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**"A FLUE GAS HEAT EXCHANGER FOR ICE FOG  
CONTROL"**

**U. S. ENVIRONMENTAL PROTECTION AGENCY  
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A FLUE GAS HEAT EXCHANGER  
FOR ICE FOG CONTROL

by

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## ABSTRACT

Water vapor emissions from combustion sources is a major cause of ice fog. A flue gas to ambient air heat exchanger (cooler-condenser) was used to condense out most of the combustion created water vapor from a 40 hp oil fired boiler in the Fairbanks area. Flue gas scrubbing by the resulting condensate also removed particulates and sulphur dioxide. Nitrogen oxide removal was insignificant. Siting and control system modifications to reduce tube freezing and increase overall thermal efficiency were suggested. Installation of flue gas cooler-condensers on all combustion sources would be a major step in reducing the Fairbanks ice fog problem.

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## BACKGROUND

Ice fog is a winter phenomenon typical of inhabited Arctic Regions. It is composed of minute ice crystals produced when water vapor is released into ambient air that is too cold to hold the water vapor in solution. This undissolved water vapor crystalizes into small (2 to 100 micron) particles. The larger sizes tend to precipitate out and attach themselves to tree limbs and other structures. It is the smaller sizes which do not readily precipitate out, that cause the reduced visibility problem. Particulate matter such as soot and flyash from combustion sources provides ample condensation nuclei. Oxidation of the hydrogen in hydrocarbon fuels provides water vapor in the flue gasses, thus adding to the ice fog problem. Combustion of more common fuels such as gasoline and fuel oil result in about one gallon of water formed per gallon of fuel burned. Removing this water vapor from the flue gasses would eliminate combustion produced ice fog. This paper is limited to a discussion of water vapor control from combustion sources and of the effect of a gas cooler-condenser upon other stack gas components.

## DESCRIPTION

Ice fog-causing water vapor can be removed from flue gasses by several techniques. A simple method is to drop the temperature of the flue gasses well below the flue gas dew point, thus condensing out the water vapor. The flue gasses can be cooled by two convenient methods. One method is by direct contact with a cooling medium such as cold water. A second method employs the use of an ambient air to flue gas heat exchanger. This method was evaluated at the Bureau of Land Management (BLM) Operations Center in Fairbanks, Alaska.

The heat exchanger as set up by the BLM in 1971 was designed to cool the flue gasses from their oil fired boilers. The setup and operating results from the first winter have been reported by the University of Alaska, Institute of Arctic Environmental Engineering, Report #7204. The original setup for the heat exchanger is shown in Figure 1. There were considerable problems with condensate freezing in the tube bundle during extreme cold; therefore, a supplementary space heater was added to blow warm air into the heat exchanger air box.

During 1972, the heat exchanger was modified as shown in Figure 2. The modifications consisted of the use of larger diameter copper and steel tubes in the tube bundle and an insulated air box with control louvers such that the cooling air could be recirculated in the air box. The addition of the insulated air box and the control louvers made operation of the exchanger much simpler and apparently reduced the tube freezing problem. There are still some modifications to the control system and to the air box that would further improve operational performance of the heat exchanger. They will be discussed under the "Recommendations" section.

#### DATA ANALYSIS

In December 1972, the BLM, Alaska District, and the EPA, Arctic Environmental Research Laboratory (AERL) agreed to cooperatively monitor the performance of the exchanger during the winter of 1972-1973. Under the terms of the agreement the BLM personnel were to operate the exchanger and record boiler firing rate and temperatures and pressures within and around the exchanger. The AERL personnel were to establish the condensate and flue gas quality before and after the heat exchanger use. The heat exchanger was designed with the primary purpose of condensing water vapor from the flue gas and in that service it performed quite well. The exchanger was also somewhat

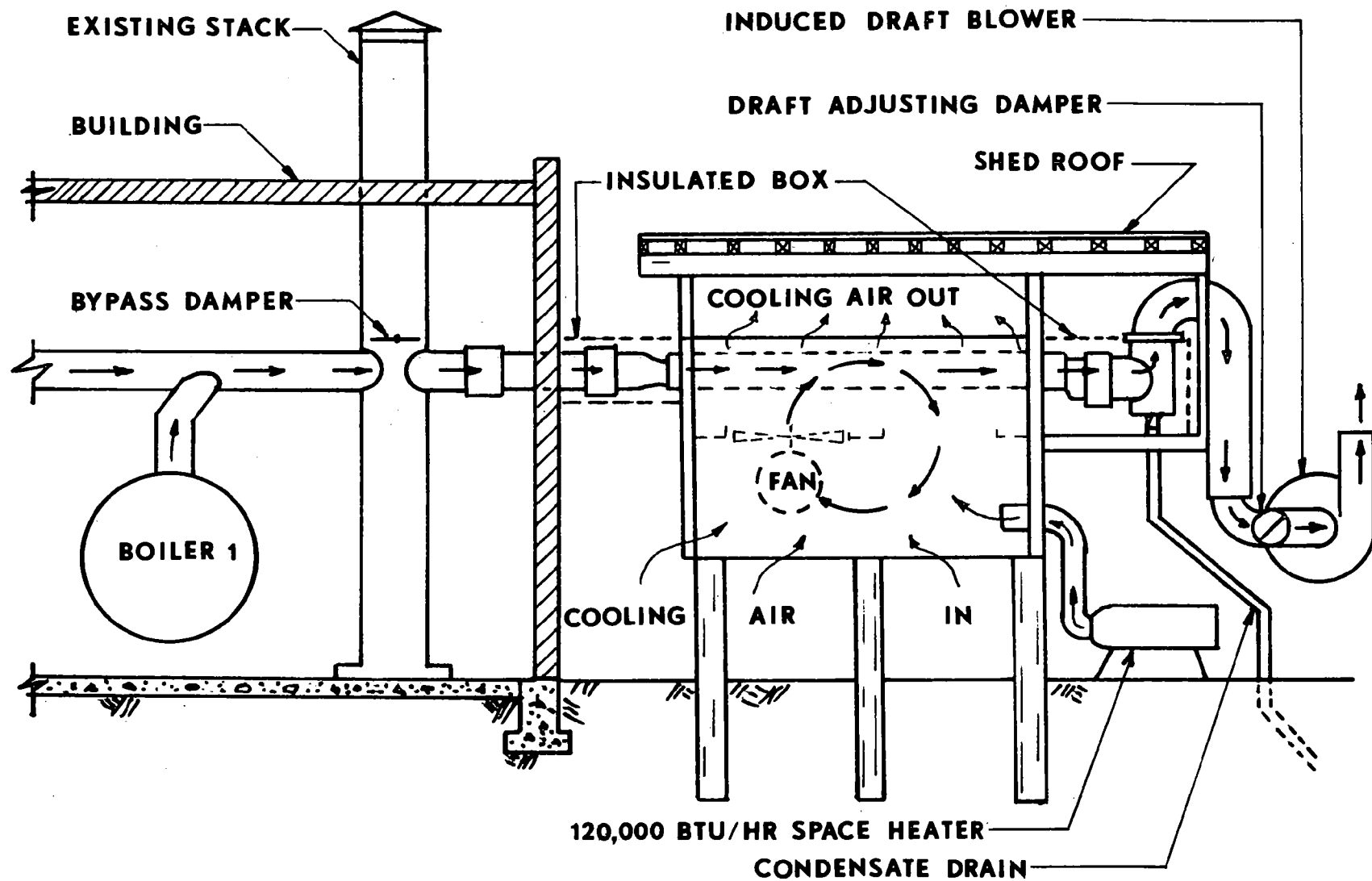


Figure 1. ORIGINAL CONFIGURATION (1971-72) Figure From U.of A. I.A.E.E. Report 7204

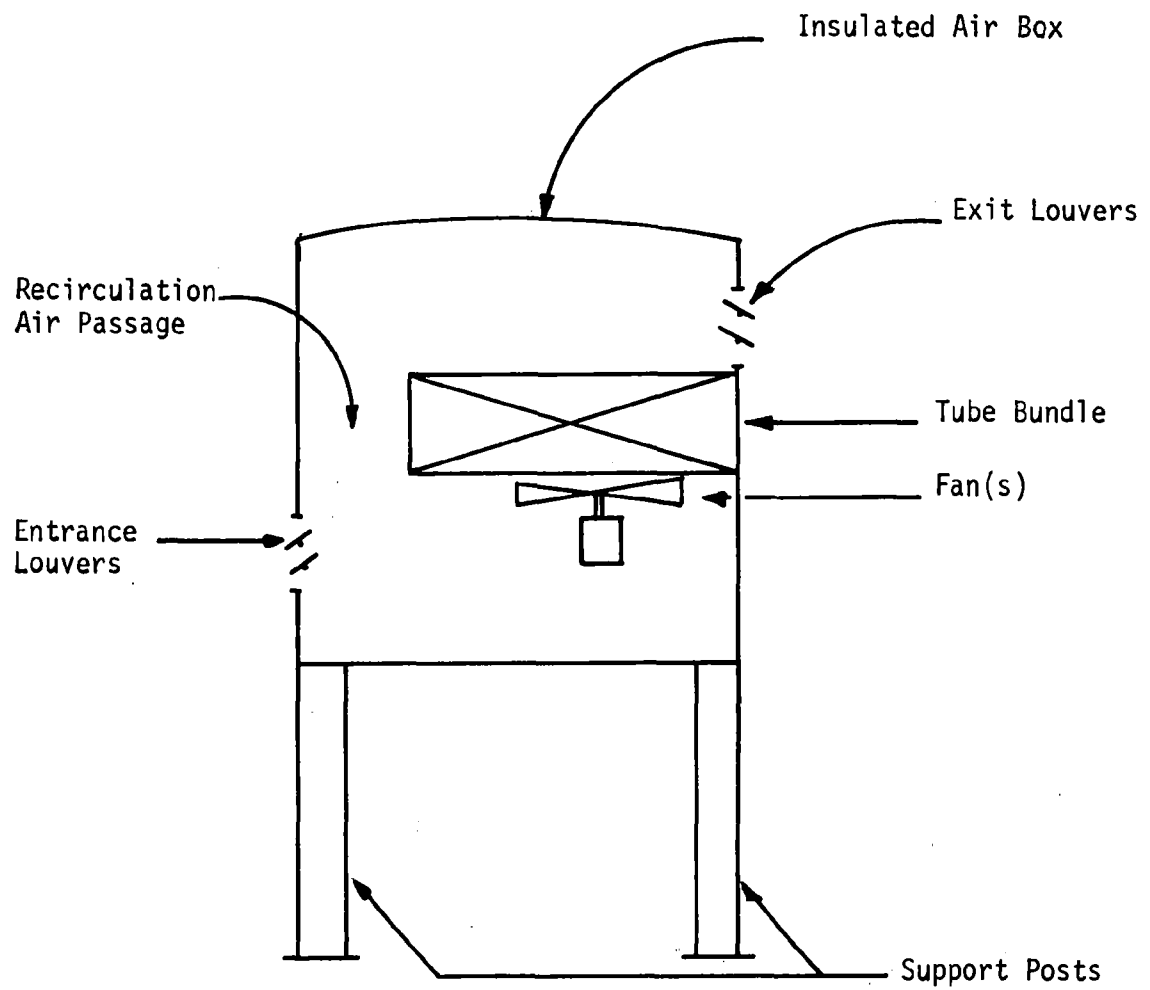


FIGURE 2

BLM Flue Gas Heat Exchanger After 1972 Modification

effective in removing sulphur dioxide. Other measured flue gas parameters were concentrations of: oxygen ( $O_2$ ) and carbon dioxide ( $CO_2$ )(percent), nitrogen and sulphur dioxide ( $NO_2$  and  $SO_2$ )(parts per million), carbon monoxide ( $CO$ ) and hydrocarbons (parts per million), and particulates (grains per standard cubic feet, gr/scf). The results of the flue gas analysis are summarized in Table 1.

Carbon dioxide and oxygen concentrations were determined by Orsat analyses. The excess air (above that required for combustion) was calculated from the oxygen concentration in the flue gas.

Figure 3 shows what the calculated water removal efficiency would be for various heat exchanger flue gas outlet temperatures. As can be seen on this curve, the water removal efficiency is higher with less excess air in the boiler. At 30 percent excess air approximately 50 percent of the combustion created, water vapor would be condensed at about  $90^\circ F$  while only 22 percent will be condensed at 132 percent excess air. To remove over 90 percent of the water vapor, the flue gas temperature would have to be reduced to less than  $40^\circ F$  which would increase the risk of freezing condensate in the tubes.

For the various runs, the percent of the water vapor that was condensed is shown in the last column in Table 1. These are calculated numbers based upon the exchanger outlet temperatures. In most cases the collected condensate was about the same as the calculated condensate (within 10 percent). It should be noted that the calculated condensate or the percent water condensed did not exceed 90 percent. This is of course due to the high exchanger outlet temperature which can be related back to poor control of the recirculated air and the warm ambient temperatures during the runs. A suggested modification for more accurate control of the recirculated air will be discussed in the "Recommendations" section.

TABLE I

BLM FLUE GAS COOLER-CONDENSER  
EXHAUST PRODUCTS DATA

Date	Run #	Ambient Air Temp. °F	BEFORE HEAT EXCHANGER					Pressure Drop in. H <sub>2</sub> O	AFTER HEAT EXCHANGER			
			% O <sub>2</sub>	% CO <sub>2</sub>	% Excess Air	NO <sub>2</sub> ppm	SO <sub>2</sub> ppm		NO <sub>2</sub> ppm	SO <sub>2</sub> ppm	Temp. °F	% H <sub>2</sub> O Condensed
2/5/73	1	2	9.0	3.9	71	5.5	-	-	2.2	-	-	-
6	2	0	11.3	7.2	111	5.8	-	-	-	-	-	-
8	3	3	5.5	12.5	34	5.6	-	0.9	4.4	-	50	-
9	4	-5	8.9	9.9	70	2.0	-	0.9	6.8	-	50	-
13	5	-12	13.4	6.1	-	5.1	-	0.9	7.1	-	49	-
13	6	-19	-	-	156	-	-	0.6	-	-	54	79
13	7	-19	-	-	-	-	-	0.6	-	0.9	43	-
14	8	-2	12.6	6.7	132	4.8	-	0.6	11	1.5	50	-
14	9	-14	-	-	-	-	-	0.5	-	0.7	48	80
27	10	10	12.6	6.7	132	5.0	1.9	0.5	-	-	58	-
27	11	13	11.9	7.1	117	4.2	1.8	0.6	-	-	56	74
28	12	12	13.1	6.4	144	*8.5/10	1.3	0.7	*7.2/-	-	55	-
28	13	12	12.1	7.0	122	-	-	0.6	-	-	64	71
3/1/73	14	7	12.4	6.6	133	2.2	-	0.7	3.9	-	66	-
1	15	11	12.9	6.9	142	3.1	1.0	0.3	4.2	-	69	67
1	16	11	-	-	142	-	-	0.3	*12/5.5	-	52	-
6	17	18	13.1	7.6	140	*13/-	1.3	0.5	4.0	-	53	77
7	18	20	8.1	8.0	58	*28/-	1.0	0.5	*30/-	-	50	87
9	19	-	10.4	8.2	92	*11/3.5	-	-	3.6	-	-	-
9	20	16	8.7	8.7	67	2.8	1.2	0.6	*12/5	-	53	84
13	21	2	7.3	10.3	50	*13/4.3	-	0.8	*2.9/-	-	52	86
13	22	7	6.7	10.5	46	-	-	1.0	-	-	65	78
14	23	3	5.5	12.0	34	-	-	1.1	-	-	62	82
14	24	2	4.9	12.2	29	*13/-	-	1.2	*13/-	-	63	82
30	25	45	(8.5)	8.8	(65)	*4.6/-	-	0.4	-	1.0	81	61
30	26	-	-	-	-	-	-	0.4	-	-	69	-
4/2/73	27	35	8.0	10.8	59	*4.2/-	-	0.4	*6.8/-	1.2	60	81
2	28	34	8.1	10.2	60	*1.9/-	-	0.4	*6.6/-	0.7	60	81

\* (NO + NO<sub>2</sub>)/NO<sub>2</sub>

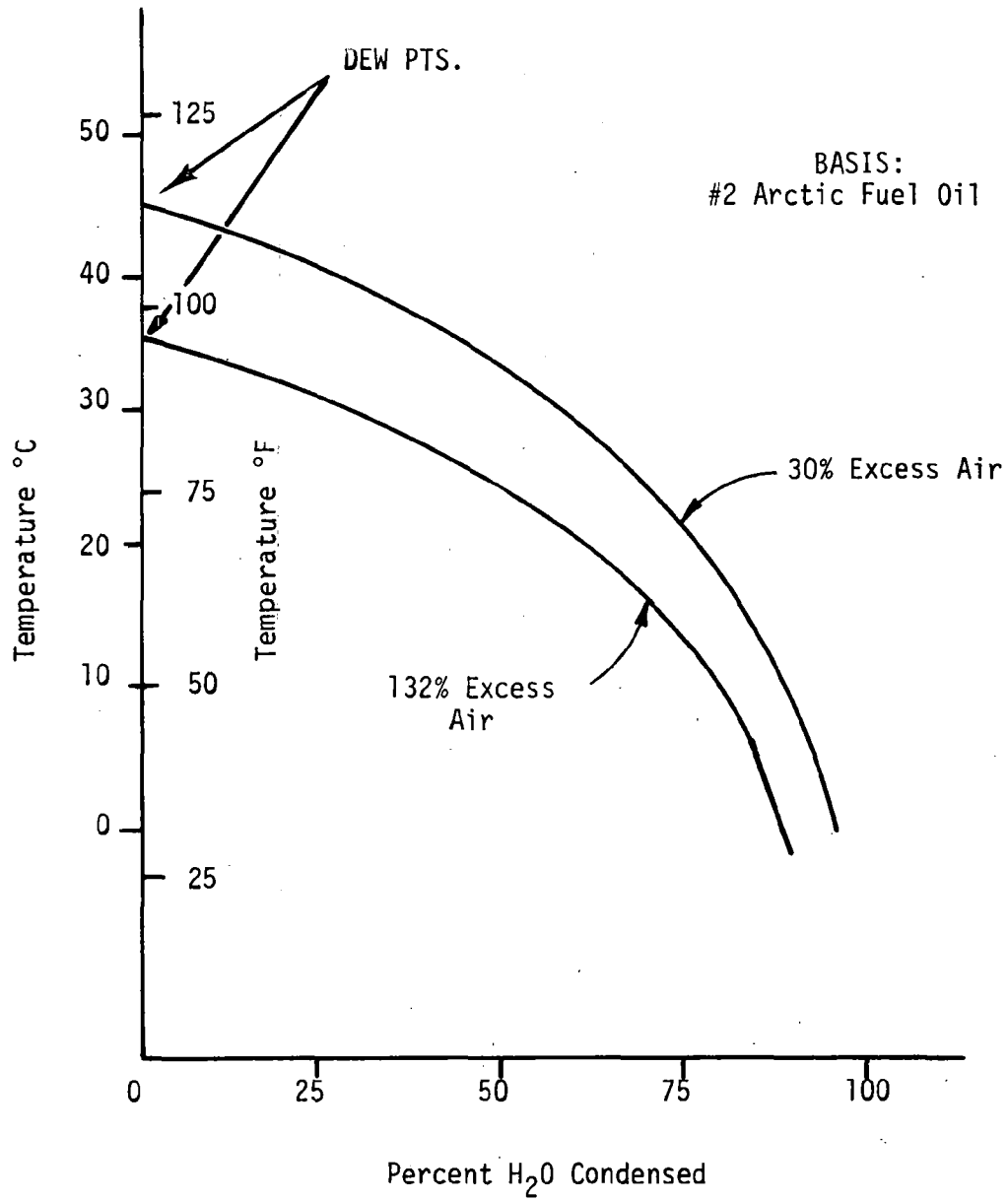


FIGURE 3

Flue Gas Condensation Curve

The sulfur dioxide and nitrogen oxide analyses were performed in accordance with the USPHS publication "Selected Methods for the Measurement of Air Pollutants," 999-AP-11, 1964. The sulfur dioxide ( $\text{SO}_2$ ) was determined by the West and Gaeke Method and the nitrogen dioxide was determined by the Saltzman Method.

The hot flue gas contained considerable interfering substances which prevented direct  $\text{SO}_2$  measurement in the West and Gaeke absorption solutions. To remove the interferences, the flue gas sample was bubbled through distilled water before contacting the absorption solutions. Disolution of sulfur oxides in the distilled water would form sulfites ( $\text{SO}_3^-$ ) and sulfates ( $\text{SO}_4^-$ ). It was assumed that oxygen in the flue gas would oxidize the sulfites to sulfates. Sulfate levels in the distilled water were converted to  $\text{SO}_2$  equivalents and included in the  $\text{SO}_2$  levels listed in Table 1.

Information from the fuel oil supplier indicates that the fuel oil contained 0.01 to 0.02 percent sulfur. Complete combustion with low excess air should, therefore, yield a flue gas  $\text{SO}_2$  concentration of 10 to 20 ppm. The  $\text{SO}_2$  levels in Table 1 are much lower, probably due to incomplete oxidation of sulfite to sulfate in the distilled water bubbler. Analysis of the Table 1 data indicates significant  $\text{SO}_2$  removal by the flue gas heat exchanger. The  $\text{SO}_2$  that is removed from the flue gas ends up as sulfite and/or sulfate in the condensate.

The nitrogen oxide data (measured as nitrogen dioxide,  $\text{NO}_2$ ) are also listed in Table 1. The nitrogen oxide level before and after the heat exchanger appears quite erratic but generally indicates insignificant nitrogen oxide removal. The nitrogen oxide data that has the asterics (\*) is nitric oxide ( $\text{NO}$ ) plus nitrogen dioxide ( $\text{NO}_2$ ) over the nitrogen dioxide ( $(\text{NO} + \text{NO}_2)/\text{NO}_2$ ).

In the combustion process most of the nitrogen oxides are generated as nitric oxide. Once the NO from the flue gas is mixed with atmospheric oxygen it is then slowly oxidized to nitrogen dioxide. With the low NO concentrations in the flue gas, oxidation to NO<sub>2</sub> takes more than 1 minute for greater than 10 percent conversion. Detention time in the exchanger was less than 10 seconds, therefore, the NO at the inlet of the exchanger was not oxidized to NO<sub>2</sub> with the oxygen present in the flue gas. This short detention thus allows direct comparison of inlet and outlet NO<sub>2</sub> levels.

The NO + NO<sub>2</sub> data was obtained by taking a sample of the flue gas, adding atmospheric oxygen and allowing 2 days for oxidation of the NO to NO<sub>2</sub>.

Empirical data on larger oil fired burners indicates nitrogen oxide (NO<sub>x</sub> = NO + NO<sub>2</sub>) emission levels from 10 to 1000 parts per million for flame temperatures above 2000°F. The BLM boilers fall on the low end of the NO<sub>x</sub> emission scale as would be expected from a small boiler with high excess air.

Flue gas particulates were collected in an isokinetic stack sampler. The particulate levels in the flue gas were quite low and well below any combustion source emission standard. The particulates in the flue gas were essentially soot; the soot level was so low that it was below the low level accuracy limit of the particulate sampling equipment. The particulate levels in the flue gas, before passing through the heat exchanger, were measured for runs 3 and 4 and 10 through 20. The average level was  $2.5 \times 10^{-3}$  grains per standard cubic foot of the flue gas, corrected to 12 percent CO<sub>2</sub>. The particulate levels in the flue gas, after passing through the exchanger, were measured in runs 5 through 9. The average effluent particulate concentration was  $0.2 \times 10^{-3}$  grains per standard cubic foot, corrected to 12 percent CO<sub>2</sub>. The exchanger therefore removed approximately 90 percent of the flue gas particulates.

It should be recognized that gun type (pressure atomizing) oil burners are essentially soot free in normal operation after the firebrick has reached normal operating temperatures. Soot formation is caused mainly by flame chilling due to a cold combustion chamber. The particulate samplers were designed to operate only at steady state conditions. Therefore, samples were taken only after the firebrick had heated up and most of the soot for any one firing cycle had passed through the breaching.

The flue gas carbon monoxide levels were measured with an electrochemical instrument. The heat exchanger was found to have no effect upon the carbon monoxide in the flue gas. This was expected, since carbon monoxide is not appreciably soluble in water. The carbon monoxide values were effected by air to fuel ratios; i.e., they decreased with increased excess combustion air. At about 120 percent excess air, the carbon monoxide concentration was about 25 ppm while at 60 percent excess air, the value increased to about 60 to 70 ppm.

During steady state operation hydrocarbon levels in the flue gas were below the detection level (50 ppm as hexane) of an infra-red total hydrocarbon instrument. Hydrocarbon in the condensate could not be detected by gravimetric analysis after pentane extraction.

The condensate quality is shown in Table 2. All condensate analyses were performed in accordance with the EPA publication "Methods for Chemical Analysis of Water and Wastes," 1971. The condensate was very corrosive as indicated by its pH, which varied from 3 to 4 and by its acidity which averages 290 milligrams per liter as calcium carbonate ( $\text{CaCO}_3$ ). The condensate is very acid because of the nitrogen dioxide, sulfur dioxide and carbon dioxide which dissolve to form nitric, sulphuric and carbonic acids. Acidity caused by carbonic acid is usually a milder form which would give pH values from 7 down to 4.5. Any pH values less than 4.5 can be attributed

TABLE 2

BLM FLUE GAS COOLER-CONDENSER  
CONDENSATE DATA

Date	Run #	pH	Acidity mg/l as CaCO <sub>3</sub>	NH <sub>3</sub>	NO <sub>2</sub> <sup>-</sup> +NO <sub>3</sub> <sup>-</sup>	SO <sub>4</sub> <sup>=</sup>	TS	TVS	Fe	Cu	Zn
2/5/73	1	-	-	-	-	-	1680	650	280	18	0.3
6	2	-	-	1.2	1.6	81	540	490	100	10	1.3
8	3	-	-	2.2	2.3	104	570	240	73	32	0.3
9	4	-	-	1.3	2.3	106	580	210	68	29	0.4
13	5	3.5	280	0.7	0.88	115	340	140	88	19	0.1
13	6	3.3	297	0.9	1.1	48	560	170	98	17	0.2
13	7	3.4	298	0.9	1.1	78	520	170	97	22	0.1
14	8	3.1	274	1.2	1.0	62	560	190	110	15	0.6
14	9	3.1	260	0.7	0.87	98	530	160	86	16	0.2
27	10	-	-	-	-	-	-	-	-	-	-
27	11	-	-	-	-	-	-	-	-	-	-
28	12	4.8	266	0.9	0.67	92	570	170	94	12	0.1
28	13	3.6	231	1.0	0.75	95	550	150	91	8	0.2
3/1/73	14	3.3	252	1.3	0.88	109	570	200	93	22	0.1
1	15	3.5	252	1.0	0.57	112	470	170	100	73	0.1
1	16	3.4	247	0.9	0.83	98	450	290	90	10	0.1
6	17	3.3	269	0.9	0.76	134	360	150	82	12	0.2
7	18	3.3	253	0.7	0.60	140	-	150	98	13	0.5
9	19	3.2	289	-	-	151	490	200	100	22	0.1
9	20	3.3	248	-	-	106	420	230	82	12	0.1
13	21	3.2	272	1.1	0.73	101	440	170	89	14	0.2
13	22	3.4	266	1.0	0.61	146	460	200	100	8	0.2
14	23	3.3	266	1.1	0.58	126	520	170	95	15	0.4
14	24	4.8	286	0.8	0.40	151	440	190	98	10	0.2
30	25	-	-	-	-	-	-	-	-	-	-
30	26	3.7	649	4.4	2.6	300	1290	650	286	17	0.1
4/2/73	27	3.4	340	3.3	1.8	244	610	230	130	18	0.1
2	28	3.4	268	1.5	1.9	216	530	180		12	0.1

to mineral acidity. The mineral acidity in this case would be mostly due to sulfates ( $\text{SO}_4^{=}$ ) and hydrolysis of iron sulfates. The concentration of nitrite plus nitrate ( $\text{NO}_2^- + \text{NO}_3^-$ ) appears to be too small to contribute to acidity.

The total nitrogen compounds in the condensate appear to be equally split between ammonia ( $\text{NH}_3$ ), nitrite, and nitrate. The ammonia is produced in the reducing section of the flame where atmospheric nitrogen combines with hydrogen in the hydrocarbon fuel.

As a result of the low pH and high acidity, considerable amounts of iron (Fe) from the tubes is dissolved in the condensate. Iron salts and soot contribute to high total solids values in the condensate. The total solids (TS) average about 580 ppm; the total volatile solids (TVS) average about half that. The total volatile solids are essentially soot. The total non-volatile solids (TS-TV) are essentially the remaining mineral salts, primarily, iron sulfates.

The analysis for copper (Cu) show that some of the copper tubes were also being dissolved by the acidic condensate. The copper values would probably be much higher if it were not for the fact that the copper solutions had to flow over an iron alloy header before collection. This results in plating out of the copper and dissolution of the iron. The zinc (Zn) content in the condensate is probably due to zinc contamination of the fuel oil or the metals in the heat exchanger.

Thermistors were inserted into the exchanger tubes to allow better definition of overall heat exchanger performance. Data from run 27 indicated that the overall exchanger duty was roughly divided between cooling the gasses down to the dew point (110°F) and condensing the gasses down to 60°F (see Figure 4). On that figure also is plotted a profile of percent of total duty versus tube length (from inlet). This indicates that approximately 50 percent of the duty, i.e., down to the dew point, is handled by the first

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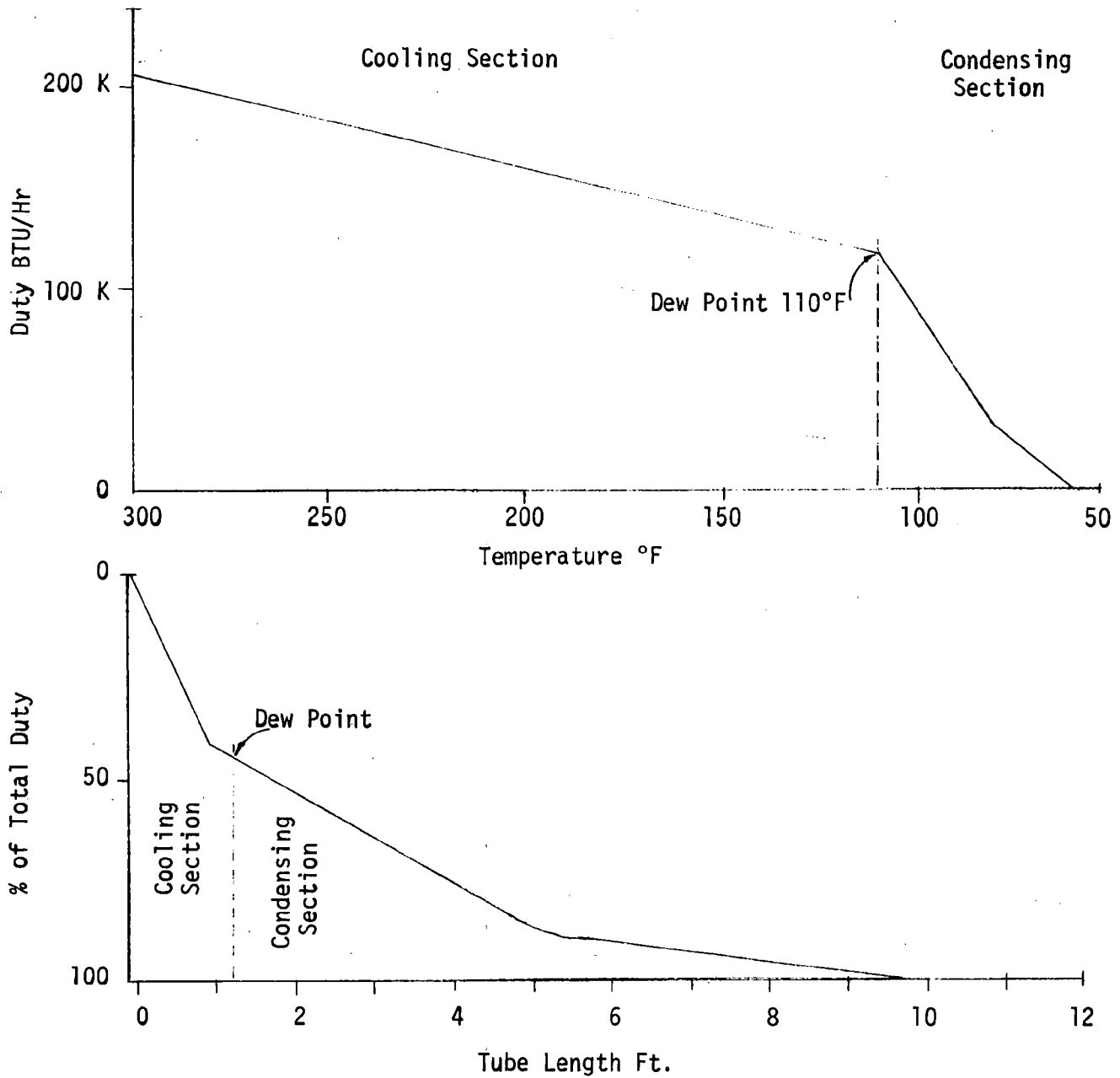


FIGURE 4

BLM Flue Gas Heat Exchanger

Duty vs. Temperature and

Percent of Duty vs. Length Down Tubes

14 percent of the exchanger length. The overall heat transfer coefficient observed in run 27 was 4 BTU per hour per square foot per log mean temperature difference °F.

For this run the pressure drop through the exchanger was less than 1/2-inch of water, which would indicate that there were negligible freezing problems in the tubes and that the overall coefficient was based upon all the tubes and not part of the tubes as would be the case if some of them were plugged with ice.

The pressure drops through the exchanger (inches of H<sub>2</sub>O) are listed in Table 1. The pressure drop through the tubes of the exchanger in this case is generally a function of gas flow. An increase in the percent excess air, resulting in increased combustion products flowing through the exchanger tubes, would cause a higher pressure drop. Condensate freezing in the tubes would also result in excessive pressure drop. Condensate freezing appeared to be happening in some of the earlier runs and in run 22 through 24. The problems of condensate freezing in the tube is shown in Figure 5 which is a picture looking into the exhaust header inspection port. In this case, the condensate froze mainly in the tubes and where it drained from the tubes on the right side of the exchanger. The freezing on this side of the exchanger can probably be attributed to a closed recirculation air passage, which allowed ambient air to rush into the exchanger and pass up through the tubes on the right side exiting the right side louvers.

The debris shown in Figure 5 on the bottom of the header just below the bottom row of tubes is soot and corrosion products from the tubes and discharge manifold. The corrosion products are mainly rust and iron sulfates. Total analysis of these deposits would allow calculation of corrosion rates in terms of pounds of iron dissolved (from the exchanger) per gallon of fuel consumed.

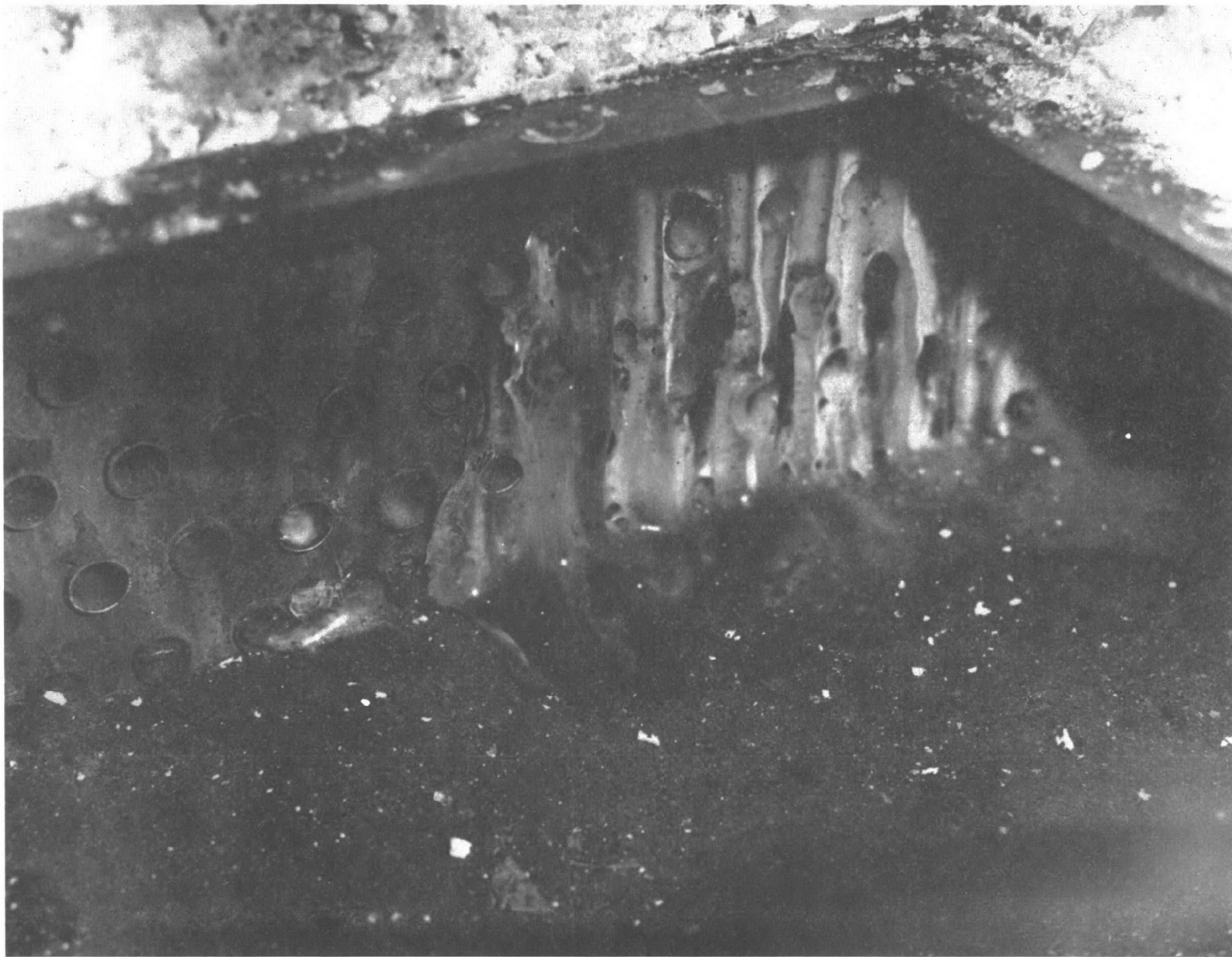


Figure 5. Exhaust Manifold of BLM Flue Gas Heat Exchanger. March 1973

Since the tubes were composed of 4 different materials (3 different steels and copper) it would be necessary to pull and examine the particular tubes to determine respective corrosion rates for each alloy.

#### SUMMARY AND RECOMMENDATIONS

Since corrosion appears to be a major problem because of acidic condensate, it is recommended that tubes for future heat exchangers be either glass lined, coated with a thermal setting plastic or be constructed of an alloy designed to handle the acidic condensate.

The cool flue gas passing from the exchanger is too cold to have enough bouyant force to create a natural draft in any reasonably sized flue stack. Lack of this draft would then require an induced draft fan. Data on the exchanger shows a pressure drop from about 0.4 to 1.2 inches of water. An induced draft fan would have to be sized to compensate for this pressure drop. An alternative would be to use a boiler with a pressurized combustion chamber designed to operate under a positive pressure of 1.5 to 2 inches of water. Commercial boilers should be available which can operate at 2 inches of water pressure in the combustion chamber.

A suggested air box setup is shown in Figure 6 for a heat exchanger located in the outside environment. In this drawing it should be noted that there are louvers in the recirculation air passage which allow control of recirculated air. This setup is a standard cold climate design which should be familiar to commercial fan tube heat exchanger manufacturers.

An alternative to wasting the flue gas heat to the environment would be to site the exchanger in a partially heated area, such as a warehouse where the (flue gas) heat would be used to keep the area at about +35°F. The advantage of this arrangement would be the extra overall thermal efficiency of the boiler heating system. Assuming a normal boiler exhaust stack

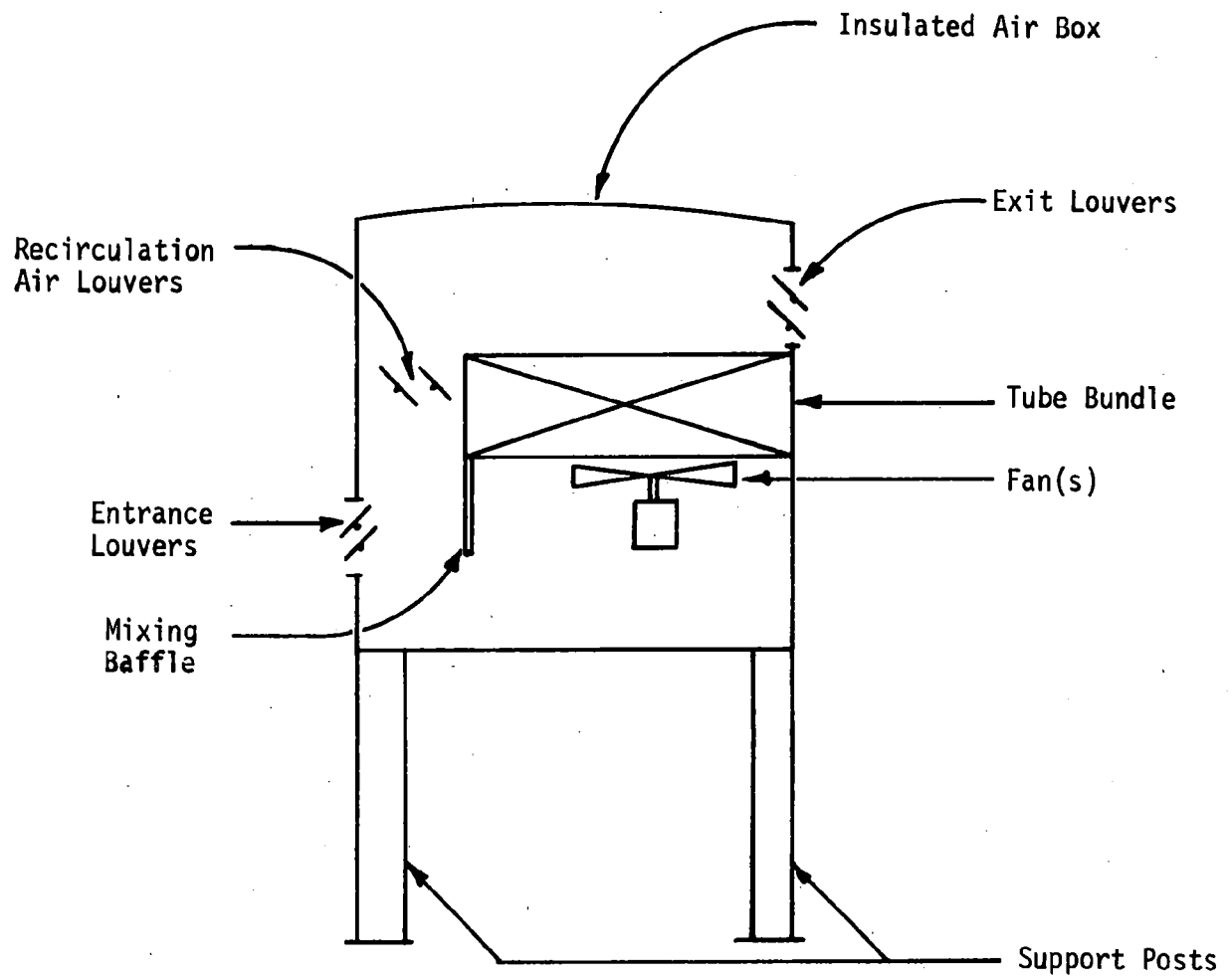


FIGURE 6

AIR BOX SETUP FOR COLD CLIMATES

temperature of 300°F and using a heat exchanger that would drop the flue gas down to 60°F (as in runs 27 and 28), then additional reclaimed heat would be 15 percent above that which is normally utilized in a boiler. This is essentially free heat in terms of fuel cost.

The data presented have shown that the flue gas heat exchanger can be an effective ice fog control device. However, the temperature control system needs to be carefully engineered for optimum performance. Temperature is very important because, for effective operation, the flue gas must be cooled to less than 45°F for efficient water condensation, but not less than 35°F for prevention of freezing.

If water vapor limiting devices (cooler-condensers) were attached to all combustion sources in the Fairbanks area, the ice fog problem would be alleviated, but not entirely eliminated. Ice fog that now occurs at -20°F would probably not occur until -30°F and would only be concentrated around exposed water surfaces.

Other flue gas control systems need to be evaluated before any cost comparisons can be performed.