PROCEEDINGS : COFA–1997
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High temperature boiler tube failures – Case studies

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ABSTRACT

Numerous investigation on high temperature failures of boiler tubes received from different thermal power plants had been carried out This paper presents three case studies of such failures. These include failures of (i) reheater tube of 1.25Cr–0.5Mo steel, (ii) carbon steel tube and (iii) final superheater tubes of 2.25Cr–1Mo steel. The reheater tube had extensive damage in the form of pitting on outersurface. X-ray microanalysis using SEM revealed the presence of corrosive elements viz. K, Ca etc. on the pitted surface. Sticking of fly ash particles containing such elements causing reduction in effective tube wall thickness is responsible for the failure of reheater tube. The carbon steel tube showed a brittle window fracture. Decarburized metal containing intergranular cracks at the inner surface is indicative of hydrogen embrittlement responsible for this failure. In contrast, an extensive study on final super heater tube conclusively proves that the failure took place due to short term overheating. The extent of overheating had been estimated from the kinetic data on oxide scale growth and was found to be about 830°C. Surprisingly the tube had experienced a circumferential expansion as high as 19%. The wall thinning due to fireside corrosion, embrittlement and oxidation are primarily responsible for the failure of these tubes. It had been established considering the influence of wall thinning that irrespective of operating temperature, pressure and damage development, modified 9Cr–1Mo steel exhibits longest life among the various grades of Cr–Mo steel.

INTRODUCTION

The boilers are energy conversion systems where heat energy is used to convert water into high pressure steam, which can further be used to drive a turbine for electric power generation or to run plant and machineries in a process or manufacturing industry. The fuel used is fossil fuel which can be solid, liquid or gas. The water is heated indirectly and hence transmission of heat takes place through the tube wall. This leads to high temperature corrosion on the fireside as well as o the water side [1,2]. On fireside there can be attack by fly ash as well as salt deposit like Na_2SO_4, V_2O_5 etc. On water side the reaction between water and pipe materia gets accelerated due to high temperatures. There is a tendency of salt deposition o the inner surface of the tube. The formation of oxide layer and deposits may decreas the heat transfer from fireside to water side leading to an increase in tube wal temperature.

The boiler tubes are subjected to a wide variety of failures involving one o more mechanisms. The most prominent among these are fireside corrosion, wate side corrosion including hydrogen damage and fracture including thermal fatigue LCF, HCF and creep rupture. Some of the major causes of failures can be classifie as improper selection of material, improper operation including maintenance an inadequate water treatment, design and fabrication defects. Amongst these imprope operation which includes evidence of overheating, corrosion both water/steam sid and fireside as well as improper defective material together account for more tha 75% of all failures. A few typical characteristics of such failures are summarised i the following section:

Overheating

Superheater and reheater tubes of a power plant boiler normally operate a temperature 30°C to 85°C higher than the temperature of the steam inside the tube Although high heat flux causes high tube wall temperature, deposits have a greate effect on tube wall temperature and therefore on overheating [3].

A tube rupture caused by overheating may occur within a few minutes or tak several years. The fracture path is longitudinal with some detectable plasti deformation.

Thick lip rupture is the characteristics of boiler tube failure due to stress ruptur as a result of prolonged overheating at a temperature slightly above the operatin temperature. Such failures often reveal the evidence of low ductility, insignificar tube swelling, excessive inner scale and other evidences of oxidation and corrosio damages. The microstructure exhibits the evidence of spheroidisation of carbid particles, intergranular oxide penetration, cavitation etc. In contrast, thin lip rupture are transgranular tensile fracture, occurring at a temperature beyond the lower initi temperature of the tube material, caused by rapid overheating. Even though tub wall thinning characterises all rapid overheating failures, rapid overheating ma not necessarily be the cause of all ruptures that exhibit tube wall thinning. Erosio and corrosion are mechanisms that can also cause tube wall thinning and subseque rupture.

Embrittlement

Tube rupture caused by embrittlement of the tube material result from metallurgical changes that affect its ability to sustain service loads. Hydrogen damage is the main mechanism responsible for making the tube material susceptible to brittle fracture. The tubes that have undergone this type of damage often rupture exhibiting window type fracture in which a portion of tube wall is detached. The microstructures of the tubes, failed due to hydrogen damage, exhibit discontinuous intergranular cracking accompanied by decarburisation. Between tube metal and the deposit, the steel is actively being corroded in acidic conditions when the boiler water pH is below 7.

$$2H^{+} + Fe = Fe^{2+} + 2H$$

Nascent or atomic hydrogen diffuses into steel and reacts with cementite to form ferrite and methane

$$4H + Fe_3C = 3Fe + CH_4$$

Methane being a large molecule cannot diffuse out of steel. It collects at ferrite grain boundries and when pressure is high enough, leaves cracks behind.

Fireside corrosion

The combustion of fossil fuels produces solid, liquid and gaseous compounds that can be corrosive to heat-transfer surfaces. The composition of coal ash obtained from combustion process varies widely but is chiefly composed of Si-, Al-, Fe- and Ca–compounds with smaller amounts of Mg-, Ti-, Na- and K- compounds. A liquid phase is formed in the ash deposit adjacent to the tube surface. In coal fired boilers, the liquid phase is a mixture of Na and K-Fe-trisulphate – [$Na_3Fe(SO_4)_3$ and $K_3Fe(SO_4)_3$], respectively. The melting point of this mixture is about 555°C. In oil fired boiler the liquid phase that forms is a mixture of V_2O_5 with either Na_2O or Na_2SO_4. Mixture of these compounds have melting points below 540°C.

Coal ash corrosion starts with the deposition of fly ash on the surfaces that operate predominantly at temperatures from 540°C to 705°C of superheater and reheater tubes. Over an extended period of time, volatile alkali and sulphur compounds condense on fly ash and react to form complex alkali sulfate, such as $KAl(SO_4)_2$ and $Na_3Fe(So_4)_3$ at boundary between the metal and deposit. The deposit consists of three distinct layers : (i) The porous, outermost layer comprises the bulk of the deposit and is composed essentially of the same compounds found in fly ash, (ii)The inner most layer is a thin, glassy substance composed primarily of corrosion products of iron, (iii) The middle layer known as white layer is whitish or yellowish in colour and is water soluble, producing acid solution. The fused layers contain sulfides as part of corrosion product. None of the conventional tub material is immune to such attack, although austenitic stainless steels corrode ε slower rates than lower alloy grades. Coal ash corrosion causes significant wa thinning to a point at which the steam pressure in the tube constituted an overloa of the remaining wall. Failure of tubes due to coal ash corrosion is accelerated b increase in operating temperature and also by the use of inferior grade of coal.

In this paper three case studies related to failure of boiler tubes primarily due t fireside corrosion, embrittlement and overheating due to high temperature oxidatio at the inner wall of the tubes have been discussed. Since the prevalence of suc events causes significant wall thinning, it is imperative that from the view point c safety and economical reasons one must look into the life prediction aspect considering the influence of wall thinning. This paper, therefore, also presents simple methodology of life estimation under wall thinning condition highlightin some typical results.

CASE STUDY - I

FAILURE OF A REHEATER TUBE

Figure 1 shows a failed reheater tube from a 500 MW boiler. The reheater tub was of pendent type placed in the convective zone. The operating pressure was 2: kg/cm^2 and steam outlet temperature was 535°C. Flue gas temperature in the zon was 700–720°C (design). The tube material was 1.25Cr–0.5Mo (T11 grade).

Fig. 1 : Extensive damage on outersurface of a failed reheater tube

The tube had suffered extensive damage on the outer surface in the form o pits. The dimension of the pits at some places were as big as 40 mm x 10 mm witl a maximum depth of 2 mm. The pitted surface bore brownish colour in contrast tc the damage free surfaces of the tube. The latter bore usual black oxide. The failur had occurred after about 24,000 hours of service life.

The investigation carried out at NML showed that the tube had the typical microstructure consisting of ferrite and bainite and the mechanical properties were also found to be normal [4]. Also, no appreciable diametrical expansion was observed.

Since the tube showed extensive pitted surfaces, x-ray microanalysis using SEM was carried out on the pitted surfaces to ascertain the presence of corrosive elements. The results of the analysis are given in Fig. 2. The presence of highly corrosive elements like K and C1 were observed. The other elements present in the pitted surface as evident from Fig. 2 were Ca, Si and S. The presence of these elements suggested that the attack was caused by the fusion of ash particles. Such attack usually occurs due to :

- volatalisation and condensation of volatile ash constituents containing Na_2SO_4 or $CaSO_4$
- temperature excursion beyond 650°C particularly during the starting period when no steam flows through the reheater tubes.

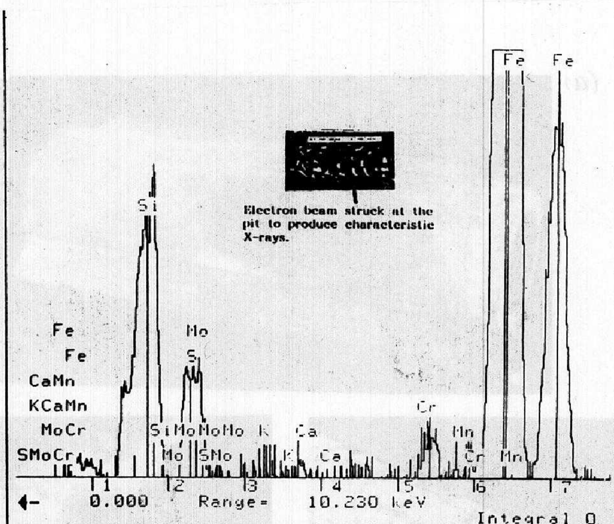

Fig. 2 : Presence of corrosive elements (Si, S, K etc.) on pitted surface of reheater tube

Ash particles of low fusion point can fuse and stick on the tube surfaces at such temperatures. It may be noted that alkali metals along with S and Fe can form ash with fusion temperature as low as 620°C. The fuel oil used for the support can also cause this problem if the oil contains corrosive elements like V and S. Tube wall thinning due to sticking of fly ash particles is primarily responsible for the failure of the reheater tube.

CASE STUDY - II

FAILURE OF CARBON STEEL TUBE

Figure 3(a) shows a failed carbon steel tube. The outer diameter and thicknes of the tube are 45 mm and 4.5 mm respectively. The fracture was of the brittl window type, without the fish mouth appearance which is a characteristic of over heating failure. Visual examination showed a substantial degree of corrosion o the water surface leaving a rough area in the vicinity of rupture. Microstructura examination of a cross section through tube wall, as shown in Fig. 3(b), reveale decarburisation and extensive discontinuous intergranular cracking. The presenc of laminated oxide layer (Fig. 3(b)) and concentration of chlorides at the interfac between oxide and metal at the base of corrosion pits (Fig. 3(c)) are also eviden from microstructural examination. The combination of water side corrosion (oxi dation), decarburisation and intergranular cracking, as observed in this case, led t the conclusion that the tube had failed because of hydrogen damage involving th formation of methane by the reaction of dissolved hydrogen with carbon in steel

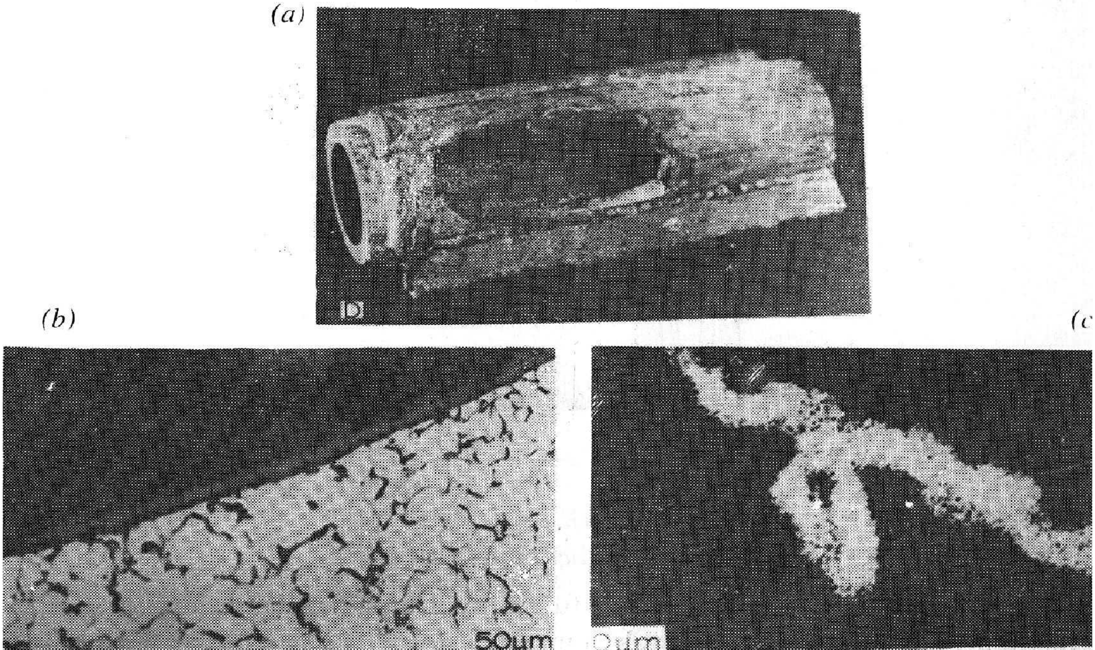

Fig. 3: (a) Brittle window type fracture of a carbon steel tube, (b) Microstructure, throug tube wall near rupture, revealing decarburised metal and extensive discontinuous inte granular cracking and (c) Microstructure revealing chloride distribution at the interfac between oxide and metal at corrosion pits.

CASE STUDY – III

FAILURE OF FINAL SUPERHEATER TUBES

Failure of final superheater tubes of a 500 MW boiler occurred during trial run following a service exposure of about 100 hours. Material specification and operating parameters of the tubes are summerised in Table 1.

Table 1 : Material specification and operating parameters of superheater tubes

Material	:	2.25 Cr-1Mo Steel as per ASTM A 213 T22
Outer diameter	:	44.5 mm
Thickness	:	10 mm
Steam temperature	:	560°C–580°C
Steam Pressure	:	185 kg/ cm²
Steam flow rate	:	1700 tons/hr.

The tube samples selected for this investigation, as shown in Fig. 4, are (i) a piece of tube from the zone of failure, (ii) a piece of tube adjacent to the failed tube, termed as undamaged tube and (iii) a piece of virgin tube.

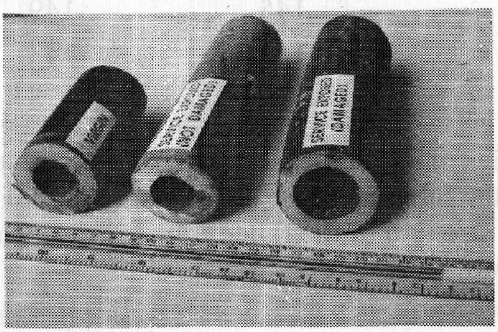

Fig. 4 : Virgin, undamaged and failed final superheater tubes of a 500 MW boiler

The chemical composition of the failed and virgin tube, reported in Table 2, indicates that the chemistry of both tubes meets the ASTM specification. The outer diameter of the failed tube was found to be 49.2 mm against the original diameter of 44.5. The most significant point in this case is the gross circumferential expansion of the failed tube upto about 19%. Such an extensive expansion cannot be expected under normal operating condition within a short span of service exposure of about 100 hours.

Table 2: Chemical composition (in Wt%)

Element	Failed Tube	Virgin Tube	Specification ASTM A 213 T22
Carbon	0.12	0.1	0.06–0.15
Manganese	0.41	0.42	0.30–0.60
Silicon	0.22	0.22	0.50 max
Phosphorus	0.013	0.012	0.025 max
Sulphur	0.003	0.003	0.025 max
Chromium	2.16	2.13	1.90–2.50
Molybdenum	1.05	1.00	0.87–1.13

It is evident from the measurement of hardness at the inner surface, mid section and outer surface of all tubes (Table 3) that the hardness of the failed tube is significantly higher than that of virgin and undamaged tubes.

Table 3 : Hardness values of as received tubes

Tubes	Hardness, HV20		
	Inner	Middle	Outer
Virgin	145	149	151
Undamaged	143	143	145
Failed	179	178	180

The tensile properties of all tubes, as shown in Fig. 5, revealed that irrespective of test temperature all the tubes meet the minimum specified properties of 2.25Cr–1Mo steel. The tensile strength of the failed tube is, however, significantly higher than that of the other tubes.

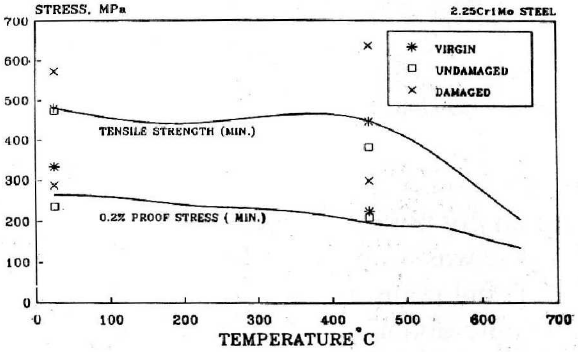

Fig. 5 : Tensile properties of virgin, undamaged and failed final superheater tubes of a 500 MW boiler

The microstructures of virgin (Fig. 6a) and undamaged (Fig. 6b) tubes are almost similar, consisting of ferrite and tempered bainite. In contrast the microstructure of the failed tube (Fig. 6c) showed the presence of freshly formed bainitic areas. Besides, the oxide scale thickness on the inner surface of the failed tube (Fig. 7a) was found to be several folds more than that of the undamaged tube (Fig. 7b). In the failed tube the oxide scale thickness was of the order of 0.25 mm.

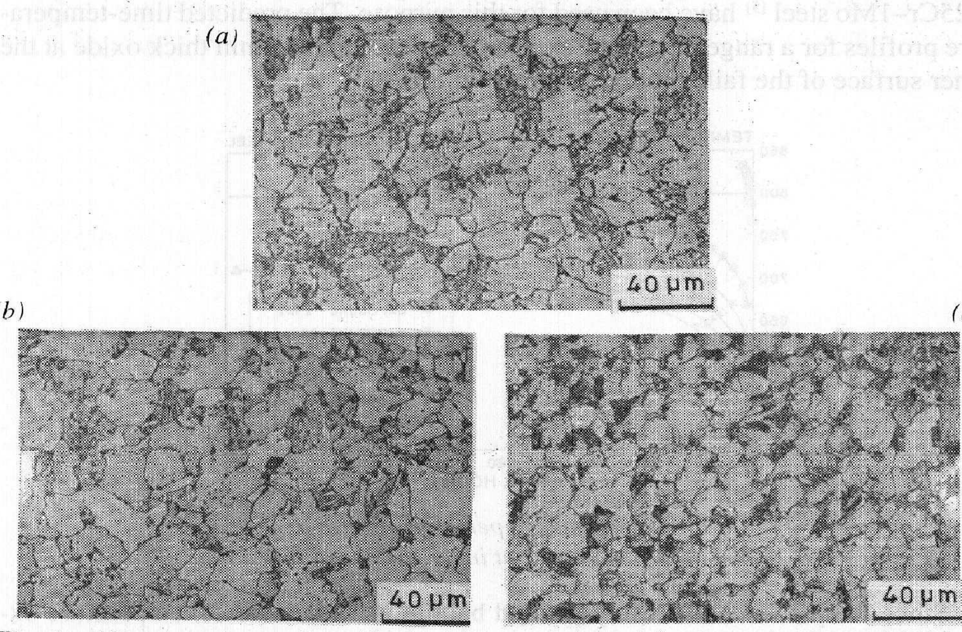

Fig. 6 : Microstructures of (a) Virgin tube consisting of ferrite and tempered bainite; (b) Undamaged tube consisting of ferrite and tempered bainite and (c) Failed tube showing freshly formed bainitc areas

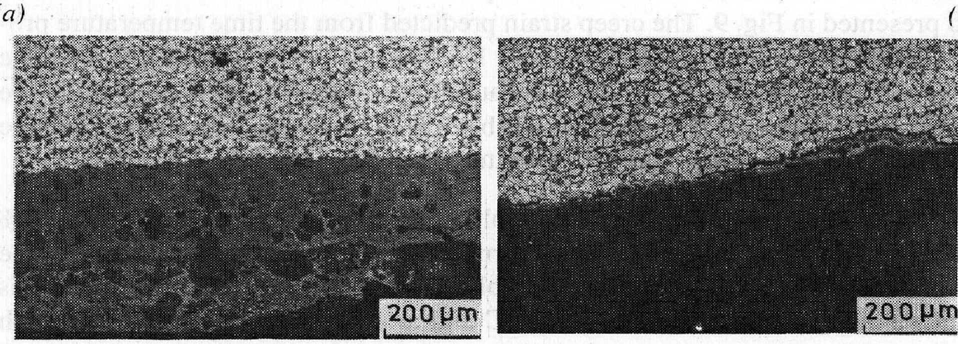

Fig. 7 : (a) 0.25 mm thick oxide scale at inner surface of failed tube and (b) Insignificant oxide scale at inner surface of undamaged tube

All the above observations can be reconciled in a situation only if the temperature had exceeded the lower critical temperature which is reported to be about 800°C for 2.25Cr-1Mo steel.

In order to predict the extent of temperature excursion beyond the critical temperature some detailed analysis was made based on oxide thickness as obtained on the inner surface of the failed tube. Published kinetic data on oxide scale growth of 2.25Cr–1Mo steel [5] have been used for this purpose. The predicted time-temperature profiles for a range of service exposure to develop 0.25 mm thick oxide at the inner surface of the failed tube are shown in Fig. 8.

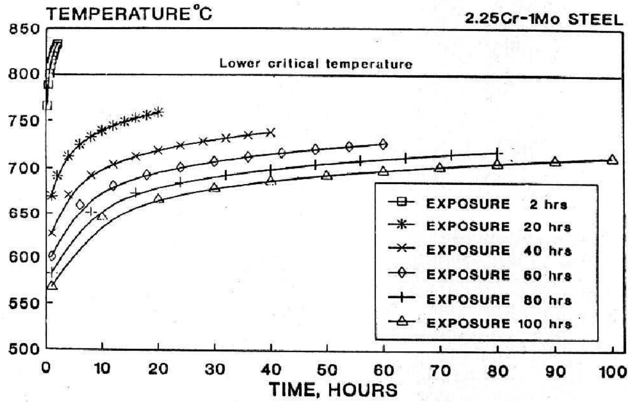

Fig. 8: Predicted time temperature profiles to develop 0.25 mm thick oxide layer at inner surface of failed tube.

Since the presence of freshly formed bainite is indicative of temperature excursion beyond the lower critical temperature, the most probable profile that the tube experienced is the one having an exposure of 2 hours, the maximum temperature being 830°C. Corresponding to each time-temperature profile (Fig. 8), accumulation of strain and the diametrical expansion of the tube have been calculated and presented in Fig. 9. The creep strain predicted from the time temperature profile for 2 hours exposure comes to about 1% which is indeed quite lower than the observed value of 19%. It is mainly because the existing material database in the temperature range of 500°C to 600°C has been used for extrapolation. Clearly there is a need to collect creep data at temperatures beyond 600°C.

In order to ensure whether it is possible to achieve a creep strain of about 19% within a short time at 830°C, a short term creep test has been carried out in the laboratory. Based on this it has been established that a creep strain of about 16% is achievable in less than 2 hours at 830°C and at a stress level of 30 MPa which represents the hoop stress corresponding to the maximum operating pressure of 185 kg/cm^2 for the tube in question. This, therefore, conclusively proves that the

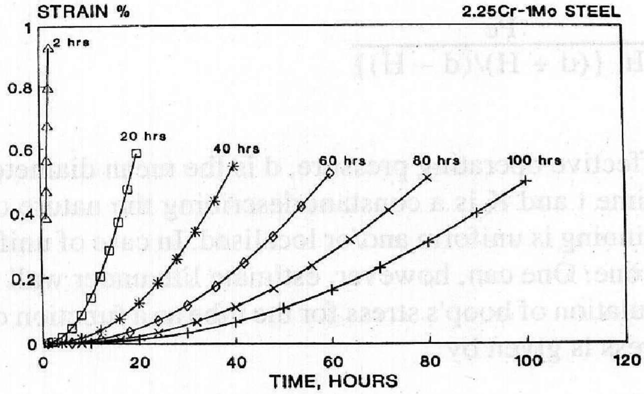

Fig. 9: Predicted creep strain corresponding to time temperature profiles shown in Fig. 8

failure of the tube took place due to short term overheating to a temperature of about 830°C. Partial chocking of the tube by some foreign material could be responsible for such overheating. The other tubes, however, did not suffer any heavy temperature excursion beyond 650°C.

Although the high temperature mechanical properties of service exposed components are often found to be better than the minimum specified level, the component dimensions often change as a result of prolonged service. The most prominent amongst these is the loss of tube wall thickness. The growth of oxide scale at tube surfaces is primarily responsible for this. Other external processes such as coal ash corrosion, flame impingement and fly ash erosion also contribute to such damage development in service. A need is thus felt to look into the life prediction problems considering the influence of wall thinning due to the existence of corrosion and erosion processes during operation of the plant. Keeping this in view the methodology recently developed for creep life estimation of boiler tubes under wall thinning condition highlighting some typical results has been discussd in the next section.

LIFE ESTIMATION UNDER WALL THINNING CONDITION

Method of life estimation

A simple method for estimating creep life of boiler tubes in presence of corrosion and erosion processes has recently been proposed by Zarrabi [6]. This is based on calculation of reference stress for the tube as a function of time assuming constant thinning rate on either side of the tube. For various components, expressions for reference stress are available in the literature [7]. Such an expression for boiler tube is given by

$$\sigma_{Ref} = \frac{\sqrt{3}}{2} K \frac{Pe}{\ln\{(d+H)/(d-H)\}} \qquad \ldots \quad 1$$

where Pe is the effective operating pressure, d is the mean diameter, H is the wall thickness at any time t and K is a constant describing the nature of wall thinning i.e. whether the thinning is uniform and/or localised. In case of uniform thinning K becomes equal to one. One can, however, estimate life under wall thinning condition based on calculation of hoop's stress for the tube as a function of time. Expression for hoop's stress is given by

$$\sigma_{Hoop} = Pe.d/(2H) \qquad \ldots \quad 2$$

For a constant thinning rate ($\overset{o}{H}$) wall thickness (H) at any time (t) can be expressed as

$$H = Ho - \overset{o}{H}\,.\,t \qquad \ldots \quad 3$$

where Ho is the initial wall thickness of the tube. Another important factor to be considered for life estimation is the prediction of stress rupture properties of service exposed material from its master rupture plot. The intersection of two curves representing σ_{Ref} or $\sigma_{Hoop} = f(t)$ and $\sigma_{rupture} = g(T,t)$ provides an estimate of life, where $\sigma_{rupture}$ is the time dependent rupture strength at a temperature (T).

Chaudhuri [8] and Ghosh et. al. [9] carried out extensive analysis and reported the results on estimated creep-lives of several alloy steels over a wide range of operating temperature, pressure, tube wall thickness and thinning rate. The material database and the range of parameters selected for this study by Chaudhuri [8] are summarised in Table 4 and Table 5 respectively.

Table 4 : Materials database

0.50Cr – 0.5Mo Steel [10]
1.00Cr – 0.5Mo Steel [11]
5.00Cr – 0.5Mo Steel [12]
2.25Cr –1.0Mo Steel [13]
9.00Cr – 1.0Mo Steel [14]
Modified 9Cr Mo Steel [15]

Table 5 : Range of parameters

Temperature °C	:	535–600
Pressure, MPa	:	10–18
Original Tube wall thickness, mm	:	5–10 mm
Thinning rate mm/year	:	0.22–0.75
Original outer diameter, mm	:	50

Comparative study following this showed that for a wide range of thinning rate and tube wall thickness, the longest life and resistance to creep damage is achievable in modified 9Cr–1Mo steel, followed by 2.25Cr–1.0Mo Steel (Figs. 10-11).

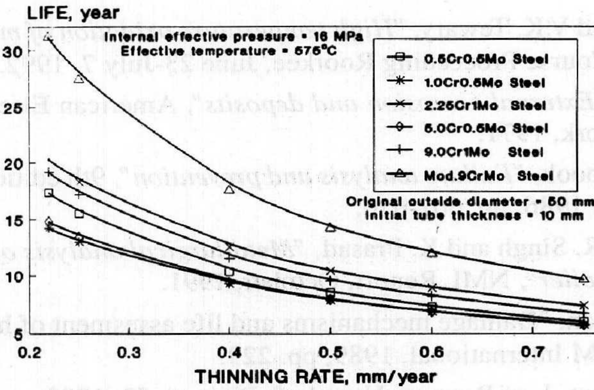

Fig. 10 : Influence of wall thinning rate on creep lives of several alloy steels

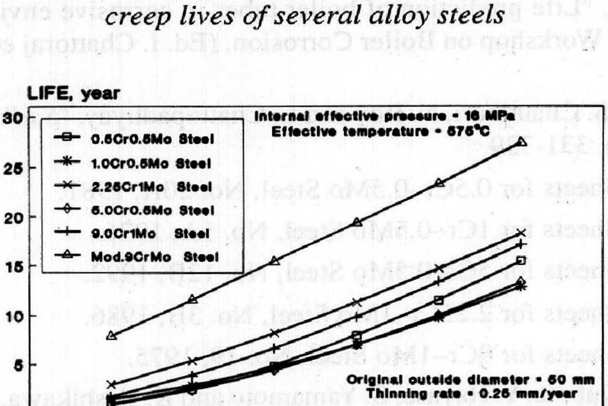

Fig. 11 : Influence of tube wall thickness on creep lives of several alloys steels

CONCLUSION

In conclusion it may, therefore, be said that coal ash corrosion, hydrogen dam age and overheating are mainly responsible for the failure of reheater tubes, car bon steel tubes and final superheater tubes respectively. Analysis of large databas clearly indicates that irrespective of operating temperature and pressure to whicl the boiler tubes are exposed as well as loss of wall thickness due to the corrosion oxidation and erosion processes in service, modified 9Cr–1Mo steel exhibited th longest life/resistance to creep damage. The next candidate material recommende for such operating condition is 2.25Cr–1Mo steel upto a temperature of about 585°C beyond which 9Cr–1Mo steel shows longer creep life.

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