

SUPERHEATER TUBE CORROSION ON MUNICIPAL
SOLID WASTE FIRED BOILERS AT NASHVILLE

by

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Introduction

The municipal refuse fired boilers supplied to the Nashville Thermal Transfer Corporation by the Babcock & Wilcox Company experienced extensive corrosion during their first year of operation. The corrosion occurred on both furnace and superheater tubes. This paper will describe the installation, the extent of the corrosion and the conclusions reached. Particular emphasis will be given to the problems associated with the superheaters.

Equipment Description

The two boilers supplied by the Babcock & Wilcox Company were designed to burn unprocessed municipal refuse on Detroit Reciprocating Grate Incinerator Stokers. The scope of supply included the boilers, furnaces, stokers, superheaters, economizers, mechanical dust collectors, auxiliary gas and oil burners, and forced draft fans. Each of the units were designed to burn 327 metric tons (360 U.S. tons) of refuse per day, converting the energy values to steam for heating and cooling 33 public and private buildings in metropolitan Nashville, Tennessee. The engineers whose vision made the project possible were I.C. Thomasson & Associates, Incorporated.

The boilers and their expected performance are shown in Figure 1. Membrane furnace walls [6.4 cm (2.5in.) diameter tubes on 7.6 cm (3 in.) centers] were supplied on these units. The furnace walls were bare except for cast iron wear blocks on the lower sidewalls near the stoker grate. A rear wall furnace arch helped direct the combustion gases horizontally through the single-gas pass superheater and boiler bank. The average gas temperature entering the superheater was expected to be 1089°K (1500°F) HVT, and the velocity of the gas in the superheater and boiler under performance conditions was predicted to be 5.5 and 9.1 meters (18 and 30 ft.) per second, respectively.

The parallel flow, single flow, single steam-pass superheater was arranged as shown in Figure 2. A terminal spray attemperator was used to maintain 596°K (613°F) steam temperature at the design steam capacity. The 5.72 cm (2.25 in.) O.D. electric resistance welded tubes (SA 178A) used throughout the superheater were spaced on 23 cm (9 in.) side spacing and 7.6 cm (3 in.) back spacing with a nominal thickness of 0.457 cm (0.180 in.). It consisted of 16 sections wide and eight elements deep per section. At the 49,440 kilograms (109,000 pounds) per hour design steam capacity of the boiler, the expected superheater pressure drop was 320 kPa (32psig) [corresponding steam mass flow through the superheater was 1,710,000 kilograms per hour per square meter (350,000 pounds per hour per square foot)].

Two full travel retractable soot blowers were provided in the 86 cm (34 in.) cavity between the superheater and convection tube bank to keep these surfaces clean. They were designed to use 1135 kPa (150 psig) superheater steam. These soot blowers were operated routinely, once each shift.

The No. 2 boiler (No. 1 is a Package Boiler) began operation in May, 1974 and the No. 3 Unit in August, 1974.

Description of Superheater Test Sections

With the Owner's permission, it was decided to operate two of the 16 sections of the superheater on the No. 3 boiler at higher steam temperatures to determine if elevated temperatures had any effect on corrosion tendencies.

Section No. 7 and Section No. 10 (numbering from left side of the boiler) were selected for this experiment. Each of these sections was piped up with a fixed orifice, isolation valves and drains as shown in Figure 3. By calculation, later refined by trial operation, the orifices were set to produce a steam flow which yielded an outlet steam temperature of approximately 714°K (825°F) on Section No. 7 and 728°K (850°F) on Section No. 10. Thermocouples were installed on the outlet legs in the penthouse of a representative number of superheater sections to monitor their outlet steam temperatures. The No. 7 section was constructed of seamless carbon steel tubing (SA-210) while the No. 10 section was made of a composite of materials ranging from SA-210 carbon steel to SA-213TP-304H stainless steel tubing. (See Table 1.) This table gives the physical description of each section including: average steam, tube metal, and gas temperatures for both the production and test superheater sections. An effort was made to test a wide selection materials in No. 10 section, however, it was found many of the materials desired were not classified as boiler code materials and were not available in the form of tubing.

Shut-off valves were provided at each end of these test sections to permit isolating them should either section fail. It was hoped it would not be necessary to use these provisions. Failure of an element in either

section and its subsequent isolation would certainly destroy the test tubing.

Another feature tested on this superheater was shields. The first tube facing the furnace in Section No. 9 was protected with 14GA, TP-310 stainless steel shields constructed as shown in Figure 4. The tubes in this section were made of the normal SA-178A tube material as used throughout the rest of the superheater. The tube surface under the shield was examined about one year later and it was found to be in excellent condition. No evidences of corrosion were noted.

Boiler Operation

Figure 5 gives a pictorial view of the operation of the refuse boilers from May, 1974 to October, 1975. In February, 1975, the first tube failure occurred in the sidewall of No. 3 boiler. At the time it was speculated the wastage may have been caused by high temperature corrosion and out-of-service corrosion. Cause for the latter speculation arose from the appearance of the ash on the walls. The ash was hygroscopic and many rivulets of rusty liquid could be seen on the surface of the ash covered tubes. Scabs of ash on the tubes covered rusty attacks on the tube surfaces.

When outages permitted, in April and early May, 1975, the furnace tubes of both boilers were ultrasonically tested. The equipment used was a Panametrics 5221-B Ultrasonic Thickness Gage with digital readout. These tests disclosed that many of the tubes in the sidewalls of both units were very thin while others showed signs of overheating due to internal scale. The boilers were acid cleaned, the thin tubes were replaced and the lower part of the furnaces was studded and covered with silicon carbide refractory. At this time the lead tubes of the superheater on No. 2 boiler were also tested ultrasonically. While some wastage was present, it was not deemed serious at that time.

On the 29th of July, 1975, a superheater tube failure occurred on the No. 2 boiler. It was located in the fourth section from the left side and in the seventh tube from the front. A closer examination found that much of the tubing in the section was very thin, consequently the entire section was replaced. The damaged section was sent in its entirety to the Company's Research Laboratories in Alliance, Ohio for metallurgical and chemical analyses.

Superheater Corrosion on Section No. 4, Boiler No. 2

Extensive examinations were performed on Section No. 4 at Alliance. To permit a comparison of the extent of wastage at various positions on the section from top to bottom, five locations were examined. These locations shown in Figure 6 were identified as locations, A, B, C, D and E,

and the tube rows at these locations front to back, as Rows 1 through 8. A three-inch long ring segment was removed from each of the eight tubes at each of the five locations, 40 samples total. The samples were cleaned with inhibited acid and visual and low powered magnification examination showed that all 40 samples displayed some degree of external wastage. The thickness of each sample was taken on all four sides of the tubes and reported in Table 2. A pictorial representation of the wastage on this section is shown in Figure 6. The figure shows lines of equal thickness based on using the average thickness of the sides of each of the 40 samples. It shows the failure was near the lower soot blower and was due to severe external surface metal wastage. However, the maximum loss of metal occurred near the center of the section. A review of the table also indicates that the most severe wastage was on the sides of the tubes and that it was not uniform on both sides of the tube. A close look at one tube as seen in Figure 7 showed uneven surface attack resulting in a general metal roughness.

The laboratory metallurgists reported that their examination revealed the external surfaces were covered with relatively heavy striated deposit layers. The attack on the metal under this deposit displayed a general transgranular attack typical of chemical or solution type wastage. No evidence of intergranular penetrations was observed nor were there any indications of overheating. Since the deposits had various mixed alkalis and metal sulfates with significant chlorine, it was concluded that chlorides were strongly associated with this observed corrosion attack.

Investigation of Superheater Condition

From August to October, 1975 an extensive investigation was made of the condition of the superheater on No. 3 boiler.

Physical Condition

During the September 30-October 3, 1976 period, ultrasonic measurements were made to determine the thickness of each tube in the superheater at the three elevations shown in Figure 8. Because of the close back spacing on the tubes (5.72 cm (2.25 in.) O.D. on 7.6 cm (3 in.) back spacing), it was only possible to measure the first and last tube in the direction of the gas flow, the rest of the measurements were taken perpendicular to the gas flow. It was in this latter location that the greatest wastage was evident. In Figure 9, we have plotted the thickness of the sides of the tubes for the average production sections and also test section Nos. 7 and 10 at the above mentioned three elevations. (For average tube thickness data see Table 3.)

The superheater sections near the sidewalls experienced less wastage than the other sections due to decreased gas flow and temperature. However,

the wastage pattern shown was representative of the physical condition of the superheater as it existed at that time.

These data, Figure 9, show that the production sections experienced the greatest loss of metal in the center of the section, tube Nos. 2 and 7 inclusive, with tube Nos. 3 to 6 being hardest hit. The test sections which operated at higher steam temperatures had less wastage overall. These sections in direct contrast to the production sections looked best or experienced minimum wastage in the center tube row Nos. 3 to 6 inclusive. Superheater section Nos. 7 and 10 show the most loss of metal on the entrance to row Nos. 1 and 2 where gas temperature is greatest.

On an individual tube basis, the wastage pattern was not the same on each side of the tube. It varied from section to section and elevation to elevation. In general, it can be said that the pattern appeared to fit the fact that all superheater sections did not hang in a true vertical position.

Deposit Analysis

To help explain the wastage on these superheaters, many analyses of the deposits on the various sections were made. One representative study compared the deposits on test section No. 7 with those found on production section No. 12. Samples were taken at the mid-elevation of the superheater (between retractable soot blower locations) and from tube Nos. 1, 5 and 8. In this study a total of six samples were analyzed.

The samples were ground to pass through a 100 mesh screen. The metallic components which could not be ground were sieved out and analyzed separately. Work performed consisted of "wet" analysis for total chlorides, phosphorus and sulfur forms, semi-quantitative spectrographic analyses, x-ray diffraction analysis for crystalline components, determination of behavior at temperatures up to 1573°K (2372°F) using a Lietz Heating Microscope and conventional fusion point determinations. Table 4 lists the analytical results.

The following general statements can be made about the chemical analysis of the deposits:

1. The major constituents were compounds of lead, sulfur, sodium, aluminum, zinc and silica.
2. The lead content of the deposits was very high, particularly those on the first tube in both sections and of all three of the tubes analyzed from Sect. No. 12, where the content was greater than 10 percent.
3. The sulfur content was high, above 20 percent in all the deposits.

4. Calculations indicate the sulfur content is in excess of that needed to account for all the lead as $2 \text{PbO} \cdot \text{PbSO}_4$, and so some of the sulfur must be as other compounds.
5. The chloride content in all the deposits was below 2 percent. A review of the chloride distribution between the sections showed:
 - a. There were higher concentrations in deposits from Sect. No. 12, than from Section No. 7.
 - b. For both sections the chloride contents were higher in the deposits on the first tube than those downstream.
 - c. The deposits on tube Nos. 5 and 8 in Section No. 7 contained less chlorides than the deposits on the corresponding tubes in Section 12 (0.44 and 0.32 percent versus 1.44 and 1.16 percent).
 - d. On both sections, the chloride content of the deposits decreased from front to back (tube Nos. 1 to tube 8).
6. The major crystalline constituent of the deposits was lead oxide lead sulfate (basic lead sulfate). Other crystalline constituents were calcium sulfate (found in all the deposits on Section No. 7, and on tube No. 1 in Section No. 12), silica (SiO_2), and magnetite (Fe_3O_4).
7. The x-ray diffraction examination detects only crystalline constituents. Compounds which are glassy or amorphous, such as sodium iron-sulfate (a likely iron compound), do not have an x-ray pattern, and so are not specifically indicated in this type analysis.
8. The metallic portions of the deposits (+ 100 mesh) was greater in the deposits from Section No. 12 than those from Section No. 7.
9. The metallic portions consist primarily of iron and aluminum components (metal and compounds), with appreciable portions of lead, zinc and sodium components.

Of significance is the fact that these samples plus other samples in the superheater and boiler area showed the presence of metallic aluminum which can be volatilized and persists only in the presence of reducing conditions during operation.

Thermal Behavior of Deposits

Examination of the thermal behavior of the deposits with a Leitz Heating Microscope and classical fusion point determination disclosed the following:

1. The deposits on tube Nos. 1 and 5 of Section No. 7 showed no physical change at temperatures below 1366°K (2000° F), indicating that although they may have been molten in the gas stream before deposition, they either deposited as solids or liquids which subsequently changed so that they now behave as high temperature solids. The deposits on tube No. 8 of Section No. 7 showed shrinking, or sintering, at low temperatures 866-1255°K (1100-1800° F), which is an indication that chemical changes took place in the solids after deposition. The deposit on tube No. 8 also showed gas evolution at temperatures above 1480°K (2200° F), which indicates post-deposition chemical changes.
2. The deposit on tube No. 1, Section No. 12, showed sintering at 866°K (1100° F) and melting below 1033°K (1400° F), which indicates chemical changes occurred after deposition, or deposition as molten droplets, with the first explanation more probable. The deposit on tubes Nos. 5 and 8 (Section No. 12) showed no low temperature changes, and probably deposited as solids particles.

This examination showed the behavior of the deposits at the time the samples were taken, and not necessarily as they were in the gas stream at the time of deposition.

Deposit Appearance

In general, the deposits on the production sections were thin and appeared to have undergone melting or sintering; those on test Section Nos. 7 and 10 were more friable and crystalline and looked as though the material had deposited as solids and did not melt. The thickness of the deposits on these two sections was much greater than those of the others.

Comparison With Past Analyses

Analysis of deposits in incinerators have been reported several times in the past. Table 5 shows a compilation of such results based on deposits found on incinerators at Oceanside Long Island, Norfolk, Va. and a unit in Germany.¹ In what follows, a comparison will be made between the deposits found in these three units with the deposits from Nashville as reported in Table 4. Battelle Memorial Institute² (BMI) studied the analysis of the deposits found on short term probes inserted into the incinerators at Miami County, Ohio. As a matter of interest their findings are also shown in Table 5.

1. All of the deposits on the tubes of the regular Section No. 12 and high temperature Section No. 7 had higher levels of lead (except for tube No. 5 of Section No. 7) than the 3 other units.
2. The sulfur content of the Nashville deposits were comparable with those found in the German and Oceanside units, but higher than the Norfolk unit.
3. In regard to chloride content, the data reported on the German and Norfolk plants showed amounts less than 1% while the Oceanside plant showed a level of 1.58%. At Nashville all 3 tubes tested in Sect. No. 12 had levels greater than 1% chloride in their deposits. However, only tube No. 1 in Section No. 7 had levels above 1%.
4. The levels of the zinc content of the Nashville deposits were generally the same as the 3 other units, except for the high level in the first tube of Section No. 7.
5. The Nashville deposits all contained much higher levels of sodium compounds than those listed for the other 3 units.
6. The x-ray diffraction examination of the Nashville deposits indicated that major crystalline constituents were basic lead sulfate ($2\text{PbO}\cdot\text{PbSO}_4$) and minor amounts of silica (SiO_2) and calcium sulfate (CaSO_4). The BMI analysis² of the deposits collected on their Miami County probes showed appreciable amounts of calcium sulfate, silica, calcium silicate, sodium and potassium chlorides, and a mixed potassium sodium bisulfate ($\text{K}_3\text{Na}(\text{SO}_4)_2$). The BMI samples, however, were deposits collected over a 10 hour sampling period, and long-time exposure might have showed a different set of compounds.

Past investigators have expressed the general belief that corrosion of incinerator tubing increases in the presence of sodium, potassium, chlorine, zinc, and lead compounds.

Observations made during field trials in Europe show that chlorides occur in deposits in an irregular pattern, and some investigators feel that the presence of chlorides do not necessarily indicate a corrosive environment. Nevertheless, one of the differences between the composition of the deposits on Section Nos. 7 and 12 is that the deposits on tubes Nos. 5 and 8 of Section No. 12 contain more chlorides than those on corresponding tubes of Section No. 7.

Conclusions and Recommendations

Much of the data and observations made appear contradictory and inconclusive and, unfortunately, little light has been shed on the true mechanism of high temperature corrosion. It would appear, however, that

excessive cleaning of a superheater can expose the metal to the corrosive ingredients in the gas. One plausible explanation of why the high operating temperature test sections seemed to have better corrosion resistance was that they appeared to have acquired a more tenacious protective ash layer that better resisted the cleaning effect of the soot blowers.

Since the initial startup of these boilers there has been a tendency to operate at low excess air. This is known to cause oxidizing and reducing atmospheres in the superheater, a condition which is favorable for corrosion.

One of the reasons for low excess air operation can be attributed to the fact that modifications made to the wet scrubbers' internals to improve collection efficiency increased the draft loss and reduced the capacity of the induced draft fans. The effective induced draft fan capacities were further reduced because of air infiltration caused by widespread corrosion in the wet scrubber flues.

In addition to replacing the two superheaters, the following action has been taken to alleviate future superheater corrosion:

1. Sootblowing of the superheaters was reduced to a minimum.
2. Efforts have been made to operate the boilers closer to their design excess air of 84%.
3. Changes have been made to the overfire air system, and efforts are being made to complete the combustion process as low as possible in the furnace.
4. Guides have been installed on the new superheaters to help maintain the alignment of the superheater sections.
5. Stainless steel shields have been installed on the first two rows of superheater tubes.
6. To provide a greater corrosion margin the replacement superheater was designed with 0.56 cm (0.220 in.) thick tubes versus the original 0.46 cm (0.180 in.) thickness.

Acknowledgements

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References

1. Data from Bryers, R.W. & Kerekes, Z., "Recent Experience with Ash Deposits in Refuse Fired Boilers," ASME 68-WA/CD-4, The American Society of Mechanical Engineers (1968)
2. Probes from Miami County Incinerator, P.D. Miller & H.H. Krause, Corrosion 27 (1), 31-45 (1971)

TABLE 1
CORROSION DATA FROM BRYERS & KEREKES (1968)

Boiler No.	Material	Temp. (°F)	Pressure (PSI)	Corrosion Rate (mpy)	Notes
1	SA-266-2	500	150	0.001	
2	SA-266-2	500	150	0.001	
3	SA-266-2	500	150	0.001	
4	SA-266-2	500	150	0.001	
5	SA-266-2	500	150	0.001	
6	SA-266-2	500	150	0.001	
7	SA-266-2	500	150	0.001	
8	SA-266-2	500	150	0.001	
9	SA-266-2	500	150	0.001	
10	SA-266-2	500	150	0.001	
11	SA-266-2	500	150	0.001	
12	SA-266-2	500	150	0.001	
13	SA-266-2	500	150	0.001	
14	SA-266-2	500	150	0.001	
15	SA-266-2	500	150	0.001	
16	SA-266-2	500	150	0.001	
17	SA-266-2	500	150	0.001	
18	SA-266-2	500	150	0.001	
19	SA-266-2	500	150	0.001	
20	SA-266-2	500	150	0.001	
21	SA-266-2	500	150	0.001	
22	SA-266-2	500	150	0.001	
23	SA-266-2	500	150	0.001	
24	SA-266-2	500	150	0.001	
25	SA-266-2	500	150	0.001	
26	SA-266-2	500	150	0.001	
27	SA-266-2	500	150	0.001	
28	SA-266-2	500	150	0.001	
29	SA-266-2	500	150	0.001	
30	SA-266-2	500	150	0.001	
31	SA-266-2	500	150	0.001	
32	SA-266-2	500	150	0.001	
33	SA-266-2	500	150	0.001	
34	SA-266-2	500	150	0.001	
35	SA-266-2	500	150	0.001	
36	SA-266-2	500	150	0.001	
37	SA-266-2	500	150	0.001	
38	SA-266-2	500	150	0.001	
39	SA-266-2	500	150	0.001	
40	SA-266-2	500	150	0.001	
41	SA-266-2	500	150	0.001	
42	SA-266-2	500	150	0.001	
43	SA-266-2	500	150	0.001	
44	SA-266-2	500	150	0.001	
45	SA-266-2	500	150	0.001	
46	SA-266-2	500	150	0.001	
47	SA-266-2	500	150	0.001	
48	SA-266-2	500	150	0.001	
49	SA-266-2	500	150	0.001	
50	SA-266-2	500	150	0.001	



TABLE 2
CORROSION DATA FROM MILLER & KRAUSE (1971)

Probe No.	Material	Temp. (°F)	Pressure (PSI)	Corrosion Rate (mpy)	Notes
1	SA-266-2	500	150	0.001	
2	SA-266-2	500	150	0.001	
3	SA-266-2	500	150	0.001	
4	SA-266-2	500	150	0.001	
5	SA-266-2	500	150	0.001	
6	SA-266-2	500	150	0.001	
7	SA-266-2	500	150	0.001	
8	SA-266-2	500	150	0.001	
9	SA-266-2	500	150	0.001	
10	SA-266-2	500	150	0.001	
11	SA-266-2	500	150	0.001	
12	SA-266-2	500	150	0.001	
13	SA-266-2	500	150	0.001	
14	SA-266-2	500	150	0.001	
15	SA-266-2	500	150	0.001	
16	SA-266-2	500	150	0.001	
17	SA-266-2	500	150	0.001	
18	SA-266-2	500	150	0.001	
19	SA-266-2	500	150	0.001	
20	SA-266-2	500	150	0.001	
21	SA-266-2	500	150	0.001	
22	SA-266-2	500	150	0.001	
23	SA-266-2	500	150	0.001	
24	SA-266-2	500	150	0.001	
25	SA-266-2	500	150	0.001	
26	SA-266-2	500	150	0.001	
27	SA-266-2	500	150	0.001	
28	SA-266-2	500	150	0.001	
29	SA-266-2	500	150	0.001	
30	SA-266-2	500	150	0.001	
31	SA-266-2	500	150	0.001	
32	SA-266-2	500	150	0.001	
33	SA-266-2	500	150	0.001	
34	SA-266-2	500	150	0.001	
35	SA-266-2	500	150	0.001	
36	SA-266-2	500	150	0.001	
37	SA-266-2	500	150	0.001	
38	SA-266-2	500	150	0.001	
39	SA-266-2	500	150	0.001	
40	SA-266-2	500	150	0.001	
41	SA-266-2	500	150	0.001	
42	SA-266-2	500	150	0.001	
43	SA-266-2	500	150	0.001	
44	SA-266-2	500	150	0.001	
45	SA-266-2	500	150	0.001	
46	SA-266-2	500	150	0.001	
47	SA-266-2	500	150	0.001	
48	SA-266-2	500	150	0.001	
49	SA-266-2	500	150	0.001	
50	SA-266-2	500	150	0.001	

TABLE 1
SUPERHEATER DATA **

* PRODUCTION SECTIONS

TUBE NO.	TUBE O.D. IN.	TUBE THK IN.	TUBE MAT'L	EST. AVE STEAM TEMP LVG ROW-F	EST. AVE TUBE METAL TEMP-F	EST. AVE GAS TEMP ENT ROW-F
1	2½	0.180	SA-178A	480	567	1540
2				502	566	1527
3				522	580	1514
4				540	581	1502
5				558	595	1490
6				575	612	1478
7	↓	↓	↓	593	628	1466
8	2½	0.180	SA-178A	613	656	1454

TEST SECTION NO. 7

TUBE NO.	TUBE O.D. IN.	TUBE THK IN.	TUBE MAT'L	EST. AVE STEAM TEMP LVG ROW-F	EST. AVE TUBE METAL TEMP-F	EST. AVE GAS TEMP ENT ROW-F
1	2½	0.220	SA-210A ₁	512	694	1540
2				563	691	1528
3				610	705	1516
4				652	723	1504
5				694	748	1492
6				734	782	1481
7	↓	↓	↓	776	817	1470
8	2½	0.220	SA-210A ₁	825	877	1459

TEST SECTION NO. 10

TUBE NO.	TUBE O.D. IN.	TUBE THK IN.	TUBE MAT'L	EST. AVE STEAM TEMP LVG ROW-F	EST. AVE TUBE METAL TEMP-F	EST. AVE GAS TEMP ENT ROW-F
1	2½	0.180	SA-210A ₁	516		1540
2		0.240	CR½	571		
3		0.240	CR½	621		
4		0.180	CR2½	666		
5		0.220	CR2½	711		
6	↓	0.260	CR-5	754		
7	2½	0.308	CR-9	799		
8	2.222	0.180	TP 304	850	904	1459

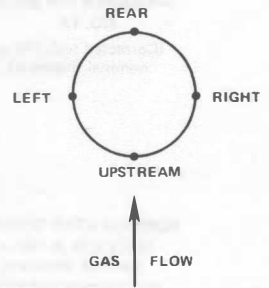
* 14 SECTIONS (EXCLUDES SECTION NOS. 7 & 10)

**Conversion factors: (inch) = 2.54 (cm)
(°K) = 5/9(°F - 32) + 273.15

TABLE 2

NO. 4 SUPERHEATER SECTION TUBE WALL THICKNESS – (inch)*
NO. 2 BOILER

ELEV.	ROW NO. 1	ROW NO. 2	ROW NO. 3	ROW NO. 4	ROW NO. 5	ROW NO. 6	ROW NO. 7	ROW NO. 8	SIDE OF TUBE MEASURED
A	0.134	0.124	0.140	0.128	0.141	0.145	0.157	0.175	UPSTREAM
	0.140	0.091	0.077	0.040	0.050	0.092	0.096	0.127	LEFT
	0.153	0.130	0.142	0.111	0.120	0.164	0.163	0.162	REAR
B	0.140	0.101	0.094	0.067	0.066	0.139	0.135	0.153	RIGHT
	0.132	0.119	0.146	0.126	0.136	0.146	0.172	0.187	UPSTREAM
	0.134	0.088	0.071	0.083	0.102	0.124	0.135	0.141	LEFT
C	0.153	0.131	0.140	0.148	0.155	0.146	0.168	0.183	REAR
	0.140	0.114	0.088	0.114	0.131	0.137	0.137	0.174	RIGHT
	0.118	0.117	0.096	0.119	0.147	0.161	0.163	0.180	UPSTREAM
D	0.134	0.071	0.023	0.014	0.126	0.051	0.024	0.119	LEFT
	0.153	0.134	0.125	0.124	0.120	0.139	0.168	0.155	REAR
	0.124	0.080	0.053	0.046	0.088	0.122	0.112	0.141	RIGHT
E	0.108	0.145	0.129	0.151	0.174	0.172	0.178	0.188	UPSTREAM
	0.114	0.104	0.059	0.073	0.101	0.135	0.164	0.177	LEFT
	0.171	0.159	0.148	0.156	0.172	0.173	0.182	0.181	REAR
E	0.145	0.120	0.111	0.113	0.162	0.168	0.179	0.180	RIGHT
	0.142	0.179	0.182	0.182	0.180	0.183	0.189	0.203	UPSTREAM
	0.168	0.171	0.178	0.177	0.178	0.185	0.184	0.185	LEFT
E	0.181	0.180	0.181	0.189	0.183	0.182	0.193	0.198	REAR
	0.174	0.180	0.173	0.177	0.181	0.182	0.186	0.185	RIGHT



*Conversion factor: (inch) = 2.54 (cm)

TABLE 3
AVERAGE THICKNESS OF SUPERHEATER TUBES
AS MEASURED AT SIDE FACES -(inch)*

TUBE ROW NO.	1	2	3	4	5	6	7	8	ELEV.
SUPERHEATER SECTION NO. 7 (0.220 in nominal thickness)	.182	.215	.226	.238	.238	.243	.226	.240	2
	.190	.200	.233	.240	.240	.230	.228	.235	3
	.183	.205	.233	.246	.253	.240	.239	.216	4
SUPERHEATER SECTION NO. 10 (Corrected to 0.240 in. nominal thickness)	.183	.238	.263	.255	.251	.254	.239	.246	2
	---	.227	.250	.238	.247	.254	.240	.251	3
	---	.228	.250	.247	.240	.262	.266	.246	4
SUPERHEATER SECTION NO.'s 1-16 (0.180 in. nominal thickness) (EXCLUDES SECTION NO.'s 7 & 10)	.143	.122	.099	.092	.087	.094	.139	.159	2
	.135	.121	.100	.091	.088	.094	.118	.157	3
	.151	.109	.108	.077	.078	.073	.080	.089	4

*Conversion factor: (inch) = 2.54 (cm)

TABLE 4

DEPOSIT ANALYSIS

Sample Description Lab No.	Platen 7 Tube 1 M-28415		Platen 7 Tube 8 M-28414		Platen 7 Tube 8 M-28413		Platen 12 Tube 1 M-28418		Platen 12 Tube 5 M-28417		Platen 12 Tube 8 M-28416	
	"A" -100 mesh	"B" +100 mesh	"A" -100 mesh	"B" +100 mesh	"A" -100 mesh	"B" +100 mesh	"A" -100 mesh	"B" +100 mesh	"A" -100 mesh	"B" +100 mesh	"A" -100 mesh	"B" +100 mesh
% of Sample	97.8	2.2	97.1	2.9	97.6	2.4	100	—	95.2	4.8	96.5	3.5
Chloride as Cl**	1.74	NA*	0.44	NA*	0.32	NA*	1.86	NA*	1.44	NA*	1.16	NA*
Sulfur as SO ₄ **	24.4	NA*	30.9	NA*	32.1	NA*	27.9	NA*	21.4	NA*	25.0	NA*
Phosphorus as P ₂ O ₅ **	0.60	NA*	0.78	NA*	0.62	NA*	0.44	NA*	0.76	NA*	0.69	NA*
Spec Semi-Quant Analysis***												
Silicon as SiO ₂	11.5	7.8	10.5	1.3	10.0	6.8	8.5	NA*	8.5	2.3	11.0	2.0
Aluminum as Al ₂ O ₃	11.0	MAJOR	8.5	MAJOR	8.0	MAJOR	6.4	NA*	11.5	MAJOR	10.0	MAJOR
Iron as Fe ₂ O ₃	1.6	MAJOR	5.8	<0.1	3.8	18.0	3.7	NA*	17.0	19.0	1.4	12.0
Titanium as TiO ₂	0.5	0.1	0.4	0.4	0.4	0.1	0.1	NA*	0.4	0.1	0.4	0.1
Calcium as CaO	1.4	1.8	9.0	1.5	9.0	5.0	5.8	NA*	7.0	1.5	9.8	1.0
Magnesium as MgO	1.0	MAJOR	MAJOR	0.1	MAJOR	8.7	MAJOR	NA*	0.9	0.2	1.2	0.4
Nickel as NiO	MAJOR	<0.2	<0.2	<0.2	<0.2	<0.2	<0.2	MAJOR	<0.2	<0.2	<0.2	<0.2
Chromium as Cr ₂ O ₃	<0.2	<0.2	<0.2	<0.2	<0.2	<0.2	<0.2	NA*	<0.2	<0.2	<0.2	<0.2
Molybdenum as MoO ₃	<0.06	<0.06	<0.06	<0.06	<0.06	<0.06	<0.06	NA*	<0.06	<0.06	<0.06	<0.06
Vanadium as V ₂ O ₅	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	NA*	<0.1	<0.1	<0.1	<0.1
Cobalt as CoO	<0.06	<0.06	<0.06	<0.06	<0.06	<0.06	<0.06	NA*	<0.06	<0.06	<0.06	<0.06
Manganese as MnO ₂	0.06	0.1	0.6	0.1	0.06	0.2	0.06	NA*	0.06	0.1	0.06	0.06
Copper as CuO	<0.1	0.1	<0.1	<0.1	<0.1	<0.1	<0.1	NA*	<0.1	0.2	<0.1	<0.1
Zinc as ZnO	14.0	4.5	4.5	<0.5	4.0	<0.5	8.8	NA*	5.0	3.0	6.0	2.3
Lead as PbO	MAJOR	6.1	5.4	0.3	12.0	0.5	MAJOR	NA*	11.5	1.9	19.0	1.7
Tin as SnO ₂	1.0	0.06	0.3	0.06	0.3	0.1	0.7	NA*	0.6	0.06	0.9	0.06
Zirconium as ZrO ₂	<0.06	<0.06	<0.06	<0.06	<0.06	<0.06	<0.06	NA*	<0.06	<0.06	<0.06	<0.06
X-Ray Diffraction (Crystalline Ingredients)												
Major	2PbO·PbSO ₄	NA*	2PbO·PbSO ₄	NA*	2PbO·PbSO ₄	NA*	2PbO·PbSO ₄	NA*	2PbO·PbSO ₄	NA*	2PbO·PbSO ₄	NA*
Minor	CaSO ₄	NA*	CaSO ₄	NA*	CaSO ₄	NA*	Unidentified	NA*	Fe ₂ O ₃	NA*	CaSO ₄	NA*
	Unidentified	NA*	SiO ₂	Unidentified	Unidentified	Unidentified	Unidentified	Unidentified	Unidentified	Unidentified	Unidentified	Unidentified

** Not Analyzed

*** Wet Analysis

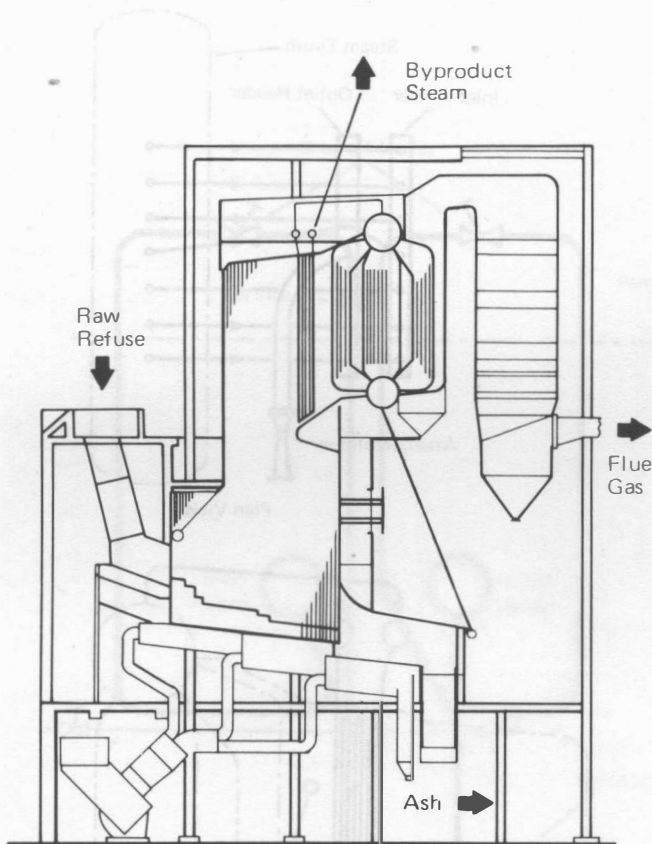
*** The elements are reported as the oxide because of the analysis method used. This does not necessarily imply their presence as such.

TABLE 5
ANALYSIS OF DEPOSITS FROM VARIOUS INCINERATORS

<u>Location</u>	<u>German</u> ¹	<u>Norfolk</u> ¹	<u>Oceanside</u> ¹	<u>Probe 1</u> ²	<u>Probe 2</u> ²
Chloride as Cl, %	0.40	0.02	1.58	1.0	3.8
Sulfur as SO ₃	31.7	8.40	26.1	20.6	20.9
Phosphorus as P ₂ O ₅	1.31	1.71	0.60	—	—
Silicon as SiO ₂	15.0	36.5	6.00	5.3	3.2
Aluminum as Al ₂ O ₃	7.0	17.5	4.0	9.4	3.8
Iron as Fe ₂ O ₃	7.0	12.0	18.0	10.7	4.3
Titanium as TiO ₂	0.65	2.0	0.50	—	—
Calcium as CaO	8.0	10.0	1.80	1.4	2.1
Magnesium as MgO	4.1	0.90	NIL	—	—
Sodium as Na ₂ O	2.40	3.51	5.12	10.1	4.0
Potassium as K ₂ O	7.68	3.00	13.0	18.1	4.8
Nickel as NiO	0.18	0.25	0.13	—	—
Chromium as Cr ₂ O ₃	0.20	0.60	NIL	—	—
Molybdenum as MoO ₃	0.15	0.10	NIL	—	—
Vanadium as V ₂ O ₅	NIL	0.75	NIL	—	—
Manganese as MnO ₂	0.10	1.00	NIL	—	—
Copper as CuO	0.12	0.31	NIL	—	—
Zinc as ZnO	5.61	7.44	9.65	9.3	9.4
Lead as PbO	8.0	0.67	5.12	10.8	21.6
Tin as SnO ₂	1.02	0.40	1.12	—	—
Silver as Ag ₂ O	NIL	0.15	0.08	—	—

(1) Data from Bryers & Kerekes, ASME 68-WA/CD-4

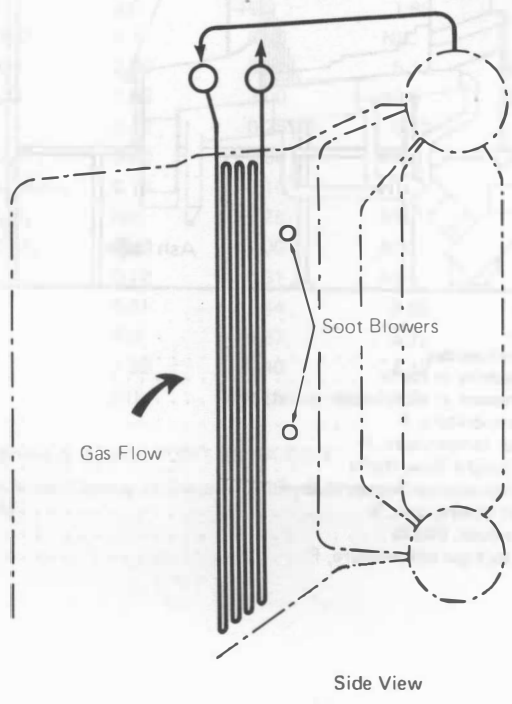
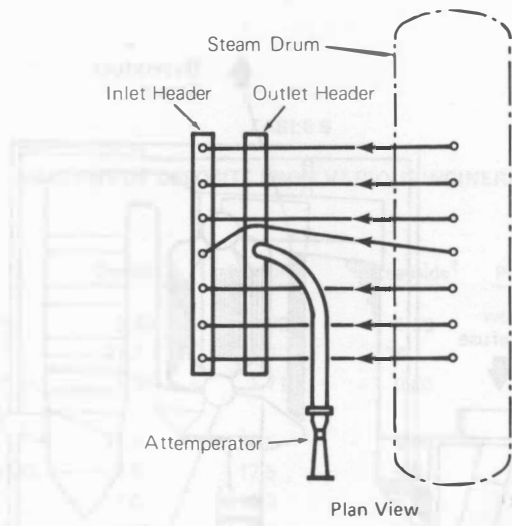
(2) Probes from Miami County Incinerator, Miller & Krause, Corrosion 27 (1), 31-45 (1971)



Tons of refuse/day	360	(327 metric tons/day)
Steam capacity in lbs/hr	109,000	(49442 kg/hr)
Steam pressure at superheater outlet, psig	400	(2859 kPa)
Steam temperature, F	613	(596°K)
Feedwater temperature, F	240	(389°K)
Flue gas weight flow, lbs/hr	273,000	(123831 kg/hr)
Economizer exit gas temperature, F	537	(554°K)
Excess air leaving unit, %	84	
HHV of refuse, Btu/lb	6,000	(13955 Kj/kg)
Furnace exit gas temperature, F	1,500	(1039°K)

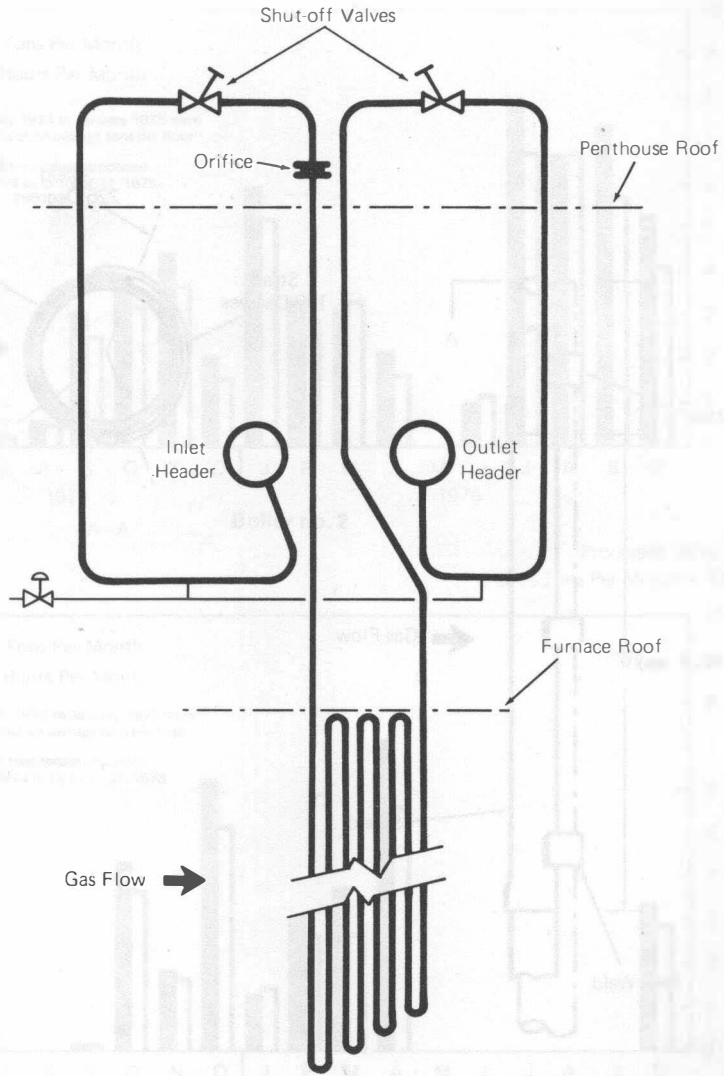
Boiler and expected performance

Figure 1



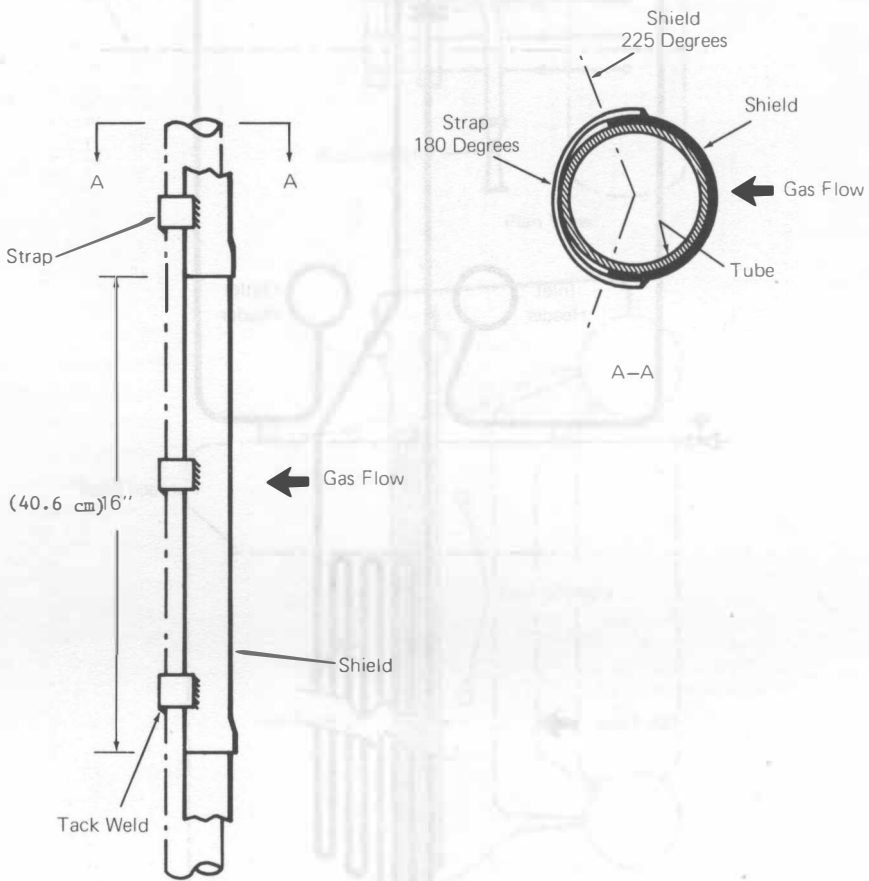
Superheater arrangement

Figure 2



Superheater test section

Figure 3

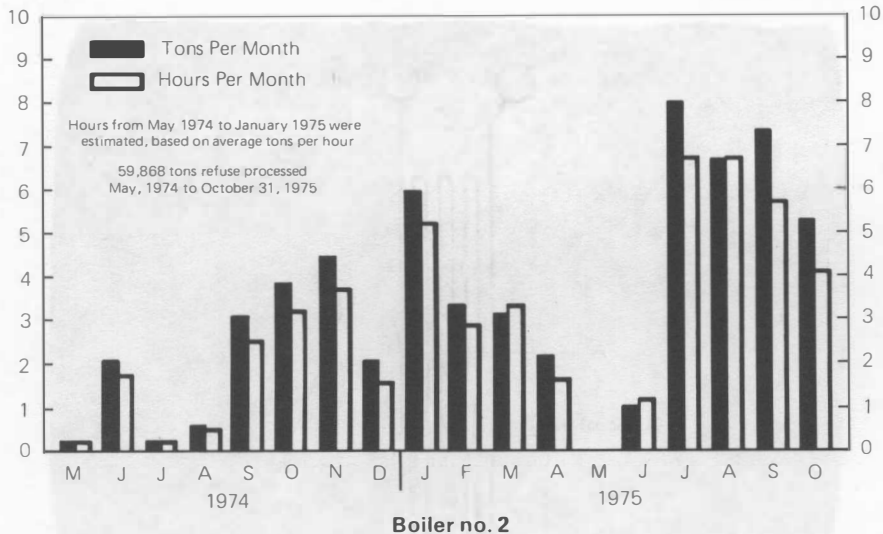


Arrangement of superheater tube shield

Figure 4

Monthly Hours
of Operation x 100

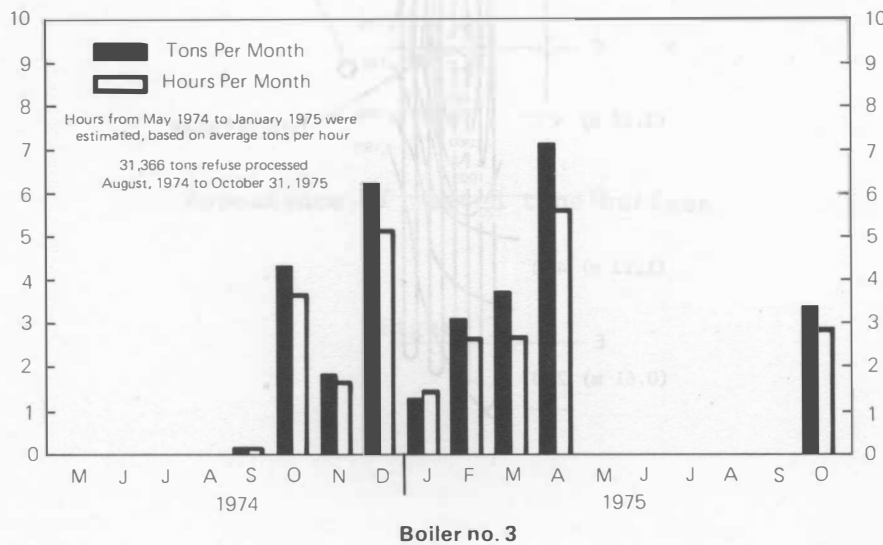
Processed MSW
U.S. Tons Per Month x 1000 *



Boiler no. 2

Monthly Hours
of Operation x 100

Processed MSW
U.S. Tons Per Month x 1000 *

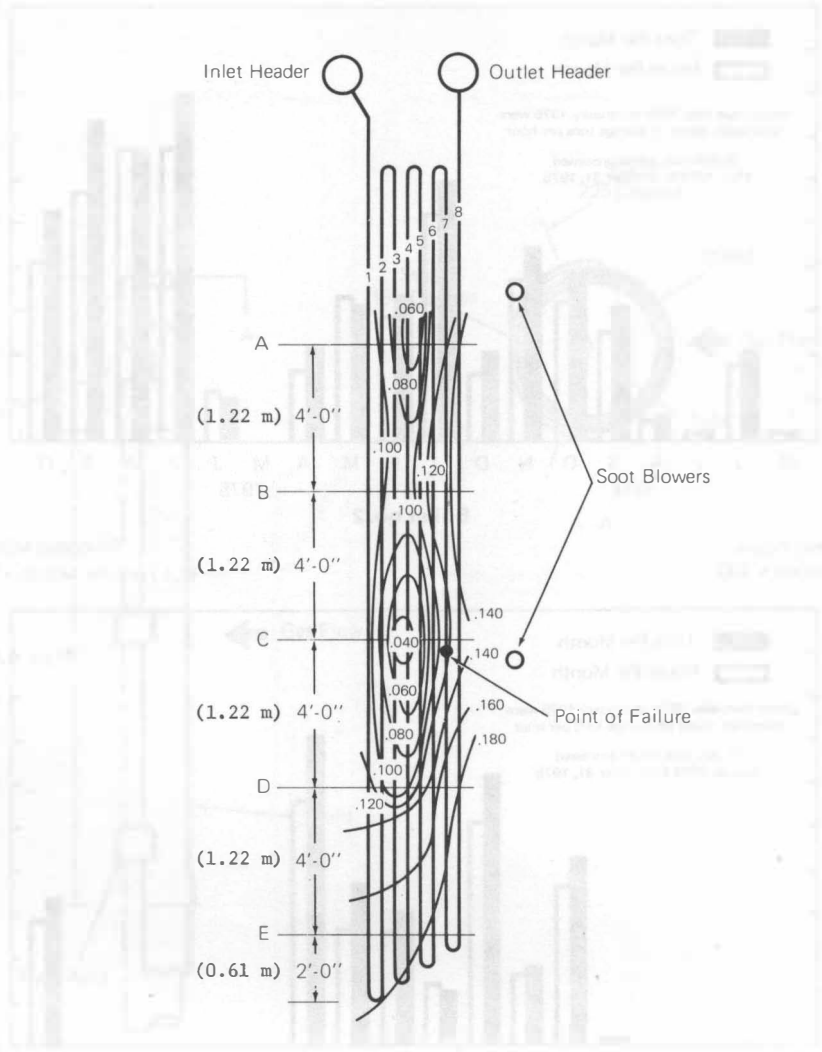


Boiler no. 3

Operating history

Figure 5

*Conversion factor: (U.S. ton) = 0.907 (metric ton)



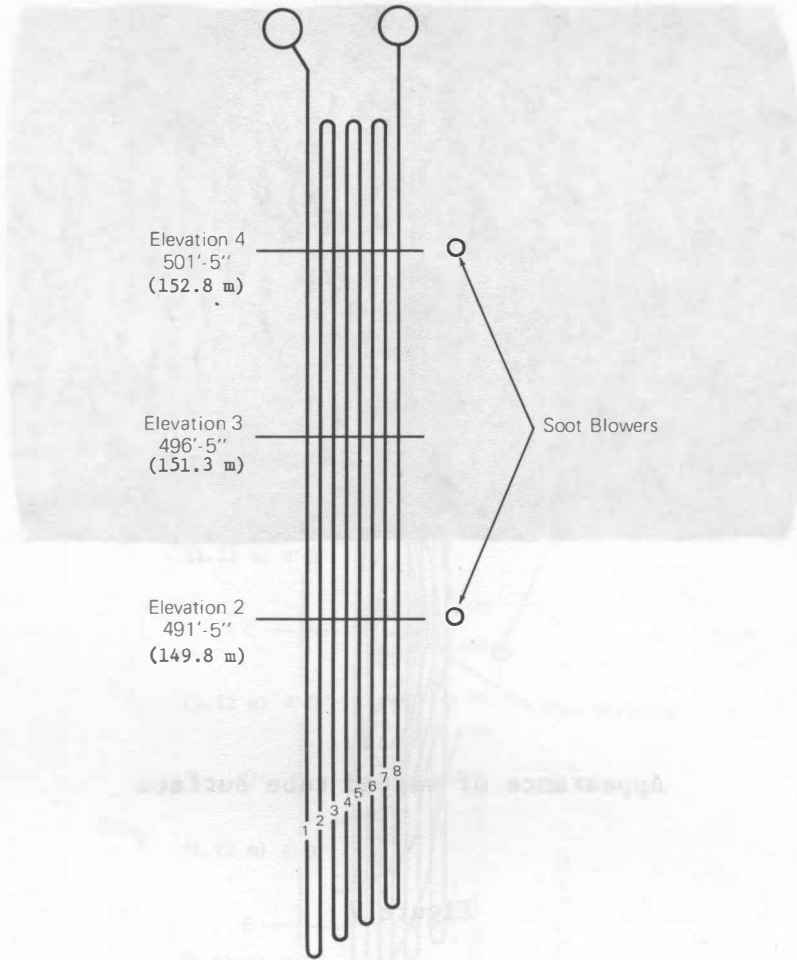
Wastage pattern

Figure 6



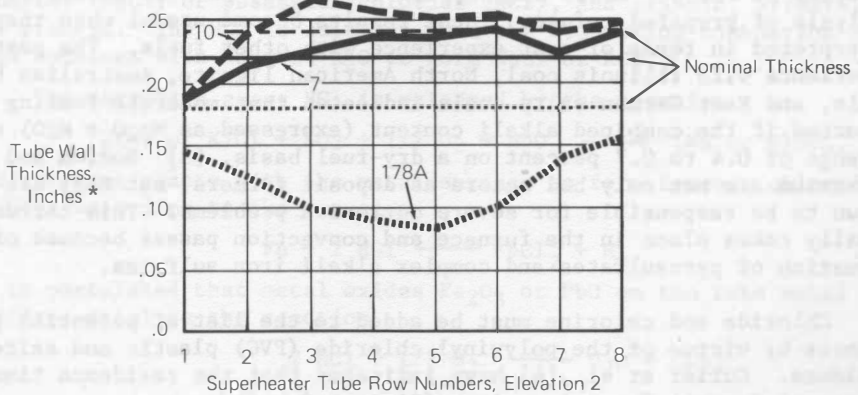
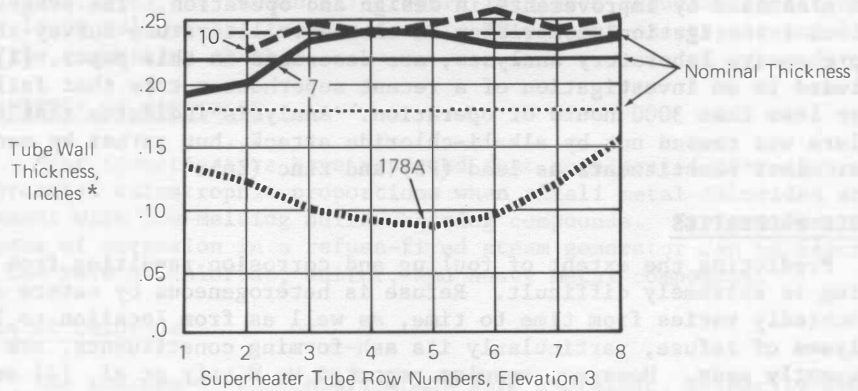
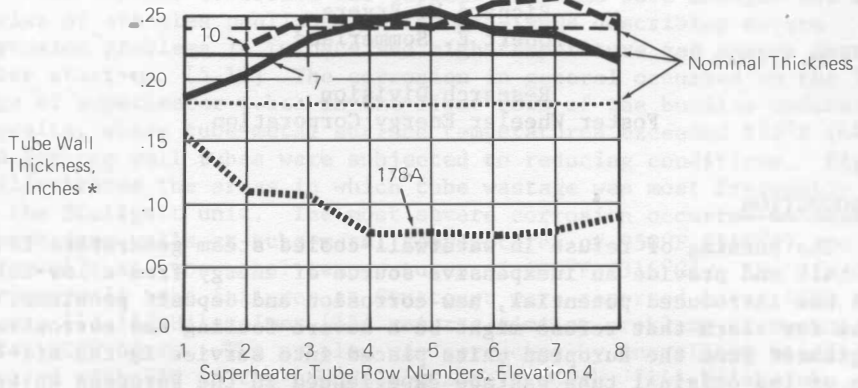
Appearance of wasted tube surface

Figure 7



Location of tube wall thickness measurements

Figure 8



Tube wastage

Test sections vs production sections

Figure 9

*Conversion factor: (inch) = 2.54 (cm)