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**Best Practice for Recovery Boiler Inspection**

**(Optimizing Inspection Scope)**

**Scope**

This TIP describes a process for planning a recovery boiler inspection by specifying an inspection scope for each boiler zone to find possible damage mechanisms in their most likely locations, using the most efficient inspection and non-destructive testing (NDT) methods to quantify and trend the damage. Using the practices described in this TIP, a recovery boiler owner/operator can rationally allocate the correct amounts of time, scaffolding and inspection/NDT resources to learn everything necessary to improve the boiler's reliability at lowest cost.

Built on inspection design practices in regular use in the nuclear, refining and chemical industries, the inspection planning process described in this TIP can ensure that an inspected recovery boiler returns to service with the owner having an understanding of the extent and rate of damage mechanisms affecting each part of the boiler. This method of designing the inspection scope applies equally well to power boilers and other fixed equipment.

Appendix A has a comprehensive list of damage mechanisms and corresponding recommended inspection methods. Nothing in this document is intended to replace or supersede jurisdictional requirements.

**Safety precautions**

No safety precautions are associated with this TIP, which provides guidance to experienced owners and operators for systematically planning the scope of a boiler inspection.

**Management of Change**

Inherent in the methodology in this TIP is the requirement that changes to boiler design, materials of construction, operating parameters, black liquor properties, etc., beyond predetermined ranges and limits, shall in turn be analyzed for their potential effect on the rate and occurrence of the boiler damage mechanisms. A mill handling hazardous chemicals covered by OSHA’s Process Safety Management (PSM) rules is required to have an approved Management of Change (MOC) process in its PSM program. Alternatively the mill must create a functional and accountable MOC process, or hire a qualified MOC analyst, to cover changes in the recovery boiler that could affect inspection plans.
Basic Principles

Creating an efficient and cost-effective inspection plan for a recovery boiler requires knowing the damage mechanisms affecting tubes in different boiler zones and using the most effective, qualified inspection methods for finding the damage and quantifying its extent and rate. Comprehensive information on damage mechanisms affecting components in recovery boilers is in WRC publication WRB 488, *Damage Mechanisms Affecting Fixed Equipment in Pulp & Paper Mills*, (Ref. 1).

The rate of a predictable damage mechanism defines how often to inspect the affected parts. Reliable rate trending typically requires more than two consecutive data sets. Inspection intervals in risk-based inspection programs depend on the part's "remaining life" due to each damage mechanism. Decades of practical recovery boiler operating and inspection experience and corrosion research prove that tubes and headers in many parts of a recovery boiler have no significant fireside and waterside damage mechanisms. These parts typically are fully identified by visual inspection or by NDT in a boiler after a few years of operation.

Non-predictable damage mechanisms, notably thermal and mechanical fatigue cracking, are covered in the inspection plan by crack testing in boiler components known to be affected by thermal and/or mechanical cycling, either from the history of the actual boiler in question or from industry-wide experience. Fatigue crack damage has a time aspect to it - more cycles increase the probability of initiation - and cracks may be found by crack testing but cannot be 'inspected out' since they may initiate any time after testing found no crack in the part.

*An essential part of every valid inspection is for the boiler owner/operator to qualify the inspectors' and NDT technicians' skill and experience, and to qualify by test each NDT method according to its written procedure.*

A quality assurance program that verifies that the NDT method accurately quantifies the damage symptoms is of critical importance for all NDT. At a minimum, a qualified representative of the mill should verify that people doing NDT can readily meet their company’s standards for accuracy and productivity with the specified NDT procedure.

*Each recovery boiler is unique and requires a customized inspection plan*, based on its design, materials of construction, and its operation and repair histories. By deliberately focusing on locations where damage mechanisms could feasibly affect the boiler’s reliability, a recommended, evidence-based inspection plan rationally minimizes close inspection of tubes where no measurable damage occurs, using visual inspection from a reasonable distance with periodic, closer inspection when the opportunity arises.

*An important benefit of this approach is the role it plays in supporting evidence-based extension of the interval between inspection outages.*

In addition, less frequent shutdowns reduce the risk of component failure on startup and reduce overall wear-and-tear on the boiler.

Corrosion Loops

In complicated fixed equipment like a boiler, an inspection plan is devised for each zone of the boiler that represents a different corrosion loop. For the purposes of planning inspections, a ‘corrosion loop’, is a collection of connected parts, which, by being made from similar materials and exposed to a common environment, are susceptible to the same damage mechanisms. Fireside corrosion loops are defined primarily by the temperature and chemical characteristics of the combustion gas and the steels that they come into contact with in different parts of the boiler. Steel in contact with treated feed-water and steam is one corrosion loop.
Most tubes, drums, headers, pipes and ducts in a recovery boiler are made from carbon steel. Stainless steel and nickel-based alloys may be strategically used in wrought form as tubes in the hottest parts of the superheater, or as a composite layer or weld overlay, a thermal sprayed coating or a chromium-rich diffusion layer to protect carbon steel tubes. Stainless steel resists hot oxidation, hot sulfidation, gas erosion and acid condensate corrosion in saltcake/ash hoppers, precipitators, fans, ducts and stacks better than carbon steel.

**Fireside environments**

The fireside of the steel tubes in a recovery boiler is exposed to hot flue gas and alkaline saltcake dust at decreasing temperature as it moves through the boiler zones. The tube temperature depends on whether it contains pressurized water or steam, the latter possibly above 500°C (930°F) and if there is a temperature gradient associated with heat flux. The most important aspect of a recovery boiler in the Kraft pulping process is that hot, reducing (sulfide-rich) gas in the bed area reacts with combustion air to become hot oxidizing (oxygen rich) gas above the secondary air level. Severe gas turbulence in the lower furnace can see reducing gases that go higher than expected produce steel corrosion patterns related to the gas flow. In some boilers this corrosion affects steel tubes above the composite ‘cut-line’.

The flue gas carries with it massive amounts of sodium carbonate-rich dust (salt cake), chemical vapors and possibly unburned fuel particles. In addition to water vapor produced by burning black liquor and auxiliary fuels, steam is added in upper zones of the boiler by the process of sootblowing. Non-dried, heated air is blown into the air ports, and the induced draft sucks air and humidity into the boiler at wall openings. All of these conditions determine the damage mechanisms.

Wall tubes in the lower furnace are covered with a layer of frozen smelt. Because smelt solidifies at temperatures >400°C hotter than the tube, liquid smelt only contacts the tube for an instant to form a frozen layer. Direct contact of molten smelt with a tube surface hot enough to keep it in a molten state will cause rapid corrosion, whether it is steel or stainless steel.

A tube’s external fire-side surface is briefly exposed to water-washing when the boiler is taken out of operation. Corrosion of a tube’s external cold side surface happens when that surface gets wet. Cold-side wetness typically occurs when the boiler is washed; when soot blower condensate is not properly drained, and when water or steam used to shatter smelt flows sprays on the cold-side of the wall around the spouts.

When visual inspection of the cold-side, supplemented with infra-red inspection, reveals signs of wetness the affected tubes should be directly examined for active cold-side corrosion. A more cost-effective way to avoid cold-side corrosion might be to coat the tubes and/or minimize repeated wetting.

**Waterside environments**

Carbon steel inside the tubes and headers is in contact with treated boiler feedwater at the saturated steam temperature for boiler pressure, and by steam in the superheater section. Damage mechanisms in this corrosion loop mostly are defined by the feed-water quality. Inconsistent water quality can result in waterside deposits or corrosion, especially where tubes are exposed to the highest heat flux. Waterside cracking (see section below) severity correlates directly with the dissolved oxygen content of the feed-water.

Waterside local metal loss can be characterized with UT from the OD, internal laser optical profilometry and ultrasonic scanning methods similar to those used to test for near-drum corrosion. Absent external indications of tube damage, such as a leak or bulge, ‘searching’ for internal metal loss with UT a survey is not recommended.

“Shadow” RT, or “profile shots” can find waterside pits and also cracks whose depth dimension aligns with the radiation beam.
Damage Mechanisms

Predictable damage mechanisms allow the “remaining life” of a component to be estimated. Remaining life refers to the time left to reach a defined state of failure, which is not necessarily a rupture or a leak. This section discusses damage mechanisms on “fireside” surfaces contacted by hot combustion gases and consisting of carbon steel and corrosion-resistant alloys, respectively. As stated earlier, formal descriptions of damage mechanisms in recovery boilers are in Reference 1.

Industry experience

Decades of service experience and research (Refs. 2, 3) have generated extensive knowledge of the damage mechanisms in recovery boilers. For example, multi-million dollar research programs from 1986 – 1998 (AF&PA) and 1995 – 2007 (DOE) established to investigate fire-side corrosion and cracking mechanisms for carbon steel and for composite layer alloys and coatings used to protect tubes in the lower furnace, found the following:

1. Wall tubes in the lower furnace, unprotected by a smelt bed or a corrosion resistant barrier, corrode in contact with hot reducing (sulfidic) gas. Higher concentrations of organic sulfide gases produced by liquor pyrolyzing on the tubes accelerate this corrosion mechanism.

2. Steel corrosion by hot reducing gas is highly temperature dependent. Corrosion accelerates markedly above a critical temperature, which is around 315°C (600°F) for carbon steel, and 340°C (650°F) for stainless steel. It could be higher for chromium-nickel alloys.

3. Hot oxidizing gases, found in the upper furnace, do not corrode carbon steel.

4. Smelt melting around 760°C (1,400°F) freezes on a cooler tube surface. In water-filled tubes the saturation temperature is 260°C (500°F) for 40 bar (600 psi) and 310°C (590°F) for 100 bar (1,450 psi). Tube surfaces hotter than or in direct contact with molten smelt corrode very rapidly. A frozen smelt layer does not prevent combustion gas from reaching the tube surface – a physical reality that undermines the notion that studs prevent corrosion by increasing the thickness and stability of the frozen smelt layer.

5. Sodium sulfide-rich solutions created by water-washing cause stress corrosion cracking of austenitic stainless steel and nickel alloy composite layers. (Ref. 4)

Pitting

Pitting can affect steel tubes at intermediate temperatures in the generating section and economizer sections, where Tran has described the formation of low-melting acidic sulfate compounds, mostly sodium bisulfate and pyrosulfate. This specific damage mechanism must be distinguished from slow, general corrosion and resulting roughness found in all tubes. Presence of low-melting sulfur compounds along with humidity from soot-blowing are believed to have a major role in near-drum corrosion, which affects tubes right at the mud drum.

“Pocket corrosion”

“Pocket corrosion” is localized steel corrosion where saltcake deposits wetted by washing stay in pockets, crotches and corners where tubes cross and intersect at rear, side walls and where superheater tubes penetrate roof tubes. Pocket corrosion is slow because it only occurs when the boiler is not operating.

Molten salt corrosion

Molten salt corrosion was shown in decades of published research by Hupa, Tran and others to affect superheater tubes with partly molten saltcake deposits on the surface. This mechanism naturally affects the hottest superheater tubes first and worst, depending on the chemical composition of the deposits, especially their potassium and chloride contents. Because thermal models typically show superheater bottom loops that are shielded by the nose arch are the coolest part of the superheater section, corrosion of these loops is less likely there than on the hottest tube legs and loops.
Acidic condensate corrosion

Acidic condensate corrosion occurs where the flue gas temperature falls below the dew point. Since most recovery boiler flue gas particulates are alkaline salts, acidic condensates are less acidic than in a power boiler. They can affect the economizer but are more likely to form in gas ducts after the precipitator and in the stack.

Corrosion resistant alloys (CRAs) and stainless steels

In addition to damage mechanisms affecting carbon steel, the ‘composite’ layer, typically 304 SS or a nickel alloy in N. American boilers, is susceptible to its own damage mechanisms, including:

- Stress corrosion cracking (SCC) – from hot hydrated sodium sulfide in boiler washing environments. (Ref. 4)
- Localized “balding” corrosion in crevices open to flue gas – attributed to condensed sodium hydroxide vapor with hydrated sodium sulfide believed to be involved in corrosion less deep in corners and crevices.
- Thermal fatigue, an unpredictable cracking mechanism (see below) that can affect bent tubes at wall openings below the tertiary air or burner level, depending on the wall opening design and operating practices that tend to maximize thermal cycling of tubes at the opening.

Ferritic stainless steel weld overlay used to protect tubes in Japan and Brazil reportedly does not have these damage mechanisms - lower nickel and higher chrome content may offer benefits not fully explored and ferritic grades are less susceptible than austenitic grades to thermal fatigue.

Non-predictable damage mechanisms

Non-predictable damage mechanisms, by their nature, cannot be "inspected out" and monitored. Many cases exist in which tubes that are found to be of nominal thickness or free of cracks in one inspection are thinned or cracked in the next outage. Rates of erosion corrosion and fatigue crack growth, for example, typically vary over time.

Erosion corrosion

Erosion corrosion creates smooth, directional, flow-related metal loss from gas-borne particulates randomly and unpredictably affects tubes subjected to high flue-gas velocity in narrow gas passages between deposit build-ups in fully surrounded tubes - generator, superheater and economizer tubes. Erosion corrosion from sootblowing, especially likely when the steam is laden with condensate, typically affects tubes closest to the sootblower wall in the sootblower path.

Fatigue cracking damage mechanisms include:

- Thermal fatigue cracking of carbon steel tubes in high heat-flux zones, especially in studded tubes.
- Thermal fatigue of membrane and fill-plate (flat stud) welds at wall openings.
- Thermal fatigue of austenitic alloy welds, overlay and the composite layer on bent tubes at lower furnace wall openings. (Ref. 5)
- Thermal and mechanical fatigue at tube connectors in superheater screen tube platens.

Waterside cracking

Waterside cracking is a non-predictable corrosion-accelerated, cracking mechanism that affects the feedwater and steam sides of steel tubes and headers. It is attributed to cyclic fracture of the magnetite scale upon which the steel relies to minimize corrosion. Cyclic scale fracture where local stress repeatedly fractures the scale produces waterside cracking, also called stress-assisted corrosion (SAC) and “corrosion fatigue” in the fossil power industry. TAPPI TIP 0402-38 (Ref. 6) describes industry best practices for detecting and managing waterside cracking.
Matching Inspection/NDT Methods to Damage Mechanisms

Inspector qualification

Successful inspection planning requires specifying and qualifying the correct inspection/NDT method to find the damage symptom in boiler locations where the damage logically is likely to occur.

*Visual inspection by a qualified* inspector is the primary inspection method for finding boiler components with corrosion and other damage.

* Inspector qualification may include testing according to national standards such as ASNT Recommended practice SNT-TC-1A. (Ref. 7) Recovery boiler inspection experience and familiarity with the equipment are definite ‘pluses’ in qualifying an inspector.

Inspection and NDT

Visual inspection is the primary tool because it is the most effective and efficient way to find color changes, surface roughness and gouges, and even minor distortion from corrosion and overheating damage in tubes, and to inspect welds and headers. Bright oblique lighting is a good way to see even slight flaws in tube surfaces.

NDT is used to quantify the extent of damage and allows for damage rate trending. *A grid UT survey of steel tube thickness is only required to establish the boiler’s pattern of corrosion, as a baseline for future inspections.* Corrosion patterns on steel tube panels are revealed in most recovery boilers after three or four years. Steel tubes protected with stainless steel are likely to corrode only where the protective barrier is lost: again the rate of steel corrosion typically is determined after a few years and, depending on the nature of the local gas environment, could be insignificantly low.

Testing for metal loss (thinning)

The recommended best practice arising from this inspection planning approach is to use UT solely to locally determine the consequences of visible corrosion and/or distortion of carbon steel tubes. When years of earlier UT survey data confirm that uniform corrosion is not happening, additional UT surveys simply waste time and money. This confirms what extensive experience and research, including the afore-mentioned, multi-year research program on recovery boiler corrosion funded by AF&PA and DOE, showed - steel tubes exposed to oxidizing hot gas conditions in a recovery boiler do not corrode at a measurable rate.

Provided no significant changes have been made to the boiler air system, materials, operating settings or black liquor chemistry, the inspection scope should be limited to those tubes known to have a remaining life < three years. Sampling with UT can confirm corrosion rates predicted by previous surveys. When tube repair decisions are based on UT data the owner should follow guidelines in Part 1 of TAPPI TIP 0402-18 (Ref. 8) for verifying the data’s accuracy.

In 2-drum boilers, *near-drum corrosion* that affects generating tubes where they exit the rolled joint in the mud-drum is detected and monitored from inside the mud drum using specialized, rotary scanning, water-coupled, UT probes and computerized data management.

Testing for cracks

Cracks open to the surface may be visible, especially thermal fatigue cracks in crotch/fill plates and welds at openings and in membranes. Stress corrosion cracks and corrosion fatigue in stainless steel and nickel-alloy composite layers may be faintly visible only on tube surfaces prepared by light sanding. External cracks in steel tubes and headers can be non-destructively detected and characterized:

- TAPPI TIP 0402-30 (Ref. 5) describes penetrant testing (PT) methods for reliably finding cracks, including the most potentially harmful, thermal fatigue cracks in the composite layer of bent tubes at wall openings.
Cracks in carbon steel and other ferromagnetic materials can be sized with magnetic particle testing (MT). MT is acceptable for finding fatigue cracks at attachments, including at welds for connectors between superheater tubes and in screen tube platens.

Eddy current testing (ET) was used to locate cracks in the composite layer, especially stress corrosion cracks in floor tubes. Specialized eddy current/flux leakage testing methods can find metal loss in boiler tubes. As with every NDT procedure, the ET procedure should be fully qualified before it is employed.

Waterside cracking, also called stress-assisted corrosion (SAC), and corrosion fatigue in the power industry, affects the water or steam contacted steel surfaces where attachments or other geometric conditions produce strain > 0.2% in the internal surface. Cyclic strain (stress) repeatedly fractures magnetite scale that ordinarily protects the internal surface, producing elongated pits and cracks in the internal surface which decrease the tube or header’s pressure rating only when the cracks are very long and deep, frequently causing a leak first. TAPPI TIP 0402-38 (Ref. 6) describes industry-recommended best practices for detecting and managing waterside cracking.

Acceptable limits for thinning and cracks – Fitness-for-service (FFS) assessment

In a major change from traditional practice, many recovery boilers are safely operated with corroded and cracked tubes and headers. By defining acceptable limits for thinning and cracks especially waterside cracks, the owner may safely postpone repairs that do not extend the boiler’s remaining life or improve reliability.

Tube thinning limits

Defining limits for tube thinning starts with a “Code minimum thickness”, as defined in ASME B&PV Code Section I (Ref. 9). API 579-1/ASME FFS-1, Fitness for service, (Ref. 10) the post-construction Code accepted by NBIC, uses the minimum thickness, t, as the basis for Part 5, Local thinned area, and Part 6, Pitting, Level 1 and Level 2 FFS assessments. Part 5, for example, accounts for the axial and transverse dimensions of the thinned area in an engineering assessment for acceptable local metal loss. Part 6 (and the NBIC code) recognizes that pits can be substantially deeper than the nominal corrosion allowance. Using API 579-1/ASME FFS-1 methods to define a valid limit for the remaining thickness of a corroding tube requires accurate damage characterization and typically leads to fewer tube replacements.

Crack-like damage limits

Crack mechanisms that do not lead to leaks in tubes can be acceptable. For example, sulfide stress corrosion cracks (SCC) in the stainless alloy composite layer almost never propagate past the clad layer interface. Severe SCC leads to peeling of the composite layer but has caused no tube leaks. SCC in the composite layer and weld overlays is characterized by multi-directional “snowflake” or “spider web” cracks. SCC has not been reported in ferritic stainless steel overlays and is not feasible in thermal sprayed coatings.

Thermal and mechanical fatigue cracks, which generally are singular; shorter and straighter than SCC; spaced and parallel if there are more than one, can lead to leaks. However, because fatigue is not predictable, finding a fatigue crack is serendipitous: a tube with no crack after many years could crack in the next six months if thermal fatigue conditions persist.

NOTE: It is generally recommended practice to convert a sharp fatigue crack into a blunt groove - without filling the groove by welding, depending on the groove depth. Welding produces tensile residual stress that increases the probability of a new fatigue crack.

Inspection intervals

Because every pressurized part of a new boiler was intended to have a service life of at least 20 years, the interval between inspections can nominally be many years. Warranty, jurisdictional, and performance or process considerations may require a shorter interval than is suggested by risk-based methods. To safely increase the interval of inspection of particular zones, an engineering approach must be applied that recognizes both risk-based thought, and known damage mechanisms affecting the particular boiler.
The standard risk-based method for establishing the time interval before the next inspection of pressurized equipment begins with estimating the equipment or component’s remaining life as a result of known, predictable damage mechanisms. Analysis should begin with places with the known shortest remaining life first. Usually, this is where predicted corrosion damage rates are fastest, or most significant.

“Remaining life” typically is calculated from the predicted consumption of the corrosion allowance, or the rate at which another time-dependent damage mechanism could reach a defined limit. The next inspection typically is scheduled around halfway through the estimated remaining life, with greater confidence the more accurately the damage rates are known. This clearly requires reliable inspection and testing over a reasonable time.

A risk-based inspection program would allow extended intervals between tube inspections where the half-life of the tube is two years or greater. Repair or replacement of the tube would likely be more cost-effective than continuing inspections for tubes with a lesser half-life.

Persistent unpredictable problems, such as cracking in airport fill plates and welds, can be mitigated by design or material changes to eliminate that as a reason for taking a recovery boiler out of service every year. This also applies to smelt spouts which can be made to last more than two year by systematically mitigating corrosion and cracking damage mechanisms that compromise the spouts’ reliability.

Keywords
Recovery, boiler, inspection, corrosion, damage

Additional information

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References
8. TAPPI Technical Information Paper 0402-18, Ultrasonic testing (UT) for tube thickness in black liquor recovery boilers: Part 1- Guidelines for accurate tube thickness testing (2015 or later) www.tappi.org
9. ASME Boiler & Pressure Vessel Code, Section 1, Power boilers  www.asme.org
10. ANSI Standard API 579-1/ASME FFS-1, Fitness for service  www.api.org
Appendix A – Inspection methods by boiler zone

Review boiler inspection and repair history for evidence of mechanisms and affected locations in the boiler. Tubes to be inspected must be acceptably clean – saltcake deposits and residues prevent effective visual inspection and nondestructive testing and adversely affect the safety of those entering the boiler.

<table>
<thead>
<tr>
<th>Material</th>
<th>Visually inspect for these damage mechanisms</th>
<th>Other NDT</th>
<th>Supplemental NDT</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Floor underside (vestibule)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon steel, coated overlaid composite</td>
<td>Smelt leaks, tube dents/ crimping from impacts (indicators for topside investigation). Tube leaks at headers.</td>
<td>PT or MT for membrane cracks, UT</td>
<td></td>
</tr>
<tr>
<td><strong>Floor fireside (topside)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon steel – plain</td>
<td>Uniform/ localized corrosion, denting, bulging, ESP damage</td>
<td>UT</td>
<td></td>
</tr>
<tr>
<td>Carbon steel – studded</td>
<td>Same as plain, plus divots and restudding damage</td>
<td>UT</td>
<td></td>
</tr>
<tr>
<td>Carbon steel – thermal sprayed</td>
<td>General condition; CS corr. at coating failure</td>
<td>UT</td>
<td></td>
</tr>
<tr>
<td>Carbon steel – CRA overlay</td>
<td>General condition; CS corr. at coating failure</td>
<td>UT, PT</td>
<td></td>
</tr>
<tr>
<td>Composite tube</td>
<td>General condition; CS corr. at coating failure</td>
<td>PT for cracks, UT</td>
<td></td>
</tr>
<tr>
<td><strong>Lower furnace – straight wall tubes (up to tertiary air level)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon steel - plain</td>
<td>Uniform/ localized corr., denting, bulging, ESP damage</td>
<td>Trend corrosion pattern by UT grid survey or EMAT UT.</td>
<td>Monitor worst corrosion with UT</td>
</tr>
<tr>
<td>Carbon steel – studded</td>
<td>Same as plain; therm. fatigue; stud divots &amp; restudding damage</td>
<td>Monitor worst corrosion with UT</td>
<td></td>
</tr>
<tr>
<td>Carbon steel – thermal spray</td>
<td>Corrosion at coating failures</td>
<td>UT exposed CS</td>
<td></td>
</tr>
<tr>
<td>Carbon steel – CRA overlay</td>
<td>Corrosion at overlay flaws</td>
<td>UT exposed CS</td>
<td></td>
</tr>
<tr>
<td>Composite tube</td>
<td>Surface roughness (overheat)</td>
<td>UT exposed CS</td>
<td></td>
</tr>
<tr>
<td><strong>Lower furnace – bent wall tubes at openings and elsewhere (up to tertiary air level)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon steel (no CS corrosion in air-rich gas)</td>
<td>Therm. fatigue cracks at welds</td>
<td>PT, MT</td>
<td></td>
</tr>
<tr>
<td>Composite tube</td>
<td>Overheat evidence, “balding” corr., thermal fatigue cracks</td>
<td>PT per TAPPI TIP 0402-30</td>
<td>Monitor exposed carbon steel w/ UT</td>
</tr>
<tr>
<td><strong>Upper furnace</strong></td>
<td></td>
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</tbody>
</table>
### Carbon steel

<table>
<thead>
<tr>
<th>Section</th>
<th>Inspection Focus</th>
<th>Testing Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Best Practice for Recovery Boiler Inspection</td>
<td>Oblique VT for reducing gas corrosion above cutline</td>
<td>UT (EMAT UT)</td>
</tr>
<tr>
<td>Best Practice for Recovery Boiler Inspection</td>
<td>Pocket corrosion; superheater tubes rubbing roof tubes</td>
<td>Pit probe/ gauge</td>
</tr>
<tr>
<td>Screens</td>
<td>Pocket corrosion; sootblower erosion</td>
<td>Pit gauge, UT</td>
</tr>
<tr>
<td>Superheaters</td>
<td>Molten salt corrosion in hottest part; overheat corrosion; sootblower erosion</td>
<td>UT (EMAT UT)</td>
</tr>
<tr>
<td>Superheaters</td>
<td>Thermal &amp; mechanical fatigue at connections with stress risers, esp. distorted tubes</td>
<td>MT or PT</td>
</tr>
<tr>
<td>Generating section</td>
<td>Uniform pitting/ localized corr. (acidic sulfates); sootblower accel. corr in s/b lanes</td>
<td>Special test for near drum corrosion UT (EMAT UT)</td>
</tr>
<tr>
<td>Generating section</td>
<td>Uniform pitting/ localized corr. (acidic sulfates); sootblower accel. corr in s/b lanes</td>
<td>UT (EMAT UT)</td>
</tr>
<tr>
<td>Economizer</td>
<td>Uniform pitting/ localized corr. (acidic sulfates); sootblower accel. corr in s/b lanes Acid condensate corr. on coldest tubes &amp; heaters</td>
<td>UT</td>
</tr>
<tr>
<td>Penthouse</td>
<td>Ash/ saltcake deposits from roof leaks; erosion or rubbing at tube intersections</td>
<td></td>
</tr>
<tr>
<td>Nose arch airspace</td>
<td>Look for gas/ saltcake leaks</td>
<td></td>
</tr>
</tbody>
</table>