This is an edited version of Case Study 2 from Corrosion and Stress Related Boiler Tube Failure Case Histories by E.M. Labuda and R.D. Bartholomew (both of STPA) presented at Corrosion 2007, NACE.

ABSTRACT

A case study involving a waterwall tube from a conventional high-pressure boiler is presented. The tube was affected by cracking initiated on the waterside surface. The cracking was associated with cyclic thermal stresses. Results of visual examination, waterside deposit density and elemental composition, and optical metallography are provided. The effects of the environment and cyclic thermal stresses on the crack morphology are discussed.

INTRODUCTION

Cyclic thermal stresses can contribute to waterwall tube cracking. Thermal stresses have been defined as "stresses in metal resulting from non-uniform temperature distribution" [1]. The stresses can be grouped into the following categories for waterwall tubes:

1. Expansion of two pieces of metal at different rates. For example, weld attachments where thermal expansion or contraction of one or both pieces of metal results in tensile stresses (strain) on the tube interior or exterior. Pad welding and dissimilar metal weld overlay also can add to surface stresses. During operation, the resultant stress can be fixed or cyclic. Stressed surfaces are more susceptible to cracking and corrosion (stress-assisted corrosion).
2. Sudden longitudinal expansion or contraction of the waterwall tube causing brittle fracture of the protective oxide coating. Where the oxide is ruptured, oxide rapidly reforms on the exposed metal surface. If this cycle is repeated many times or if the environment is particularly corrosive, significant corrosion can result. Corrosion results in thinner walls, and thinner walls result in higher hoop stresses that increases the potential for cracking. Excessive cyclic stresses can result in predominantly cracking mechanisms (e.g., thermal fatigue cracking or circumferential waterwall cracking). In waterwall tubes, corrosion often is a contributing factor due to the corrosivity of the fireside environment of a boiler burning coal or other mixed fuels (e.g., black liquor, refuse-derived fuels, etc.) or the rapidity of the iron/water reaction on the waterside surfaces of all boilers and heat recovery steam generators via the Schikorr reaction [2]. Cracking usually is circumferential.
3. Varying hoop stress caused by temperature fluctuations. Cyclic hoop stress can cause tube expansion resulting in creep-like longitudinal waterwall tube cracking. These cracked areas may be subject to corrosion as well. Once-through and other high pressure boilers will tend to be more susceptible to this type of failure due to the higher operating temperatures and higher internal pressures.

Thermal stress-related failure mechanisms for steam generators and other power plant equipment are not new and have been well described in past references [1, 3]. However, there has been a plethora of these types of failures in recent years in heat recovery steam generators (HRSGs) and a number of papers have been written discussing factors to reduce thermal stresses [4, 5]. Also, thermal fatigue cracking of waterwalls is reported to be the leading boiler tube failure mechanism in supercritical boilers [6]. The focus of this discussion is on conventional boilers.

Thermal stresses in boilers have been attributed to the following:

1. Rapid boiler startups or shutdowns. Boiler manufacturers generally have guidelines on the rate of heating and cooling for proper startup and shutdown of boilers. Reference 7 provides an example for once-through supercritical boilers [(7)].
2. Water quenching of fireside surfaces from condensate in steam sootblowers (or from water canons - where used).
3. Water quenching in bottom ash hoppers (for wet-bottom boilers).
4. Weld overlays applied to the boiler furnaces resulting in thicker walls and greater outer diameter tube metal temperatures.
5. Flame impingement due to long flames experienced with some low NOx burners.
6. More reducing environment on the fireside surfaces (due to low NOx burners and greater use of over fire air introduction), which can result in uncontrolled loss of the protective slag and oxide layer. In addition to increased fireside corrosion, lack of a stable slag layer results in higher fireside tube surface temperatures. Use of lower quality coal or supplemental fuels also is believed to have contributed to molten slag problems at some facilities.
7. Extended operation with thick waterside scales, which raises the tube metal temperatures. This can result from the accumulation of deposits. Also, for some once-through boilers formation of a very dense, oxide layer on waterside surfaces have been noted. In the past, some once-through boilers needed to be cleaned frequently due to high pressure drops created by a rippled magnetite on the tube interiors. The implementation of oxygenated feedwater treatment in once-through boilers has allowed extended operation without chemical cleaning. The longer operating periods provided extended time for iron and water reaction resulting in thick oxide formation.

As indicated by the preceding discussion of contributing factors, control of thermal stresses is dependent on the design, operation, and maintenance of a unit. Because of the difficulty in controlling thermal stresses, thermal stress induced damage is expected to be an ongoing concern for boilers in power plants and industrial facilities.

CASE HISTORY

Waterwall Tube Failure

A waterwall tube with a large portion of the hot side missing was received for metallurgical examination. Based on the information provided, the failure was about one tube west of an observation port and approximately two feet from an angled corner where oil guns were located. Figure 1 shows the failed waterwall tube in the as received condition. The tube exhibited two, longitudinal thick-lip failure edges, which were very close to the tube membrane separating the hot and cold sides. The circumferential edges of the failure show plastic deformation, which was the result of tensile overload during the final stage of tube rupture. Note that both longitudinal edges are covered with melted metal since a torch was used to remove the failed tube from the wall. Removing failed tubes with a torch is not a good practice and should be avoided because it alters both the morphology of the fractured surface and the tube metal microstructure at the failure edge. Dry saw-cutting is preferred.

Visual examination of waterside surfaces revealed the presence of short, disconnected ID cracks along the plane of failure near the open rupture. Also, there was an attachment on the cold side. However, no corrosion fatigue cracking at or near the attachment on the waterside surface was noted. No significant general or localized waterside corrosion was apparent away from the plane of failure. Waterside surfaces supported a dark brown-colored buildup with a reddish tint. The extent of hot waterside deposit accumulation away from the failure was equivalent to 27 g/ft^2 (29.1 mg/cm^2). No ID pitting or cracking was apparent away from the failure. No wall thinning from the fireside surface near the failure opening was evident.

Hot waterside deposit was composed primarily of iron oxide (30%) and copper and copper oxide (45%). An additional 21% of the deposit was composed of nickel and zinc oxides. The relative proportions of zinc and nickel oxides suggested corrosion of cupronickel heat exchanger tubing as the primary source of copper. The only other ingredients at significant concentrations were hardness phosphates. About 2% calcium and magnesium phosphates was detected; however, there was more phosphate than can be accounted for by the hardness. This suggests the potential for phosphate/magnetite interaction, which typically leads to boiler water chemistry control problems (particularly during cyclic operation).

Metallurgical examination revealed the presence of longitudinal cracks at and near the heat-affected zone from the membrane weld. Two mounted and polished specimens cut from the failure edge are exhibited in Figure 2. The morphology of the fracture edge is shown in Figure 3. Multiple parallel cracks were noted in the vicinity of the failure. The tube failed along one such crack as evidenced by the presence of corrosion products along the entire failure edge. Other ID cracks found in the vicinity of failure were blunt-tipped with no branching; these cracks did, however, exhibit signs of discontinuous growth. The cracks were filled with waterside corrosion products/deposits. The presence of metallic copper within the waterside buildup was evident. Note that all ID cracks near the failure were localized and grouped on the ID surface along the heat-affected zone from the membrane weld on the fireside (see Figure 2). In addition to localized ID cracking, minor OD cracking was noted from the fireside surface at the toe of the membrane weld. The morphology of both ID and OD cracks near the membrane indicates the presence of thermal cyclic stresses. Similar ID cracking in the vicinity of failure, although less intense, was noted on the opposite side of the membrane on the cold side. Again, the location of this ID crack corresponded to the toe of the membrane weld on the cold side. The presence of ID cracks on both sides of the membrane weld is consistent with cyclic thermal stresses acting on the waterwall tube from both hot and cold sides of the membrane weld, although to a much lesser degree on the cold side than on the hot side - as is typical.

ID cracks were both transgranular and intergranular and exhibited an irregular profile, as is typical of corrosion fatigue (Figure 4). The tube metal microstructure at and near the failure was overheated. However, since the cracking propagated through the heat-affected zone of the membrane weld, the extent of in service overheating, if any, could not be determined. Also, the overheating, at least in part, could be the result of the tube removal process. Note that failure edges were covered with melted metal as a result of torch cutting (see Figure 1).

The condition of the ID surface in the plane of failure but about one inch (2.54 cm) from the rupture opening is shown in Figure 5. The presence of small, fatigue-type cracking in the plane of failure was evident. The morphology and depth of cracking changed with the distance from the membrane weld. The cracks were smaller and more irregular farther away from the membrane weld (Figure 6). At the center of the hot side, only ID pitting was noted (Figure 7). The presence of metallic copper scattered throughout the deposit is evident. Since the water environment along the affected surfaces should have been the same, the different crack morphology probably was the result of different orders of magnitude of cyclic stresses - depending on the distance from the membrane weld. As a result, corrosion rather than stress appeared to have a large impact on the morphology of the smaller ID cracks away from failure and closer to the center of the hot side. Such morphology of small cracks away from failure can be classified as stress-assisted corrosion rather than corrosion fatigue (compare cracks in Figures 3 and 6).

Hot waterside deposits were rich in metallic copper (Figures 3, 5, and 7). Bulk metal microstructures on the hot and cold sides away from the membrane were practically the same and consisted of partially spheroidized carbides within the pearlite areas in ferrite colonies. Since the degree of spheroidization on the cold side was very similar to that on the hot side, it was concluded that spheroidization was the result of the initial heat treatment rather than in-service tube metal overheating. The waterwall tube sample failed due to ID cracking along the heat-affected zone of the membrane weld. The morphology of cracking was consistent with thermal cyclic stresses. ID cracks were noted on both sides of the membrane; however, cracks were deeper on the hot waterside of the membrane than on the cold waterside of the membrane. Also, the size of the cracks on the hot waterside diminishes with distance from the membrane. No cracking or significant ID pitting was apparent along the hot side crown.

The major factor contributing to this failure appears to be cyclic thermal stress near the membrane weld in the area where the tube metal temperature is expected to be higher than in the rest of the boiler (near the oil guns). This type of cracking is accelerated by increased cyclic operation.

SUMMARY AND CONCLUSIONS

This case study discussed cracking of a water wall tube related to thermal stresses and corrosion. Cracks, which formed due to thermal stresses in an area without significant waterside corrosion were examined.

Intergranular and transgranular cracking with no branching was found in the areas affected by high stresses and nominal waterside corrosion. It was shown that the morphology of cracks depends on the magnitude of cyclic stress.

In the absence of cyclic thermal stress but in the presence of potentially corrosive environment, only gouging, underdeposit corrosion and/or hydrogen damage are expected on the hot waterside surface of a boiler tube. In the presence of cyclic thermal stresses, previously corroded areas are expected to be susceptible to cracking leading to premature (catastrophic) tube failure. Possible sources of thermal stresses were briefly discussed.

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