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EXAMINATION OF T11 AND T1A SUPERHEATER TUBING AFTER 61,000 HOURS OF SERVICE

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INTRODUCTION

The Baltimore Gas and Electric Company had experienced a few failures in T11 (1.25Cr 0.5Mo) steel tubing in the secondary superheater of Number 1 Unit, Wagner Station. Mr. Robert Fitzgerald of the Baltimore Gas and Electric Company reported that their investigations had shown the following pertinent information:

(1) Due to partial blockage of steam flow in one circuit, operating metal temperatures were higher than design temperatures. This accelerated both creep and corrosion.

(2) The failures in the T11 tubing occurred at spots where localized coal-ash corrosion had caused considerable thinning of the wall thickness of the tubes. Wall thickness values less than 70% of the minimum specified wall thickness were measured in some localized spots of corrosion.

(3) Measurements of T11 tube diameters at points where there was no wastage due to coal-ash corrosion indicated no measurable creep. In spite of over-temperature the creep was not measurable in the uncorroded T11 tube after 61,000 hours of service.

(4) As much creep as 1.3 % was measured in T1A tubes adjacent to the T11 tubing at locations in the furnace gas stream where temperatures were high. Sections of the same tube a short distance away and outside of the hottest gas stream showed no measurable creep.

The investigation had the following objectives:

(1) Estimation of actual operating temperatures.

(2) Measurement of the remaining creep rupture strengths of the tubing which had been exposed to over-temperature.

(3) Analysis of the data in terms of performance expected based on the stresses in Table P7, Section 1, "Power Boilers", ASME Boiler and Pressure Vessel Code. Particular emphasis was placed on the T11 tubing since the Table P7 values are now being questioned and have been reduced.

Materials Investigated

Samples of T11 (1¼Cr 0.5Mo) steel and T1A (0.5Mo) steel tubing from

Wagner Station, Number 1 Unit, secondary superheater, were supplied for the investigation. The two tubing materials were in series. Both operated at some unknown over-temperature due to partial obstruction of steam flow in the circuit involved. The time period of over-temperature is not known but it could have been for the entire service period. The hours of service were estimated at 61,000.

T11 (1¼Cr 0.5Mo) Steel Tubing

The design conditions were:

Metal temperature (°F)	1006
Operating pressure (psi)	2075

The research has been carried out in terms of the metal stress of 7800 psi code stress value at 1000°F in Table P7, Section 1, "Power Boilers", ASME Boiler and Pressure Vessel Code. This was done although the design conditions required a stress no higher than 7524 psi, as code value at 1006°F.

The tube had undergone considerable thinning in certain local areas due to coal-ash corrosion. A few creep rupture failures had occurred where the wall had thinned to as low as 70% of the minimum allowable wall thickness.

The sample supplied had been removed from a location where there had been little or no corrosion. Tube diameters indicated that there was no measurable creep. The experimental material therefore is representative of tubing which had not undergone extensive corrosion or creep in 61,000 hours of service.

The tubing was nominal 2-inch O.D. by 0.260-inch wall. Wall thickness values as low as 0.160 - 0.180-inch had been measured at the points of most severe corrosion and excessive creep.

Photomicrographs supplied indicated that the carbides in the microstructure were highly spheroidized.

T1A (0.5% Mo) Steel Tubing

The design conditions were:

Metal temperature (°F)	925
Pressure (psig)	1900
Service hours	61000

Presumably the design metal stress was 10,500 psi, the stress obtained by interpolation between the values for 900° and 950°F in Table P7, Section 1, "Power Boilers", ASME Boiler and Pressure Vessel Code.

Measurements of tube diameters by Baltimore Gas and Electric Company had been made for the tube from which the two lengths of tubing submitted had been taken.

Mark	Creep measurements
1-2	1.3% at end marked "1", the hot end - 1.0% at end marked "2"
2-3	1.0% at end marked "2", 0.0% at end marked "3"

The tube had been measured at several points below point "3" and was consistent at 1.995-inches. This was used as the base line to estimate the amount of creep. The sample marked "1-2" was from tubing in the gas stream where the service temperatures were high. The sample marked "2-3" was down out of the main gas stream where the metal temperatures were not so high.

PROCEDURE

Specimens were machined from the tubes and subjected to rupture tests. Tests were conducted at the following temperatures:

T11 tubing .... 1000°, 1050°, 1100° and 1200°F

T1A tubing............... 935°, 1000° and 1100°F

The lower temperatures were selected to cover possible metal temperatures in service. Tests at 1100° and 1200°F were used to aid in extrapolation to prolonged time periods. The test temperature of 935°F was selected on the basis of design metal temperature estimated over the telephone. A later written analysis gave a design temperature of 925°F.

The maximum time of testing was rather short in duration. Originally an attempt was made to estimate the properties if the T11 tubing in less than a month. At that time it was not known that the tubing had been operating at an over-temperature. When the over-temperature had been recognized it was requested that the objective be shifted to estimation of the temperature of operation. The T1A tubing was supplied as indicative of tubing which had been damaged by over-temperature and material which had not been damaged. Testing the two materials was designed to obtain an estimate of the actual temperature of operation.

Both log-log stress rupture time curves and parameter correlations were used to evaluate the creep rupture properties. It is to be emphasized that the program was designed to provide data for estimation of strengths and temperatures. Long duration tests for exact data were not contemplated.

The specimens used had a gage length of 0.64-inch with a diameter of 0.160-inch. The axes of the specimens were parallel to the tube axis. They were also taken from a single location in the tubes so as to avoid any variations in the amount of creep around the tubes and along the tube lengths. The T11 samples and the "undamaged" T1A samples were taken at a point where measurements of tube diameters and surface condition indicated the lowest temperatures and least creep. The "damaged" T1A samples were taken at the point of maximum creep (the 1.3% increase in diameter noted by the measurements made by Baltimore Gas and Electric Company).

The 0.160-inch diameter specimens are rather small. They are, however, about the largest round specimens which could be machined from the tubes. Secondly, it was desired to have the specimens typical of specific locations in the tubes and this could only be done with small specimens. It was also considered necessary to machine off the surfaces to eliminate corrosion effects. Testing times were, moreover, quite short and oxidation was not expected to be a factor except possibly to a minor extent at 1100° and 1200°F.

The T1A materials were also examined metallographically to aid in selecting the location of specimens in the tube circumference.

RESULTS

The stress rupture time data (Table 1) for the T11 tube were plotted to obtain the stress rupture time curves of Figure 1 and the Parameter curve of Figure 2. The specimens were taken from a location on a tube where there had been no coal-ash corrosion and no measurable creep.

They therefore represent tubing which had undergone very little creep in service.

The stress rupture time data (Table 2) for the T1A tubing which exhibited measurable creep ("damaged" tubing) gave the stress rupture time curves of Figure 3 and the Parameter curve of Figure 4. The data for the T1A tubing which had not undergone measurable creep ("undamaged" tubing) are included in Table 2 and in Figures 3 and 4.

Analysis of the Data for the T11 Tube

The following tabulation compares the indicated stresses for rupture in 100, 000 hours from Figures 1 and 2 with comparative data for new tubing. The data for new tubing was taken from the recent Code Committee compilation by Dr. George Smith when the reduced stresses of Case 1319 were set.

T11 Tube Tested

Temperature (°F)	Figure 1 log-log curves(psi)	Figure 2 parameter (psi)	New Material (a) Average (psi)	New Material (a) minimum (psi)	Code Stresses Table P7	Code Stresses Case 1319
1000	10500	8600	9400	6500	7800	6550
1050	7400	(6500)[b]	5800	4000	5500	4050

(a) Dr. George Smith's recent values used to set Case 1319 values

(b) Required considerable extrapolation

These data indicate the following:

(1) The log-log curves at 1000° and 1050°F extrapolate to higher values than the Parameter correlation. The similarity of slopes of the log-log curves at 1000° and 1050° to those at 1100° and 1200°F suggest that their extrapolation should not be very much in error.

(2) The indicated 100, 000 hour strengths by both methods are within the range for new materials.

(3) The log-log curves of Figure 1 indicate 100, 000 hour strengths at 1000° and 1050°F that satisfy the requirements of the old Table P7 values. The Parameter extrapolations are slightly below the minimum requirements for the old Table P7 values. Both methods are well above the minimum requirements of Case 1319. (These observations are based on the requirement that the Code stress be equal to or above 80% of

the minimum rupture strength).

(4) If consideration is given to the materials already having been in service for 61,000 hours at a temperature above design conditions it seems probable that the Parameter extrapolations would also indicate at least original minimum required properties for the Table P7 values.

Extensive consideration was given to estimation of the actual service temperature from the data. No way was found to arrive at a satisfactory answer. If the tube had originally had creep rupture strengths on the high side of the range, the present properties would suggest considerable damage from the prior service. If the properties had been average according to Smith's correlation there was very little damage during service. Figure 5 shows that the log-log curves give rupture times under 7800 psi somewhat above Smith's average while the Parameter was somewhat below. Comparison with average data leads to the conclusion that the service temperature either was not high enough to induce considerable damage in 61,000 hours or the material was initially considerably stronger than the average.

The absence of measurable creep when the tube diameters were measured suggest that the temperature had not been high enough to cause much creep. If so then the tube probably had initial strengths above average. This involves two questionable assumptions. The measurement of tube diameters includes several uncertainties. Also, it is not certain what the relationship is between total creep up to 1 percent and the rupture life. It is presumed, however, that the temperature was less than that required to induce 1 percent creep in 61,000 hours under 7800 psi. The actual service stress was probably below this value according to the analysis of this unit by Paul Brister, furnished with the records for the unit.

Analysis of Data for T1A Tube

The stresses for rupture at short time periods (Figure 4), were considerably reduced from those characteristic of new material. The stress rupture time curves (Figure 3), however, had less slope than is characteristic of new material with the result that extrapolation to long times gave strength values nearer to those for new material.

The tests on the sample of the tube which did not show creep (undam-aged'' tubing) resulted in slightly higher rupture strengths (Figures 3 and 4) than those for the tubing where the creep was 1.3 percent (''damaged'' tubing). The data for the undamaged tubing was minimal. Available funds restricted the testing to two specimens at each temperature. The curves were therefore drawn with considerable recourse to judgment. The indicated stresses for rupture in 100,000 hours were as follows:

Temp. (°F)	Log-log stress rupture time curves (psi)		Parameter (psi)		Values used to establish Code stress (psi)		Code Stress (psi)
	Damaged	Undamaged	Damaged	Undamaged	Average	minimum	
900			13000	13800	28500	25000	12500*
925			10900	11600	21000	17000	10500**
935	11500	13000	10300	10900	18000	14000	9700**
950			9300	9800	15000	10500	8500
1000	7900	8800	6400	6800	9200	6800	5500

* Controlled by tensile properties

** Obtained by interpolation

These data show the following:

(1) The 100,000 hour rupture strengths at 900° - 925°F for both samples of tubing were below the range for the new material used to establish the present Table P7 values for the ASME Power Boiler Code. The difference decreased with increasing test temperature so that at 1000°F the values were at least as high as the minimum value for new material.

(2) Short-time tensile properties had been used to establish the Code stress at 900°F because the creep rupture values were higher than the values derived from tensile tests. The service, however, reduced rupture strengths at 900°F to the point where they indicate a lower allowable stress than the Table P7 value based on the tensile properties of new material. The ''design'' temperature for the tubing was 925°F. Presumably this indicates a service stress of 10,500 psi, the interpolated Code stress for 925°F. Examination of the data show that the creep rupture strengths after service hardly meet minimum Code requirements even though the Table P7 value was well below that which rup-

ture data for new material would have allowed.

If it is assumed that the "undamaged" sample had not undergone significant creep, then the difference in rupture time between the curves for the undamaged and damaged tubing represents the amount of rupture life "used up". The difference in rupture time was about 50 percent. This suggests that the operating temperature was high enough so that 61,000 hours represented about one-half the rupture life at 10,500 psi. The data for the damaged tube indicates that the temperature for rupture in an additional 61,000 hours at 10,500 psi (Figure 6) would have been about 961°F, based on log-log extrapolations of the rupture data. The Parameter data indicate that the operating temperature was approximately 943°F. Based on the assumption that 50 percent damage was accumulated in 61,000 hours under a stress of 10,500 psi, the T1A tubing would have had another 61,000 hours of life remaining at the over-temperature had it not been removed from service.

There is considerable question about the reliability of the determination of the probable operating temperature of the "damaged" tubing. For instance:

(1) The data were not only extrapolated excessively but the amount of testing was minimal.

(2) Either the "undamaged" tube actually underwent considerable creep which was not found by tube diameter measurements: or the thermally induced structural changes reduced rupture strengths at 900° - 925°F for long time periods to values well below those for new material. The alternatives would be initially weak material; or, incorrect extrapolation of data for new material to higher values at long time periods than are actually characteristic of the material.

(3) The "undamaged" tubing had a considerable amount of intergranular oxidation in decarburized surface layers. This suggests considerable creep during service. It seems possible that the tube diameter measurements missed the creep which had occurred. If this is correct then the operating temperature of the tubing in the damaged area was

higher than the estimated value of 961°F to the extent that the undamaged tube was also overheated. There is no way to estimate this temperature if in fact this is what happened.

(4) There was a difference in rupture strengths indicated by the log-log curves and the Parameter extrapolation. The data are inadequate to define the cause. It could be an incorrect constant in the Parameter; or the slopes of the stress rupture time curves had not been completely established. There is a strong possibility that the prior service or the oxidation during testing gave too low Parameter values at 1100°F. The slopes of the stress rupture time curves at 1000° and 1100°F were close enough to those at 935°F to indicate that extrapolation to long time periods ought to be quite reliable. If the log-log curves were actually reliable then the undamaged tubing still would meet minimum requirements for the present Code stress.

General Discussion

The extrapolated values for rupture in 100,000 hours for the T1A tubing at 935°F were at most only 1500 psi lower for the "damaged" than for the "undamaged" tubes. Yet the rupture times of the two samples of the tube showed about a 50-percent difference. For materials which have stress rupture time curves with so little slope, a large loss in rupture life is reflected in only a relatively small change in the stress for rupture in a given time period.

The rupture strengths at short time periods were very low compared to new material. It is presumed that most of this was due to thermally induced structural changes. Simply heating either T11 or T1A steel for prolonged time periods in the same temperature range would be expected to have a very similar effect. There is data to support the concept that the stress rupture time curves incorporate the effects of thermally induced structural changes on long time rupture strength. Presumably material which had undergone such prolonged heating would therefore have long time rupture strengths similar to those for new material if the amount of creep life used up was small.

The tests conducted were some of the few cases available to the authors where the material was known to have undergone considerable creep. Probably the most important feature of the data was the recognition that large percentage of rupture life could be used up with relatively little change in long time rupture strength. If stress rupture time curves have very little slope this would seem to be inevitable.

The lower strengths predicted by the Parameter method as compared to those indicated by log-log curves should be cleared up. Research is needed to establish the influence of thermally induced structural changes and prior creep on both the log-log and Parameter relationships. There is also need to know to what degree the oxidation of the specimens may have been involved.

CONCLUSIONS

The actual operating temperature of the T11 tubing could not be estimated from the stress rupture tests. The long time rupture strengths were similar to those for average new material. The original creep rupture strength of the material was not available. This information is necessary before an estimate of the actual operating temperature can be made.

The T1A tubing gave data which indicated that the operating temperature at the point where 1.3 percent creep had occurred was 943° - 961°F in comparison to a design temperature of 925°F. This valuation of the operating temperature is questionable. The data suggest that the tube sample which had not shown creep by measurement of diameters probably had operated under conditions which used up considerable creep life. There are also several other questionable features of the data.

The data for the T1A tubing demonstrate that the change in 100,000 hour rupture strength from "using up" large amounts of creep life can be very small.

The T11 tubing still had strengths well within the range required by Case 1319. Most of the data indicate that it would still meet the higher values of Table P7 of the Power Boiler Code and quite certainly did before service.

The T1A tubing had minimal or below minimal rupture strengths for the present Code stresses. The rupture strength at 925°F was quite low compared to the expected values for new material. There is need for more information on the effects of service in this temperature range where the controlling Code criteria shifts from tensile properties to creep rupture properties.

Rupture Properties of T11 Tubing

Temperature (°F)	Stress (psi)	Rupture Life (Hrs.)	Elongation %
1000	(UTS) 36,200	(Tensile Test)	43
1000	18,500	230.7	66
1000	22,000	35.6	51
1000	20,000	84.2	47
1050	15,000	216.3	57[a]
1050	16,500	76.1	63
1050	18,000	47.0	57
1100	12,000	239.7	45[a]
1100	13,000	109.6	70
1100	15,000	40.9	62
1100	16,000	21.0	52
1200	6,000	115.1[b]	0[a]
1200	7,000	115.5[b]	5[a]
1200	8,000	130.6	52[a]
1200	10,500	23.7	79[a]

a - Estimated value

b - Test discontinued

RUPTURE PROPERTIES OF C - Mo TUBING

Damaged

Spec.	Temp. °F	Stress psi	Rupture Life hours	Elong. %	R. A. %
120	935	39,800 (UTS)		28.2	72.5
121	935	30,000	12.6	38.7	71.7
124	935	27,500	36.1	37.4	75.5
127	935	25,000	95.7	31.0	64.4
131	935	22 000	275.0	39.0	46.4
126	1000	24,000	11.0	44.0	67.0
129	1000	20,000	64.4	32.2	57.0
130	1000	18,000	197.6	28.1	36.8
132	1000	16,000	386.5		
123	1100	16,000	15.0	33.7	57.6
125	1100	14,000	40.7	33.4	40.1
128	1100	12,000	92.4	25.3	32.8

Undamaged

Spec.	Temp. °F	Stress psi	Rupture Life hours	Elong. %	R. A. %
136	935	41,800 (UTS)		36.0	70.5
137	935	30,000	40.2	23.6	64.7
142	935	28,000	108.0	27.3	54.5
139	1000	24,000	29.6	35.2	61.0
141	1000	21,000	104.4	27.8	48.6
138	1100	16,000	23.6	42.2	47.6
140	1100	13,000	55.9	29.3	36.0
143	1100	11,500	168.5	20.7	37.6