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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.

TIP Category: Automatically periodically reviewed (Five years)



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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

Predictable corrosion 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.