the problem-solving and corrective action processes.

Pad Welding As an Approved Repair?

Due to the historical failure rates of pad welding, we believe that replacement is far superior to pad welding. These replacements will reduce failures. However, in many cases, pad welding is the only feasible repair. About 15 years ago, when pad welding was required, we began an effort to install pad welds in a more survivable manner. This involved installing filler metal in the coolest possible way. Pad welding should never be used to close a breach in the tube wall. It should be used only to refurbish or thicken the thin area. Experience has proven that a properly installed pad weld on a tube will be less likely to fail than one below that threshold. Restoration of a tube wall is no different than what is considered overlay welding.

Best Practice—Great River Energy

Great River Energy provided the following information:

> We minimize pad welding as much as possible and make the proper repair to give long run times.

On-Line Instrument Monitoring

Thermal Monitoring

Thermocouples are designed for welding directly to boiler tubes. These thermocouples sense tube surface temperatures up to 2012°F (1100°C.) with a corrected minimum accuracy of ±2%. They are typically furnished with a 310 stainless steel sheath over the compacted magnesium oxide insulation, with type K wires. These thermocouples can be supplied with a Hastelloy X sheath material for superior resistance to the most corrosive atmospheres. Thermocouples are easy to install, yet rugged enough to withstand the roughest handling.

The next section introduces heat flux sensors. These sensors can be used in boiler water wall applications for detection of fouling (boiler fouling sensor).

Heat Flux Sensors

Heat flux sensors can be used in boiler water wall applications for detection of fouling (see Figures 9-7 through 9-10). These sensors measure the flow of energy to or from a certain object. Heat flux is expressed in BTU per square foot. In many boilers, the furnace walls suffer from fouling (also called *slagging*). In many cases, it is possible to put heat flux sensors on the water wall tubing. By monitoring the heat flux from the boiler to the steam/water mixture in the tubing, the process of fouling can be detected. An added thermocouple can also be used for estimating tube surface temperature (*chordal thermocouple*).

The total system leads to the following:

- Automation of the process of soot blowing (intelligent soot blowing)
- Better system efficiency
- Savings on servicing
- Optimal estimation of tube lifetime
- Extension of tube lifetime

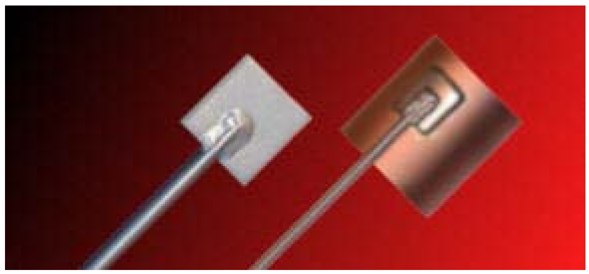


Figure 9-7
Heat flux sensors

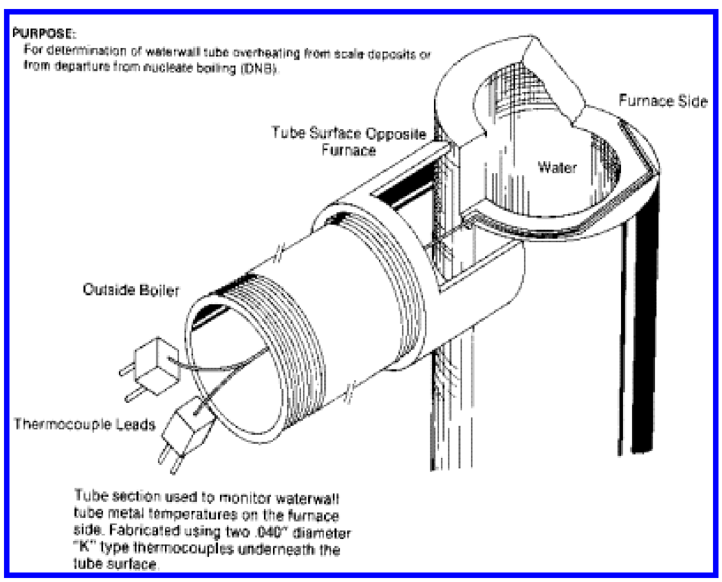


Figure 9-8
Boiler water wall with incorporated heat flux and temperature sensor. The sensor is connected to an external readout.

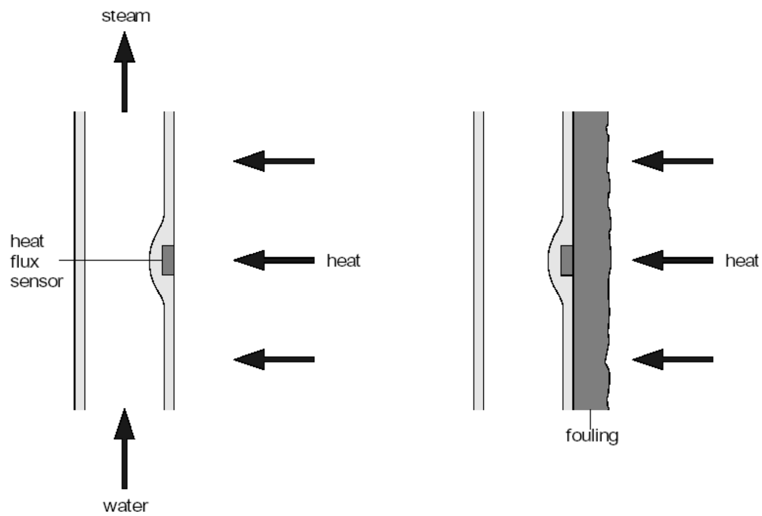


Figure 9-9
Heat flux sensor, showing how fouling affects heat transfer.

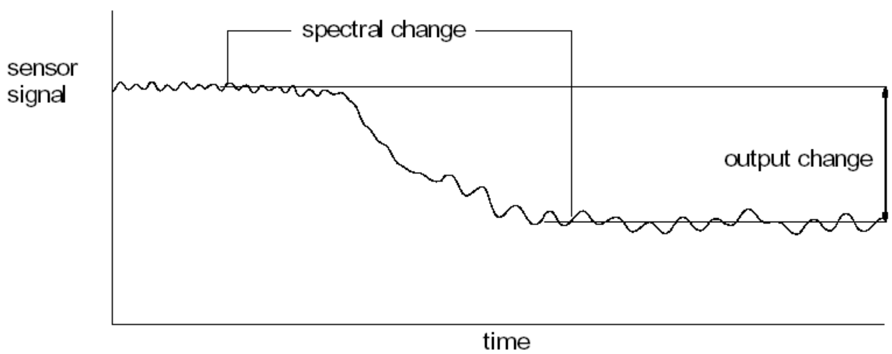


Figure 9-10
The heat flux signal, starting with a clean tube that gradually fouls. There is a change in heat flux level, and at the same time, the spectral content of the signal changes; the fast changes are damped by the added heat capacity of the soot.

10
SCIENTIFIC VALIDATION WITH CURRENT TECHNIQUES

Remaining Life Assessment Methodology

The science of determining a plant's actual condition and how much of its entire service life has been depleted lies in combining analytic considerations, calculation methods, relevant inspection, nondestructive tests, and destructive tests. An important basis for the results is the analysis of the actual operational data (such as temperature, pressure, and throughput), operational experience, and operational tenders.

A systematic approach that allows assessment of the plant's current operational capability and safety is possible only by correctly drawing a correlation between the operational load and swings and the actual status of the plant or its components, which has been obtained from tests and inspections. Based on these results, the correct actions for future procedures can be initiated. Our recommended remaining life assessment methodology is ordered in a three-level approach, as follows:

- Step 1. Collect design data.
- Step 2. Collect operating, maintenance, and inspection history.
- Step 3. Use a scientific approach based on the data collected in steps 1 and 2 in combination with quantified material properties.

Figure 10-1
Nondestructive material testing

Phased Array Technology

Phased array ultrasonics is a newer method of generating and receiving ultrasound. Instead of a single ultrasonic element, it uses multiple ultrasonic elements and electronic time delays to create beams by constructive and destructive interference (see Figure 10-2). Ultrasonic phased arrays are similar in principle to phased array radar, sonar, and other wave physics applications. However, ultrasonic development is behind the other applications due to a smaller market, shorter wavelengths, mode conversions, and more complex components.

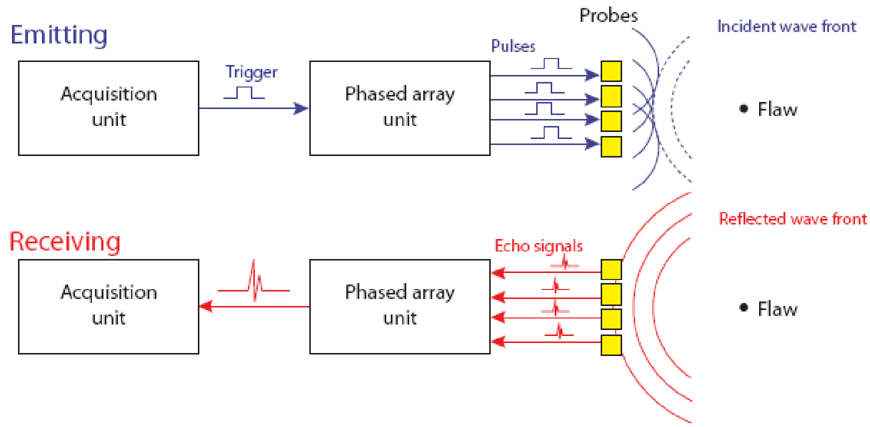


Figure 10-2
Phased array technology

The technique typically incorporates a multielement array transducer that generates a sweeping beam that can examine a part from various angles and focal points to create a detailed picture of internal conditions. Typical arrays have up to 128 elements, pulsed in groups of 8 to 16. The phased array beams can be steered, scanned, swept, and focused electronically. Using electronic pulsing and receiving provides significant opportunities for a variety of scan patterns. The two basic patterns are electronic and sectorial scans.

Electronic scans are performed by multiplexing along an array. Electronic focusing permits optimizing the beam shape and size at the expected discontinuity location, as well as optimizing the probability of detection. Sectorial scans use the same set of elements but alter the time delays to sweep the beam through a series of angles. Beam steering permits the selected beam angles to be optimized ultrasonically by orienting them perpendicular to the predicted discontinuities, such as lack of fusion in welds.

The phased array unit records full waveform data at multiple angles and positions and can display A, B, C, D, S, and combined scans. This gives much increased imaging capability. There is a special calibration process for phased arrays to ensure uniform signal strength across the array (and wedge).

Figure 10-3 illustrates the detection of misoriented cracks by a single-element probe (left) and a multielement probe (right). The sound beam is divergent and unidirectional for the single-element probe, whereas the multielement probe is multi-angled and can be focused. This increases the detection of most orientations of discontinuities, such as cracks, lack of fusion, and so on.

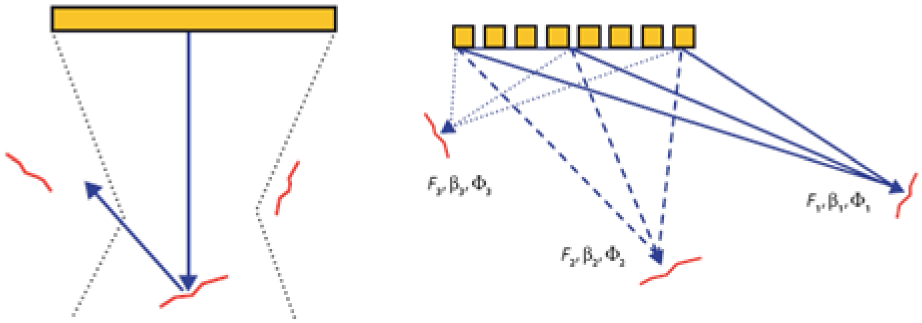


Figure 10-3
Single-element and multielement probes

Phased array ultrasonics has the following advantages over radiography:

- No radiation safety issues
- Better detection of planar defects
- Vertical sizing capability
- Near-real-time displays
- Great flexibility in parameter range
- Compliant with all known codes

Phased array ultrasonics has the following advantages over conventional ultrasonics:

- High speed, excellent data storage, and more cost effective (equipment costs are similar; higher instrumentation costs are offset by lower mechanical costs for phased arrays)
- Better imaging, displays, and interpretation
- Better probability of detection
- Easier defect sizing and much more flexibility
- Many more angles and scan patterns available
- High repeatability and reproducibility
- Easy and comprehensive reporting

Portable phased arrays are commercially and technically viable for a wide range of applications. They have major advantages for high-speed testing, setup flexibility, multiple test angles and wave modes, and limited access testing. They should be cost effective for a number of standard applications (such as welds), and standard code-compliant procedures should significantly increase their application. Overall, the use of phased arrays permits optimizing discontinuity detection and minimizing testing time.

Field Metallography

Field metallography describes the practice of performing microstructural analysis outside the metallurgical laboratory. It can include everything from grain sizing of titanium forgings on a production floor to steam boiler failure analysis on a ship. The process required involves all the specimen preparation procedures performed in the metallography laboratory. The environment in which field metallography is performed makes it a challenging endeavor. The equipment used in field metallography is quite diverse. For rough grinding, right-angle grinders or portable belt sanders are popular. Fine grinding and polishing can be accomplished with variable-speed drills or Dremel tools, which can be found at hardware stores. Portable electrolytic polishers and etchers are also used.

Figure 10-4
Indications identified on a header through field metallography

Field metallography begins with rough grinding of the selected area, followed by a 60-grit abrasive wheel. The beginning surface is often in a much poorer state than any surface found in the laboratory. Thick scale and rust must be removed in an area larger than the ultimate spot. Each area worked should be smaller than that worked in the previous step. This reduces the opportunity of dragging large particles across a prepared area.

Figure 10-5
Surface preparation

After rough grinding, several fine grinding steps occur. Fine grinding is performed with abrasives in the 80 through 600 grit range. As with metallography performed in the laboratory, each successive abrasive step should remove the surface scratches and deformations produced by the previous step.

The next step is polishing the surface. Similar to laboratory work, this is done with polishing cloths and compounds. Due to the importance of turnaround time frequently found on field metallography work sites, diamond compounds are preferred over other slower working products. Again, each polishing step should remove the scratches and deformation of the previous step. Proper etchant use after polishing is usually required to bring out the relevant microstructure. Extra care must be taken with these fluids because of the less-than-perfect locations requiring field metallography. A nital etchant is used, usually mixed in strengths of 2% to 7%.

Figure 10-6
Identified areas that might require additional testing

Analysis and documentation are the final steps in field metallography. A portable microscope is used for the field analysis, but complete documentation and laboratory analysis can be achieved with the cellulose acetate tape used with a replication technique. Prepared properly and secured in the field with glass slides, field replicas can be analyzed using scanning electron microscope magnifications with good results.

Superheater/Reheater Tubes Using Oxide Thickness Measurements

Superheater and reheater tubes operating at temperatures above 900°F (482°C) are subject to creep failure (see Figure 10-7). These tubes form an internal oxide layer that inhibits heat transfer through the wall and causes the tube metal temperature to increase over time. The thickness of this oxide can be used with unit operating data and wall thickness measurements to estimate the remaining creep failure life of a tube. Before 1986, the only method to measure this internal oxide was through the destructive removal of tube samples. The application of nondestructive evaluation methods makes it possible to evaluate a large number of tubes in a short time. By assessing a large number of tubes within a superheater/reheater, rather than assessing only a few tube samples, better decisions can be made regarding component replacements and the identification of unusual unit operating conditions.

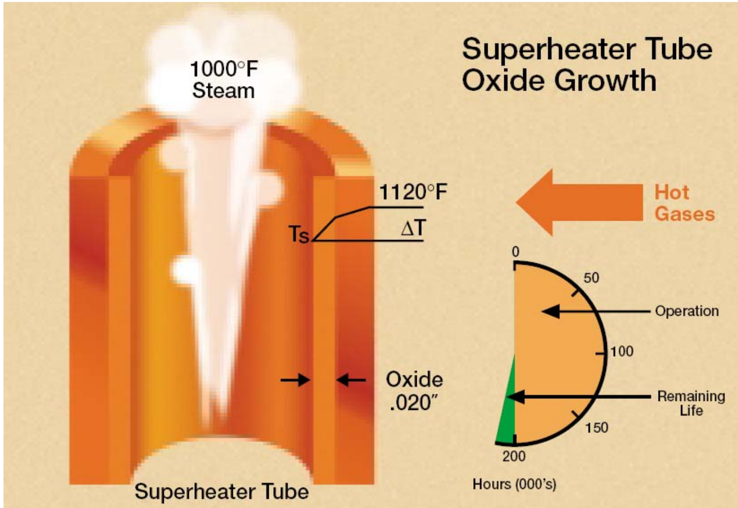


Figure 10-7
Oxide growth is an obstacle to efficient heat transfer

For alloy superheater tubes, such as SA-213 grades T11 and T22, stress and temperature are rarely constant throughout a tube's life. When a tube is new, the metal in contact with the steam begins to form a layer of magnetite (Fe304) scale. This oxide grows thicker in service, and its growth over time is dependent on metal temperature. This oxide layer is also an obstacle to efficient heat transfer; as its thickness increases, metal temperatures must also increase to maintain a constant outlet steam temperature. Typically, tube metal temperatures increase from 1°F to 2°F for each 0.001 in. of internal oxide formed. In addition to the metal temperature increase, tube wall thinning due to erosion, corrosion, or other wastage mechanisms can occur over time. This tube wall loss causes increased stress in a tube operating at a constant internal pressure. Allowing for these changing conditions of tube metal temperature and tube stress over time is key to reliable creep life prediction of alloy superheater tubes.

The prediction of remaining life due to creep limitations is based on published stress rupture curves and log stress versus Larson-Miller parameter (LMP) curves. At any given stress, failure will occur over a wide range of times, which in turn leads to the concept of minimum and mean failure curves. The most obvious benefit of using a nondestructive method to assess the remaining creep life of tubes is the large number of tests that can be conducted in a short period of time. Thus, decisions regarding the overall condition of a superheater/reheater can be based on a much broader and more representative sampling than could be accomplished economically through the destructive removal of tube samples. Also, a careful review of the oxide thickness, wall thickness, and remaining life data can provide much information about the operation of the unit.

The Larson-Miller parameter is given by the following equation:

$$LMP = (T + 460)\ (20 + \text{Log } t)$$

Where:

LMP is the Larson-Miller parameter

T is the temperature, °F (980°F)

t is the time to rupture, hours ($27 \times 365 \times 24 \times 0.85 = 2.0 \times 10^5$ hours)

20 is an empirical constant

For T = 980°F at 27 years, LMP = 36500.

In this example, the calculated Larson-Miller parameter and associated stress for rupture is well below the minimum creep stress rupture failure line for SA-213-T11 steel tubing based on the time and temperature information provided. Even if the actual maximum wall thickness hoop stress is used, the probability of failure is unlikely for a tube without external weldment attached.

As tube metal temperatures increase due to internal scale development or stresses increase as wall thinning increases hoop stress, the Larson-Miller parameter increases, and stress rupture becomes more likely (see Figure 10-8).

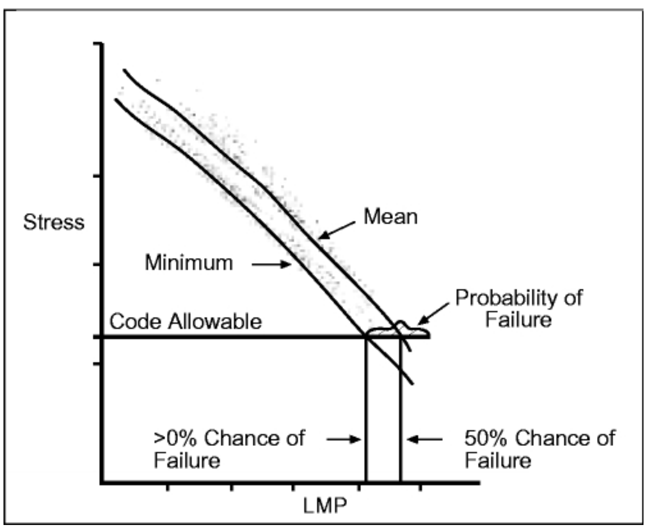


Figure 10-8
A stress versus Larson-Miller parameter plot, illustrating the statistical distribution of failure for a specific classification or grade of tubing.
Courtesy of David N. French Metallurgists and Engineers

Temperature Estimation

To begin estimation of tube creep life, the metal temperature in operation must be known. Metal temperatures are infrequently measured directly in boiler tubes. Fortunately, each tube contains a record of its thermal history in its internal (steam-side) oxide scale. Because the growth of this internal scale is a function of time and temperature, it provides a means for estimating the tube's average metal temperature. This is true of the intermediate chromium molybdenum (Cr-Mo) alloys containing up to about 9% chromium, carbon-molybdenum steels, and carbon steels.

A number of published algorithms are available for estimating metal temperature from oxide thickness data. These expressions typically cover the intermediate Cr-Mo alloys containing from 1% to 3% chromium, such as SA-213 grade T11 (1-1/4Cr-1/2Mo) and grade T22 (2-1/4Cr-1Mo). One of the most widely known formulas is the following, developed by Dr. David French (where X is the oxide thickness in mils, and t is the time in hours):

$$\text{Log } X = 0.00022(T+460)(20 + \log t) - 7.25$$

A mathematical model of the oxide growth rate can thus be defined, and a tube metal temperature that considers the insulating property of the oxide is then calculated.

A linear rate of wall thinning is determined for the tube. This rate is based on the present measured tube wall thickness, an assumed original tube wall thickness, and the hours that the tube has spent in service. The original tube wall thickness, because it is likely unknown, is assumed to be the minimum specified tube wall thickness plus the manufacturer's tube wall tolerance. A function describing wall thickness and time can then be defined, and a wall thickness in each time interval can be calculated. This predicted wall thickness is used with the tube diameter and operating pressure to calculate a stress for each interval of time.

With a stress and a temperature determined, the creep life is determined. Given the stress, the Larson-Miller parameter of failure can be found from the creep rupture database. Knowing the temperature and the Larson-Miller parameter of failure, the time a new tube would last at each set of conditions can be determined.

Oxide Thickness Measurement

The technique used for nondestructive oxide thickness readings is similar to standard ultrasonic wall thickness tests. A unique transducer, connected to a pulser receiver, is coupled to a tube's outside diameter surface, and a pulse of sound is directed into the tube. The reflections from the oxide-metal interface and the oxide-air interface are displayed on the equipment (see Figure 10-9), and the times of travel from the outside diameter surface to the metal oxide and oxide-air interfaces are measured. The time of flight measurements are then converted to wall and oxide thickness (see Figure 10-10). The technique provides a resolution of 1 mil and an accuracy of ±2 mil. Oxides as small as 4 mil can be measured using this system with proper surface preparation.

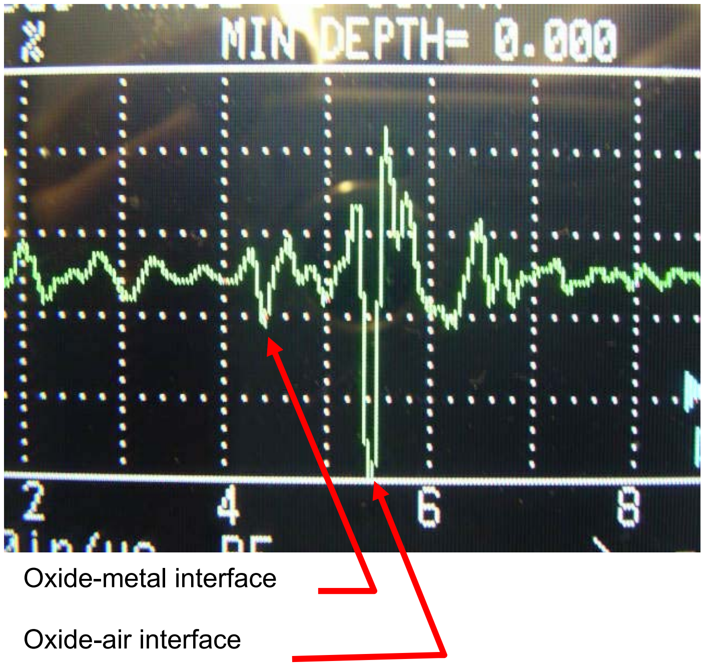


Figure 10-9
Reflections from the oxide-metal interface and the oxide-air interface

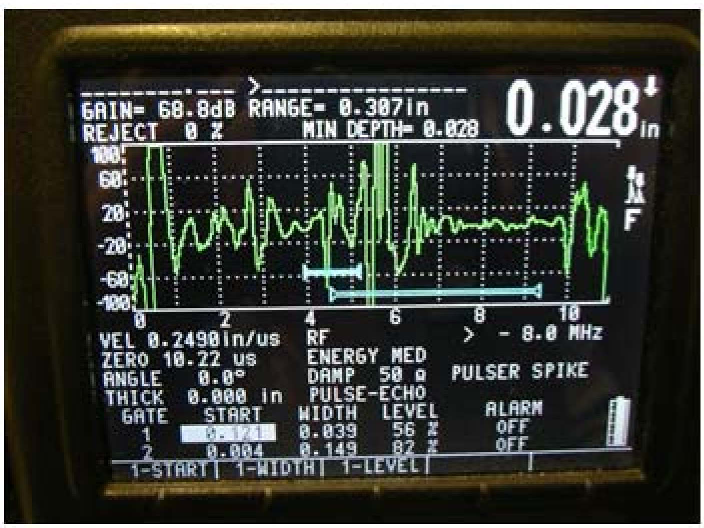


Figure 10-10
An oxide reading of 28 mil obtained by positioning the gates (shown in blue)
Courtesy of David N. French Metallurgists and Engineers

11 NONDESTRUCTIVE EXAMINATION

Nondestructive examinations (NDE) are essential constituents of any remaining life assessment program. The objective of such assessment is to compare the current condition of the material of a given component with its original condition to define the amount of deterioration of the component.

Three major questions have to be answered before starting NDE: Where? When? How?

The inspection techniques used depend on the component, the location on the component, the damage modes, and the material used. Some of the regularly used methods to establish the material condition provide data that can be quantified in analyses, whereas others can only indicate whether a defect is present.

Best Practice—Duke Energy

Duke Energy provided the following information:

> **NDE Coordinators:** Internal NDE coordinators manage the NDE vendors. This drives quality and productivity of the different vendors in the plant by having one focal point who understands NDE. This NDE coordinator is a corporate role that moves from outage to outage.

Inspection Plan

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 the following:

- Attemperators
- Deaerator
- Drums—steam, lower
- Headers—both steam and water
- Piping—steam and feedwater
- Tubing—superheater, generating, water wall, economizer

Inspection Checklists

Figures 11-1 through 11-29 provide examples of inspection checklists for various components.

TITLE: WALK DOWN (UNIT ONLINE)

HISTORY:

GENERAL: Thermal and audio devices will aide greatly during inspection

WALK DOWN (UNIT ONLINE) INSPECTION RECOMMENDATIONS:

1. Piping hangers. Record any excessive vibrations or limits of travel, and mark hot positions.
2. Inspect all valves for proper installation, flow direction, and leakage (sacrificial valves)
3. Inspect for valve packing leakage
4. Document all hanger positions for SH and RH steam lines
5. Monitor all blowers while charged to determine if there is condensate in the lines
6. Inspect blower system drains to ensure condensate is being adequately removed
7. Listen to all blowers between blowing cycles for bypass
8. Trace all blower supply lines for adequate pitch and inspect connecting hanger supports for damage
9. Center wall hanger springs. Record measurement of spring height between plates.
10. Furnace insulation/lagging. Record any casing rips cracks and leaks in lagging, and missing insulation.
11. Upper side wall water cooled doors; record any casing or seal leaks, water leaks from door cooling coils or water feed lines.
12. Furnace sidewall throat doors. Record any leaking seals or water feed lines.
13. Retract soot blowers and wall blower seal boxes/air lines. Record any corrosion, leaking air or oil, and cracked seal boxes.
14. Steam cooled wall access doors. Record any air leaks, casing tears or broken seals, and cracked seal boxes.
15. Integral duct, Wind box pant leg, hot/cold air to mills, AH bypass and flue gas ductwork. Record any casing tears, missing insulation, air/gas leaks and discoloration, loose hangers or leaking doors. Pay special attention to the expansion joints throughout the unit.
16. Site in all buckstays & guides. Record any cracked, twisted, thinned or corroded support beams, including the horizontal truss. Record any bound up buckstay guides and mark hot positions. Document all burned areas from gas leakage around buck stay stirrup bolts.
17. Pay close attention to the areas adjacent the pleated joint that allows expansion between the furnace and convection pass. The vertical stay in this area has a tendency to detach from the stirrup plates allowing the pleated joint to be pulled and cracked. NOTE: IN ORDER TO INSPECT THIS AREA THOROUGHLY THE LAGGING AND INSULATION WILL NEED TO BE REMOVED FROM THE UDAS TO THE PENTHOUSE FLOOR.
18. Inspect the slip plate expansion guides located behind the vertical buck stay that runs between the UDAS to the Penthouse. NOTE: IN ORDER TO INSPECT THIS AREA THOROUGHLY THE LAGGING AND INSULATION WILL NEED TO BE REMOVED FROM THE UDAS TO THE PENTHOUSE FLOOR.
19. Air heater motor. Record any oil leaks or grinding noise.
20. Wind box air damper drives. Record damper positions, disconnected Hagan drives or leaking shaft bushings.
21. Ductwork/Flues document all capsulhelic readings. (pressure)
22. Burner corner insulation/hot spots. Record any missing or tore insulation. Record "HOT" spots.
23. Check all drive shaft keys for play
24. Inspect all linkages for missing hardware, and note any linkages that are disconnected or binding
25. Check all gates adjacent the burner corner for coal leakage

Figure 11-1
Example walkdown inspection checklist (page 1)

26. Oil guns/igniters. Record any leaks from the gun or the gun supply hoses.
27. Leaking coal pipes/couplings/slide gates. Record corner, elevation.
28. Bottom ash hopper seal trough. Record any leaks in the plate, corrosion or hopper wall problems.
29. Inspect the seal trough for proper level and circulating flow
30. Document weir header pressure
31. Penthouse pipe penetration seals.
32. Inspect the Penthouse pressurization fan to ensure that it is working and open
33. Penthouse roof for breaches
34. Select criteria for control room data review and view trends recorded since the last scheduled maintenance outage
35. Check all safety valves for bypass and ensure the inspection plugs are capped and the drain lines are piped away from traffic areas
36. Inspect all boiler vents and drains for bypass
37. Document all expansion markers including the Drum positions
38. Solid hanger rods. Record any loose, broken hanger rods, nuts.
39. Spring hangers. Record hanger positions any broken or cocked springs, eroded cover boxes, or springs at the wrong height.
40. Boiler roof weather casing record any tears, cracks, or holes, sizes, repair.
41. Vent pipe and T/C penetrations. Record any leaks or tears in casing or insulation, leaks in flexible seal, and missing pick cable pipe caps.
42. Insulated links. Record any missing insulation or covers.
43. Relief valve penetrations. Record any leaks and missing casing or insulation.
44. Super structure beams. Record any broken, bowed, or twisted roof beams.
45. Sky climber cable pipe caps.
46. Thermocouples. (roof steel)

VALK DOWN (UNIT OFFLINE) INSPECTION RECOMMENDATIONS:

1. Penthouse roof beams once roof plates are removed. Record any broken, bowed, or twisted roof beams, and missing refractory under plating, spot UT, and use beam chart to identify.
2. Beam end connections. Record any broken or distorted connections, corrosion, etc.
3. Cross reference all expansion markers, drum positions, hangers, etc. in cold/hot position
4. Crosscheck for debris accumulation in seal trough

Figure 11-2
Example walkdown inspection checklist (page 2)

Best Practice—Midwest Generation

Midwest Generation provided the following information:

> When performing walkdown inside the boiler, look for areas of plugging. Depending on the length of the outage and the severity of the ash accumulation, have cleaners remove ash. This can be either by water blasting or sawing. Removing this ash will eliminate localized areas of fly ash acceleration and erosion. Also reassess the soot blower pressures in the area where the boiler was plugged.
>
> If an area of the boiler is plugged and there is no other reason to take the unit off line, consider on-line water blasting. This will eliminate a thermal cycle that would be needed to take the unit off to clean it; however, any other possible damage that could be done needs to be considered.

TITLE: ASH PIT

HISTORY:

GENERAL:

ASH PIT INSPECTION;

1. Water seal trough. Record any corroded plates, cracked welds, and missing or broken drain and vent piping, or ash & debris accumulation.
2. Clean the drip screen and seal skirt attachments to the bottom side of the Coutant for inspection, recommend sandblasting for time efficiency
3. Seal skit record any corrosion, holes, cracks, bent or broken stitch welds. May need to sandblast the water air interface (waterline) for UT mapping for thinning from possible galvanic corrosion
4. Drip screen. Record any tears or holes in screen, missing, burnt or broken brackets or screens.
5. Hopper bottom refractory. Record any cracked, spalled, eroded or missing refractory. Record any buckling in hopper walls, missing or blackened refractory may indicate damaged weir header or supply lines, in addition document missing or damaged refractory at the lower sidewall crotch area
6. Jetting nozzles inspect nozzles and shields for pluggage, and document nozzle positions. Note that the measured diameter should not exceed 1/8" over the original ID. Please note that nozzles must be directed parallel to walls.
7. Ash hopper weir header heat shield. Record any cracks in directional plate or plugged nozzles.
8. Crickets. Record any missing or cracked angle iron on divider. Refractory on cricket (cricket is the apex of the division slope between hoppers)
9. Hopper water over flow weir box. Record any sediment build up. Inspect for corrosion of the weir box itself, also remove the outside cover to ensure the cavity is clear
10. Inspect the clinker grinder gate for damage, record cracks, holes, missing refractory (if applicable)

Figure 11-3
Example ash pit inspection checklist

TITLE: COUTANT

HISTORY: Cold side failures due to corrosion fatigue, impact damage and erosion in Coutant area, degradation of Deflection Arch casing and fins

GENERAL: Elevations for documenting repairs is most easily referenced by number of feet from the apex of the throat tubes, i.e.; Rear Coutant tube 75, 25% reducing I.D. dent approximately 13' measured from the apex of the Coutant towards the rear wall.

COUTANT TUBES INSPECTION RECOMMENDATIONS:

1. Bowing or tube to tube mismatch, reducing I.D. dents 15% or greater, record beginning and ending elevations, tubes involved, and severity of displacement. Not all impact damage needs to be removed, if the tube I.D. or MWT has not been effected there is minimal danger of failure
2. Inspect for overheating; three indicators are blackened tube appearance, elephant/alligator hide, and bulging. Record tube number, length of indication, and elevation.
3. Record improper membrane; welds, mismatch, cracking, improper membrane termination's (max. 3/8" radius), propagation cracks (transverse) towards tube. Elevation and adjacent tube numbers should be noted.
4. For erosion record flats (spot "UT" thickness examine), pitting, tube, elevation, description, wall loss >20%.
5. Previous pad & seal welds. Record cracking, improper weld technique (horizontal weave, weld, undercuts, excessive reinforcement), steam cuts, tube, thickness, elevation, and length. Due to past plant procedure of pad weld repairing dent tubes, recommend all pad welds in the Coutant area be scheduled for replacement, dents without actual wall loss should either be removed or left alone, never weld repaired.
6. For circumferential or quench cracking. Record tube number, elevation, and severity of cracking.
7. Slope bends. Record tube dents or gouges, depth, surrounding wall thickness, elevation, tube, length.
8. Record any gouges, flat spots, erosion, or dents from slag fall. Typically the impact damage is more prevalent on the rear Coutant along the throat, sidewalls, and transition bends to rear wall. At a minimum the listed areas should be UT mapped every outage to establish erosion trends.
9. Slope to sidewall seal. Record cracks and record, tubes, elevations, & furnace.
10. Record quench cracking typically resulting from slag fall splash, differential temperatures between supply water and furnace temperatures, and damaged weir header system.
11. Seal plate scallop bar, and drip screen to tube welds. Record cracking in welds (propagation), deformation, tube, and location. Estimate length of material and sketch
12. Pitting on the underside of the Coutant throat tubes from corrosion, should be documented; tubes, location, length, depth, and NDT
13. Pitting on the upper side from reducing atmosphere; record, tube, length, elevation, severity, NDT
14. Inspect for misapplication of materials such as all thread bar as wear bars, the threaded sections of the bar will ultimately crack and propagate into the tube.
15. If applicable inspect all wear bar for propagating cracks; record, tube locations, elevation

Figure 11-4
Example coutant tube inspection checklist

TITLE: Water wall Inlet Headers Insp.

HISTORY:

WATER WALL INLET HEADER INSPECTION RECOMMENDATIONS:

1. Water wall inlet header terminal tube welds. Record any crack indications and paint any nipple welds that need cleaned for PT/MT.
2. If the units share combined blow down tanks inspect header adjacent the drain lines for thermal fatigue cracking caused from back tracking steam
3. Leave drains fully open to ensure no debris is preventing full drainage, check for standing water
4. Header supports, record any loose, bent, or missing rods or plates.
5. Record any bowed tubes and severity of bowing visible through the orifice plates; this typically appears to be accumulation of water in the tubing.
6. Inspect the face of the doors for adequately rough surface to maintain gasket seal
7. Ensure the lock nuts and safety retaining bolt are in place on the door swing arm, this will prevent the door from falling off the swing arm
8. Inspect for corrosion cracking typically found in the welds of the Down Comers, Crossover Links, drain penetrations, tube penetrations, and attachment welds. NOTE: 2003 REPORTS DOCUMENTED CORROSION ASSISTED CRACKING AROUND THE CROSSOVER LINKS, THIS AREA SHOULD BE CLOSELY MONITORED AND SHEARWAVE TESTED TO ENSURE THE CRACKS ARE NOT PROPAGATING.
9. Inspect the Drum shell and heads for signs of notching, gouges and/or nicks, record location and depth.
10. Inspect for pitting on drum bores (tube penetrations)
11. Cleanliness- look for debris, magnetite, oxide, or copper deposits
12. Blocked and or missing orifice plates
13. look for swelled terminal tubes as a sign of overheat
14. Check for water lay up in tube penetrations, this will help identify structural failure and or misalignment
15. Inspect all screens as well as attachment hardware, document loose, missing and corroded

Figure 11-5
Example water wall inlet header inspection checklist

TITLE: STEAM AND COLLECTOR DRUMS

HISTORY:

GENERAL:

STEAM AND COLLECTOR DRUMS INSPECTION RECOMMENDATIONS:

1. Record any crack indications and paint any Welds that need cleaned for PT/MT.
2. Leave drains fully open to ensure no debris is preventing full drainage, check for standing water
3. Drum supports record any loose, bent, or missing rods or plates.
4. Record any bowed tubes and severity of bowing.
5. Inspect the face of the door for adequately rough surface to maintain gasket seal
6. Ensure the lock nuts and safety retaining bolt are in place on the door swing arm, this will prevent the door from falling off the swing arm
7. Inspect for corrosion cracking typically found in the welds of the Down Comers, Crossover Links, drain penetrations, tube penetrations, and attachment welds.
8. For gouges and/or nicks, record location and depth.
9. Inspect for pitting on the inside diameter of the tube penetrations, heads, and shell
10. Cleanliness, look for debris, magnetite, oxide, or copper deposits
11. Cracks and deformation of liner, conduct wet box test
12. Check for water lay up in tube penetrations, this will help designate structural failure and or misalignment, resulting in possible pitting
13. Document missing or loose bolts, nuts, and washer
14. Inspect feed water supply lines, chemical feed lines etc. for alignment, corrosion and degradation
15. Inspect all crossover steam lines for valve bypass

Figure 11-6
Example steam and collector drum inspection checklist

TITLE: WATER WALLS

HISTORY:

GENERAL: The furnace should be full scaffold for a thorough inspection as well as for accessibility reasons; up front the cost is more significant however the ability to perform multiple tasks in all areas of the furnace safely is more cost efficient in the long run.

WATER WALLS INSPECTION RECOMMENDATIONS:

1. For slag. Inspect water walls for excessive slag buildup and any unusual slag patterns (i.e. color, texture) prior to deslagging or cleaning of the furnace. Record thickness, length, width of buildup, and elevation.
2. For bowing. Record beginning and ending elevations of bowed or misaligned tubes or panels, tubes involved, and severity of displacement. NOTE: CORRELATE BOWED TUBING TO THE BOILER EXTERNAL AND CHECK ALL BUCKSTAY STIRRUPS AND BOLTS FOR DAMAGE
3. For overheating. Three indicators are blackened tube appearance, elephant hide, and bulging. Record tube number, length of indication on tube, and elevation. NOTE: THE REMOVAL OF JUST ONE BOILER CIRCULATING PUMP FROM SERVICE MAY CAUSE BULGING "OVERHEAT" IN THE FURNACE WALLS
4. Membranes. Record incomplete membrane welds, proper membrane termination's (max. 3/8" radius), crack propagation (transverse, longitudinal, @ tube), length, tube (between, on), and elevation. NOTE: MEMBRANE WELDS ARE NOT ONLY A SEAL BUT ALSO PART OF THE STRUCTURAL SUPPORT OF THE BOILER, MEMBRANE WELDS SHOULD BE COMPLETE ON BOTH HOT/COLD SIDES OF THE WATER WALLS
5. Around soot blowers. Record erosion (spot UT), flat or pitting, membrane (cracks, width > 3/4"), circumferential tube cracking (severity), tube, length, location, retract or soot blower, wall loss > 20%, pre blow.
6. For fireside corrosion. Tubes are worn flat or pitted (spot UT). Record alligator hide, tube, elevation, panel (type, material), tube wall loss > 20%. Sandblast 3" bands around the perimeter of the firebox at intervals of 6' to monitor for fireside corrosion and erosion, pay special attention to areas that the fuel nozzle appear to have been flame impinging the adjacent walls
7. Previous pad welds. Record cracks, horizontal weave (weld technique), undercut, excessive reinforcement, steam cuts, tube, elevation, and length.
8. Inspect for improper window weld repairs, document; tube number, location, and elevation. NOTE: ALTHOUGH WINDOW WELDS ARE AN ACCEPTED FORM OF REPAIR, ALL WINDOW WELDS ARE RECOMMENDED FOR REPLACEMENT
9. Sand blast 3" bands in 1' intervals in all water cannon and water lance areas to inspect for quench cracking, or circumferential tube cracking. Record tube number, elevation, severity of cracking.
10. For tube shotgun dents or gouges. Record depth, surrounding wall thickness, and elevation. Usually due to deslagging, also document tool marks and scaffold abrasion. NOTE: THE USE OF CLASS III EXPLOSIVE NOZZLE SHOTGUN SHELLS DRASTICALLY DECREASES IMPACT DAMAGE FROM SHOTGUN CLEANING
11. All welds record cracks with tube numbers and elevation.
12. Perform a close up Deflection Arch elevation inspection for cracked peg fin/membrane, missing refractory erosion flats, corrosion, swelling, and pinhole leaks in tubes.
13. Remove all lagging and insulation from the top and bottom sides of the Wind box at the connection to water walls, and 4' around the burner corner attachment to the water walls. The area adjacent all connecting water wall attachments should be sandblast clean for visual and possible radiography inspection for corrosion fatigue cracking. In addition the plate that covers the dead air void between the wind box and the burner corner connection to the water walls should be removed to inspect the gusset plates and tie back bars for integrity as well as corrosion fatigue cracking.
14. Inspect for corrosion pitting on wall tubes below wall blowers and soot blowers. Pitting in this area is indicative of water (condensate) leaking through the system and corroding the adjacent wall tubes.

Figure 11-7
Example water walls inspection checklist (page 1)

15. Around observation ports. Record tubes worn flat or pitted, erosion (spot UT), corrosion, membrane cracks termination's, (contour), pad welds (proper material), circumferential tube cracks, length, elevation, tube wall loss > 20%. NOTE: THE TERMINATIONS OF FIN IN THIS AREA ARE NOTORIOUS FOR THERMAL FATIGUE CRACKS AND SHOULD BE CLEANED THOROUGHLY FOR INSPECTION
16. Upper arch (Deflection Arch) on the rear wall, soot blowers frequently erode the upper arch @ the lower bend. Record tube numbers, U.T. readings, length of erosion, elevation, and materials.
17. Document all pad weld repaired areas, if under deposit corrosion exists in the unit, the underside of the Deflection Arch is typically the most severely affected. Remove samples of pad weld repaired sections of tube in this area for analysis.
18. Inspect the center wall seals for cracks and holes that would allow for channeled erosion or propagating cracks into tube
19. Lower slope/sidewall membrane termination. Inspect membrane termination for cracking.
20. Inspect embedded thermo couples for cracking
21. Refractory @ upper arch transition bends from rear wall into nose record missing refractory, missing or eroded peg fins.
22. Upper arch tubes for gouging. Gouging may occur due to small clearance between arch floor and elements. Record tube and depth of gouge. NOTE: IF ABRASION IS EVIDENT IN THIS AREA CROSSCHECK HANGERS AND SUPPORT SYSTEM FOR THE PARTICULAR COMPONENT
23. Erosion cracking at peg fins. Record (spot "UT" thickness examine), cracking, tube, elevation, tube wall loss > 20%.
24. Existing tube shields record shields eroded through, missing (if missing "UT" thickness examine tube), loose, turned, tube, elevation, tube wall loss > 20%. (typically located at roofline)
25. Previous pad welds. Record cracks, horizontal weave (weld technique), undercut, excessive reinforcement, steam cuts, tube, thickness, elevation, and length.
26. For retract erosion. Tubes are worn flat (spot "UT" thickness examine). Record tube, soot blower, elevation, tube wall loss > 20%.
27. Seal @ sidewalls. Record bowing, cracking. Use sidewall tubes as reference for cracking.
28. Upper arch tubes for shot gun dents. Shot gun dents occur when the boiler is being deslagged while on-line. Record tube and depth of dent. Make note of any cracking.
29. Seal @ sidewalls. Record bowing, cracking. Use sidewall tubes as reference for cracking.
30. Erosion or cracking at membranes. Record (spot "UT" thickness examine), cracking, tube, elevation, tube wall loss > 20%.
31. Conduct UT scan across the upper slope of the Deflection Arch for erosion; typically located at the apex of the Deflection Arch and the slope section between the Hangers and Screen tubes
32. Inspect the side walls at intersection of the Deflection arch for fly ash erosion
33. Tubes @ access openings. Record erosion (spot "UT" thickness examine), flat or pitting, membrane (cracks, width > 3/4"), circumferential tube cracking (severity), tube, length, & location.
34. Previous pad welds adjacent access openings. Record any cracks, improper weld technique (horizontal weave, undercut, excessive reinforcement), steam cuts, tube, thickness, elevation and length.
35. Refractory at access openings & doors record any missing refractory.
36. Inspect for erosion in fusion welds, document tubes and elevation
37. Inspect burner crotch plates and record incomplete membrane welds and cracking (termination's (max. 3/8" radius), propagation), length of crack, elevation, and adjacent tube numbers, as well as missing or distorted plate
38. Look for missing refractory adjacent to burner compartment openings
39. Document all previous pad welds and apparent tube replacements adjacent burner corners and in the tube crotch area, these locations are also notorious for tube failures resulting from corrosion fatigue.
40. Physically feel the inside radius bends of the burner offset tubes for coal particle erosion
41. Inspect for "star burst", arc strikes on tube surface, record location, tube count, elevation
42. Spot UT the front tangential walls (corner walls) at penetration through the roofline, this area is typical for erosion

Figure 11-8
Example water walls inspection checklist (page 2)

TITLE: REAR WALL HANGER TUBES

HISTORY:

GENERAL:

REAR WALL HANGER TUBES INSPECTION RECOMMENDATIONS

1. Hanger tubes @ alignment straps. Record, corrosion, cracking, gouging, fretting (spot "UT" thickness examine), tube number, elevation, tube wall loss > 20%.
2. Hanger tubes for overheating/creep. Record bulging or bottle necking (overheat), tube number, elevation, and measure outside diameter of tube.
3. Existing tube shields. Record shields eroded through, missing ("UT" thickness examine tube), loose, turned, tube, elevation, tube wall loss > 20%.
4. For erosion @ upper arch transition. Record erosion (spot "UT" thickness examine), tube number, elevation, tube wall loss > 20%. NOTE: TYPICALLY THE GAS SIDE OF THE HANGERS @ INTERSECTION TO THE DEFLECTION ARCH SLOPE ARE ERODED FROM FLY ASH EROSION AS THE REAR SIDE OF THE HANGERS IN THE SAME LOCATION ARE ERODED FROM SOOT BLOWER EROSION
5. Look for fly ash erosion adjacent the roofline, spot UT document tube count, locations, lengths
6. Previous pad welds. Record cracks, horizontal weave (weld technique), undercut (> 1/32"), and excessive reinforcement, steam cuts, tube, thickness, elevation, and length.
7. For retract blower erosion; record flats (spot "UT" thickness examine), Record erosion, tube, retract blower, elevation, tube wall loss > 20%. Pay particular attention to the access openings near each sidewall.
8. Bowed (overloaded). Record all tubes bowed greater than 6". These tubes may be overloaded when the unit is hot. Record tube, elevation affected, and amount of bowing.
9. Inspect the intersection of Hanger tubes to the Reheat assemblies for abrasion

Figure 11-9
Example rear wall hanger tube inspection checklist

TITLE: Screen Tubes Inspection

HISTORY:

GENERAL:

SCREEN TUBES INSPECTIONS RECOMMENDATIONS:

1. Cracking, corrosion, & erosion. Record (spot "UT" thickness examine), tube, elevation, tube wall loss > 20%. (Attention should be directed where the refractory baffle is missing or broken.)
2. For bowing > 6". Record tube, beginning and ending elevations of bowing, and severity of displacement. NOTE: SEVERE BOWING IN THIS AREA MAY INDICATE STRUCTURAL FAILURE OR IMPROPER CYCLING
3. For retract erosion; tubes are worn flat (spot "UT" thickness examine). Record tube, retract, elevation, tube wall loss >20%.
4. Previous pad welds; record cracks, horizontal weave (weld technique), undercut, excessive reinforcement, steam cuts, tube, thickness, elevation, and length.
5. Existing tube shields. Record shields eroded through, missing (if missing "UT" thickness examine tube), loose, turned, tube, elevation, tube wall loss > 20%.
6. Arch floor refractory baffle. Sketch missing locations, include length. Estimate pounds of refractory. Inspect any exposed tubes for jackhammer scars, fly ash erosion.
7. Abrasion @ alignment bars. Record severity of abrasion (depth). Include tube number, letter designation, elevation, and direction (left, right, etc.).
8. Fly ash erosion located @ roof penetrations, and adjacent the top of the refractory pier
9. Document damage to refractory pier, record adjacent screen tube sets, size and repair, including a sketch and approximate material needed

Figure 11-10
Example screen tube inspection checklist

TITLE: FUEL & AUXILIARY AIR COMPARTMENT (BURNER CORNER)

HISTORY:

GENERAL:

BURNER AND AUXILIARY AIR COMPARTMENT INSPECTION RECOMMENDATIONS:

1. Coal buckets. Record whether nozzle is a one piece or two piece (removable nozzle) designs. Record any erosion, overheating, ash, coke, or slag buildup, cracking, and proper left to right alignment of buckets and splitter plates, vertical tilt angle (use a magnetic protractor).
2. Coal pipe and stationary nozzle erosion. Record any obvious coal pipe elbow / stationary nozzle erosion. Dorsal fin to be at the top of stationary nozzle.
3. Auxiliary air buckets. Record any erosion, overheating, ash or slag buildup, cracking, and proper left to right alignment, and vertical tilt angle (use a magnetic protractor).
4. Inspect compartment division plates for tears or cracking. NOTE: COMPARTMENT PLATES THAT ARE TEARING FREE FROM THE COMPARTMENT INDICATE POSSIBLE STRUCTURAL FAILURE, SUPPORTING HANGERS ETC. SHOULD BE CHECKED
5. Measure clearances between all four sides of nozzle to ensure proper alignment
6. Inspect all retaining feet on the fuel pipe and ensure that all feet are bottomed out against the compartment separation plate, this prevents misalignment of the fuel pipe
7. Manually operate all scarf plates to ensure proper seal around fuel nozzles
8. Inspect all connecting pins for erosion
9. Document locations of possible roping in the fuel line and nozzles
10. Oil gun. Record any overheating, ash buildup or pluggage of gun nozzle, measurement from nozzle to face of bucket.
11. Oil gun diffuser. Record any overheating, deformation, or fouling.
12. Air turning vanes. Record any cracks, erosion (originally 3/8" thick), broken vanes (not directing air out of the Wind box, can inspect from Wind box pant legs).
13. Scanners / flex hoses. Record any kinking, holes, or overheating. Review plant maintenance records.
14. Erosion of tubes adjacent the burner plate (carry over) NOTE: CARRY OVER IS INDICATIVE OF DETERIORATED SEALS IN THE AIR HEATER

IGNITER INSPECTION RECOMMENDATIONS:

1. Igniter horns. Record any cracking, pluggage, deformation, and centering of horn (tabs, stops, clearances).
2. Spark plug, nozzle and differential pressure ports. Record any slagging or pluggage of ports. The nozzle must be vertical in horn.
3. Horn set back. The igniter horn must be set back behind the center line of tubes.

Figure 11-11
Example fuel and auxiliary air compartment inspection checklist

TITLE: SUPERHEAT DIVISION PANELS

HISTORY:

GENERAL: For thorough inspection and baseline data the SHDP will need to be accessed from scaffold built from the dance floor adjacent the Deflection Arch to the roofline

SUPERHEAT DIVISION PANELS INSPECTION RECOMMENDATIONS:

1. Lower loops; record wastage, liquid phase corrosion, cracks, shot gun dents (depth), pad welds (heavy or magnetic), crack severity, tube wall loss > 20%, tube, platen, elevation, clearance to rear wall "bull nose".
2. Identify dented stainless steel tubes to be removed due to possible internal cracking
3. Inspect all DMW's, this will need to be conducted with NDT (RT)
4. For erosion typically @ misaligned tubes. Record tube wall loss > 20% (spot "UT" thickness examine), tube, platen, length, elevation.
5. For retract wash. Record washed tubes (spot "UT" thickness examine), flats, pitting, (bowed tubes and horizontal wrapper tubes are most prone), wall loss > 20%, tube, platen, length, elevation, retract number.
6. For bowing; record tube bow > 1 diameter, abrasion (tube to tube), tube, platen, length, elevation.
7. Flex ties. Record ties cracked, missing, gouging (depth), tube wall loss > 20%, tube, platen, elevation.
8. Scissors tubes (horizontal wrapper tubes); record missing, cracking, abrasion, erosion (@ rear scissors to scissors crossovers, and tubes to scissors), tube, platen, length, tube wall loss > 20%. NOTE: ENSURE ALL THREE PARTS OF THE ALIGNMENT SYSTEM FOR THE WRAPPER TUBES ARE IN PLACE; SUPPORT CLIP, ALIGNMENT CLIP, RETAINING CLIP
9. Tube shields; (abrasion shields) are @ water cooled spacers. Record shields eroded through, burnt, missing ("UT" thickness examine tube), loose, tube wall loss > 20%, tube, platen, elevation.
10. Rear fluid cooled spacer. Record tube wall loss > 20% (abrasion @ lugs (fretting) and rear two platen tubes, or between spacer tube and rear two platen tubes), missing or cracked lugs (support, spacer, hold down), pad welds (cracked, heavy, magnetic), erosion, retract wash, tube, platen, length, elevation. NOTE: ENSURE ALL THREE PARTS OF THE ALIGNMENT SYSTEM FOR THE WRAPPER TUBES ARE IN PLACE; SUPPORT CLIP, ALIGNMENT CLIP, RETAINING CLIP
11. Shot gun dents @ lead tube. Record any dents from shotgun deslagging.
12. Slagging. Record slag buildup on the platens. Slag will build up at the scissor tubes and at any bowed tubes. Record element, tubes involved, elevation, and amount of slag.
13. Old pad welds. Inspect old pad welds for undercut or cracking. Pay particular attention to the 347-H Stainless loops because they are more prone to cracking.
14. Inspect the front alignment tube, (knuckle tube) that ties the SHDP into the front wall for abrasion, erosion, corrosion, overheat. NOTE: THE UPGRADED ROLLER STYLE KNUCKLE TUBE ELIMINATES ABRAION ISSUES IN THIS AREA
15. Inspect roof tubes for polishing, spot UT
16. Inspect High Crown Seals for cracks and holes, if applicable document missing refractory

Figure 11-12
Example superheat division panel inspection checklist

TITLE: SUPERHEAT PENDANT PLATENS

HISTORY:

GENERAL: This area will need to be accessed via scaffold towers built from the dance floor located adjacent the Deflection Arch

SUPERHEAT PENDANT PLATENS INSPECTION RECOMMENDATIONS:

1. Lower loops record; wastage, liquid phase corrosion, cracks, shot gun dents (depth), pad welds (heavy or magnetic), crack severity, tube wall loss > 20%, tube, platen, elevation, clearance to rear wall "bull nose".
2. For erosion, typically @ misaligned tubes. Record tube wall loss > 20% (spot "UT" thickness examine), tube, platen, length, elevation.
3. For retract wash record washed tubes (spot "UT" thickness examine), flats, pitting, (bowed tubes and horizontal wrapper tubes are most prone), wall loss > 20%, tube, platen, length, elevation, retract.
4. For bowing record tube bow > 1 diameter, abrasion (tube to tube), tube, platen, length, elevation.
5. Flex ties (slip spacers) record ties cracked, missing, gouging (depth), tube wall loss > 20%, tube, platen, elevation.
6. Scissors tubes located rear of the horizontal wrappers for the scissors; record missing, cracking, abrasion (@ rear scissors to scissors crossovers, and tubes to scissors), tube, platen, length, tube wall loss > 20%. NOTE: ENSURE ALL THREE PARTS OF THE ALIGNMENT SYSTEM FOR THE WRAPPER TUBES ARE IN PLACE; SUPPORT CLIP, ALIGNMENT CLIP, RETAINING CLIP
7. Tube shields record shields eroded through, burnt, missing ("UT" thickness examine tube), loose, tube wall loss > 20%, tube, platen, elevation.
8. Rear fluid cooled spacer. Record tube wall loss >20% (abrasion @ lugs (fretting) and rear two platen tubes, or between spacer tube and rear two platen tubes), missing or cracked lugs (support, spacer, hold down), pad welds (cracked, heavy, magnetic), erosion, retract wash, tube, platen, length, elevation. NOTE: ENSURE ALL THREE PARTS OF THE ALIGNMENT SYSTEM FOR THE WRAPPER TUBES ARE IN PLACE; SUPPORT CLIP, ALIGNMENT CLIP, RETAINING CLIP
9. Shot gun dents @ lead tube. Record any dents from shotgun deslagging. The outside tube is especially important because it is stainless steel.
10. Slagging. Record slag buildup on the platens. Refuse will build up at the scissor tubes and at any bowed tubes. Record element, tubes involved, elevation, and amount of slag.
11. D.M.W. Welds. Inspect the welds at the tube material changes for cracking. Record element, tube, and elevation. NDT will have to be performed in order to detect initiating cracks since DMW's fail from the I.D.
12. Old pad welds. Inspect old pad welds for undercut or cracking. Pay particular attention to the 347-H stainless loops because they are more prone to cracking.
13. Inspect the gas side of the assemblies adjacent the roofline for erosion
14. Inspect roof tubes for polishing, spot UT
15. Inspect High Crown Seals for cracks and holes, if applicable document missing refractory

Figure 11-13
Example superheat pendant platen inspection checklist

TITLE: SUPERHEAT FRONT PENDANT (HTSH)

HISTORY:

GENERAL: Scaffold will need to be erected for access to all blowers and the roofline

SUPERHEAT FRONT PENDANT ASSEMBLIES INSPECTION RECOMMENDATIONS (HTSH):

1. Inspect outlet header and connecting links closely for signs of overheat due to increased surface area
2. Front and rear water cooled spacer record bowing, soot blower erosion, and abrasion. NOTE: ENSURE ALL THREE PARTS OF THE ALIGNMENT SYSTEM FOR THE WRAPPER TUBES ARE IN PLACE; SUPPORT CLIP, ALIGNMENT CLIP, RETAINING CLIP
3. Flex ties record missing, cracked, disengaged, gouging, or binding flex ties, tube, element, elevation, tube wall loss > 20%.
4. Dissimilar metal welds visual cracks have already failed, NDT for internal cracking initial stage of failure
5. Alignment, bowing. Record tube bowing > ½ diameter, and clearance to arch
6. Roof tubes (this area may not be accessible) record missing refractory, burnt or missing high crown seal heat shields, penetrations through the ceiling (tube to tube abrasion), tube wall loss > 20%, roof droop > 1 tube diameter.
7. Lower loops physically touch every lower loop near the front bend for deformation. Spot "UT" thickness examines most severe flats. Record locations of flat, pitted tubes, and worn shields.
8. Vertical tubes. Record slag deposits, exfoliation, retract wash, pad welds (cracked, heavy, magnetic), abrasion, shotgun dents (stainless tubes), tube wall loss > 20%.
9. Overheat/blockage. Record black or red overheated tubes (especially @ outlet tubes); check for bulging tubes indicating overheat, possibly due to pluggage, may also appear to have alligator/elephant hide
10. Slagging record slag deposits on the elements. Record amount, element, tubes involved, bowing (if any), and elevation
11. Old pad welds. Record old pad welds. Pay particular attention to any pad welds on the 347H stainless steel tubes because these are prone to cracking.

Figure 11-14
Example superheat front pendant inspection checklist

TITLE: SUPERHEAT REAR PENDANTS (LTSH)

GENERAL: Scaffold will need to be erected for access to all blowers and the roofline especially for UT mapping of the roof tubes

SUPERHEAT REAR PENDANT ASSEMBLIES INSPECTION RECOMMENDATIONS:

1. Front and rear water cooled spacer record bowing, soot blower erosion, and abrasion. NOTE: ENSURE ALL THREE PARTS OF THE ALIGNMENT SYSTEM FOR THE WRAPPER TUBES ARE IN PLACE; SUPPORT CLIP, ALIGNMENT CLIP, RETAINING CLIP
2. Inspect tube-to-tube alignment bars for abrasion, the scalloped plate and pin arrangement should be considered for replacement with the high temperature cast arrangement to eliminate abrasion and erosion
3. Flex ties/lugs record missing, cracked, disengaged, gouging, or binding flex ties, tube, element, elevation, tube wall loss > 20%.
4. Alignment, bowing. Record tube bowing > ½ diameter, and clearance to arch
5. Roof tubes this area may not be accessible. Record missing refractory, burnt or missing high crown seal heat shields, penetrations through the ceiling (tube to tube abrasion), tube wall loss > 20%, roof droop > 1 tube diameter.
6. Roof tubes in this area known erosion problem UT map roof tube section compile past and present for trending
7. Lower loops physically touch every lower loop near the front bend for deformation. Spot "UT" thickness examines most severe flats. Record locations of flat, pitted tubes, and worn shields.
8. Vertical tubes. Record slag deposits, exfoliation, retract wash, pad welds (cracked, heavy, magnetic), abrasion, shotgun dents (stainless tubes), tube wall loss > 20%.
9. Overheat/blockage. Record black or red overheated tubes (especially @ outlet tubes); check for bulging tubes indicating overheat, possibly due to pluggage, may also appear to have alligator/elephant hide
10. Slagging. Record slag deposits on the elements. Record amount, element, tubes involved, bowing (if any), and elevation.
11. Old pad welds. Record old pad welds. Pay particular attention to any pad welds on the 347H stainless steel tubes because these are prone to cracking.
12. Inspect horizontal stretches for fly ash erosion along rear wall and the crossover tubes between vertical sections
13. Inspect outlet headers and crossover links closely for signs of overheat due to increased surface area

Figure 11-15
Example superheat rear pendant inspection checklist

TITLE: SUPERHEAT STEAM-COOLED WALLS

HISTORY:

GENERAL:

FRONT SCW HANGERS INSPECTION RECOMMENDATIONS:

1. Spacer lug connections (missing, eroded, nonfunctional), adjacent hanger (abrasion, gouging, spot "UT" thickness examine wear). Record tube, elevation, tube wall loss > 20%.
2. Existing tube shields. Shields may be eroded through, missing (if missing, "UT" thickness examine tube), loose, improperly installed. Record tube, elevation.
3. If applicable record location and length where velocity baffle is deformed, eroded, or missing. Pay particular attention to hanger tubes for erosion adjacent to where plate baffles overlap
4. If applicable inspect bifurcates (cracks, erosion). Record the tube, severity. (Note: These are below the top of the economizer and are very difficult to see)
5. Hanger tubes. Record erosion, corrosion, wear (spot "UT" thickness examine), bowing, abrasion especially adjacent roofline and floor, tube, elevation, tube wall loss > 20%.
6. Previous pad welds. Record cracks, horizontal weave (improper weld technique), undercut (> 1/32"), pad welds (excessive, steam cuts, spot "UT" thickness examine wear), tube, elevation, size.
7. Record damaged to refractory pier, location, size, and repair

SCW HEADER INSPECTION RECOMMENDATIONS:

1. Header and connecting tubes inspect for erosion, terminal tubes for cracks (especially at bowed tubes).
2. look for cracking at alignment lug attachments
3. Inspect for header misalignment or shifting
4. UT check all 90 degree bends in drain lines for flow accelerated erosion
5. Inspect the gas side of the Inlet Ring Header for erosion

STEAM COOLED WALL (CONVECTION PASS AREA)

1. Steam cooled wall ring header. Inspect upper side @ all four walls for fly ash erosion, record tube # that erosion is adjacent to, and wall. NOTE: IF APPLICABLE THE OFFSET BENDS APPROXIMATELY 2' UP THE REAR WALL FROM THE HEADER TYPICALLY ARE HIT HARDEST WITH FLY ASH EROSION
2. Inspect peg fins especially @ corners. Record missing, cracked, or broken fins, adjacent tube, and elevation.
3. Record missing refractory behind peg fins and tubes
4. Existing tube shields. Record shields eroded through, missing ("UT" thickness examine tube), loose, turned, tube (side), elevation.
5. For bowing. Record beginning and ending elevations of bowed or misaligned tubes, tubes involved, and severity of displacement.
6. Previous pad welds. Record cracking, improper weld technique (horizontal weave, undercuts, and excessive reinforcement), steam cuts, tube, thickness, elevation, and length.
7. For erosion. Record flats (spot "UT" thickness examine), pitting, tube, elevation, wall loss > 20% NOTE: INCREASED EROSION IS TYPICAL ADJACENT THE ROOFLINE, FLOOR, AND ADJACENT REFRACTORY PIERS
8. Steam cooled wall to penthouse seal. Record leaks or cracks in seal, location.
9. Around access doors. Record membrane cracks, tube erosion, tube to casing gouges, tube, and elevation. NOTE: PHYSICALLY FEEL FOR EROSION ON THE GAS SIDE OF THE UPPER OFFSET BENDS OF ALL WALL OPENINGS
10. Access doors. Record warped or burnt door casing, seal condition (@ door), tube, and elevation.
11. For retract blower erosion. Tubes are worn flat (spot "UT" thickness examine). Record tube, soot blower, elevation, tube wall loss > 20%.
12. Inspect for pitting in the lower areas of the SCW indicative of Acid Dew Point Corrosion
13. Inspect the SCW crossover floor beneath the Front SH Pendant for erosion. NOTE: TYPICALLY EROSION IS MORE SEVER TOWARDS THE CENTER ADJACENT THE HEADER DUE TO SOOT BLOWER LANCE DROOP

Figure 11-16
Example superheat steam-cooled wall inspection checklist

TITLE: REHEAT PENDANT

HISTORY: Reheat was replaced with full stainless pendants

GENERAL: For speediness of preparation and repair as to not hinder other work in the boiler the Reheat should be accessible from scaffold; the scaffold will have to protrude form scaffold towers built through the SHPP and SHDP

REHEAT PENDANT FRONT INSPECTION RECOMMENDATIONS:

Tubes for overheating. Three indicators are blackened or red color; elephant hide type cracking, and bulging. Record tube, element number, length, location, elevation, and measure tube outside diameter.

Spacer bands lugs can be cracked, missing, torn, and gouging tubes. The spacer bands can be cocked, twisted, buckled, and gouging between tubes. Air arc gouges due to past removal of old style bands may be present. Old temporary attachments have also gouged tubes. Old pad welds should be inspected for proper material. Record tube, element number, length, width, band elevation, tube wall loss >25%.

1. Water cooled spacers. The spacer tubes can be abraded (tube to tube), eroded, bent, or disengaged. The spacer tube peg fins, male or female support lugs may be missing, cracked, or abrading (fretting) the tubes. Pad welds should be inspected for cracking, wall loss, and proper material. There are front and rear spacers. Perform a close sidewall inspection on vertical spacer runs for fly ash erosion. Gaps in existing shields @ 90 degree bends, crossovers should be closely inspected. NOTE: ENSURE ALL THREE PARTS OF THE ALIGNMENT SYSTEM FOR THE WRAPPER TUBES ARE IN PLACE; SUPPORT CLIP, ALIGNMENT CLIP, RETAINING CLIP
2. For fly ash erosion. Erosion is typically at misaligned elements, side walls, lower loops, and front fireside locations. Eroded tubes are generally worn flat (spot "UT" thickness examine). Pay particular attention to the STAINLESS lower loops at the inner bends record tube, element, length, elevation, tube wall loss > 25%.
3. For retract wash. Record flats or pitting (spot "UT" thickness examine), identify retract causing wash (elevation located at the front). Record tube, element, length, wall loss >20%.
4. Existing tube shields. The shields may be eroded through or missing ("UT" thickness examine exposed tube), loose (turned, missing straps, broken welds), redirecting gas flow @ tube O.D. (gouging). Record tube, element, length of shield required, elevation type of shield required (I.D., O.D., straight).
5. Elements for alignment and clearance to arch floor should be measured record bowed tubes abrasion into adjacent bundles and > 1 diameter tube bow, tube, element, length, elevation, spot "UT" thickness examine readings @ retract washed or eroded areas
6. For excessive fouling and debris. Record blockage gas lanes and fowling on tubes and @ arch floor.
7. Roof tubes. These tubes may not be accessible. Check penetrations through the ceiling for tube-to-tube abrasion Record missing refractory, missing peg fins, burnt or missing high crown seal heat shields, tube wall loss > 20%, roof droop > 1 tube diameter.
8. Site bottom side of horizontal runs for blistering
9. Ensure operations is pulling a vacuum on the system to prevent condensate from laying up in the lower sections of the pendants, lay-up will cause internal pitting and possibly even an airlock resulting in short term overheat

Figure 11-17
Example reheat pendant inspection checklist (page 1)

REHEAT PENDANT REAR INSPECTION RECOMMENDATIONS:

Swage welds at outlet tubes (upper area). Transition= 3" to 2-1/2" O.D. Record cracking, undercut (>1/32"), tube, element, length, elevation.

1. For sigma phase. This occurs at upper outlet tubes. Record magnetism of these stainless tubes, tube, element.
2. Pad welds. Record cracking, magnetic properties (improper material), pad weld size, tube, element, elevation. Pay special attention to the 347-H stainless steel because of its brittle characteristics it is more prone to cracking.
3. For shotgun dents. Record depth, cracks (especially on stainless steel tubes prone to internal cracking), tube, element, elevation, tube material, number of dents.
4. Tubes for overheating. Four indicators are blackened or red color; elephant hide type cracking, liquid phase corrosion and bulging. Record tube, element, length, elevation, and measure tube outside diameter.
5. Front and rear water cooled spacers. Perform a close side wall inspection for erosion and gaps in existing shields. Pad welds shall be inspected for cracking, undercut (> 1/32"), proper material (magnetic properties). Record erosion, abrasion (fretting tube to tube), disengagement (@ W.C.S. to reheat tubes), peg fins and male or female lugs (missing, cracked, or abrading tubes (fretting)). NOTE: ENSURE ALL THREE PARTS OF THE ALIGNMENT SYSTEM FOR THE WRAPPER TUBES ARE IN PLACE; SUPPORT CLIP, ALIGNMENT CLIP, RETAINING CLIP
6. Flex ties. The lower flex tie elevation is most important. Record flex ties that are cracked, missing, gouging tubes (depth of gouge), related directly with bowing, tube (tube to tube number), element, elevation.
7. For fly ash erosion and fireside corrosion perform a close front and rear tube inspection. Record flats (spot "UT" thickness examine), pitting, alligator hide, wall loss > 20%, tube, element, elevation, and tube material.
8. For retract wash. Tubes are generally worn flat, or pitted. Identify which retract Record tube wall loss > 20% (spot "UT" thickness examine), tube, element, elevation.
9. For excessive fouling and debris. Record and sketch blockage of gas lanes and build-up of ash on tubes and under elements (@ arch floor), heavy or peculiar slag deposit on tubes.
10. Roof tubes. These tubes may not be accessible. Check penetrations through the ceiling for tube to tube abrasion. Record missing refractory, burnt or missing high crown heat shields, missing peg fins, tube wall loss > 20%, roof droop (> 1 tube diameter).
11. Existing shields @ front (2) tubes. Record eroded shields, burnt or missing (if missing "UT" thickness examine tube), displaced shields. Record element number, tube, elevation.

Figure 11-18
Example reheat pendant inspection checklist (page 2)

TITLE: RADIANT REHEAT WALLS

HISTORY:

GENERAL: For speediness of preparation and repair as to not hinder other work in the boiler the Reheat should be accessible from scaffold

RADIANT REHEAT WALLS

1. Sandblast lower 8' for inspection of thermal fatigue cracks; due to the relatively low pressure of this component multiple leaks may go unchecked for long periods of time drastically reducing heat rate gains.
2. Document bowing of Radiant wall from furnace wall, if > 1 diameter access will need to be provided from boiler external for repair of tie back bars
3. Document location of hit impact damage resulting in reducing I.D. or wall thickness loss, record tube count location and elevation
4. For slag. Inspect water walls for excessive slag buildup and any unusual slag patterns (i.e. color, texture) prior to deslagging or cleaning of the furnace. Record thickness, length, width of buildup, and elevation.

RADIANT REHEAT HEADERS

1. Site headers for droop and possible condensate lay-up
2. Inspect seal boxes for pinholes and cracks, lagging and insulation will need to be removed for this
3. Inspect all support plates located below the inlet headers for adequate expansion and contraction, if the plates do not show signs of movement the terminal tubes should be stripped of insulation and NDT for cracking
4. Inspect all safety valves for blockage and ensure inspection plugs are in place and drains are directed away from traffic

Figure 11-19
Example radiant reheat wall inspection checklist

TITLE: ECONOMIZER

HISTORY:

GENERAL: Provide access from scaffold to the bottom side of the lower Economizer bank for thorough inspection, in addition the entire convection pass should be washed prior to inspection

ECONOMIZER INSPECTION RECOMMENDATIONS:

1. Record percent of free gas passage and how many tubes deep for plugging of gas lane, record general areas of possible channeled erosion.
2. Indicate areas of blockage from velocity baffles, also note damaged or missing baffles
3. For overheating. Record excessive sagging of tubes, blackened appearance, elephant hide, bulging, and burnt shields, tube, element, cause of overheat, measure tube outside diameter.
4. Fly ash erosion of tubes or fins. Record tube, element length of eroded area (spot "UT" thickness examine), cause (misdirected flow), wall loss > 20%. NOTE: MOST SEVERE EROSION IS TYPICALLY LOCATED ALONG THE SIDE AND REAR WALLS, IN ADDITION PHYSICALLY REACHING UP FROM THE BOTTOM OF THE BANKS TO FEEL THE GAS SIDE OF ASSMBLIES ADJACENT THE WALLS HAS PROVEN EFFECTIVE IN FINDING SEVERE EROSION
5. For misalignment. Record misalignment into gas lanes > 1/4 diameter, erosion, abrasion, bundle, tube, element.
6. Pad welds. Record cracking, erosion, improper material, tube, and element.
7. Existing shielding. Record holes, bent, loose (redirection of flow), overheated shield conditions, missing (if missing "UT" thickness examine), tube, element, wall.
8. Gas lanes. Measure distances (center to center), record debris (shields lodged, any blockage redirecting gas flow), bundle, tube, and element.
9. Bends. Record polishing, erosion (rear bends), tube, element, tube wall loss > 20%.
10. For retract erosion. Record tube, element, soot blower, pay especially close attention adjacent economizer hangers and ladder brackets for erosion several tubes deep in the bank
11. Hangers. Record bowing, abrasion, cracked welds, missing pins, erosion, hanger, and element. NOTE: SITE DOWN EACH ECONOMIZER HANGER ON THE GAS SIDE FOR FLY ASH EROSION ADJACENT EACH SADDLE SUPPORT
12. Record fly ash erosion (spot "UT" thickness examine) inlet headers
13. Inspect for low temperature corrosion, nipple cracking adjacent the inlet header, record; tube, element, and severity.
14. Site inlet header for droop, and all support brackets for cracking and deformation
15. Inspect the lower 3rd bank closely for increased velocity erosion along the front slope and rear deflection nose due to the downsizing of the surrounding flue wall transition to the Air Heater
16. Inspect the outlet header closely for signs of overheat due to the increased surface area

Figure 11-20
Example economizer inspection checklist

TITLE: WALL, RETRACTABLE, AND FIXED BLOWERS

HISTORY:

GENERAL:

WALL BLOWERS AND SOOT BLOWERS INSPECTION RECOMMENDATIONS:

1. Nozzles. Record any cracked, burned, or missing nozzles and nozzle position. Check nozzle hole I.D. Record for centering in opening and eroded nozzles.
2. Sleeves. Record any missing, burned, or eroded sleeves.
3. Lance tube. Record any bowing.
4. Refractory at soot blower/retract openings. Record any missing refractory. Also note missing refractory in the boxes.
5. Wall boxes if visible. Record any cracks, leaks or missing boxes.
6. Surrounding tubes. Use this information to determine pre-blow, hard blow, and scraping tubes. Note O'clock positions of nozzles at rest.
7. For slag. Inspect water walls around blowers for excessive slag buildup and any unusual slag patterns (i.e. color, texture), or evidence that blower is ineffective, prior to deslagging or cleaning. Record thickness, length and width of buildup, and elevation.
8. Membranes. Record incomplete membrane welds, wide membranes (>3/4") and cracking (termination's (max. 3/8" radius), propagation), length of crack, elevation, and adjacent tube numbers.
9. Soot blowers wash. Record erosion (spot "UT" thickness examine), flat or pitting, membrane (cracks, width > 3/4"), tube, length, location, retract or soot blower, wall loss > 20%, pre blow. Spot check corner tubes, upper arch, and lower slope Coutant if needed.
10. Tubes around observation openings. Record erosion (spot "UT" thickness examine), flat or pitting, tube, length, & location.
11. For fireside corrosion. The tubes will be worn flat (spot UT), pitted, or have alligator hide. Inspect behind the tubes which form the blower opening. Record tube, elevation, severity, wall loss >20%.
12. Previous pad welds. Record any cracks, improper weld technique (horizontal weave, undercut, excessive reinforcement), steam cuts, tube, thickness, elevation and length.
13. For circumferential cracking. Record tube number, elevation, cracking (severity), use special data sheet.
14. For tube dents or gouges. Record depth (spot UT, measure), elevation, tube number.
15. Butt welds. Record cracking, tube, and elevation.
16. For lance alignment. Record any abrasion or uneven blowing.
17. For blower programming. Examine the blowing patterns where blowers are located in close proximity to a corner or slope area. Record any defect in the blowing pattern.
18. Document pitting on tubes around the blower, pitting in this area is indicative of bypass and condensate in the lines
19. Visually monitor each blower while in operation form start to stop for water leakage, binding, holes, functionality, and travel distances
20. Monitor each blower for bypass in between operating cycles
21. Inspect all drive chains and gears for slippage
22. If applicable record any missing insulation or droop in lines that would allow condensate to form and not drain correctly
23. If applicable monitor drains for proper operation
24. If applicable monitor all regulators and connecting valves in blower system

Figure 11-21
Example blower inspection checklist

TITLE: PENTHOUSE INTERNALS

HISTORY:

GENERAL: The Penthouse will need to be entirely vacuumed for a thorough inspection

PENTHOUSE INTERNAL I.E. HEADERS, VENTS, TUBES INSPECTION RECOMMENDATIONS:

1. Terminal tube welds shall be checked for cracking. Record length, propagation, header, tube. Please note that this is more likely to occur at ends, tee locations, high temperature headers.
2. Dissimilar metal welds. These tube to tube welds shall be inspected for cracks due to carbon migration at weld boundaries. Record length, propagation (direction), header, tube.
3. High crown seal structural welds. This tube to seal plate welds shall be inspected for cracking longitudinally along seal or circumferentially around tubes. Record length, propagation (direction), header, tube.
4. Header to hanger plate welds. These welds aid in the Support of the headers. Record length, propagation (direction), header, tube.
5. Penetration welds. Any penetration to the header (gamma plugs or vents) shall be inspected for borehole cracking. Record length, propagation (direction, vertical), header, penetration.
6. Headers. Record cracking, external corrosion, exfoliation, major vertical movements (header, tube), MWT (spot "UT" thickness examine ends and center of headers), circumference (ends and middle), creep. Inspect insulation & covering.
7. Vents. Record cracking, corrosion, erosion, exfoliation, holes in vent lines, hanger areas (abrasion, sagging > 2").
8. Inspect header guides, anti-moment devices for deformation
9. Inspect all casing and expansion joints for cracks, tears, general deformation
10. Inspect all hangers and tension bars for appropriate hardware
11. Look for signs of overheat on hangers, tension bars, and casing
12. Site all headers for droop and misalignment
13. Inspect all hand hole caps for cracking, and leak indications
14. Spot UT all 90 degree bends for internal flow accelerated erosion
15. Fabric seals. These links to outer wall seals shall be inspected for tears, and rips. Record locations and pipe O.D.
16. Omega seals. This floor to outer wall seals shall be inspected for cracked, eroded conditions. Record floor location, wall.
17. Floor expansion joints. These may be buckled, warped cracked. Record location, area.
18. High crown seals. These seals are usually cracked, warped. Inspect end plates, collectors, collars for corrosion and cracking. Record length, location, severity.
19. Ceiling insulation. Record loose or missing insulation.
20. Hangers. Inspect rods, collector beams to end plates, rods to plates, clevis pins. Record bending, corrosion, deformation, cracking, shearing, loose, length of cracking, location of hangers, item, severity.
21. Floor casing. Record all warping, cracking, holes, area, and dimensions.
22. Peripheral seal.
23. Sidewall insulation.
24. Record all damaged and bare thermocouples.

Figure 11-22
Example penthouse internals inspection checklist

TITLE: LOWER DEAD AIR SPACE (LDAS)

HISTORY:

GENERAL:

LOWER DEAD AIR SPACE INSPECTION RECOMMENDATIONS:

1. Center wall to lower slope seal box. Record any tears or cracks. Estimate type of repair.
2. Left and right sidewall to slope seal plate and finger bar welds at sidewalls inspect for cracking and holes.
3. Horizontal beams on slope. Record any twisting, missing or broken beam clips, gaps between slop tubes and horizontal beams, or missing beams, bolts. And nuts.
4. Vertical buckstay truss supports. Record any Buckling.
5. Water wall inlet header hanger rods. Record any loose, bent, or missing rods.
6. Center wall inlet links. Record any cracks, loose or missing U bolts.
7. Front and rear cold side lower slope tubes and membrane. Record any slag fall deformation > than 2", look close at membrane for cracking, access condition.
8. Insulation/lagging. Record location and amount of missing insulation, type.
9. Horizontal rods that connect the water wall inlet header to the exterior truss. Record any loose, bent, or missing rods.
10. For fly ash and slag accumulation. Record location and amount of fly ash buildup (vacuum), note cause.
11. Sidewall bifurcates and membrane welds record any cracking, signs of overheat.
12. Floor casing for safety hazards. Record any loose panels.
13. Remove any ash accumulation and inspect for corrosion

Figure 11-23
Example lower dead air space inspection checklist

TITLE: UPPER DEAD AIR SPACE (UDAS)

HISTORY:

GENERAL:

UPPER DEAD AIR SPACE INSPECTION RECOMMENDATIONS:

1. For fly ash accumulation. Record location and amount of build-up, sketch patterns (vacuum), inspect tubes after ash removal for corrosion
2. Floor and side walls for proper insulation. Record any missing or cracked insulation
3. Front steam cooled wall/bullet nose casing, side walls, roof casing. Record location and total length of cracks or tears. Particular attention should be paid to the top slope area (left and right sides).
4. Sidewall to arch seal. Record any casing leaks or cracks.
5. Upper dead air structural. Record any deformations, missing or broken bolts on the vertical trusses and buckstay supports, any broken or missing clips on the brace beam clips connections to the front and upper arch, any broken or misaligned bolts connecting the horizontal buckstay to the front steam cooled wall, attachments welded to tubes.
6. Thermocouples. Record any cracked welds or bare wiring, note locations.
7. Rear wall to side wall membrane. Record any membrane cracks, improper terminations (as applicable), weld appearance (excessiveness).
8. Rear wall arch membrane. Record cracking, through wall leakage.
9. Center wall seal box. Record any leaks or cracks. Estimate type of repair required.
10. Hanger rods. Record any loose rods or rods in compression, locations, diameters, type.
11. Exterior insulation/lagging/structure.
12. If applicable inspect pleated joint for cracks and deformation

Figure 11-24
Example upper dead air space inspection checklist

TITLE: **Desuperheater Inspection**

HISTORY:

GENERAL:

DESUPERHEATER INSPECTION RECOMMENDATIONS:

1. Compare desuperheater spray frequencies pre/post to LTSH retrofit
2. Liner. This internal inspection is performed using a borescope, generally entering the I.D. through the Lower inspection plug. Inspect for other than complete conditions (broken, missing, movement) of liners (check for oblong holes at screws). Verify butt ring and liner positions (borescope, calipers).
3. Shell. Inspect shell for cracking, fretting and corrosion. Record areas and which Desuperheater.
4. Contact screws. Insure screws are intact and not collapsing liner internally.
5. Spray nozzle assembly Record wear, erosion of holes.

Figure 11-25
Example desuperheater inspection checklist

TITLE: DUCTWORK AND FLUES

HISTORY:

GENERAL:

DUCTWORK AND FLUES INSPECTION RECOMMENDATIONS:

1. For fly ash accumulation. Record location and amount of build-up, sketch patterns (vacuum), inspect plate and or supports after ash removal for corrosion
2. Document all pluggage of differential pressure taps
3. Research temperature trends to determine acid dew point corrosion
4. Inspect all plate and structural struts for erosion
5. Inspect all expansion joints for holes and missing insulation
6. Document all hanger positions both hot and cold
7. Inspect ammonia and sulfur injectors for pluggage, leaks, and missing nozzles
8. Inspect all damper shafts for erosion adjacent the walls, and document damage or erosion to the blades
9. Inspect all probes for erosion and degradation
10. UT scan high erosion and corrosion areas for wall thinning
11. Inspect all hoppers for erosion and cracks especially adjacent doors and wrappers
12. Inspect all doors for gasket material, open and close doors to ensure the gasket material has adequate seal
13. Inspect all wash lines utilized for cleaning for holes and cracks
14. Document missing or damaged lagging and insulation

Figure 11-26
Example ductwork and flue inspection checklist

TITLE: AIR HEATER

HISTORY:

GENERAL:

AIR HEATER INSPECTION RECOMMENDATIONS:

1. Inspect all probes ensure all connecting wires are in tact
2. Document all damaged insulation and lagging
3. Document damaged inspection port glass and seals
4. Inspect support pads for cracks and degradation
5. Note positions of sector plate jack screws
6. Document oil levels and coloration of both drives
7. Record rotational direction of air heaters
8. listen for grinding or scraping while in operation
9. Inspect all doors for degradation and adequate seal
10. Open side doors and inspect rack and pinion for abrasion
11. document expansion joints in hot/cold positions and compare to design
12. Inspect all EJ for holes and cracks, also document any structural or temporary steel welded across the expansion joint opening
13. Inspect the lower support grid for erosion from soot blowers
14. Record condition of basket material; clean, loose or tight packed, discoloration, which zone is in need of repair
15. Check all radial and bypass seals for appropriate clearance, abrasion damage, and erosion; also cross check direction of the radial seals to rotational direction of the air heater
16. Measure distance between the floating T-bar and the sector plate for misalignment
17. Inspect diaphragm plates for cracking
18. Document any oil leakage on the shaft or basket material
19. Inspect the static seal and ensure proper installation
20. Inspect was line for operation, plugged nozzles, cracks and erosion
21. Inspect all duct and flue walls for erosion, cracks, and holes; the rear gas side hot wall should be scaffold for UT mapping
22. Inspect for holes and cracks in the shaft seal

Figure 11-27
Example air heater inspection checklist

Condition Assessment of Boiler Sections—5-Year Plan

1 WATER WALLS

1. During outages when fixed scaffold access is provided, "UT" thickness survey of all four water walls should be conducted to isolate fireside corrosion or erosion and determine remaining life of tubing. The scope would include sampling the first and last ten (10) tubes including every 5th tube between on three points, left, center and right. Typically after the furnace is scaffold the inspection team will measure from a common point in the firebox intervals of 6' marked in one corner with the elevation and a band around the perimeter with spray paint for the sandblast crew as a guide. In order to maintain consistency from year to year ideally a small marker is welded in the corner for reference. This marker is usually a small bead across the crown of the tube in a designated corner or a pin welded to the membrane at specified locations.
2. Inlet Header replications of four different points on each of the lower inlet headers should be taken and reviewed by a metallurgical lab.

Superheaters

1. An operating cycle analysis should be conducted to determine the need for DMW (dissimilar metal weld) replacements.
2. Replications of two different points on the outlet headers should be taken and reviewed by a metallurgical lab.
3. Dimensional measurements should be conducted at a minimum of 4 locations on each header
4. Conduct a "UT" thickness survey inspection of all areas subject to high temperature corrosion.
5. Samples should be removed from the outlet for metallurgical analysis. This analysis will determine the useful life of the Superheater when lab results are correlated with field thickness data.
6. The outlet header should be borescoped on the header ID through the sample tube locations.
7. Insulated headers should be uncovered for inspection of the terminal tubes
8. Sandblast and MT should be conducted on all seamed sections of header
9. The outlet header should also be measured for diameters at four different points across the width. This will allow us to determine if the header is in a creep condition.
10. An operating cycle analysis should be conducted to determine the need for DMW (dissimilar metal weld) replacements.
11. Replications of two different points on each of the inlet and outlet headers should be taken or digital microscope and reviewed by a metallurgical lab.

1.1 SUPERHEATER AND REHEATER DESUPERHEATERS

1. All desuperheaters should be borescopically inspected to examine the liners and inner parts of the equipment.
2. Each desuperheater will require that a gamma plug be removed from each component. These have to be ground out and re welded.

1.2 SUPERHEATER AND REHEATER CONNECTING LINKS

1. All superheater and reheater connecting outlet links and seam welds should be "MT" (Magnetic Particle Tested).
2. The diameters should be measured on the connecting piping connected to the reheat and superheat finals. These should be measured downstream about 20' from the header outlet. All the exposed welds should be "MT" examined as well.
3. Replications of six different points on each of the inlet and outlet links should be taken and reviewed by a metallurgical lab.

Figure 11-28
Example 5-year plan for condition assessment of boiler sections (page 1)

2 REHEAT

1. Samples should be removed from the reheater outlet pendant for metallurgical analysis. This analysis will determine the useful life of the reheater when lab results are correlated with field thickness data. This is needed due to the history of running the reheat pendant over design temperature in the past.
2. The reheat outlet header should be borescoped on the header ID through the sample tube locations.
3. The header should also be measured for diameters at four different points across the width. This will allow us to determine if the header is in a creep condition.
4. An operating cycle analysis should be conducted to determine the need for DMW (dissimilar metal weld) replacements.
5. Radiant Reheat wall should be sandblasted for thermal fatigue crack inspections
6. Replications of six different points on each of the outlet links should be taken and reviewed by a metallurgical lab.

2.1 ECONOMIZER

1. Inlet headers should be borescopically inspected for thermal fatigue, quench cracking

Low temperature Headers (General)

2. Generally low temperature headers should be borescopically inspected every ten years unless known problematic conditions substantiate otherwise.

Main Steam stop valves

3. Remove valve internals and inspect valve body for cracking

2.2 STEAM DRUM

1. The steam drum should have all circumferential and longitudinal welds "MT" examined.
2. Replications of six different points on the Drum seam welds.

2.3 SUMMARY

All data from all sources should be assimilated and represented in a coherent report including projections of individual component expected life as well as recommended repairs to correct suspect items before they become problems.

Figure 11-29
Example 5-year plan for condition assessment of boiler sections (page 2)

12
DESTRUCTIVE TESTING

The wide band of material properties (creep strength) is an important source of uncertainty for the oxide calculation of the life assessment based on NDE results. It might, therefore, be necessary to determine mechanical property values from specimens of material taken from the actual components. Destructive testing can have following objectives:

- Verification of NDE results
- Direct assessment of the degree of damage (structural and mechanical)
- Determination of component material mechanical properties
- Post-failure search for the damage mechanisms

Typically, samples are removed from the boiler in 2-ft sections (see Figure 12-1)and then photographed. After the sample is documented, it is sectioned into many smaller parts (see Figure 12-2). Micrographs (see Figure 12-3) are made from these pieces; the physical attributes are visible on the micrographs.

Figure 12-1
Samples are photographed

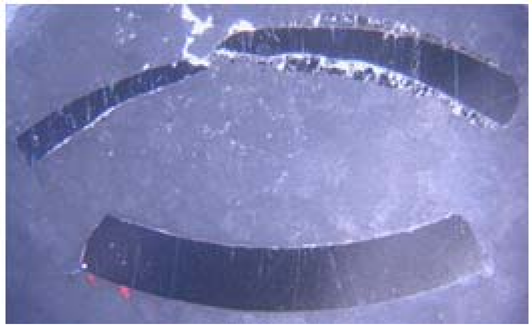


Figure 12-2
Samples are sectioned into smaller pieces

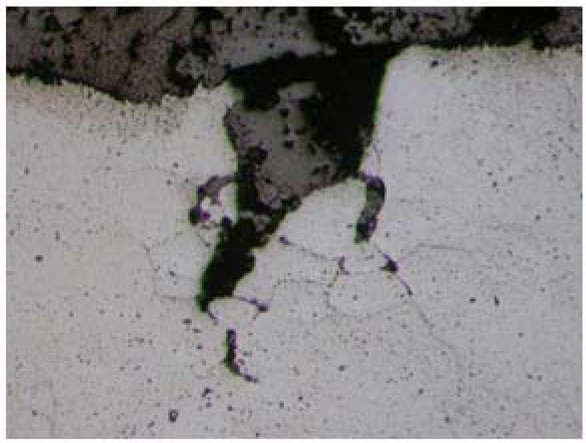


Figure 12-3
Micrographs show the physical attributes

Best Practice—TransCanada Ravenswood

TransCanada Ravenswood provided the following information:

> **Water side tube samples:** "Unusual" failures are analyzed in the laboratory (Alstom). Also, every year removing a few water wall samples (failure free tubes).
>
> **Steam side tube samples:** Based on the opportunity; on average one per year. Based on the units' outage schedule, performing tubes' analysis for the remaining life by measuring ID scale.
>
> **Steam drum carryover test:** Every outage (every 3–5 years).

13
OWNER UPGRADES

Upgrades to Improve Historical Stress Corrosion Cracking Problems

Three elements are required for stress corrosion cracking—a susceptible material, stress, and a corrosion reactant. If you remove one or more of these elements, the condition is less likely to occur. Consider the following:

- Design can reduce the overall stress in the component.
- Proper maintenance of the desuperheating system will reduce the possibility of a contaminant in the steam.
- Any materials fabricated for installation should be properly stress-relieved before installation.

Upgrades to Improve Historical Dissimilar Metal Weld Problems

The component can be designed to reduce the total number of dissimilar metal welds required. The location of the dissimilar metal weld has a great deal to do with the overall survivability of the weld. Welds should never be in the horizontal runs. Welds located in the penthouse, for example, will last longer than ones in the firebox. The use of Inconel (nickel-based) attachment welds will also improve the longevity of dissimilar metal weld.

Upgrades to Improve Historical Ash Corrosion Problems.

The use of 45Cr-50Ni replacement material will resist corrosion. This material is approximately 10 times as expensive as a 304 grade stainless steel. Overlay welding using 45Cr-50Ni will also resist corrosion (see Figure 13-1).

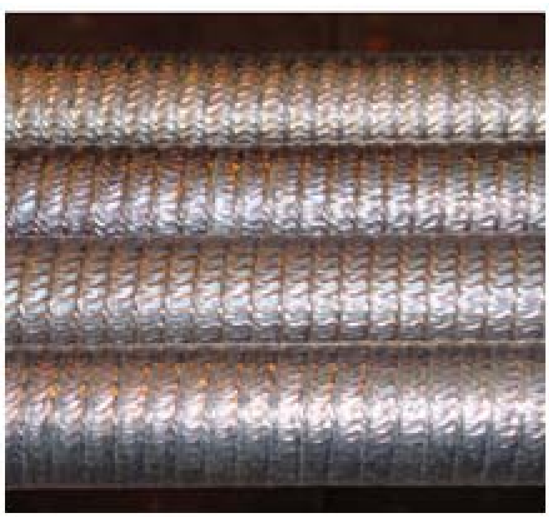


Figure 13-1
Overlay welding using 45Cr-50Ni resists corrosion

Best Practice—Midwest Generation

Midwest Generation provided the following information:

> Work to install progressive helix mechanisms on all unit 8 IK soot blowers. This will change the starting point for each blower each time it is activated to reduce erosion.
>
> Use tube shields to minimize erosion in areas directly in the path of IK soot blowers. Depending on failures during the year it may become necessary to remove some shields to inspect below for localized erosion. Arrange clips so they will not redirect steam below shield and damage tube.

Best Practice—American Electric Power

American Electric Power provided the following information:

> Significant things done were system-wide Triple 5 tube leak acoustic monitoring systems for early detection.

Case History of Component Upgrades

Figures 13-2 through 13-7 are presented to show how an effective component upgrade can be implemented. Figure 13-2 shows a side view of a 528 MW Powder River Basin coal-fired subcritical Combustion Engineering boiler (circa 1975). The original design consisted of superheater and reheater components of mixed metals (shown in red, green, and blue). Due to the unit's age dissimilar metal welds and creep damage were the primary concerns in retrofit decisions.

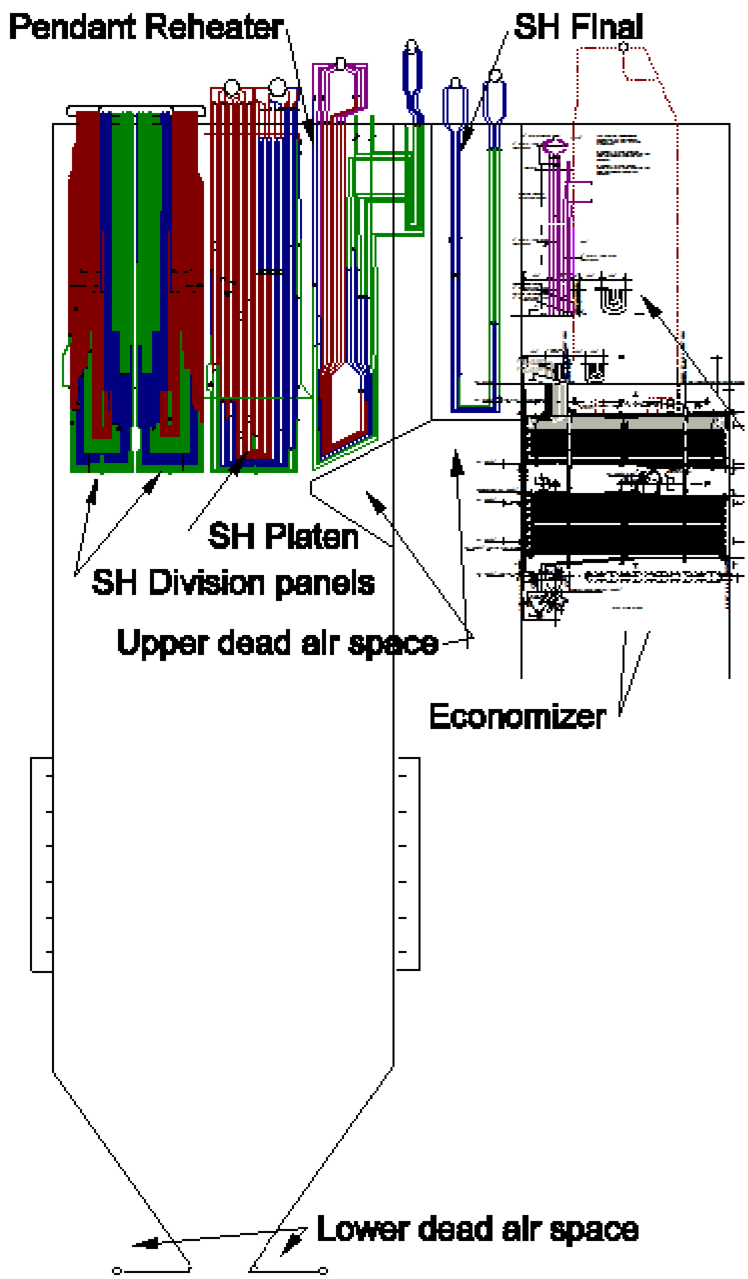


Figure 13-2
A subcritical Combustion Engineering boiler with mixed metals

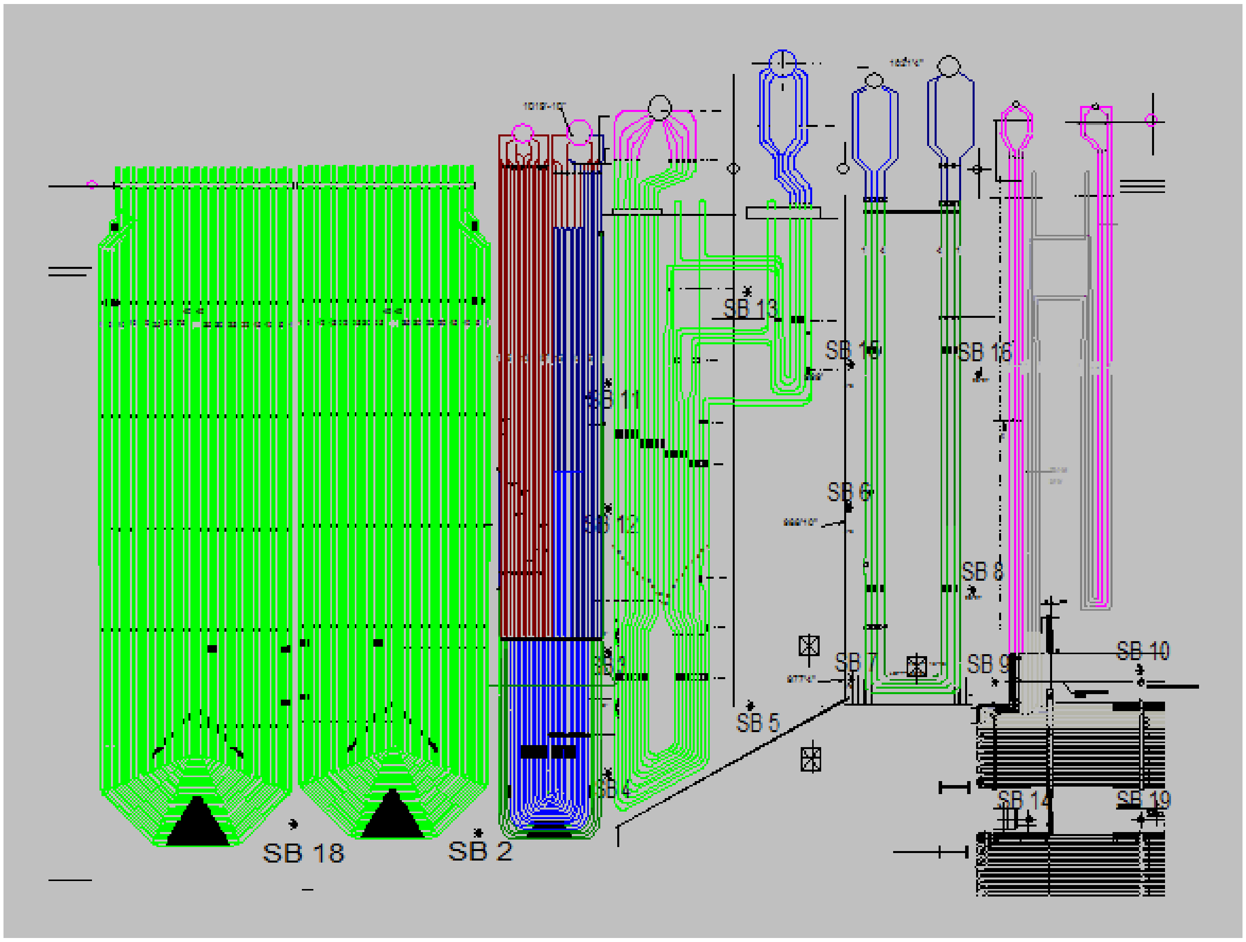


Figure 13-3
The upper furnace area after upgrades

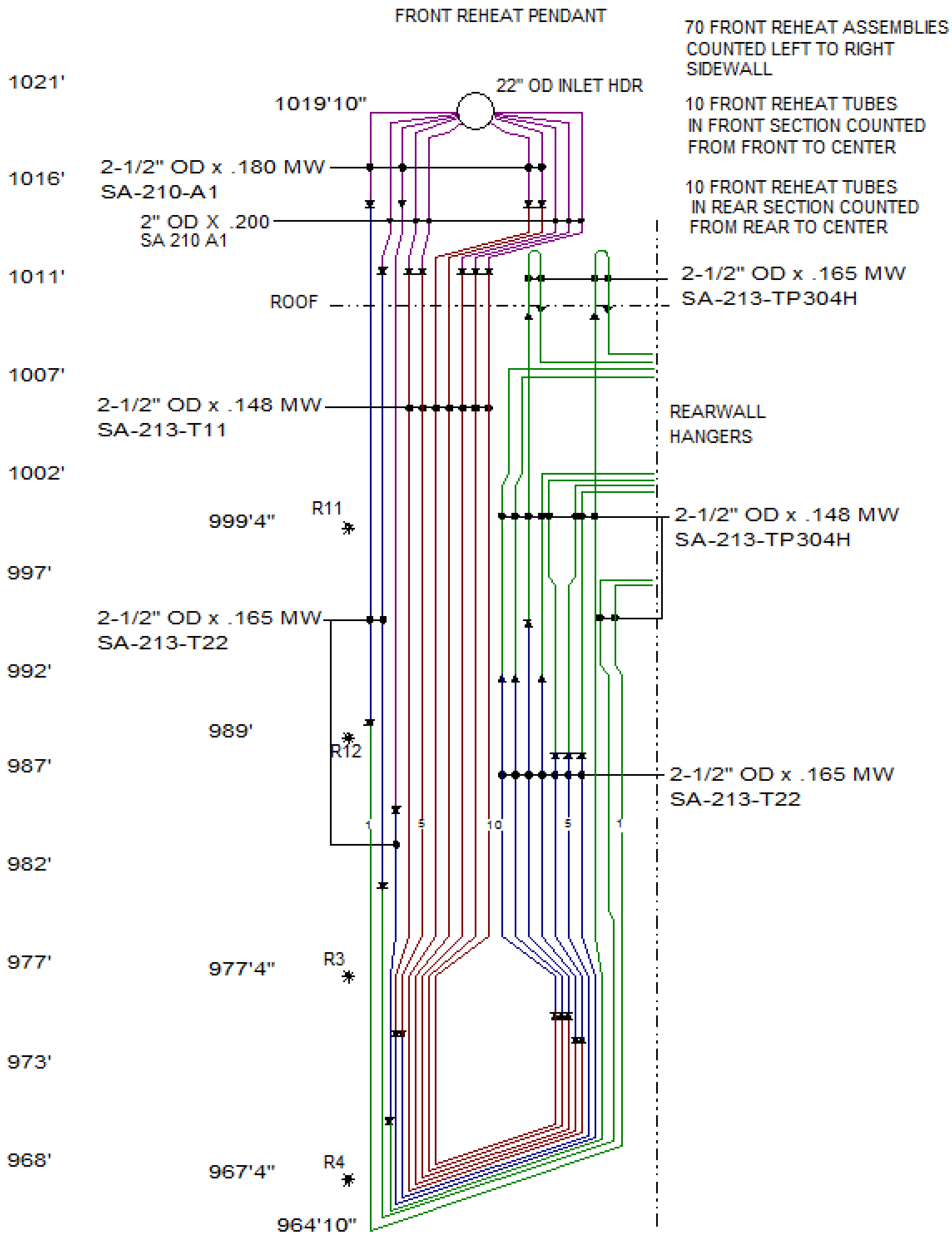


Figure 13-4
The old pendant reheater. Note the many material changes.

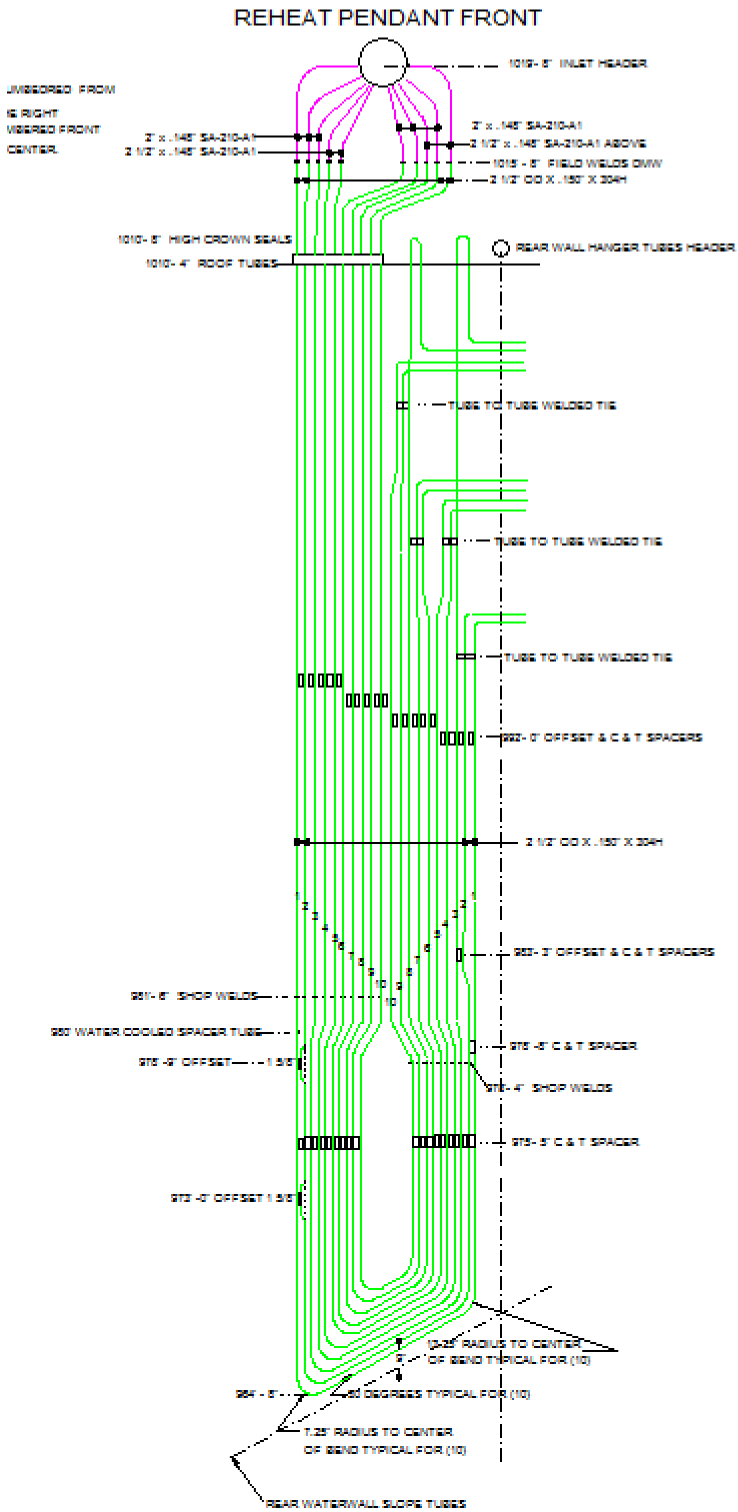


Figure 13-5
The upgrade removed all dissimilar metal welds and used all stainless steel construction.

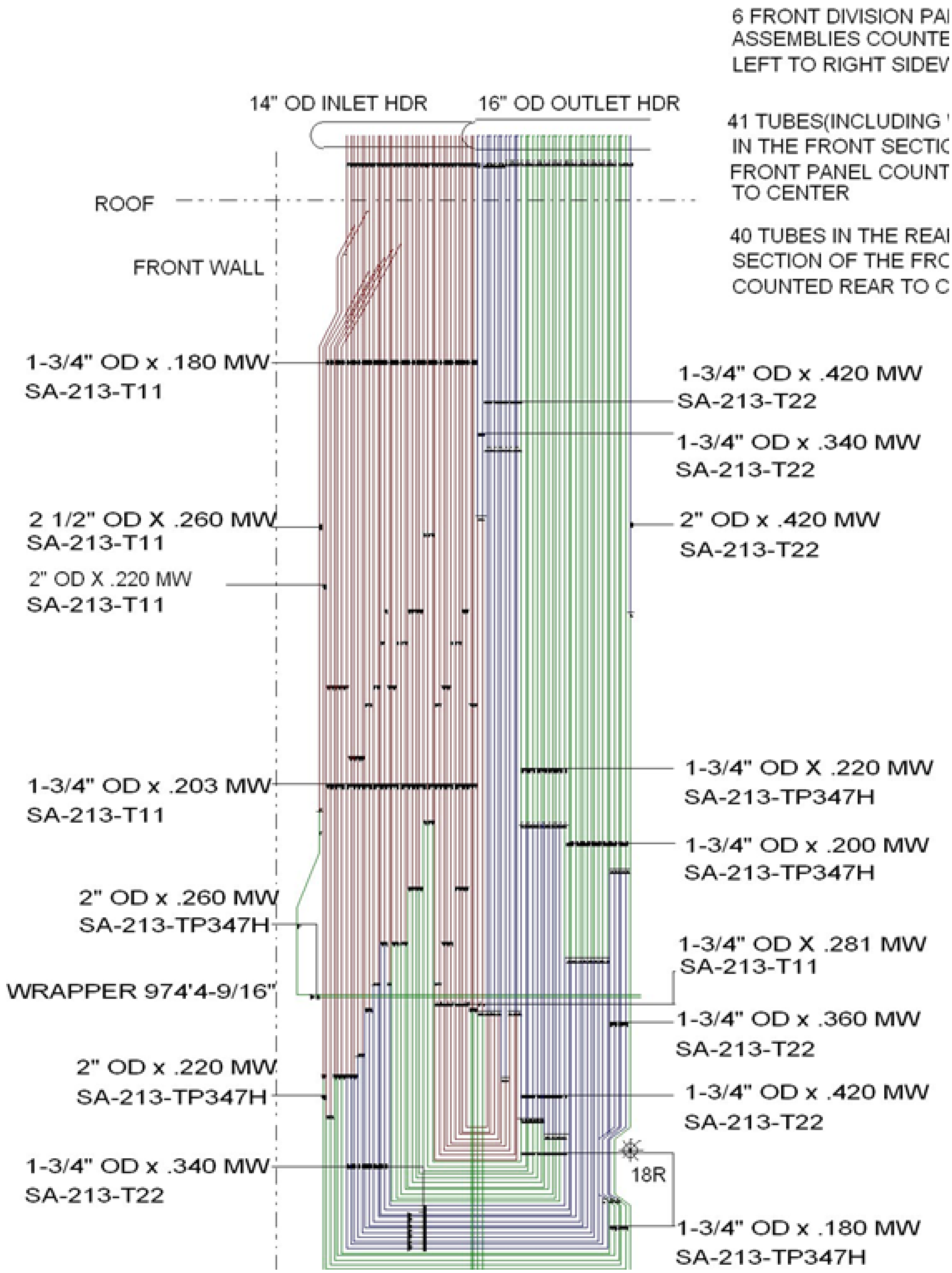


Figure 13-6
The original division panel. Note the many material changes and the complex geometry.

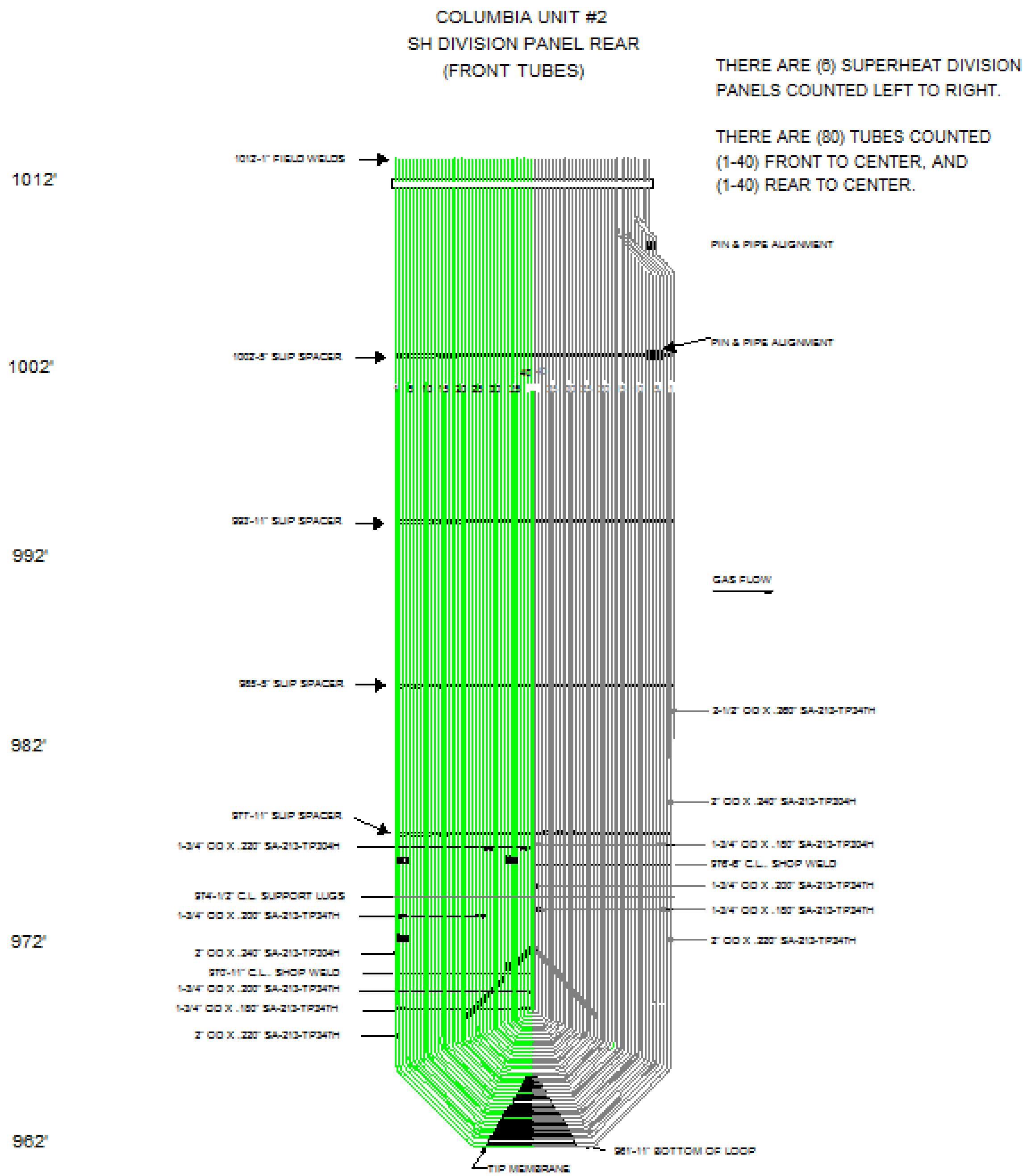


Figure 13-7
The upgrade removed all dissimilar welds from this area and used stainless steel. The design was also modified to reduce clinker trapping on the original alignment system.

Materials Selection

Figure 13-8 shows some design factors that must be considered when selecting materials.

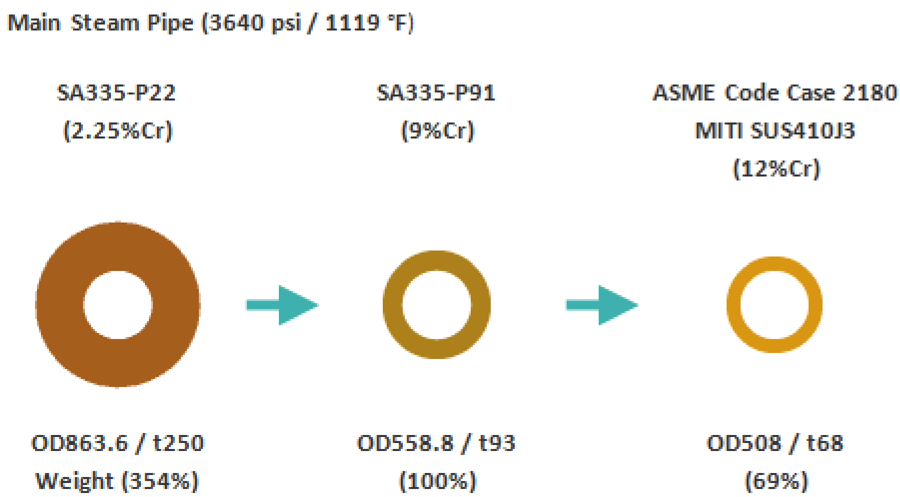


Figure 13-8
Design factors (failure considerations) for writing specifications

Creep

We select materials based on several factors. The first is creep. In terms of creep rupture strength, application of ferritic steels for tubes made of T22 should be limited to steam temperature of 540°C (1005°F); alloys T91, HCM12, EM12, HCM9M and HT91 should be limited to steam temperature of 565°C (1050°F); alloys T-92, P-122 and E911 should be limited to steam temperature of 593°C (1100°F). Under corrosive conditions, however, even the best ferritic steel might be limited to 563°C (1050°F), and austenitic steels are needed, although the creep resistance of 9Cr steels is adequate for use at 593°C (1100° F)

In practice, the high-Cr, high-strength ferritic steels have found little use in the United States due to welding problems. The T22, SS304H and SS347 steels are most commonly used in supercritical boilers (3500 psig).

Corrosion

Fireside corrosion results from the presence of molten sodium-potassium-iron trisulfates. Because resistance to fireside corrosion increases with chromium content, the 9% to 12% Cr ferritic steels are more resistant than the 2-1/4Cr-1Mo steels that are currently used. The 12% Cr steel, in turn, shows better corrosion resistance than 2-1/4Cr steel and 9Cr steel. Stainless steels and other super alloys containing up to 30% Cr represent a further improvement. Increasing the chromium content beyond 30% results in a saturation effect on the corrosion resistance, at least in the laboratory. For practical purposes, when corrosive conditions are present, fine distinctions between ferritic steels can be academic, and it is usually necessary to use austenitic steels containing chromium in excess of 20%.

It can be concluded that substantial superheater corrosion can occur, especially in high-strength austenitic alloys with a low chromium content. For most coals, high-strength modified alloy 800–type alloys such as NF709 will probably have sufficient corrosion resistance, whereas for more corrosive coals, modified SS 310–type alloys such as HR3C should give an extra margin of safety. The T-91 sample exposed in the low-sulfur coal-fueled boiler had a corrosion loss similar to SS 347, which is considerably less than that of SS 304 and 17-14CuMo. A probable reason is that scales and deposits usually adhere tightly to ferritic and martensitic steels but spall off readily from all austenitic steels.

Increasing the Cr content of the alloy from 18% to 20% to a range of 23% to 25% will significantly increase corrosion resistance only when the corrosivity of the deposits is moderate—that is, ≤0.5 mm/year (20 mil/year) for 18-8 stainless steels. For more corrosive conditions, coextruded tubes or weld overlay claddings containing at least 40% Cr are strongly recommended.

Steam-Side Oxidation

Steam-side oxidation of tubes and exfoliation of the oxide scale and its consequence in terms of solid-particle erosion damage to the turbine are well known.

Limited data are available regarding the steam-side scale-growth characteristics of the ferritic tubing alloys. In a study by Sumitomo Metal Industries, the oxide growth in steam for alloys T22 (2-1/4Cr-1Mo), T9, HCM9M, and the modified 9Cr-1Mo (T91) were compared based on 500-hour tests. Results showed the superiority of the T91 alloy over the other alloys.

Masuyama et al compared alloys HCM12, HCM9M, 321H, and 347H in field tests in the temperature range 550°C to 625°C (1020 to 1155°F) over a period of one year. Samples were inserted in the tertiary and secondary superheaters and reheaters.

From the results, they concluded that the resistance to steam oxidation of HCM12 is superior to that of 321H and HCM9M and comparable to that of fine-grained 347H for exposure to the high-temperature region of the reheater.

Subsequent monitoring over a period of three years has borne out their earlier conclusions. In addition to the inherent resistance of HCM12M steel to steam-side oxidation, Masuyama et al suggest that the tendency toward exfoliation of oxide scale would also be less for this alloy than for austenitic steels. Additional improvements in 9% to 12% Cr steels might be possible by extending the chromizing and chromate conversion treatments that currently are applied to lower alloy steels; grain refinement during heat treatment has been shown to be clearly beneficial, as well.

Internal shot blasting is also known to improve the steam oxidation resistance of 300 series stainless steels by enhancing chromium diffusion. It is therefore anticipated that these steels would be used in the fine-grain and shot-peened conditions. Results of steam oxidation tests at 650°C (1200°F) for times up to 2000 hours have been reported for several austenitic steels.

Summary of Materials Selection

For normal steam conditions, alloys HCM12M, AISI, and type 304 stainless steel are viable candidates for superheater and reheater tubing, provided that fireside corrosion is not a major problem. Under mildly corrosive conditions, 310NbN stainless steel might be the most cost-effective option. For severe corrosion cladding, SS 304 with IN72 (44%Cr) should be considered.

For intermediate-temperature applications corresponding to phase 1 steam conditions (595°C [1100°F]), Tempaloy A-1 and type 347 fine-grained stainless steel are deemed to be adequate in the absence of corrosive conditions. Under mildly corrosive conditions, 310NbN stainless steel might offer the best combination of creep strength and corrosion resistance. For severe corrosion, cladding with IN72 should be considered.

For temperatures at 620°C, Super 304H, Tempaloy, Esshete 1250, and 17-14 Cu-Mo might be acceptable under noncorrosive conditions. For mildly corrosive conditions, alloys with 20% to 25% Cr, such as HR3C and NF709, will have the best combination of creep strength and corrosion resistance. For severe corrosion, cladding with IN72 should be considered.

For the highest-temperature application corresponding to (650/650°C [1200/1200°F]), the creep strength requirements are met by Inconel 617, 17-14 Cu-Mo steel, Esshete 1250, and NF709. Among these alloys, 17-14 Cu-Mo steel and Esshete 1250 have inadequate corrosion resistance and must be clad with corrosion-resistant claddings of Inconel 671 if corrosive conditions are present. NF709 and CR30A can be used without corrosion protection for mildly corrosive conditions but require cladding with IN72 for severely corrosive conditions.

T91 material is not popular superheater or reheater tubing. The problem in T91 application is in post-weld heat treatment. Because T91 is tempered steel, it derives its strength from a heat treatment process in its manufacture.

Over-tempering causes a coarsening of critical precipitates, with a corresponding loss in creep rupture strength due to the loss of the restraining influence of these precipitates.

Under-tempering also can jeopardize the high-temperature properties, because the required precipitation does not go to completion, and the precipitates either are absent or are of insufficient size to stabilize the structure. Other complications associated with under-tempering, such as the risk of brittle fracture and stress corrosion cracking, also must be considered.

Perhaps the most common problem with grade 91 is post-production exposure to temperatures in the intercritical region above the temperature at which the tempered martensite begins to transform back into austenite, the *lower critical transformation temperature*, and below the temperature at which phase transformation is complete the *upper critical transformation temperature* (see Figure 13-9).

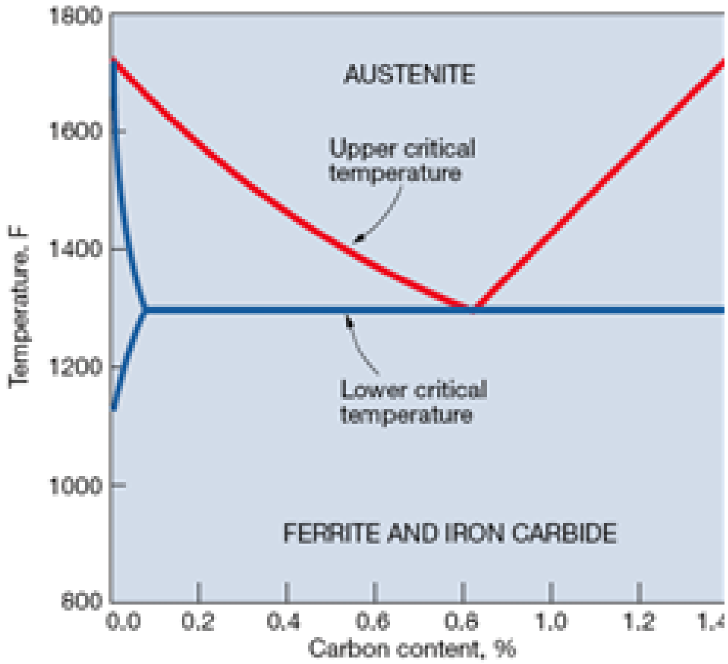


Figure 13-9
Two important parameters for grade 91 components are the upper and lower critical transformation temperatures

When grade 91 is heated into this intercritical region, the material partially reaustenitizes, and the resulting structure will have substantially reduced creep rupture strength. In the worst case, this material will have lower creep rupture strength than that of traditional grade T22.

Having said that, how do you heat treat the entire T91 component in the field? If you do not, you will have reduced creep strength. Wherever the heat treatment ends, there is a deficiency; this end point will be a weak area susceptible to failure, and common attachments will likely be problematic.

Acceptable Repairs

Ligament (or borehole) cracking is a significant, life-limiting problem in headers subjected to elevated temperature service. Replacement is the only suggested repair.

Upgrades to Improve Historical Header Thermal Fatigue Problems

Header thermal fatigue is best prevented through design and operation to minimize thermal stresses and thermal cycling. Designs that incorporate reduction of stress concentrators, such as blend grinding weld profiles and smooth transitions, should be used. Several methods of prevention apply, depending on the application. Controlled rates of heating and cooling during startup and shutdown of equipment can lower stresses, where appropriate. Differential thermal expansion between adjoining components of dissimilar materials should be considered. Designs should incorporate sufficient flexibility to accommodate all differential expansion.

A

INSPECTION DATABASE EXAMPLES

United Dynamics Corporation has compiled an inspection database containing more than 105,000 boiler inspections and repairs conducted on various boilers throughout the world during the past 30 years. Figures A-1 through A-3 represent reports created with basic data mining.

EPRI 2011							
All boilers of sub and supercritical pressure ratings							
By age of unit:	0-20 years	21-30 years	31-40 years	41-50 years	51-60> years	61> years	Total
Total of events							0
"P1" events	242	1035	16441	5790	3644	1216	28368
"P2" events	242	1109	12292	4856	4340	1709	24548
"P3" Events	800	2232	17771	8617	8076	3025	40521
Total of events	1284	4376	46504	19263	16060	5950	93437
All boilers of supercritical pressure ratings							
Total of events							
"P1" events	0	95	1872	1548	0	0	3515
"P2" events	0	114	1492	808	0	0	2414
"P3" Events	0	325	3046	1492	0	0	4863
Total of events	0	534	6410	3848	0	0	10792
All boilers of sub critical pressure ratings							
Total of events							
"P1" events	242	940	14866	4286	4028	1216	2237
"P2" events	242	995	11095	4103	4711	1709	2026
"P3" Events	800	1907	15512	7380	8508	3205	3712
Total of events	1284	3842	41473	15769	17247	6130	7975

By age											
SUB	8		10		114		72		68		24
SUPER	0		21		12		0		0		0
By type	PC	CYC	HRSG	CFB	Other				184		
p1	27395	430	63	82	91				167		
p2	25172	363	97	57	96				100		
p3	41926	606	485	228	73				77		
Total	95437	1397	653	367	261				55		
									566		
									1149		

Figure A-1
Data on boilers of subcritical and supercritical pressure ratings (page 1)

Causes	Soot blower	Fly ash	Fatigue	Hit	Other	Vibration				
P1	8868	3834	1866	874	6666					
P2	4630	2424	5756		4910	660				
P3	3253	2594	8119		8245	2980				
Total	16751	8852	15741	874	19821	3640				
Repairs	Monitor	Info	Shield	Debris	Other	Restore	Refractory	Attach	Replace	Weld
P1	40	59	583	87		6012			10305	22847
P2	52	78	7434	141	17304	1716	1676	1003	289	4752
P3	7110	2275	3552	1789	31634	475			152	6702
Total	7202	2412	11569	2017	48938	8203	1676	1003	10746	34301
Specific examples of major causes										
Creep / Overheat long term		1087								
Overheat short term		497								
Soot blower erosion		17435								
Fly ash erosion		9231								
Corrosion Fatigue		613								
Corrosion		1149								
FAC		8								
Fatigue (thermal)		15827								
Vibration		1510								
Abrasion		2731								
Alignment		226								
Defect		27								
Work quality		3964								
Weld work quality		1613								

Figure A-2
Data on boilers of subcritical and supercritical pressure ratings (page 2)

Problems by area		
Economizer		3783
Penthouse		2496
Waterwall Front		1354
Waterwall Rear		1320
Waterwall right		885
Waterwall Left		907
Waterwall extended		60
Superheater		
Primary		4436
Secondary		1164
1st Radiant		
2nd Radiant		
Final		739
Finishing		434
Radiant		656
Furnace bed		
H.T. Superheater		71
High temp superheat		672
Horizontal SH		2198
HT Superheat		90
Initial Superheat		743
Intermediate		893
Low temp		1405
LTSH		36
L.T.		169
Pendant		1953
Platen		2028
Pri		
Bank 1		1108
Bank 2		892
Bank 3		375
Bank 4		92
Reheater		14478

Figure A-3
Boiler data (problems by area)

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