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April 1976

FIELD TESTING: APPLICATION OF COMBUSTION MODIFICATIONS TO CONTROL POLLUTANT EMISSIONS FROM INDUSTRIAL BOILERS--PHASE II

by

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SECTION 1.0

SUMMARY

1.1 OBJECTIVE AND SCOPE

Industrial combustion devices of all kinds contribute a large fraction of the total air pollution from stationary sources. Studies have found as much as 40% of the stationary source total nitrogen oxides emissions originate from devices such as industrial boilers.[1,2,3] A similar figure was obtained for oxides of sulfur, while particulate emissions were more than 80%. Combustion modifications have been demonstrated for utility boilers which can reduce emissions of NOx, CO, and hydrocarbons while improving boiler efficiency. Application of these modifications to industrial combustion devices, if successful, could have a profound impact on air quality and energy conservation.

An objective of the field testing portion of the program was to determine the level of emissions of pollutant gases, particulates, and toxic elements and organics from industrial-sized boilers of 11 to 527 GJ/hr (10,000 to 500,000 lbs steam/hr) capacity. It also was an objective to determine the effectiveness of combustion modifications to reduce emissions and the extent to which a reduction in one pollutant such as total nitrogen oxides, might cause an increase in other pollutants, such as particulates or hydrocarbons, or a decrease in boiler efficiency.

In addition, the program sought to establish what design and/or operational changes that boiler manufacturers and operators could make to reduce emissions and where future combustion research activities should be concentrated. The measurements of toxic emissions will be used to determine if industrial boilers as a class are a significant source of these pollutants.

The program was conducted in two phases, and this document is the Final Report of the second phase. The first phase was one year in duration and involved the selection of forty-seven representative industrial boilers for testing, construction of a mobile flue gas analysis laboratory, and field testing for emissions. Measurements were made of boilers operating normally and in certain low-nitrogen-oxides-emission modes that could be obtained without having to modify the boiler, such as reducing the amount of excess air. The pollutants of interest in Phase I in addition to oxides of nitrogen were oxides of sulfur, hydrocarbons, carbon monoxide, carbon dioxide, smoke, and particulates.

The Phase II activities were of fourteen months duration and involved the intensive testing of nineteen individual boilers to measure the sensitivity of boiler efficiency and emissions to combustion modifications that sometimes required retrofit of the boiler. Examples of such combustion modifications are overfire air ports and flue gas recirculation.

In addition to total particulate emissions data, the particle size distribution from thirteen oil and coal-fired industrial boilers was determined during Phase II. The identity and quantity of elemental metals originally contained in the fuel and organic compounds released by the combustion process were established for several boilers. Also, the enrichment of certain sizes of particulates by toxic elements was investigated.

The program documentation consists of Phase I (Ref. 4) and Phase II Final Reports, and two Guideline Manuals. One Guideline Manual is for industrial boiler manufacturers to provide information on total nitrogen oxides, particulates, and efficiency trends with boiler design characteristics to aid them in designing new boilers and modifying existing boilers to produce low nitrogen oxides emissions. The other Guideline is for industrial boiler operators and contains specific operating instructions and recommended steps for reducing nitrogen oxides and particulate emissions from various types of boilers. The Final Report also contains recommendations for future research.

The results of the collection and analyses of toxic metals and gases and of organic emissions are reported in a third report (Ref. 5).

1.2 RESULTS

Measurements of pollutants were made when the boilers were operating at 80% of capacity and normal control settings (called the baseline setting) and when the combustion process was modified in a way that reduced the total nitrogen oxides (NO_x) emissions.

The primary categorization of boilers when they originally were selected was by capacity or size, and one objective was to determine if the larger boilers had the larger emission factors. It was found that the total nitrogen oxides emissions from coal- and natural gas-fueled boilers increased slightly with size but the emissions from oil-fueled boilers did not. The nitrogen oxides emissions, however, were very dependent upon the fuel being fired regardless of the boiler size, with coal fueled boilers being the greatest emitters of total nitrogen oxides.

The particulate emissions were not at all dependent upon the boiler size, but were strongly dependent upon the fuel type. The particulate emissions from coal were about ten times greater than from oil and about one hundred times greater than from natural gas.

The measured total nitrogen oxides and solid particulates emissions at baseline are shown in Figures 1-1 and 1-2. The emission levels at baseline of the other pollutants are listed in Table 1-1. The meaning of the abbreviations and symbols used is given at the end of Table 4-1.

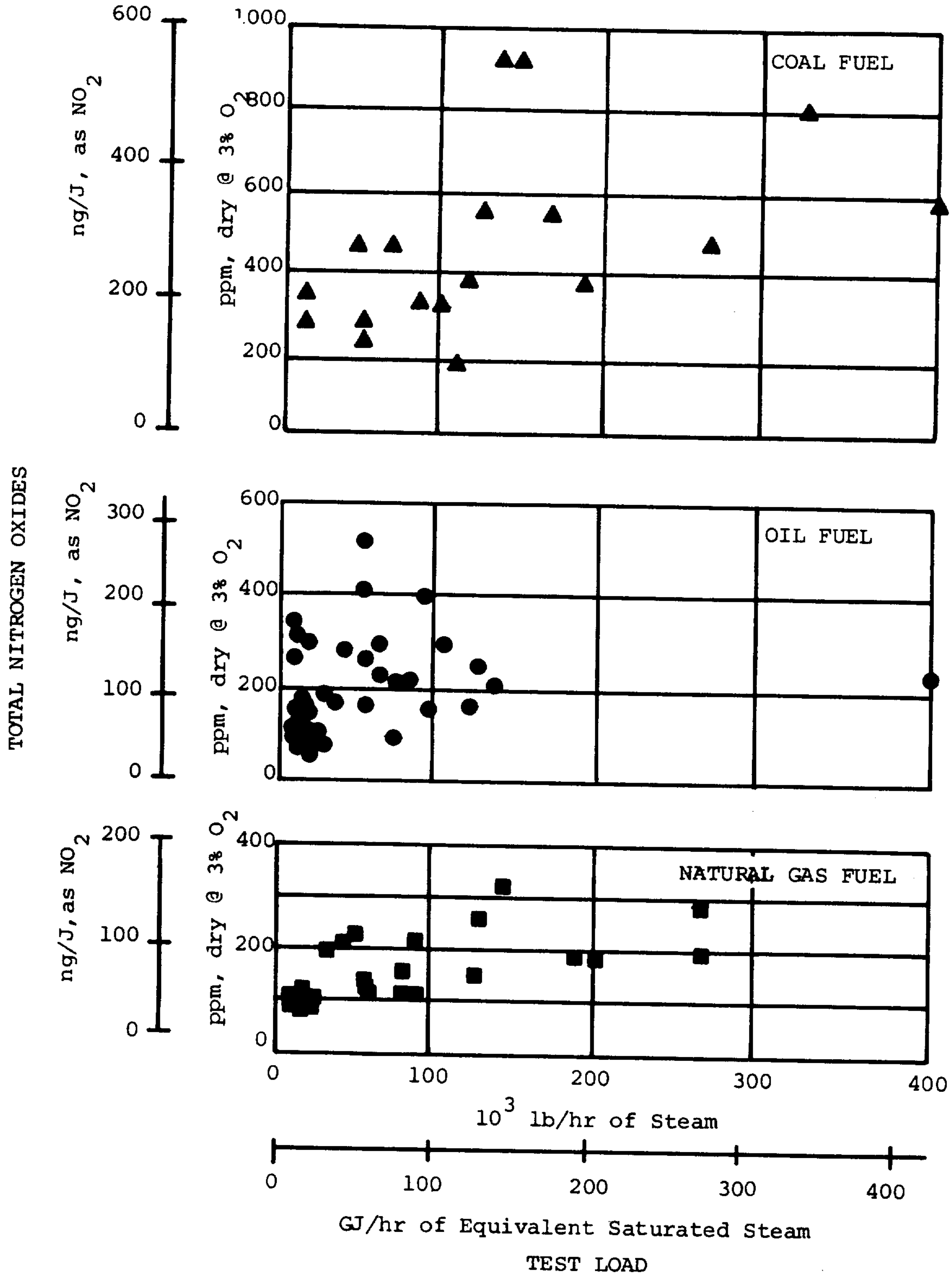

Figure 1-1. Total oxides of nitrogen emissions at baseload.

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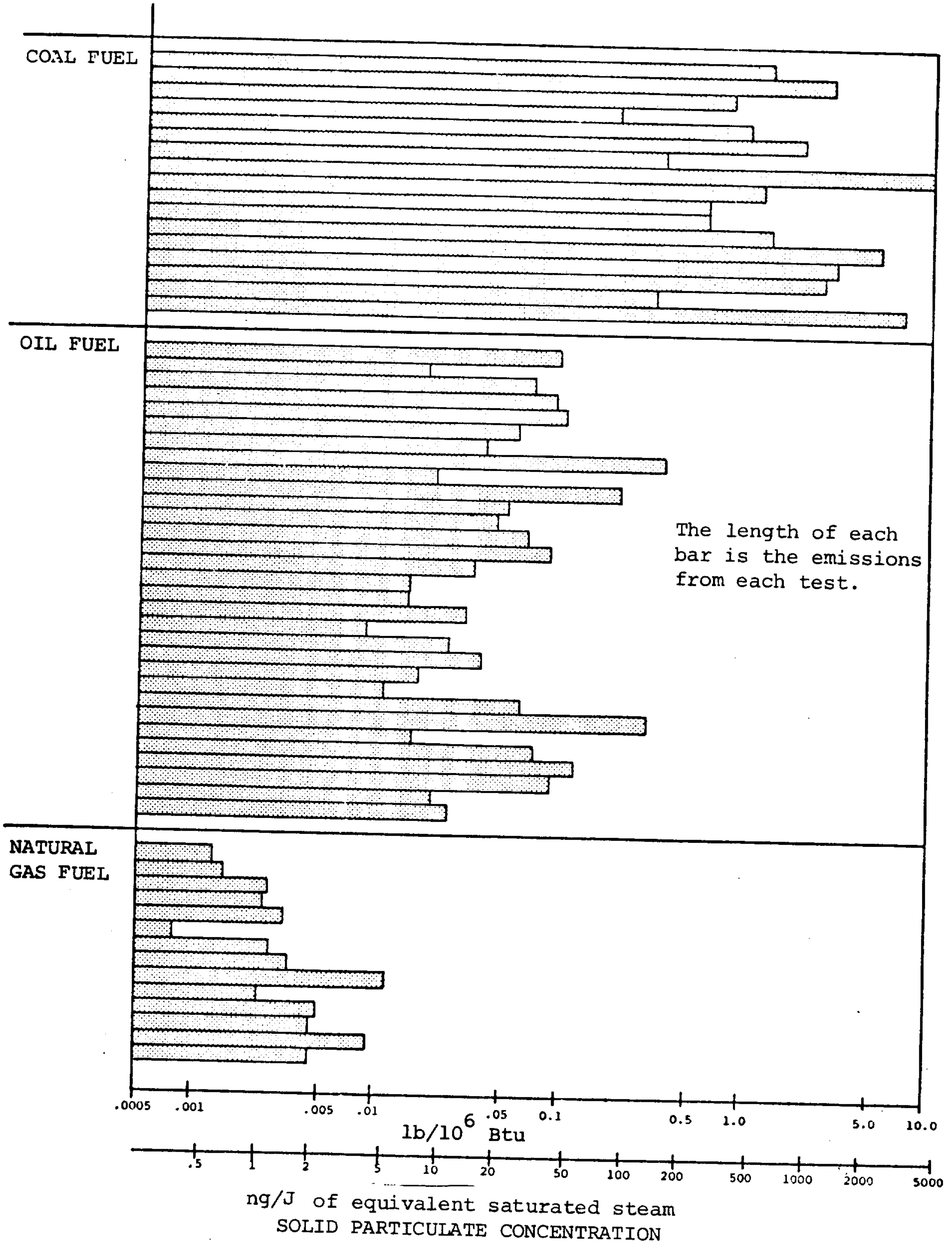

Figure 1-2. Solid particulate emissions at baseload.

Table 1-1. BOILER EMISSION MEASUREMENTS AT BASELINE AND LOW NOx TEST CONDITIONS (1,3)

				Burner		BASELINE TEST CONDITIONS AND EMISSIONS (1)								LOW NITROGEN OXIDES TEST CONDITIONS AND EMISSIONS (1)								
Test No. From-Thru	Loc. No.	Boiler Capacity GJ/hr (10^3 lb/hr)	Test Fuel	(1) Type	No. Of	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NOx (2) ng/J (ppm)	CO_2 (2) %	CO (2) ng/J (ppm)	HC (2) ng/J (ppm)	SOx (2) ng/J (ppm)	Solid Part. ng/J (lb/MBtu)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NOx (2) ng/J (ppm)	(2) CO_2 %	CO (2) ng/J (ppm)	HC (2) ng/J (ppm)	SOx (2) ng/J (ppm)	Solid Part. ng/J (lb/MBtu)	Test Type
101 only	1	31 (29)	NG	Ring	1	18 (17)	2.2	39.6 (77.7)	10.8	21 (67)	-	-	-	Baseline Test Only Conducted								
102-103	1	31 (29)	#2	Steam	1	18 (17)	5.3	50.7 (90.3)	11.6	31 (90)	-	188 (241)	7.31 (.017)	20 (19)	4.7	47.1 (84)	11.7	51 (150)	-	-	-	LowAir
104-106	1	31 (29)	NG	Ring	1	25 (24)	0.9	38.0 (74.5)	11.2	152 (489)	-	-	-	25 (24)	2.6	41.8 (81.9)	10.4	0 (0)	-	-	-	BrTune
107-108	1	31 (29)	#2	Steam	1	26 (25)	2.7	47.7 (85)	13.2	139 (407)	-	300 (384)	4.73 (.011)	25 (24)	3.8	48.3 (86.1)	12.5	38 (110)	-	-	12.0 (.028)	BrTune
109-110	27	106 (100)	NG	Ring	1	79 (75)	6.6	56.6 (111)	7.9	0 (0)	-	-	-	82 (78)	2.4	77.5 (152)	9.3	0 (0)	2.5 (14)	-	-	BrTune
111-112	27	106 (100)	PS300	Steam	1	90 (85)	9.3	257 (458)	8.8	40 (116)	-	488 (626)	26.2 (.061)	74 (70)	6.5	277 (494)	10.0	0 (0)	-	-	20.4 (.066)	BrTune
113-115	29	158 (150)	NG	Ring	2	127 (120)	5.3	78.5 (154)	8.0	0 (0)	22 (125)	-	-	Baseline was low NOx								
116-121	29	158 (150)	#6	Steam	2	126 (119)	5.0	165 (294)	11.8	0 (0)	6.9 (35)	-	-	74 (70)	6.0	99.3 (177)	9.8	3.4 (10)	2.9 (15)	-	-	BOOS LowLoad
122-125	28	74 (70)	NG	Ring	3	31 (29)	5.7	108 (211)	7.6	0 (0)	0 (0)	-	-	32 (30)	5.3	49.0 (96)	7.9	16 (50)	0 (0)	-	-	BOOS
126-130	28	74 (70)	#6	Steam	3	31 (29)	5.3	115 (205)	11.6	0 (0)	-	-	127.3 (.296)	30 (28)	4.9	101 (180)	11.6	9.5 (28)	-	-	-	LowAir
131-133	31	274 (260)	Coal	Pulv.	4	137 (130)	7.4	563 (922)	11.8	0 (0)	-	813 (956)	2279 (5.3)	66 (63)	7.5	378 (618)	11.8	0 (0)	-	-	-	BOOS LowLoad
134-139	30	132 (125)	Coal	SpStk	4	87 (82)	6.2	196 (320)	12.8	0 (0)	-	947 (1114)	1312 (3.05)	51 (48)	7.4	119 (195)	11.8	15 (40)	-	-	-	LowAir LowLoad
140-142	32	137 (130)	NG	Ring	1	81 (77)	7.1	81.6 (16C)	8.0	62 (200)	-	-	-	Basline was low NOx								
143-148	32	127 (120)	NG	Ring	4	88 (83)	4.4	117 (230)	9.4	0 (0)	-	-	-	65 (62)	4.4	74.5 (146)	9.0	13 (43)	-	-	-	BOOS LowLoad
149-152	33	580 (550)	Ref. Gas	Spud	8	506 (480)	5.1	84.8 (146)	8.4	0 (0)	-	-	-	506 (480)	3.9	53.8 (107)	9.4	80.2 (263)	-	-	-	CombCyc BOOS
153-155	34	264 (250)	NG	Spud	1	206 (195)	2.6	96.4 (189)	11.4	100 (322)	6.9 (39)	-	-	157 (149)	4.4	64.8 (127)	9.2	18.9 (61)	7.61 (45)	-	-	VPH AirReg
156-159	13	528 (500)	Coal Oil	Pulv. Steam	6 3	422 (400)	8.6	216 (353)	8.6	0 (0)	-	-	1122 (2.61)	443 (420)	7.2	166 (283)	10.0	21 (76)	-	-	-	BOOS LowAir
160-164	36	211 (200)	#2	Steam	1	72 (68)	4.4	57.8 (103)	11.2	0 (0)	0 (0)	-	6.88 (.016)	63 (60)	6.3	39.3 (70)	10.4	0 (0)	0 (0)	-	155 (.36)	Damper OFA
165-168	35	227 (215)	Coal	ChGrt	1	110 (104)	9.5	100 (164)	9.2	9.3 (25)	5.3 (25)	-	133 (.31)	111 (105)	8.7	77.0 (126)	10.3	20 (55)	3.8 (18)	-		LowAir
169 only	31	274 (260)	Coal	Pulv.	4	148 (140)	7.0	561 (918)	-	0 (0)	-	-	3014 (7.01)	Baseline Test Only Conducted								
170-175	20	84 (80)	#6	Steam	1	65 (62)	3.3	148 (264)	13.5	0 (0)	1.6 (8)	780 (1000)	31.8 (.074)	67 (63.5)	2.7	132 (236)	13.1	10 (30)	2.5 (13)	-	24.1 (.056)	AirReg & LowAir
176-179	37	42 (40)	#6	Steam	2	34 (32)	4.3	109 (195)	12.6	0 (0)	2.9 (15)	815 (1045)	50.7 (.118)	34 (32)	4.0	97.6 (174)	12.1	8.5 (25)	0 (0)	-	34.8 (.081)	LowAir
180-185	38	47 (45)	NG	Ring	1	42 (40)	1.9	112 (220)	9.4	0 (0)	1.8 (10)	-	-	41 (38.5)	2.9	52.0 (102)	8.4	11 (35)	-	-	-	OFA
186-189	38	47 (45)	#6	Steam	1	39 (36.5)	3.0	183 (326)	11.0	0 (0)	-	738 (946)	38.7 (.09)	39 (36.5)	2.9	97.0 (173)	11.8	19 (55)	3.9 (20)	-	55.0 (.128)	OFA

(1) An explanation of the abbreviations and units used is given at the end of Table 4-1.
(2) The emissions of these species are reported as dry at 3% excess oxygen.
(3) The shaded data blocks indicate tests where NO_x, CO and/or particulates were measured before and after combustion modification.

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Table 1-1. Continued (1,3)

				Burner		BASELINE TEST CONDITIONS AND EMISSIONS (1)								LOW NITROGEN OXIDES TEST CONDITIONS AND EMISSIONS (1)								
Test No. From-Thru	Loc. No.	Boiler Capacity GJ/hr (10^3lb/hr)	Test Fuel	(1) Type	No. Of	Test Load GJ/hr (10^3lb/hr)	Excess O_2 %	$NOx^{(2)}$ ng/J (ppm)	$CO_2^{(2)}$ %	$CO^{(2)}$ ng/J (ppm)	$HC^{(2)}$ ng/J (ppm)	$SOx^{(2)}$ ng/J (ppm)	Solid Part. ng/J (lb/MBtu)	Test Load GJ/hr (10^3lb/hr)	Excess O_2 %	$NOx^{(2)}$ ng/J (ppm)	(2) CO_2 %	$CO^{(2)}$ ng/J (ppm)	$HC^{(2)}$ ng/J (ppm)	$SOx^{(2)}$ ng/J (ppm)	Solid Part. ng/J (lb/MBtu)	Test Type
190-194	19	18.5 (17.5)	NG	Ring	1	14.8 (14)	3.2	30 (59)	10.0	3 (10)	0.9 (5)	-	-	14.3 (13.6)	2.8	8 (16)	10.2	37 (120)	13.3 (75)	-	-	FGP
195-199	19	18.5 (17.5)	#6	Steam	1	14.8 (14)	3.1	95 (169)	13.2	0 (0)	-	-	13.3 (.031)	14.8 (14)	2.4	61 (108)	13.6	53 (155)	0.9 (5)	-	-	OFA
200-203	19	18.5 (17.5)	#6	Air	1	14.8 (14)	2.9	91 (162)	13.2	0 (0)	0 (0)	146 (187)	13.3 (.031)	14.8 (14)	2.3	65 (116)	13.8	6.8 (20)	0 (0)	-	-	FGP
204-206	19	18.5 (17.5)	NG + #6	Ring, Air	1	14.8 (14)	3.3	59 (111)	11.2	3 (10)	4.7 (25)	-	-	14.8 (14)	2.8	49 (92)	11.8	0 (0)	4.7 (25)	-	-	FGR
207-212	39	211 (200)	NG + RG	Spud	1	169 (160)	3.7	98 (192)	8.8	8 (25)	0 (0)	-	-	169 (160)	6.4	75 (147)	7.4	48 (155)	0 (0)	-	-	OFA

(1) An explanation of the abbreviations and units used is given at the end of Table 4-1.

(2) The emissions of these species are reported as dry at 3% excess oxygen.

(3) The shaded data blocks indicate tests where NO_x, CO and/or particulates were measured before and after combustion modification.

Table 1-1 also lists the pollutant emission levels when the boiler was operated such that the total nitrogen oxides emissions were the lowest. The column on the extreme right entitled Test Type indicates the particular combustion modification that produced the lowest nitrogen oxides emissions. For example, for Tests 102-103 the lowest nitrogen oxides emissions occurred when the excess combustion air was reduced. For Tests 122-125 the lowest total nitrogen oxides were found after a burner had been taken out of service. When the emissions of total nitrogen oxides (NO_x), carbon monoxide (CO) or solid particulate (Solid Part.) were measured both before and after the combustion was modified, the data are delineated by shading the entry in the table.

The variation of the excess combustion air and the reduction of the firing rate are combustion modification methods that were applied to almost all boilers. It is common in industry for there to be boiler capacity that is used only occasionally for peaking or during overhaul periods, and it is possible to operate all of the boilers at a reduced firing rate and still meet the normal demand for process steam. The other eight methods were applied only to those boilers that were amenable to the particular modification, and the method that produced the lowest nitrogen oxides emissions is listed in Table 1-1.

The range of total nitrogen oxides concentration that was measured at the baseline load for each fuel type is listed below. The table also lists the average nitrogen oxides and excess oxygen concentrations at baseline load with normal boiler settings and with the boiler settings that emitted the lowest total nitrogen oxides concentration. The Baseline Operation columns summarize the emissions listed in the Baseline Test Conditions section of Table 1-1. The

Low NOx Operation columns summarize the emissions listed in the Low Nitrogen Oxides Test Conditions section of Table 1-1. All nitrogen oxides measurements cited in this report in parts per million (ppm) have been normalized to "dry at 3% excess oxygen."

	Range	Average			
	Baseline	Baseline Operation		Low NOx Operation	
Fuel Type	NOx ng/J (ppm)	NOx ng/J (ppm)	O_2 %	NOx ng/J (ppm)	O_2 %
Coal	100-562 (164-922)	290 (475)	8.7	225 (369)	6.7
No. 2 Oil	36-101 (65-180)	67 (120)	5.5	59 (105)	4.0
No. 5 Oil (PS 300)	112-347 (200-619)	164 (293)	5.8	142 (254)	4.9
No. 6 Oil	107-196 (190-350)	151 (269)	5.3	121 (216)	4.9
Natural Gas	26-191 (50-375)	71 (139)	4.8	57 (111)	5.0

Eleven combustion modification techniques were used to reduce the emissions of the total nitrogen oxides. These techniques were:

1. Excess Combustion Air Reduction
2. Staged Air Addition
3. Burner Out Of Service
4. Burner Register Adjustment
5. Combustion Air Temperature Reduction
6. Flue Gas Recirculation
7. Boiler Firing Rate Reduction
8. Fuel Oil Viscosity Variation
9. Burner Tune-up
10. Fuel Atomization Method Change
11. Fuel Atomization Pressure Variation

While the principal objective of combustion modification was to reduce the emissions of total nitrogen oxides, the effect of the modifications on other emissions, such as hydrocarbons or the particulate emissions, and on boiler efficiency were considered too. It was found that the combustion modification did not increase the hydrocarbon emissions to any extent, but it did have a significant effect on the particulate emissions and on the boiler heat loss efficiency.

These effects are summarized for all of the combustion modification methods in Figures 1-3 and 1-4. The effect on emissions and boiler efficiency of each of the methods of combustion modification and of each fuel type are discussed in detail in Section 5.0, Combustion Modification Test Results.

The combustion modification effect graphs are divided into quadrants. One is labeled "Best Quadrant" and a second "Worst Quadrant." The criterion for the Best Quadrant with solid particulate emissions is that the effect of the modification was to reduce the emissions of both the total nitrogen oxides and the particulates. The Worst Quadrant is when the effect was to increase both emissions.

In the case of boiler heat loss efficiency the Best Quadrant is when the total nitrogen oxides emissions decreased, but the efficiency increased.

Excess Combustion Air: The best combustion modification method on the basis of ease of implementation, emission reduction, and efficiency was to reduce the amount of excess air being fired. In about 72% of the instances when the excess air level was reduced, the nitrogen oxides emissions decreased and the boiler efficiency increased. The nitrogen oxides decreased by up to 38% of the baseline level and the efficiency increased by up to 3 percentage points.

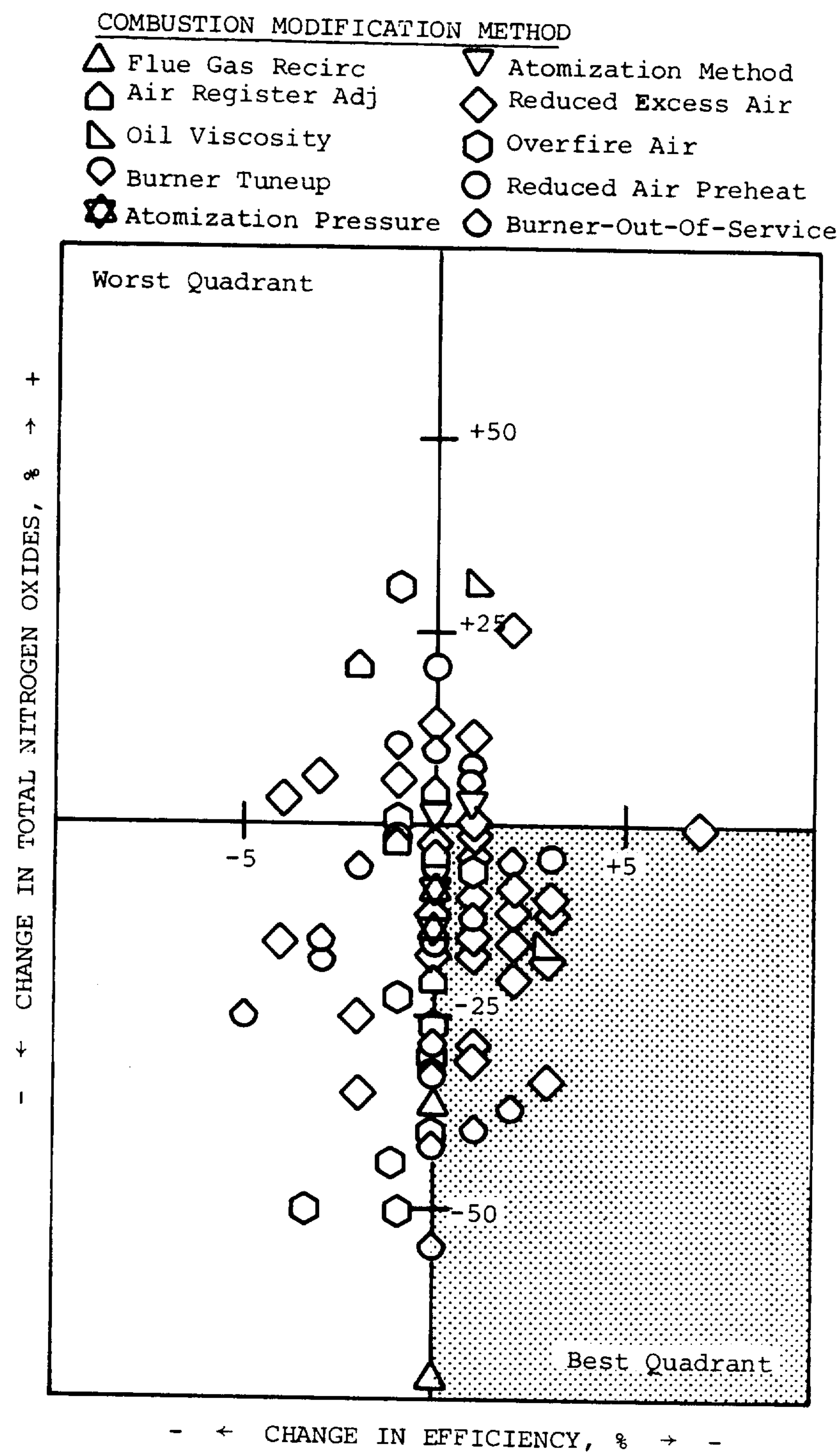

Figure 1-3. Effect of combustion modification methods on total nitrogen oxides emissions and boiler efficiency.

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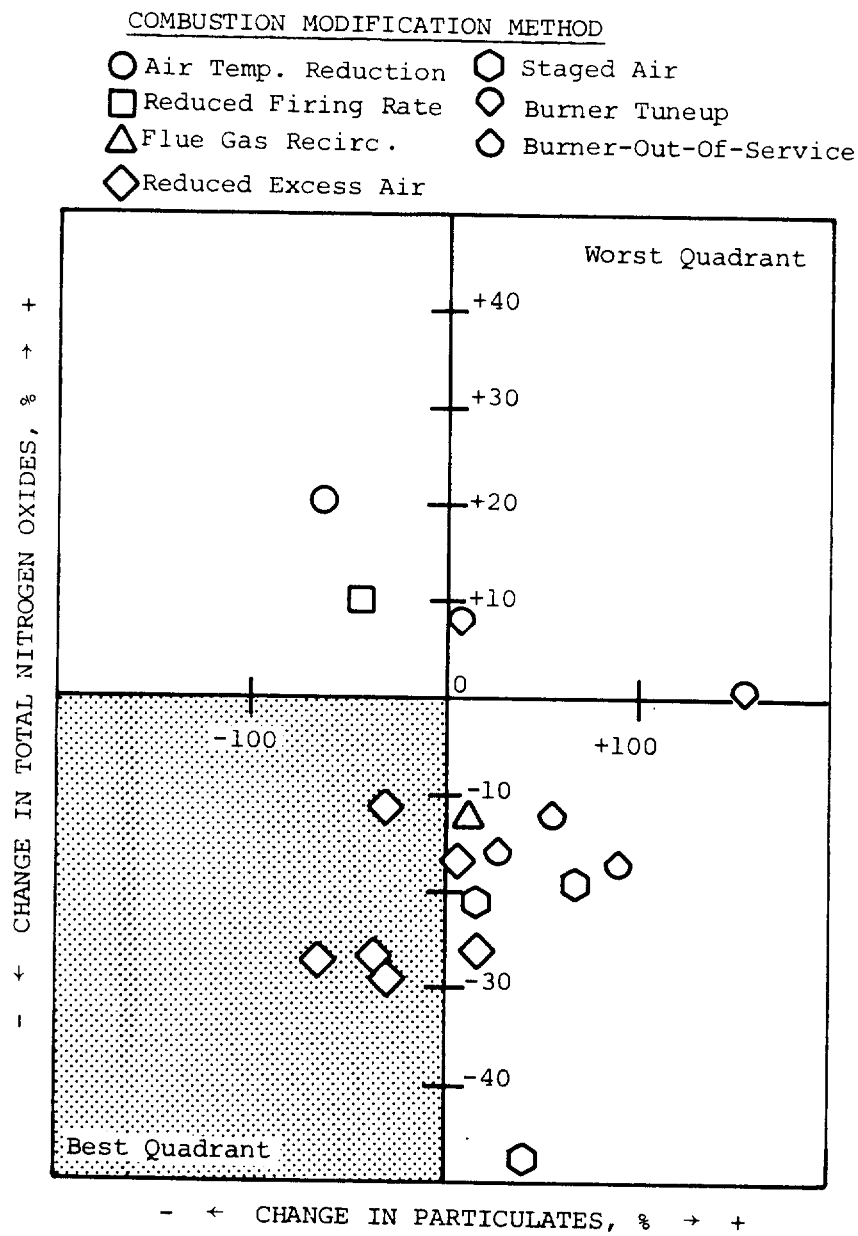

Figure 1-4. Effect of combustion modification methods on total nitrogen oxides and solid particulate emissions.

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The effect on the solid particulate emissions was to reduce them by up to about 15% with coal fuel and up to about 30% with No. 6 oil fuel. In no case did the reduction of excess air cause less complete combustion and an accompanying increase in particulate emissions. The criterion for minimum excess air was when the carbon monoxide emissions exceeded 100 ppm. Carbon monoxide usually appeared in the flue gas before smoke did.

Staged Air: The second most effective combustion modification was a form of staged combustion where the combustion air was added near the end of the flame. The nitrogen oxides emissions were reduced by up to 47% with this technique. Diverting some of the combustion air from the initial combustion zone at the burner and injecting it into the combustion zone further downflame caused the combustion to be more fuel-rich. This slowed the combustion process and the products of combustion then cooled below the nitrogen oxides formation temperature of about 2000 K (3300°F) more quickly, thus inhibiting the formation of nitrogen oxides.

In most cases, however, the boiler efficiency decreased by up to one percentage point, with some instances of decreases of up to three percentage points. The efficiency dropped because more air was required overall through the combination of the burner and the overfire ports than was required through the burner alone. This resulted in more hot air being exhausted up the chimney, and a corresponding decrease in the ASME heat loss efficiency.

Three of the staged air tests were made with No. 6 oil fuel and in all cases the particulates increased, by 12 to 68% (see Fig. 1-4). Apparently, delaying complete combustion increased the amount of unburned carbon in the flue gas.

Burner Out Of Service: The form of staged combustion that reduced the total nitrogen oxides emissions the most was operation with one of the burners out of service. In this mode the fuel, but not the air, to one of the burners was turned off. The total amount of fuel being burned was held constant by increasing the fuel, but again not the air, to the other burners. The result was that the other burners were operating fuel-rich and complete combustion was delayed by the surplus of fuel and the paucity of air.

With a burner out of service the total nitrogen oxides emissions were reduced from 9 to 54% (see Fig. 1-3). An advantage of this type of combustion modification was that the boiler efficiency was relatively unaffected and varied by only ± 0.5 percentage points over nine runs. A disadvantage was that the combustion process was disturbed such that the particulate emissions always increased. In one case the increase was about 54% and in the second case the increase was about 95% for a comparable drop in nitrogen oxides concentration.

Register Adjustment: Readjusting the burner air registers succeeded in reducing the nitrogen oxides by 3 to 21%. The efficiency varied from unchanged to 1% lower, and the particulate emissions were unchanged.

Combustion Air Temperature Reduction: Reducing the preheating of the combustion air reduced the total nitrogen oxides by up to 32%. The effect on boiler efficiency was to decrease it by 1% in one case and to increase it by 3% in another case. In three other instances the efficiency did not change.

In one test, No. 130-1, the combustion air temperature was increased above the nominal, and the particulates decreased by 64%. Probably the increased combustion air resulted in a better-mixed and hotter flame and in increased burnout of the carbon in the fly ash. No particulate emission measurements were made at low combustion air temperatures.

Flue Gas Recirculation: Flue gas recirculation was successful in reducing the total nitrogen oxides concentration in the flue gases by 10 to 40%, with one outstanding instance in natural gas fuel of a reduction of 73%. The efficiency was unaffected if the work required to operate the recirculation pump was neglected. There was an increase in the solid particulate concentration of about 5%, due probably to a slight increase in the unburned carbon in the less stable flame that resulted when flue gas was recirculated.

Firing Rate Reduction: When the combustion was modified by lowering the firing rate or steam output of a boiler the total nitrogen oxides emissions decreased in 20 instances and increased in 16 instances by up to about $\pm$ 25%. The reason for the increase was that the operational procedure in almost all boiler houses was to increase the amount of excess air being fired at the lower firing rates, and an increase in excess air often caused an increase in the total nitrogen oxides emissions.

Watertube gas-fired boilers were relatively insensitive to firing rate changes unless they had air preheaters. Then, reductions in total nitrogen oxides of about 20% were realized as the firing rate was dropped from 100% of name plate capacity to 50% of capacity. Generally, coal fired watertube boilers showed an increase in nitrogen oxides emissions when operating below 60% capacity. This increase usually coincided with an increase in the excess air level. However, the particulate emissions from the spreader stoker of Test No. 139 decreased by 44% below the baseline firing rate level. Watertube oil-fired boilers showed little or no relationship between nitrogen oxides emissions and firing rate.

Fuel Oil Viscosity: Tests were conducted with No. 6 oil over an oil temperature range of 240 K to 400 K (158°F to 248°F). No consistent relationship was observed, although in all cases the change in the total nitrogen oxides emissions ranged between a reduction of 16% and an increase of 31% of the unmodified baseline emission level. The boiler efficiency was increased from one to three percentage points.

Burner Tuneup: At Locations 1 and 27 the field maintenance technician of the burner manufacturer tuned the burner after the baseline emissions measurements had been made. Tuneup consisted of adjusting the excess air to the proper level for each load, adjusting the burner registers to give a hard, bright flame and replacing worn parts in the oil gun tips.

In all cases there was a slight increase of up to one percent in the boiler ASME heat loss efficiency. In one instance, Test No. 112, the particulate emissions were unchanged, in another instance, Test No. 108, they increased by 140%. This latter increase probably was due to flame quenching caused by an increase in the impingement of the flame on the water walls of the furnace. The oil spray angle of the burner used with this boiler was unusually large.

Atomization Method: The total nitrogen oxides emissions were found to be relatively independent of the fuel oil atomization method, i.e., steam, air, pressure or rotary cup, and dependent upon the characteristics of the individual burner. For a given oil burner the oil atomization method that produced the lowest nitrogen oxides emissions, also usually produced the highest particulate emissions of the test series. The boiler efficiency was unaffected to any significant degree by the type of atomization employed. In general the test results were that a well-maintained oil burner operating near its design point will produce about the same level of nitrogen oxides and particulate emissions regardless of the atomization method used.

Atomization Pressure: When the atomization pressure was increased and the boiler was at 80% of capacity, the nitrogen oxides emissions decreased by about 10% and the efficiency was unchanged. The series of tests done by another KVB field crew on a twin boiler in the same boiler house achieved a reduction of about 50% in solid particulates by increasing the oil pressure from 580 to 722 kPa (70 to 90 psig). The decrease was deemed to be due to the smaller oil droplets that were formed when the atomization pressure was increased.

Conclusions

On the basis of the results of the field measurements it appears to be possible and practicable to reduce the total nitrogen oxides emissions by up to 47% by six of the eleven combustion modification methods. However, with only three of the methods is the boiler efficiency unimpared: excess air reduction, staged combustion with a burner-out-of-service, and flue gas recirculation. Of these three, excess air reduction is the most attractive method because, while the nitrogen oxides reduction is only about 35%, the particulate emissions do not increase, as they do with most of the other reduction methods, and the boiler efficiency is maintained or improved. Flue gas recirculation is promising, since the increase in particulate was only 5%. Staged air addition, as with burners-out-of-service also is somewhat promising, but considerable work will be required in distributing the air so the particulates do not increase.

SECTION 2.0

TEST BOILER SELECTION

The findings of Phase I on the amount and potential reduction of pollutant emissions from industrial boilers were used in the selection of boilers for Phase II. Eighteen boilers that had the capability of one or more combustion modification categories, either as they stood or with structural modifications, were chosen for testing during Phase II.

KVB, Inc. and others have established during testing of utility boilers that certain modifications of the air-fuel mixture ratio, flame enthalpy and/or firing inputs reduced the emissions of the total nitrogen oxides significantly. During Phase I of this program several industrial-sized boilers were tested that had certain of these combustion modifications built in. Measurements were made of the emissions from these boilers and were compared to the emissions from similar boilers that did not have the combustion modification. Examples are boilers with and without combustion air preheaters and with single and dual air registers.

It was found that boilers with preheated combustion air, as a group, had higher nitrogen oxides emissions than did those without preheated air. It also was found that taking a burner out of service on a multiple burner boiler reduced the nitrogen oxides emissions. These findings were consistent with the findings for utility boilers.

It was not the purpose of the Phase I field measurements to make an extensive evaluation of the promising combustion modifications. This was, however, the purpose of Phase II. For Phase II, eleven combustion modification methods were selected for investigation and eighteen individual boilers were selected that were amenable to combustion modification.

The combustion modification methods that were investigated during both Phases I and II are listed in Table 5-1. The Phase II boilers are described in Table 7-1 of this report and the Phase I boilers are described in Reference 1.

One combustion modification technique for which no existing boiler could be found was flue gas recirculation. In this instance a boiler at Location 19 was modified by adding flue gas recirculation (see Subsection 5.2.2). Also, no existing boilers could be found where the location of the staged air injection ports could be changed. Two boilers, the one at Location 19 and one at Location 38, were modified for this purpose (see Subsection 5.1.2).

Four of the boilers tested during Phase I qualified for testing in Phase II. The other fifteen were recommended by members of the boiler and burner manufacturing industry as a result of a program review meeting that was held in June 1974. At that time, representatives of the major boiler and burner manufacturers were told of the objectives of the combustion modifications project and were asked to recommend candidate boilers for Phase II.

A total of nineteen different boilers at seventeen locations were tested. Some were suitable for more than one combustion modification method or fuel. For example, at Location No. 38 both staged air and combustion air temperature with gas and oil fuels were investigated using the same boiler. In all, forty-one combinations of combustion modification methods and fuels were tested on the nineteen boilers. In Phase I a total of seventy-five sets of test data on different boiler/burner/fuel combinations were obtained, for a total for the two phases of sixty-five boilers and one hundred sixteen combinations.

In Phase I the boilers were selected to reflect the geographical distribution of boilers and fuels throughout the continental United States. The preponderance of test boiler sites was east of the Mississippi River. This criterion was used in Phase II also, although not as rigorously, since certain specific types of boilers were sought. This is illustrated in Figure 2-1 which shows all of the sites for Phases I and II. Locations 1 through 26 were visited during Phase I and Nos. 27 through 39 during Phase II. Location Nos. 1, 13, 19 and 20 were visited during both phases.

Figure 2-1. Field test site locations.

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SECTION 3.0

INSTRUMENTATION AND TEST PROCEDURES

The emission measurements were made with instrumentation contained in the 2.5 by 9 meter (8 by 27 ft) laboratory trailer of which exterior and interior views are shown in Figure 3-1. The gaseous emission measurements, except sulfur oxides, were made with analyzers located in the measurement console in the trailer. The particulate concentration, particulate size, and sulfur oxides concentration measurements were made with instrumentation prepared in the wet chemistry area of the laboratory and taken to the sample port. The weighing and titration were done in or near the laboratory.

The emission measurement instrumentation used for the program was that shown in the table below. The operation of the instrumentation is discussed in detail in Section 3.0 of Reference 1.

Table 3-1. EMISSION MEASUREMENT INSTRUMENTATION

Emission	Symbol	Measurement Method	Equipment Manufacturer
Nitric oxide	NO	Chemiluminescent	Thermo Electron
Oxides of nitrogen	NO_x	Chemiluminescent	Thermo Electron
Carbon monoxide	CO	Spectrometer	Beckman
Carbon dioxide	CO_2	Spectrometer	Beckman
Oxygen	O_2	Polarographic	Teledyne
Hydrocarbons	HC	Flame ionization	Beckman
Sulfur dioxide and trioxide	SO_2, SO_3	Absorption/ titration	KVB Equipment Co.
Total particulate matter	PM	EPA Std. Method 5	Joy Mfg. Co.
Particulate size	-	Cascade impactor	Monsanto-Brink
Smoke spot	K	Reflection	Research Appliance Co.
Opacity	-	EPA Std. Method 9	-

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Gas Emission
Measurement
Console

Mobile Laboratory
Truck and Trailer

Sulfur and Particulate
Measurement Area -
Wet Chemistry

Figure 3-1. Interior and exterior views of mobile laboratory.

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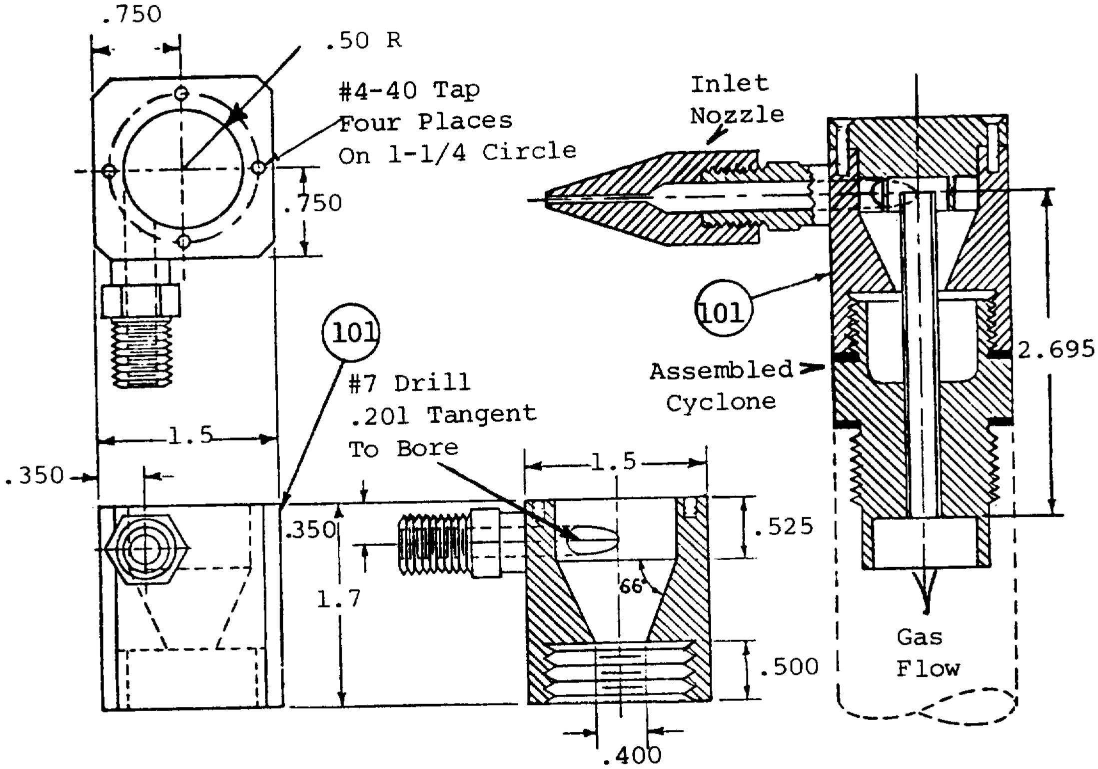
3.1 PARTICULATE SIZE

The measurement of particulate size was added to the measurements to be made during Phase II. A Brink Model "B" Cascade Impactor was selected, because the grain loading of the coal-fueled boilers was expected to be high. The nominal sample flow rate of 2.8 l/min (liters per minute) was low enough that the impactor did not readily overload. One stage of the cascade impactor is shown in Figure 3-2.

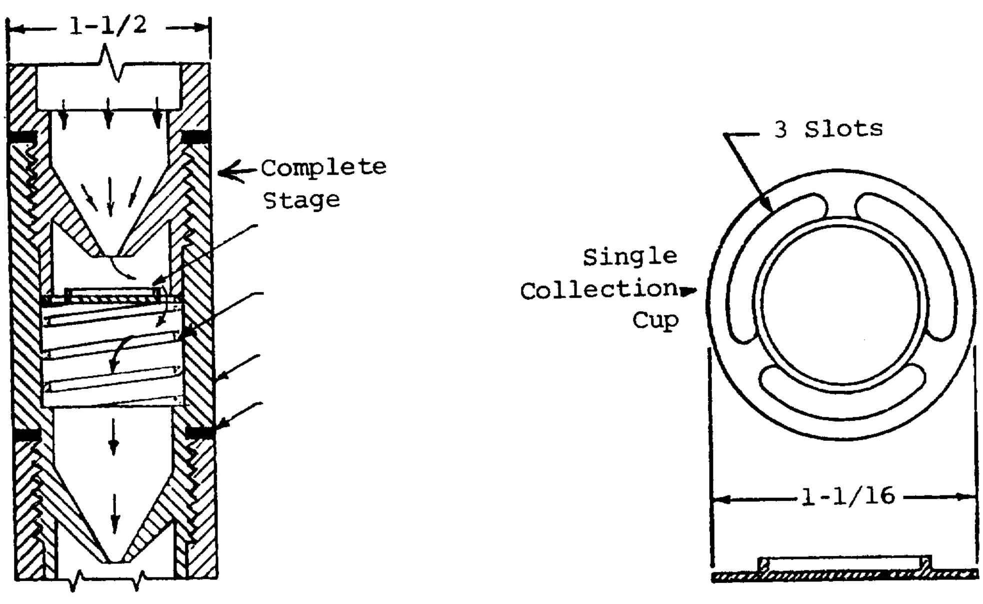
A Cahn Model G-2 Electro-balance was used to weigh the collected sample. To improve the accuracy of the weighing, an aluminum substrate was placed in each steel collection cup. The particles were collected and weighed on these lightweight discs, and the original steel collection cups were used only as a backing for these substrates.

A common problem with impactors is that the particles do not adhere to the stage surface, but strike it, rebound, and are reentrained in the flow to the next stage.[6] Reentrainment has not proved to be a problem with the cascade impactor measurements KVB has made, however. The flue gas flow rate was reduced from the nominal 2.8 l/min to 2.0 l/min or less, and visual examination of the collection stages by hand lens found no evidence of scouring or reentrainment. One set of stages was further examined under an electron microscope and there was no sign of a significant number of particulates that were larger than the aerodynamic diameter cut point of the preceding stage. There was, however, a considerable amount of sponge-like material that appeared to be an agglomeration of small particles.

Back-up filters were used as the final stage of the impactor to collect the material that passed the last impaction stage. Binderless, glass-fiber filter material, such as high-purity Gelman Type A glass fiber filter was employed for this purpose. The 25 mm diameter circular filters were placed under the spring in the last stage of the impactor.



PRECUTTER CYCLONE



STAGE

Figure 3-2. Detail of one stage and of precutter cyclone for cascade impactor.

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The filter was protected from being cut by the spring by a Teflon O-ring and a second filter disc and a wire mesh were placed beneath the filter to act as a support.

For accurate weighing of collected material, a Cahn G-2 Electro-balance with a sensitivity of 0.05 micrograms was used. This sensitivity was needed for the lower stage of the impactor where the collected weight occasionally was less than 0.1 mg.

The flow rate and nozzle size were closely coupled, and requirements for isokinetic or near-isokinetic nozzle flow sometimes forced a compromise on nozzle selection. The general order of priorities used by KVB to determine nozzle size in the field was (1) nozzle diameter (minimum only), (2) last stage jet velocity, (3) isokinetic flow rate required, and (4) nozzle diameter if greater than 2.0 mm. The impactor nozzle diameter was selected to provide as close to isokinetic collection as was practicable. Very small bore nozzles were avoided to forestall nozzle plugging by fly ash.

The impactor was placed inside the chimney and was heated to flue gas temperature by the flue gas itself before the sample collection was begun. The inlet nozzle was pointed downstream of the flow field during this heating phase to prevent the premature accumulation of particulates in the impactor.

The flow through the impactor was measured before each use to determine the actual cut points of the individual stages. This level then was maintained by monitoring the flow through the impactor assembly with the pressure gauges on the EPA Method 5 control box. The pump on the control box was used to maintain the flow. Attempts to modulate flow to compensate for changes in the duct flow rate and to maintain isokinetic sampling exactly would have destroyed the utility of the data by changing the cut points of the individual stages. During data analysis the true cut points were calculated for the actual gas flow rate through the impactor.

Measurements were made at a sufficient number of points across the flue or smoke stack, as specified by EPA Method 5, to make certain that a representative sample of particulates was obtained.

When coal fuel was fired and sampling was done upstream of the dust collector, the percentage (by weight) of material with sizes larger than ten micrometers was appreciable. In such cases the precutter cyclone shown in Figure 3-2 was used to prevent overloading of the upper impactor stages.

In those instances where a precollector cyclone was used, all material from the nozzle to the outlet of the cyclone was included with the cyclone catch. All material between the cyclone outlet and the second stage nozzle was included with material collected on the first collection substrate. All adjacent walls were brushed off, as well as around the underside of the nozzle. All material between the second stage nozzle and third stage nozzle was included with that on the second collection substrate. This process was continued down to the last collection substrate.

3.2 SMOKE SPOT

During Phase II the Bacharach smoke spot numbers were measured according to ASTM Designation D 2156-65. Smoke spot measurements were obtained by pulling a fixed volume of flue gas through a standard filter paper. The color (or shade) of the spots that were produced were matched visually with a standard smoke spot scale. The result was a (Bacharach) "Smoke Number" which was used to characterize the density of smoke in the flue gas.

The sampling device is a hand pump similar to the one shown in Figure 3-3. It is a commercially available item that can pass 36,900 ± 1650 cubic centimeters of gas at 16°C and 1 atmosphere pressure through an enclosed filter paper for each 6.5 square centimeters effective surface area of the filter paper.

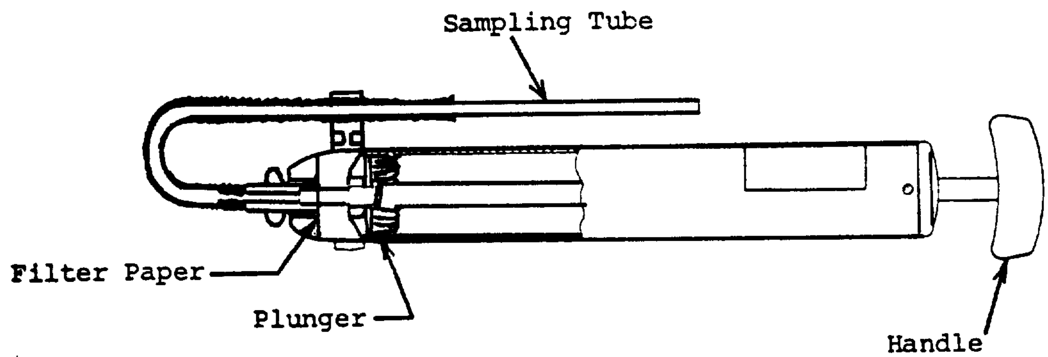

Figure 3-3. Field Service Type Smoke Tester

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The standard smoke scale consists of a series of ten spots numbered consecutively from 0 to 9, and ranging in equal photometric steps from white through neutral shades of gray to black. The standard spots are imprinted on white paper having an absolute surface reflectance of between 82.5 and 87.5%, determined photometrically. The smoke scale spot number is defined as the reduction (due to smoke) in the amount of light reflected by a spot divided by 10.

The smoke density is reported as the Smoke Spot Number of the spot on the standard smoke scale that most closely corresponds to the color of the soiled spot on the sample filter paper. Differences between two standard Smoke Spot Numbers are interpolated to the nearest half number.

3.3 PLUME OPACITY

Smoke plume opacity readings were taken by a field crew member who was a certificated graduate of a U. S. Environmental Protection Agency approved "Smoke School." Observations were made at the same time that particulate measurements are made and as often in addition as deemed necessary to gather the maximum amount of information. The procedures set forth in EPA Method 9, "Visual Determinations of the Opacity of Emissions for Stationary Sources" were followed, except that the duration of the observation period was only six minutes. Opacity measurements were made and recorded every fifteen seconds during an observation period. At least one six-minute opacity observation was made every thirty minutes.

SECTION 4.0

BASELINE TEST RESULTS

The emissions and efficiency of 47 boilers during Phase I and 19 boilers during Phase II were measured over a two year period. The Phase I data were analyzed and discussed in detail in the Phase I Final Report No. EPA-650/2-74-078-a (Ref. 1), and Phase II data and analysis are presented in this report. This section contains graphs and tables that summarize all of the data taken both at baseline and at low nitrogen oxides emission settings of the boilers. The results of the analysis of the baseline data are discussed in this section and the results of the analysis of the low nitrogen oxides data are discussed in the following section.

The total nitrogen oxides and solid (or filterable) particulate emissions at baseline settings of the boilers are shown in Figures 4-1 and 4-2. Baseline is defined as the normal boiler settings for a load of eighty percent of the nameplate capacity.

The primary categorization of boilers when the boilers were originally selected was by capacity or size, because it was expected that the larger boilers would have the larger emissions. However, the total nitrogen oxides emissions were found to be only slightly dependent upon boiler size as is indicated by Figure 4-1. The nitrogen oxides emissions, however, were very dependent upon the fuel being fired. This dependence is illustrated in the table of the range and average concentration of nitrogen oxides that is in Subsection 1.2. Coal fueled boilers were the greater emitters of total nitrogen oxides.

The particulate emissions were not at all dependent upon the boiler size, but are strongly dependent upon the fuel type. Figure 4-2 shows this relationship. The particulate emissions from coal fuel were ten times greater than from oil and one hundred times greater

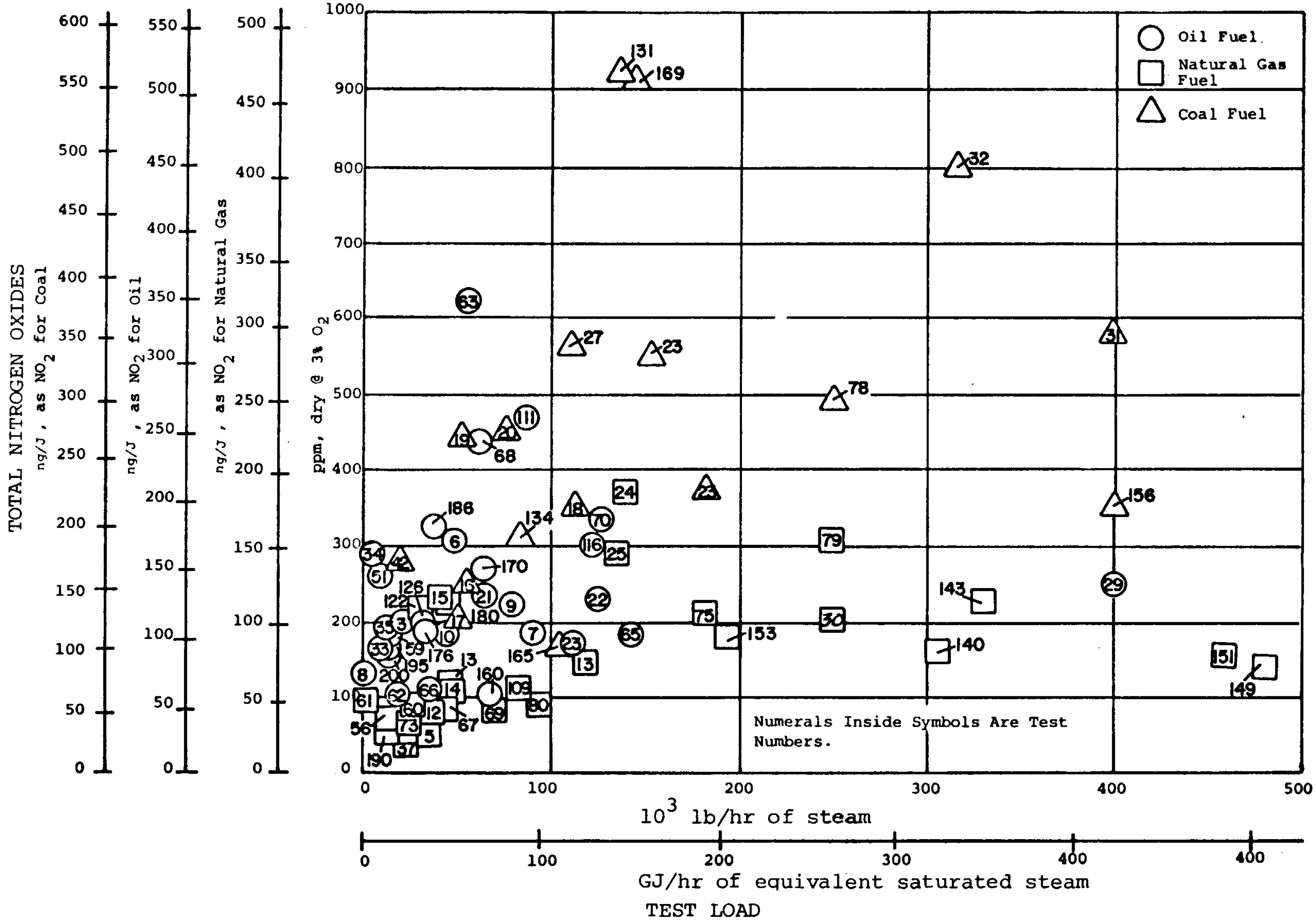

Figure 4-1. Total oxides of nitrogen concentration at baseload.

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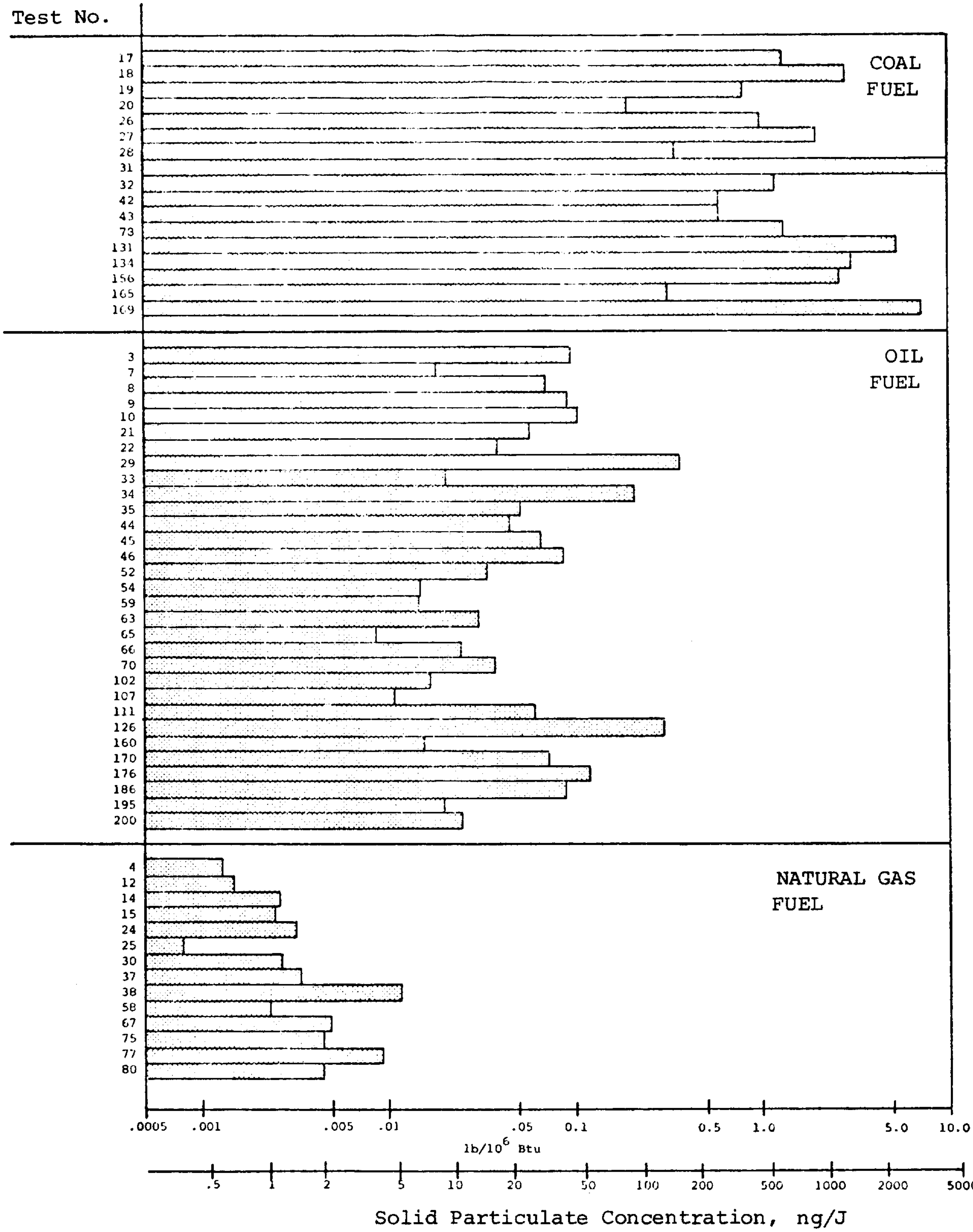

Figure 4-2. Solid particulate emissions at baseload.

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than from natural gas fuel. The solid particulate concentration includes only the solid particulate that was caught by a filter and not the gaseous that was condensed and scrubbed out by the water-filled bubblers. The total particulate emissions, including both filterable and condensable, are listed in Table 4-1.

Table 4-1 lists the Phase II emissions measurements made both with the baseline boiler settings and with the combustion process modified to achieve low nitrogen oxides emissions. A similar table of Phase I measurements is contained in Section 2 of Reference 1.

The data in Table 4-1 are tabulated in order of Test Run Numbers. The Test Run Number consists of two parts: the basic test number designation which corresponds to a particular combination of boiler, fuel, and combustion modification to the left of the dash and the run number within the given test to the right of the dash. A typical test may have consisted of up to ten individual measurement runs made with different settings of the boiler controls. Some tests with the staged combustion modification were comprised of as many as 50 individual runs.

The Location Number in the second column positions the test site geographically on Figure 2-1. Locations distributed throughout the continental United States were chosen to insure that a variety of fuels would be tested.

The columns from Furnace Type through Test Load indicate where the particular test falls among the principal test variables developed during the initial test planning of Phase I. The columns to the right of the one labeled Test Load are data taken during the corresponding Test Run.

For all boilers, two basic types of measurements were made:

1. Baseline: approximately eighty percent of rated capacity and normal control settings.
2. Low Air: Minimum excess air level at baseline load at which the boiler could be operated without smoke, excessive carbon monoxide, or hydrocarbon emissions.

Test types which are the various combustion modification methods tested are listed in the sixth column. The column titled Test Fuel indicates the fuel being fired at the time of the test run. A brief explanation of the abbreviations and symbols used follows the table, and a complete glossary of terms used throughout the report is in Section 10. A list of conversion factors for English and Systéme International d'Unités (designated SI units in all languages) is contained in Section 11.

In the balance of this section, the baseline gaseous and particulate emission measurements for coal, oil, natural gas, refinery gas and mixed fuels are discussed in detail.

Table 4-1. BOILER EMISSION MEASUREMENTS.

Test Run No.	Location	Burner Type	Test Fuel	Test Type	Capacity GJ/hr (10^3 lb/hr)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NO_x ng/J (ppm)	NO ng/J (ppm)	CO_2 dry %	CO ng/J (ppm)	HC ng/J (ppm)	SO_x ng/J (ppm)	SO_2 ng/J (ppm)	Total Partic. ng/J (lb/MB)	Solid Partic. ng/J (lb/MB)	Boiler Efficiency %	Bacharach Smoke Spot No.
[illegible]	1	Ring	NG	Base	31 (29)	19 (17)	2.2	39.6 (77.7)	37.7 (74)	10.8	21 (67)	- -	- -	- -	- -	- -	79	-
102-6	1	Steam	#2	Base	18 (29)	18 (17)	5.3	50.7 (90.3)	48.2 (86)	11.6	31 (90)	- -	188 (241)	176 (226)	[illegible] (0.[illegible]23)	7.3 (0.017)	80	-
103-1	1	Steam	#2	LowAir	31 (29)	20 (19)	4.7	47.1 (84)	44.9 (80)	11.7	51 (150)	- -	- -	- -	- -	- -	81	-
104-1	1	Ring	NG	Base	31 (29)	25 (24)	0.9	38.0 (74.5)	36.2 (71)	11.2	152 (489)	- -	- -	- -	- -	- -	81	-
105-1	1	Ring	NG	HiAir	31 (29)	25 (24)	1.8	40.7 (79.8)	38.8 (76)	10.9	0 (0)	- -	- -	- -	- -	- -	81	-
106-1	1	Ring	NG	BrTune	31 (29)	25 (24)	2.6	41.8 (81.9)	39.8 (78)	10.4	0 (0)	- -	- -	- -	- -	- -	80	-
107-2	1	Steam	#2	Base	31 (29)	26 (25)	2.7	47.7 (85)	45.4 (81)	13.2	139 (407)	- -	300 (384)	289 (371)	7.7 (0.018)	4.7 (0.011)	83	-
108-3	1	Steam	#2	BrTune	31 (29)	25 (24)	3.8	48.3 (86.1)	46 (82)	12.5	38 (110)	- -	- -	- -	19.4 (0.045)	12.0 (0.028)	83	-
109-1	27	Ring	NG	Base	106 (100)	79 (75)	6.6	56.6 (111)	55.6 (109)	7.9	0 (0)	- -	- -	- -	- -	- -	82	-
110-1	27	Ring	NG	BrTune	106 (100)	82 (78)	2.4	77.5 (152)	75.0 (147)	9.3	0 (0)	2.5 (14)	- -	- -	- -	- -	83	-
111-1	27	Steam	PS300	Base	106 (100)	90 (85)	9.3	257 (458)	248 (442)	8.8	40 (116)	- -	488 (626)	483 (619)	30.9 (0.072)	26.2 (0.061)	81	-
112-6	27	Steam	PS300	BrTune	106 (100)	74 (70)	6.5	277 (494)	269 (479)	10.0	0 (0)	- -	- -	- -	32.7 (0.076)	28.4 (0.066)	82	-
113-2	29	Ring	NG	Base	158 (150)	127 (120)	5.3	78.5 (154)	73.4 (144)	8.0	0 (0)	22 (125)	- -	- -	- -	- -	82	-
114-4	29	Ring	NG	LowAir	158 (150)	126 (119)	3.2	81.6 (160)	78.0 (153)	8.8	3.4 (11)	12 (70)	- -	- -	- -	- -	83	-
115-1	29	Ring	NG	VPH	158 (150)	126 (119)	5.2	81.1 (159)	78.5 (154)	7.8	0 (0)	12 (65)	- -	- -	- -	- -	84	-
116-1	29	Steam	#6	Base	158 (150)	126 (110)	5.0	165 (294)	158 (282)	11.8	0 (0)	6.8 (35)	- -	- -	- -	- -	87	-
117-2	29	Steam	#6	LowAir	158 (150)	129 (122)	3.1	138 (246)	135 (240)	13.4	0 (0)	4.9 (25)	- -	- -	- -	- -	88	-
118-1	29	Steam	#6	VPH	158 (150)	127 (120)	4.8	158 (282)	155 (276)	11.8	0 (0)	4.9 (25)	- -	- -	- -	- -	88	-
119-1	29	Steam	#6	LowLoad	158 (150)	74 (70)	5.5	139 (248)	134 (239)	11.2	0 (0)	- -	- -	- -	24.5 (0.057)	18.9 (0.044)	88	-
119-4	29	Steam	#6	BOOS	158 (150)	74 (70)	6.0	99.3 (177)	94.8 (169)	9.8	3.4 (10)	2.9 (15)	- -	- -	- -	- -	87	-
119-6	29	Steam	#6	BOOS	158 (150)	74 (70)	5.4	104 (186)	102 (182)	11.8	6.8 (20)	6.8 (35)	1018 (1305)	1005 (1289)	70.5 (0.164)	67.1 (0.156)	88	-
120-3	29	Steam	#6	Viscosity	158 (150)	74 (70)	5.2	138 (246)	136 (242)	12.0	0 (0)	- -	- -	- -	- -	- -	88	-
121-1	29	Steam	#6	TP	158 (150)	76 (72)	5.4	142 (254)	140 (250)	11.4	0 (0)	3.9 (20)	- -	- -	- -	- -	88	-
122-1	28	Ring	NG	Base	74 (70)	31 (29)	5.7	108 (211)	97.4 (191)	7.6	0 (0)	0 (0)	- -	- -	- -	- -	83	0

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Table 4-1. Continued

Test Run No.	Location	Burner Type	Test Fuel	Test Type	Capacity GJ/hr (10^3 lb/hr)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NO_x ng/J (ppm)	NO ng/J (ppm)	CO_2 dry %	CO ng/J (ppm)	HC ng/J (ppm)	SO_x ng/J (ppm)	SO_2 ng/J (ppm)	Total Partic. ng/J (lb/MB)	Solid Partic. ng/J (lb/MB)	Boiler Efficiency %	Bacharach Smoke Spot No.
123-2	28	Ring	NG	LowAir	74 (70)	31 (29)	3.7	85 (166)	82 (160)	9.1	3.4 (11)	0 (0)	-	-	-	-	85	0
124-1	28	Ring	NG	BOOS	74 (70)	31 (29)	.4	62 (122)	61 (119)	7.8	0 (0)	0 (0)	-	-	-	-	83	-
124-5	28	Ring	NG	BOOS	74 (70)	32 (30)	5.3	49.0 (96)	46.4 (91)	7.9	16 (50)	0 (0)	-	-	-	-	83	0
125-3	28	Ring	NG	VPH	74 (70)	31 (29)	5.6	99.5 (195)	98.9 (194)	7.6	0 (0)	-	-	-	-	-	83	0
126-2	28	Steam	#6	Base	74 (70)	31 (29)	5.3	115 (205)	112 (200)	11.6	0 (0)	-	-	-	140 (0.325)	127 (0.296)	86	5.5
127-3	28	Steam	#6	LowAir	74 (70)	30 (28)	4.9	101 (180)	97.6 (174)	11.6	9.5 (28)	-	-	-	-	-	87	8.0
128-1	28	Steam	#6	BOOS	74 (70)	31 (29)	5.9	125 (223)	121 (215)	11.2	33 (98)	-	-	-	-	-	86	7.0
128-5	28	Steam	#6	BOOS	74 (70)	32 (30)	4.8	105 (188)	103 (183)	11.6	34 (100)	-	-	-	-	-	86	7.0
129-1	28	Steam	#6	Viscosity	74 (70)	31 (29)	5.2	151 (269)	148 (263)	11.9	0 (0)	-	-	-	-	-	87	3.0
130-1	28	Steam	#6	VPH	74 (70)	32 (30)	5.2	138 (246)	135 (241)	10.0	0 (0)	-	1037 (1330)	1022 (1310)	64.5 (0.150)	46.4 (0.108)	86	3.0
131-4	31	Pulv.	Coal	Base	274 (260)	137 (130)	7.4	563 (922)	559 (915)	11.8	0 (0)	-	813 (956)	807 (949)	2286 (5.32)	2279 (5.30)	88	-
132-1	31	Pulv.	Coal	LowAir	274 (260)	139 (132)	6.6	529 (866)	519 (850)	12.5	0 (0)	-	-	-	-	-	88	4.5
133-1	31	Pulv.	Coal	LowLoad	274 (260)	70 (66)	7.2	618 (1011)	615 (1006)	11.9	0 (0)	-	-	-	-	-	88	2.0
133-2	31	Pulv.	Coal	BOOS	274 (260)	66 (63)	7.5	378 (618)	361 (591)	11.8	0 (0)	-	-	-	-	-	88	6.5
134-2	30	SpStk	Coal	Base	132 (125)	87 (82)	6.2	196 (320)	192 (314)	12.8	0 (0)	-	947 (1114)	927 (1091)	1320 (3.07)	1312 (3.05)	97	5.0
135-2	30	SpStk	Coal	LowAir	132 (125)	87 (82)	4.7	142 (233)	135 (221)	14.2	8.2 (22)	-	-	-	847 (1.97)	839 (1.95)	88	[illegible]
136-3	30	SpStk	Coal	SCA	132 (125)	87 (82)	6.1	145 (237)	140 (229)	12.9	18 (49)	-	-	-	-	-	87	9.0
137-1	30	SpStk	Coal	TP	132 (125)	Toxic element test - no gaseous emission data taken												
138-2	30	SpStk	Coal	VPH	132 (125)	88 (83)	5.0	134 (219)	132 (216)	13.8	3.7 (10)	-	-	-	-	-	84	7.0
139-4	30	SpStk	Coal	LowLoad	132 (125)	51 (48)	10.3	214 (351)	213 (348)	9.4	13 (35)	-	-	-	757 (1.76)	740 (1.72)	85	6.0
139-3	30	SpStk	Coal	LowAir LowLoad	132 (125)	51 (48)	7.4	119 (195)	117 (191)	11.8	15 (40)	-	-	-	-	-	88	4.0
139-7	30	SpStk	Coal	OFA LowLoad	132 (125)	53 (50)	9.6	209 (342)	205 (335)	9.8	15 (40)	-	-	-	-	-	85	-
139-10	30	SpStk	Coal	OFA LowLoad	132 (125)	53 (50)	7.7	164 (269)	163 (266)	11.5	20 (53)	-	-	-	-	-	86	-

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Table 4-1. Continued

Test Run No.	Location	Burner Type	Test Fuel	Test Type	Capacity GJ/hr (10^3 lb/hr)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NO_x ng/J (ppm)	NO ng/J (ppm)	CO_2 dry %	CO ng/J (ppm)	HC ng/J (ppm)	SO_x ng/J (ppm)	SO_2 ng/J (ppm)	Total Partic. ng/J (lb/MB)	Solid Partic. ng/J (lb/MB)	Boiler Efficiency %	Bacharach Smoke Spot No.
140-2	32	Ring	NG	Base	137 (130)	81 (77)	7.1	81.6 (160)	78.5 (154)	8.0	62 (200)	-	-	-	-	-	82	-
141-1	32	Ring	NG	AirReg LowAir	137 (130)	81 (77)	6.1	100 (197)	97.9 (192)	8.0	32 (103)	-	-	-	-	-	82	-
141-5	32	Ring	NG	AirReg VPH	137 (130)	85 (81)	6.[illegible]	100 (196)	98.9 (194)	7.8	0 (0)	-	-	-	-	-	82	-
141-6	32	Ring	NG	AirReg VPH	137 (130)	84 (80)	6.7	119 (234)	118 (232)	8.1	18 (58)	-	-	-	-	-	83	-
142-1	32	Ring	NG	VPH	137 (130)	81 (77)	7.1	83.1 (163)	81.6 (160)	8.0	70 (227)	-	-	-	-	-	83	-
143-3	32	Ring	NG	Base	127 (120)	88 (83)	4.4	117 (230)	116 (228)	9.4	0 (0)	-	-	-	-	-	83	-
144-2	32	Ring	NG	VPH	127 (120)	87 (82)	4.4	116 (228)	115 (226)	8.6	15 (48)	-	-	-	-	-	82	-
145-3	32	Ring	NG	LowAir	127 (120)	88 (83)	2.2	111 (218)	110 (216)	9.6	0 (0)	-	-	-	-	-	83	-
146-1	32	Ring	NG	LowLoad	127 (120)	64 (61)	4.0	106 (207)	105 (205)	9.6	0 (0)	-	-	-	-	-	83	-
147-1	32	Ring	NG	BOOS	127 (120)	66 (63)	4.0	105 (206)	105 (205)	9.6	0 (0)	-	-	-	-	-	83	-
147-4	32	Ring	NG	BOOS	127 (120)	65 (62)	4.0	107 (209)	106 (207)	8.7	0 (0)	-	-	-	-	-	83	-
147-7	32	Ring	NG	BOOS	127 (120)	65 (62)	4.4	74.5 (146)	72.4 (142)	9.0	13 (43)	-	-	-	-	-	83	-
148-4	32	Ring	NG	AirReg	127 (120)	87 (82)	4.7	111 (218)	110 (216)	9.4	0 (0)	-	-	-	-	-	83	-
148-6	32	Ring	NG	AirReg LowAir	127 (120)	88 (83)	2.5	100 (197)	100 (196)	10.0	0 (0)	-	-	-	-	-	83	-
149-1	33	Spud	Ref Gas	Base CombCyc	580 (550)	506 (480)	5.1	73.4 (146)	69.4 (139)	8.4	0 (0)	-	-	-	-	-	-	-
150-1	33	Spud	Ref Gas	HiLoad CombCyc	580 (550)	544 (516)	3.8	69.4 (138)	65.9 (131)	10.0	4.9 (16)	-	-	-	-	-	-	-
150-2	33	Spud	Ref Gas	HiLoad CombCyc	580 (550)	528 (500)	10.3	65.4 (130)	62.4 (124)	6.2	0 (0)	-	-	-	-	-	-	-
151-1	33	Spud	Ref Gas	Base SnglCyc	580 (550)	481 (456)	5.5	74.9 (149)	71.4 (142)	9.2	8.9 (29)	-	-	-	-	-	-	-
151-4	33	Spud	Ref Gas	BOOS SnglCyc	580 (550)	450 (427)	6.4	61.9 (123)	58.9 (117)	8.6	8.9 (29)	-	-	-	-	-	-	-
151-5	33	Spud	Ref Gas	BOOS SnglCyc	580 (550)	433 (410)	7.3	45.3 (90)	42.8 (85)	7.8	121 (394)	-	-	-	-	-	-	-
152-1	33	Spud	Ref Gas	BOOS CombCyc	580 (550)	506 (480)	3.9	53.8 (107)	51.3 (102)	9.4	80.2 (262)	-	-	-	-	-	-	-
152-2	33	Spud	Ref Gas	BOOS CombCyc	580 (550)	506 (480)	4.8	61.9 (123)	58.9 (117)	9.0	16.8 (55)	-	-	-	-	-	-	-
152-4	33	Spud	Ref Gas	BOOS CombCyc	580 (550)	468 (444)	6.0	67.4 (134)	63.9 (127)	8.2	14.7 (48)	-	-	-	-	-	-	-
152-5	33	Spud	Ref Gas	BOOS CombCyc	580 (550)	468 (444)	5.5	70.4 (140)	67.4 (134)	8.4	14.4 (47)	-	-	-	-	-	-	-

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Table 4-1. Continued

Test Run No.	Location	Burner Type	Test Fuel	Test Type	Capacity GJ/hr (10^3 lb/hr)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NO_x ng/J (ppm)	NO ng/J (ppm)	CO_2 dry %	CO ng/J (ppm)	HC ng/J (ppm)	SO_x ng/J (ppm)	SO_2 ng/J (ppm)	Total Partic. ng/J (lb/MB)	Solid Partic. ng/J (lb/MB)	Boiler Efficiency %	Bacharach Smoke Spot No.
152-6	33	Spud	Ref Gas	BOOS CombCyc	530 (550)	464 (440)	5.9	54.8 (109)	52.3 (104)	8.2	14.7 (48)	-	-	-	-	-	-	-
153-1	34	Spud	NG	Base	264 (250)	206 (195)	2.6	96.4 (189)	92.8 (182)	11.4	100 (322)	6.9 (39)	-	-	-	-	-	-
154-1	34	Spud	NG	LowLoad NrmlAir	264 (250)	53 (50)	10.8	70.9 (139)	69.9 (137)	6.2	7.1 (23)	133 (752)	-	-	-	-	-	-
154-6	34	Spud	NG	AirReg	264 (250)	161 (153)	4.4	108 (211)	106 (207)	10.4	24 (76)	-	-	-	-	-	-	-
154-10	34	Spud	NG	AirReg	264 (250)	158 (150)	4.6	75.0 (147)	75.0 (147)	9.0	9.0 (29)	-	-	-	-	-	-	-
154-11	34	Spud	NG	AirReg	264 (250)	160 (152)	4.3	79.1 (155)	76.0 (149)	9.0	19 (61)	0 (0)	-	-	-	-	-	-
155-2	34	Spud	NG	VPH	264 (250)	211 (200)	2.6	70.9 (139)	68.9 (135)	11.4	112 (362)	-	-	-	-	-	-	-
155-3	34	Spud	NG	VPH	264 (250)	211 (200)	2.5	94.9 (186)	93.3 (183)	11.4	99 (320)	-	-	-	-	-	-	-
156-2	13	Pulv.	Coal	Base	528 (500)	422 (400)	8.6	216 (353)	206 (337)	8.6	0 (0)	-	-	-	1140 (2.65)	1122 (2.61)	76	9.0
157-1	13	Pulv.	Coal	LowLoad	528 (500)	338 (320)	9.6	197 (322)	187 (306)	9.0	41 (111)	-	-	-	-	-	77	9.0
157-3	13	Pulv.	Coal	HiLoad	528 (500)	485 (460)	8.6	233 (381)	222 (363)	9.0	19 (51)	-	-	-	-	-	78	9.0
158-4	13	Pulv.	Coal	Low O_2	528 (500)	411 (390)	8.1	212 (347)	202 (330)	10.0	47 (126)	-	-	-	-	-	79	-
159-1	13	Pulv. Steam	Coal &Oil	BOOS	528 (500)	433 (410)	9.2	209 (357)	199 (340)	8.2	0 (0)	-	-	-	-	-	76	8.5
159-3	13	Pulv. Steam	Coal &Oil	BOOS	528 (500)	443 (420)	7.2	166 (283)	158 (270)	10.0	21 (76)	-	-	-	-	-	79	8.0
159-6	13	Pulv. Steam	Coal &Oil	BOOS	528 (500)	422 (400)	8.9	177 (302)	168 (287)	9.4	5.3 (15)	-	-	-	-	-	79	-
160-1	36	Steam	#2	Base	211 (200)	72 (68)	4.4	57.8 (103)	57.2 (102)	11.2	0 (0)	0 (0)	-	-	11.6 (0.027)	6.88 (0.016)	85	3.0
161-3	36	Steam	#2	SCA	211 (200)	63 (60)	5.4	55.0 (98)	54.4 (97)	10.6	0 (0)	0 (0)	-	-	-	-	85	-
161-4	36	Steam	#2	SCA	211 (200)	62 (59)	5.5	57.8 (103)	57.2 (102)	10.6	0 (0)	0 (0)	-	-	-	-	84	-
161-7	36	Steam	#2	SCA	211 (200)	80 (76)	2.5	54.4 (97)	53.9 (96)	13.4	6.5 (19)	1.0 (5)	-	-	-	-	86	4.0
161-8	36	Steam	#2	SCA	211 (200)	82 (78)	2.3	61.1 (109)	60.6 (108)	13.4	4.8 (14)	0 (0)	-	-	-	-	86	4.0
162-3	36	Steam	#2	Damper	211 (200)	95 (90)	4.4	69.6 (124)	68.4 (122)	11.8	0 (0)	0 (0)	-	-	-	-	85	3.0
162-5	36	Steam	#2	Damper	211 (200)	93 (88)	3.8	45.4 (81)	44.3 (79)	12.0	0 (0)	0 (0)	-	-	-	-	85	3.0
162-11	36	Steam	#2	Damper Low O_2	211 (200)	63 (60)	6.3	39.3 (70)	38.1 (68)	10.4	0 (0)	0 (0)	-	-	12.9 (0.030)	-	-	3.0
163-1	36	Steam	#2	Atom Press	211 (200)	58 (55)	5.9	53.3 (95)	52.7 (94)	11.1	6.5 (19)	0 (0)	-	-	-	-	85	0.0

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Table 4-1. Continued

Test Run No.	Location	Burner Type	Test Fuel	Test Type	Capacity GJ/hr (10^3 lb/hr)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NO_x ng/J (ppm)	NO ng/J (ppm)	CO_2 dry %	CO ng/J (ppm)	HC ng/J (ppm)	SO_x ng/J (ppm)	SO_2 ng/J (ppm)	Total Partic. ng/J (lb/MB)	Solid Partic. ng/J (lb/MB)	Boiler Efficiency %	Bacharach Smoke Spot No.
163-2	36	Steam	#2	Atom Press	211 (200)	55 (52)	5.8	49.9 (89)	48.2 (86)	10.6	0 (0)	0 (0)	-	-	-	-	85	0.0
164-1	36	Steam	#2	Steam Injec	211 (200)	63 (60)	5.1	46.6 (83)	45.4 (81)	12.0	7.8 (23)	0 (0)	-	-	-	-	85	1.0
165-1	35	ChGrt	Coal	Base	227 (215)	110 (104)	9.5	100 (164)	99.6 (163)	9.2	9.3 (25)	5.3 (25)	-	-	176 (0.41)	133 (0.31)	76	7.0
166-1	35	ChGrt	Coal	Low O_2	227 (215)	108 (102)	9.0	74.5 (122)	73.9 (121)	9.6	22 (60)	11 (53)	-	-	161 (0.375)	156 (0.363)	76	7.0
166-4	35	ChGrt	Coal	LowAir	227 (215)	111 (105)	8.7	77.0 (126)	75.8 (124)	10.3	20 (55)	3.8 (18)	-	-	-	-	78	8.0
167-2	35	ChGrt	Coal	HiLoad	227 (215)	127 (120)	8.3	94.7 (155)	92.9 (152)	10.0	28 (75)	3.4 (16)	-	-	-	-	77	9.0
167-4	35	ChGrt	Coal	LowLoad	227 (215)	59 (56)	12.5	146 (239)	144 (236)	7.0	13 (35)	11 (50)	-	-	-	-	74	9.0
168-3	35	ChGrt	Coal	SCA	227 (215)	108 (102)	9.0	101 (166)	99.6 (163)	9.0	5.6 (15)	7.5 (35)	-	-	-	-	76	9.0
169-1	31	Pulv.	Coal	Base	274 (260)	148 (140)	7.0	561 (918)	534 (874)	-	0 (0)	-	-	-	-	3014 (7.01)	88	-
170-3	20	Steam	#6	Base	84 (80)	65 (62)	3.3	148 (264)	146 (261)	13.5	0 (0)	1.6 (8)	-	780 (1000)	-	31.8 (0.074)	82	3.0
171-1	20	Steam	#6	LowLoad	84 (80)	34 (32)	5.5	148 (264)	146 (261)	11.8	0 (0)	0 (0)	-	-	-	-	83	2.0
171-6	20	Steam	#6	LowLoad	84 (80)	53 (50)	4.5	147 (262)	145 (259)	12.4	10 (30)	1.6 (8)	-	-	-	-	81	-
172-2	20	Steam	#6	LowAir	84 (80)	67 (64)	2.7	143 (255)	142 (253)	13.7	70 (205)	1.6 (8)	-	-	-	-	83	5.0
173-4	20	Steam	#6	Vis-cosity	84 (80)	65 (62)	3.3	156 (278)	155 (277)	13.4	0 (0)	2.3 (12)	-	-	-	-	82	3.0
174-1	20	Steam	#6	AirReg	84 (80)	66 (63)	3.[illegible]	132 (236)	132 (236)	13.2	29 (85)	1.6 (8)	-	-	-	-	81	-
174-3	20	Steam	#6	AirReg	84 (80)	66 (63)	3.4	164 (292)	164 (292)	13.2	12 (35)	0 (0)	-	-	-	-	81	-
175-5	20	Steam	#6	AirReg LowAir	84 (80)	67 (64)	2.7	132 (236)	131 (234)	13.1	10 (30)	2.5 (13)	-	-	30.1 (0.070)	24.1 (0.056)	81	5.0
176-2	37	Steam	#6	Base	42 (40)	34 (32)	4.3	109 (195)	108 (193)	12.6	0 (0)	2.9 (15)	815 (1045)	803 (1029)	61.9 (0.144)	50.7 (0.118)	85	5.0
177-3	37	Steam	#6	VPH	42 (40)	33 (31)	4.5	104 (186)	104 (185)	12.0	12 (35)	2.5 (13)	-	-	-	-	83	6.0
177-5	37	Steam	#6	VPH	42 (40)	33 (31)	4.25	106 (189)	105 (188)	12.2	0 (0)	0 (0)	-	-	-	-	83	-
178-1	37	Steam	#6	Vis-cosity	42 (40)	34 (32)	4.6	107 (191)	106 (189)	11.5	0 (0)	4.9 (25)	-	-	-	-	87	7.0
178-2	37	Steam	#6	Vis-cosity	42 (40)	35 (33)	4.5	109 (194)	108 (192)	11.8	0 (0)	0 (0)	-	-	-	-	84	-
179-3	37	Steam	#6	HiAir	42 (40)	34 (32)	5.65	113 (201)	112 (199)	11.6	0 (0)	0 (0)	-	-	-	-	84	5.5
179-4	37	Steam	#6	LowAir	42 (40)	34 (32)	4.0	97.6 (174)	97.1 (173)	12.1	8.5 (25)	0 (0)	-	-	41.3 (0.096)	34.8 (0.081)	85	7.0

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Table 4-1. Continued

Test Run No.	Location	Burner Type	Test Fuel	Test Type	Capacity GJ/hr (10^3 lb/hr)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NO_x ng/J (ppm)	NO ng/J (ppm)	CO_2 dry %	CO ng/J (ppm)	HC ng/J (ppm)	SO_x ng/J (ppm)	SO_2 ng/J (ppm)	Total Partic. ng/J (lb/MB)	Solid Partic. ng/J (lb/MB)	Boiler Efficiency %	Bacharach Smoke Spot No.
180-2	38	Ring	NG	Base	47 (45)	43 (40)	1.9	112 (220)	110 (216)	9.4	0 (0)	1.8 (10)	-	-	-	-	82	-
181-2	38	Ring	NG	HiAir	47 (45)	42 (40)	3.15	119 (233)	115 (226)	9.8	0 (0)	3.5 (20)	-	-	-	-	81	-
181-4	38	Ring	NG	LowAir	47 (45)	42 (40)	1.35	92.8 (182)	91.8 (180)	9.4	279 (900)	0 (0)	-	-	-	-	83	-
182-4	38	Ring	NG	VPH	47 (45)	42 (40)	1.75	120 (236)	118 (232)	9.2	9.3 (30)	1.8 (10)	-	-	-	-	81	-
182-13	38	Ring	NG	VPH	47 (45)	40 (38)	1.6	63.2 (124)	60.7 (119)	9.2	9.3 (30)	0 (0)	-	-	-	-	79	-
183-44	38	Ring	NG	SCA	47 (45)	42 (40)	3.4	82.1 (161)	80.1 (157)	8.6	6.2 (20)	-	-	-	-	-	80	-
183-47	38	Ring	NG	SCA	47 (45)	41 (39)	2.9	52.0 (102)	51.5 (101)	8.4	11 (35)	-	-	-	-	-	79	-
184-1	38	Ring	NG	HiLoad	47 (45)	46 (44)	1.75	120 (235)	117 (230)	9.0	6.2 (20)	-	-	-	-	-	80	-
184-5	38	Ring	NG	HiLoad SCA	47 (45)	45 (43)	2.1	56.1 (110)	55.1 (108)	8.8	16 (50)	-	-	-	-	-	80	-
185-3	38	Ring	NG	LowLoad	47 (45)	34 (32)	4.1	108 (211)	106 (208)	7.8	0 (0)	-	-	-	-	-	81	-
185-5	38	Ring	NG	LowLoad SCA	47 (45)	33 (31)	2.6	59.7 (117)	59.2 (116)	8.4	23 (75)	-	-	-	-	-	82	-
186-1	38	Steam	#6	Base	47 (45)	38 (36)	3.0	183 (326)	183 (326)	11.0	0 (0)	-	738 (946)	736 (943)	45.6 (0.106)	38.7 (0.090)	87	-
187-1	38	Steam	#6	HiAir	47 (45)	38 (36)	6.2	215 (384)	214 (382)	9.2	0 (0)	-	-	-	-	-	85	-
187-5	38	Steam	#6	LowAir	47 (45)	39 (37)	1.6	136 (243)	134 (239)	11.4	40.9 (120)	4.9 (25)	-	-	-	-	87	-
188-1	38	Steam	#6	SCA	47 (45)	38 (36)	2.9	97.1 (173)	95.9 (171)	11.8	18.8 (55)	3.9 (20)	-	-	58.5 (0.136)	55.0 (0.128)	87	8.0
188-21	38	Steam	#6	SCA	47 (45)	38 (36)	3.5	90.3 (161)	88.6 (158)	11.6	30.7 (90)	0 (0)	-	-	-	-	86	-
189-5	38	Steam	#6	VPH	47 (45)	35 (33)	2.7	159 (283)	157 (280)	11.3	0 (0)	0 (0)	-	-	-	-	85	-
189-6	38	Steam	#6	VPH	47 (45)	33 (31)	2.8	153 (272)	150 (268)	11.0	0 (0)	1.0 (5)	-	-	-	-	84	4.0

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Table 4-1. Continued

Test Run No.	Location	Burner Type	Test Fuel	Test Type	Capacity GJ/hr (10^3 lb/hr)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NO_x ng/J (ppm)	NO ng/J (ppm)	CO_2 dry %	CO ng/J (ppm)	HC ng/J (ppm)	SO_x ng/J (ppm)	SO_2 ng/J (ppm)	Total Partic. ng/J (lb/MB)	Solid Partic. ng/J (lb/MB)	Boiler Efficiency %	Bacharach Smoke Spot No.
190-3	19	Ring	NG	Base	18.5 (17.5)	14.8 (14)	3.2	30 (59)	30 (59)	10.0	3.1 (10)	1.0 5	- -	- -	- -	- -	80	-
191-3	19	Ring	NG	Low Air	18.5 (17.5)	14.8 (14.0)	2.0	28.5 (55)	28.5 (55)	10.2	25 (60)	- -	- -	- -	- -	- -	80	-
192-1	19	Ring	NG	FGR	18.5 (17.5)	15.0 (14.2)	2.9	19 (37)	19 (37)	10.0	0 (0)	0 (0)	- -	- -	- -	- -	80	-
192-7	19	Ring	NG	FGR	18.5 (17.5)	14.3 (13.6)	2.75	8.2 (16)	8.2 (16)	10.2	37 (120)	13 (75)	- -	- -	- -	- -	80	-
193-8	19	Ring	NG	SCA	18.5 (17.5)	15.2 (14.4)	2.8	39 (77)	39 (77)	10.0	0 (0)	0 (0)	- -	- -	- -	- -	79	-
193-9	19	Ring	NG	SCA	18.5 (17.5)	14.6 (13.8)	2.4	27 (53)	27 (53)	10.6	3.1 (10)	0 (0)	- -	- -	- -	- -	80	-
194-1	19	Ring	NG	FGR + SCA	18.5 (17.5)	14.8 (14.0)	3.1	16 (32)	16 (31)	10.0	4.7 (15)	0 (0)	- -	- -	- -	- -	79	-
194-5	19	Ring	NG	FGR + SCA	18.5 (17.5)	14.9 (14.1)	3.15	11 (22)	11 (22)	9.8	3.1 (10)	0 (0)	- -	- -	- -	- -	79	-
195-1	19	Steam	#6	Base	18.5 (17.5)	15 (14)	3.1	95 (169)	95 (169)	13.2	0 (0)	- -	- -	- -	13.3 (0.031)	8.6 (0.020)	84	1.5
196-2	19	Steam	#6	Low Air	18.5 (17.5)	15.0 (14.2)	0.9	70 (124)	70 (124)	14.6	34 (100)	- -	- -	- -	- -	- -	85	8.0
197-4	19	Steam	#6	FGR	18.5 (17.5)	14.8 (14.0)	2.1	74 (132)	74 (132)	13.6	0 (0)	2.0 (10)	- -	- -	- -	- -	83	4.0
197-5	19	Steam	#6	FGR	18.5 (17.5)	14.6 (13.8)	2.9	81 (145)	81 (145)	13.2	0 (0)	0 (0)	- -	- -	- -	- -	84	2.5
197-8	19	Steam	#6	FGR	18.5 (17.5)	15.2 (14.4)	3.0	83 (148)	82 (146)	12.8	0 (0)	0 (0)	- -	- -	12.0 (0.028)	9.5 (0.022)	94	-
198-2	19	Steam	#6	SCA	18.5 (17.5)	14.8 (14.0)	2.4	61 (108)	61 (108)	13.6	53 (155)	1 (5)	- -	- -	- -	- -	84	8.0
198-8	19	Steam	#6	SCA	18.5 (17.5)	14.2 (13.5)	3.25	102 (182)	102 (182)	13.0	0 (0)	0 (0)	- -	- -	- -	- -	83	3.0
198-12	19	Steam	#6	SCA	18.5 (17.5)	15.1 (14.3)	3.1	75 (133)	74 (132)	12.8	0 (0)	3 (15)	- -	- -	11.6 (0.027)	9.9 (0.023)	82	4.0
199-4	19	Steam	#6	FGR + SCA	18.5 (17.5)	14.8 (14.0)	1.6	67 (119)	67 (119)	13.6	5.1 (15)	0 (0)	- -	- -	- -	- -	83	7.0
199-5	19	Steam	#6	FGR + SCA	18.5 (17.5)	14.8 (14.0)	2.5	79 (140)	77 (137)	13.2	0 (0)	0 (0)	- -	- -	- -	- -	82	6.0
200-3	19	Air	#6	Base	18.5 (17.5)	14.8 (14.0)	2.9	91 (162)	91 (162)	13.2	0 (0)	0 (0)	146 (187)	144 (184)	13.3 (0.031)	10.8 (0.032)	83	1.0
201-1	19	Air	#6	Low Air	18.5 (17.5)	14.8 (14.0)	2.25	77 (138)	77 (136)	13.4	48 (140)	0 (0)	- -	- -	- -	- -	84	9.0

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nat gas

5.1

0-0

0-8.1

0-30

oil

Table 4-1. Continued

Test Run No.	Location	Burner Type	Test Fuel	Test Type	Capacity GJ/hr (10^3 lb/hr)	Test Load GJ/hr (10^3 lb/hr)	Excess O_2 %	NO_x ng/J (ppm)	NO ng/J (ppm)	CO_2 dry %	CO ng/J (ppm)	HC ng/J (ppm)	SO_x ng/J (ppm)	SO_2 ng/J (ppm)	Total Partic. ng/J (lb/MB)	Solid Partic. ng/J (lb/MB)	Boiler Efficiency %	Bacharach Smoke Spot No.
202-2	19	Air	#6	FGR	18.5 (17.5)	14.6 (13.8)	2.7	[illegible] (141)	79 (141)	13.2	6.8 (20)	0 (0)	-	-	-	-	83	3.5
202-3	19	Air	#6	FGR	18.5 (17.5)	14.8 (14.0)	2.3	65 (116)	65 (116)	13.8	6.8 (20)	0 (0)	-	-	-	-	83	3.5
203-6	19	Air	#6	SCA	18.5 (17.5)	15.0 (14.2)	3.0	84 (149)	84 (149)	12.6	27 (80)	13 (65)	-	-	-	-	83	9.0
203-7	19	Air	#6	SCA	18.5 (17.5)	14.8 (14.0)	2.9	73 (131)	73 (131)	12.8	10 (30)	0 (0)	-	-	20.2 (0.047)	18.1 (0.042)	83	8.0
204-1	19	Ring, Air	NG + #6	Base	18.5 (17.5)	15.7 (14.9)	3.3	59 (111)	59 (111)	11.2	3.2 (10)	4.6 (25)	-	-	-	-	81	4.0
205-2	19	Ring, Air	NG + #6	Low Air	18.5 (17.5)	15.6 (14.8)	2.4	56 (104)	55 (103)	11.8	4.9 (15)	1.9 (10)	-	-	-	-	82	6.0
206-3	19	Ring, Air	NG + #6	FGR	18.5 (17.5)	14.8 (14.0)	2.8	49 (92)	49 (92)	11.8	0 (0)	4.6 (25)	-	-	-	-	81	2.0
206-7	19	Ring, Air	NG + #6	FGR	18.5 (17.5)	14.8 (14.0)	3.2	55 (102)	55 (102)	11.4	0 (0)	1 (5)	-	-	-	-	81	3.0
207-1	39	Spud	NG + RG	Base	211 (200)	169 (160)	3.7	97 (192)	97 (192)	8.8	7.7 (25)	0 (0)	-	-	-	-	83	-
208-1	39	Spud	NG + RG	Low Air	211 (200)	172 (163)	3.05	111 (220)	110 (218)	9.4	20 (65)	0 (0)	-	-	-	-	84	-
208-3	39	Spud	NG + RG	Low Air	211 (200)	169 (160)	1.3	97 (191)	95 (188)	10.0	102 (330)	0 (0)	-	-	-	-	84	-
208-5	39	Spud	NG + RG	Hi Air	211 (200)	169 (160)	5.[illegible]	83 (164)	81 (161)	8.2	4.6 (15)	0 (0)	-	-	-	-	83	-
209-1	39	Spud	NG + RG	SCA	211 (200)	172 (163)	3.6	58 (114)	57 (113)	9.2	616 (2000)	5.3 (30)	-	-	-	-	83	-
209-4	39	Spud	NG + RG	SCA	211 (200)	169 (160)	6.4	74 (147)	73 (144)	7.4	48 (155)	0 (0)	-	-	-	-	82	-
210-1	39	Spud	NG + RG	Load	211 (200)	100 (95)	8.9	44 (86)	44 (86)	6.2	0 (0)	0 (0)	-	-	-	-	81	-
211-1	39	Spud	NG + RG	Low Air	211 (200)	98 (93)	6.8	61 (120)	61 (120)	7.4	0 (0)	0 (0)	-	-	-	-	83	-
211-2	39	Spud	NG + RG	Low Air	211 (200)	100 (95)	3.4	81 (160)	81 (160)	9.0	28 (90)	0 (0)	-	-	-	-	84	-
212-4	39	Spud	NG + RG	SCA	211 (200)	100 (95)	6.6	67 (132)	67 (132)	7.4	62 (200)	1.8 (10)	-	-	-	-	83	-
212-15	39	Spud	NG + RG	SCA	211 (200)	100 (95)	3.9	56 (111)	55 (109)	9.0	616 (2000)	0 (0)	-	-	-	-	84	-

HC

4.3

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GLOSSARY OF SYMBOLS USED IN TABLES 1-1 AND 4-1

Burner Type

Air	Air Atomizer
ChGrt	Chain Grate
Pulv.	Pulverizer
Ring	Natural Gas Ring
SpStk	Spreader Stoker
Spud	Natural Gas Gun
Steam	Steam Atomizer

Test Fuel

Coal	Coal
NG	Natural Gas
Ref.Gas	Refinery Gas
NG/#6	Mixture, Natural Gas and #6 oil
#2	No. 2 Grade Fuel Oil
#5	No. 5 Grade Fuel Oil
#6	No. 6 Grade Fuel Oil
PS300	Pacific Standard Fuel Oil No. 300

Test Type

AirReg	Air Register Adjustment
Atom Press	Burner Atomizing Pressure Adjustment
BOOS	Burners Out of Service
Base	Baseline
BrTune	Boiler Tune-up
CombCyc	Combined Cycle
Damper	Air Damper Adjustment
HiAir	High Excess Air
HiLoad	High Load
LowAir	Low Excess Air
LowLoad	Low Load
NrmlAir	Normal Excess Air
SCA	Staged Combustion Air

Test Type - Continued

SnglCyc	Single Cycle
Steam Injec	Steam Injection
VPH	Variable Combustion Air Temperature
Viscosity	Fuel Oil Viscosity

4.1 NITROGEN OXIDES EMISSIONS

4.1.1 Coal Fuel

The analyses of the coals tested during Phase II are contained in Section 6.0. The moisture content of the coals tested in Phases I and II varied substantially, from less than 2% to greater than 10%. The higher heating values varied significantly also, from 0.0254 GJ/kg to 0.0326 GJ/kg (10,950 Btu/lb to 14,000 Btu/lb). The average of the fuel nitrogen of the coals burned was 1.4%. However two boilers were tested with western coals which had nitrogen contents of 0.83% and 0.94%. The baseline nitrogen oxide emissions for the coal tests are presented in Figure 4-3 as a function of boiler test load. Although the data, as shown, indicate that the baseline nitrogen oxides emissions increased with increasing boiler size, other parameters besides test load were contributing to this increase.

The lowest baseline nitrogen oxides emissions were measured on a boiler equipped with a traveling chain grate burner. The baseline nitrogen oxides was 100 ng/J (164 ppm) with an excess O_2 of 9.5%. One of the contributing factors to the low nitrogen oxides emissions was believed to be poor combustion equipment conditions. Visual examination of the furnace during the tests revealed low intensity combustion flames of a very lazy and random nature. The excess air was extremely high and the heat release rate per unit furnace volume was comparatively low, 0.496 $GJ \cdot hr^{-1} \cdot m^{-3}$ (0.013×10^6 $Btu \cdot hr^{-1} \cdot ft^{-3}$), considering the rated capacity.

Boilers equipped with underfed stoker coal burning equipment produced nitrogen oxides emissions ranging from 134 to 208 ng/J (220 to 340 ppm). These boiler designs were of a small capacity, less than 63 GJ/hr (50,000 lb/hr steam flow) and had a low hear release per unit furnace volume, 0.443 $GJ \cdot hr^{-1} \cdot m^{-3}$ (0.012×10^6 $Btu \cdot hr^{-1} \cdot m^{-3}$).

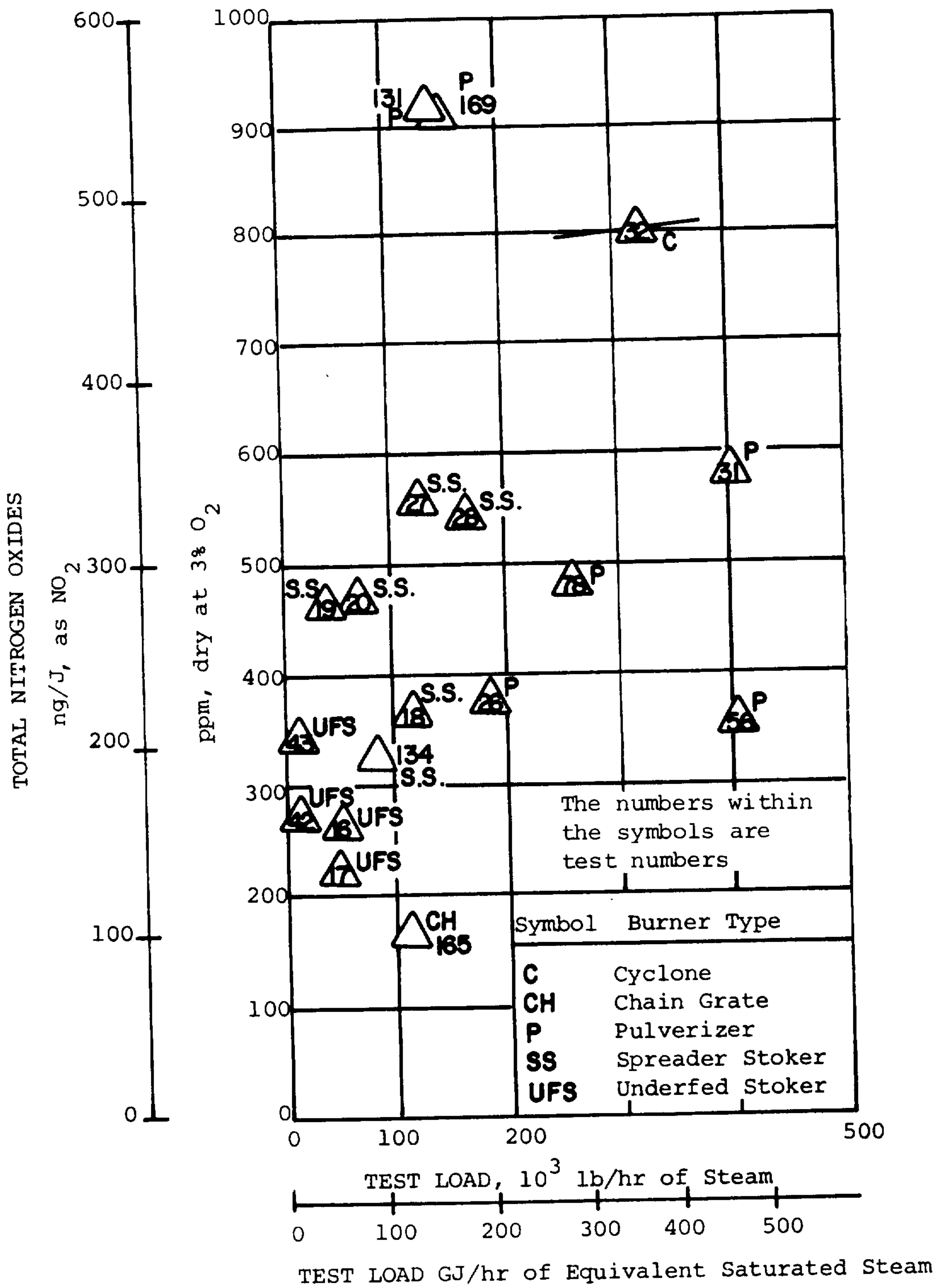

Figure 4-3. Total nitrogen oxides emissions at baseload for coal-fired boilers.

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Spreader stoker fired boilers produced NOx emissions of 196 to 336 ng/J (320 to 550 ppm). The spreader stoker equipped boilers were middle sized and all had higher heat release per unit volume and higher NOx emissions.

The largest capacity boilers tested were equipped with pulverized or cyclone burners and produced the highest level of nitrogen oxides emissions. Emissions ranged from 214 to 563 ng/J (350 to 922 ppm) on the pulverized units. The highest emitter was a four-burner, face-fired unit burning pulverized Wyoming coal (Tests 131 and 169). Nitrogen oxides emissions at 50% of rated capacity were 563 ng/J (922 ppm). The nitrogen content of the Wyoming coal fuel was 0.83% which is the lowest of any coal tested during the entire program. Thus, the uniquely high emissions were not due to a high fuel nitrogen content. However, the coal oxygen content was the highest at 12.5%.

Another pulverized unit (Test 156) with approximately the same size burners fired a coal with only half the nitrogen content, i.e., 1.5%, and 8.1% oxygen content and emissions were only 214 ng/J (350 ppm). It is theorized that emissions were high with the Wyoming coal because the high amount of fuel oxygen in intimate contact with the fuel nitrogen enhanced the low temperature conversion of fuel nitrogen to nitrogen oxides.

A spreader stoker equipped boiler fired a similar Wyoming coal with 0.94% nitrogen and 11% oxygen (Test 134). In this case, nitrogen oxides were 196 ng/J (320 ppm) which was the lowest level measured on a spreader stoker. The large differences in emissions between this and the pulverizer burning Wyoming coal may be related to the differences in combustion intensity of the two. The pulverizer had efficiently mixed fuel and air along with

530 K (500°F) combustion air temperature which resulted in a high intensity flame. The stoker, on the other hand, used 93°C (200°F) combustion air and the burning process was much slower to accomodate the larger fuel particles. The flame zone gases were cooler and less NOx was produced.

The other large coal fired boiler used cyclone type coal combustors which have a reputation for being large NO_x producers. The unit had a large heat release rate and a very small heat absorption volume and emitted 489 ng/J (800 ppm) of nitrogen oxides. Here the furnace absorption volume was defined as the volume of the cyclone combustor alone, since the combustion reactions were mostly completed before the hot gases left the combustor and entered the boiler for steam generation.

4.1.2 Oil Fuel

The oil fuels tested during Phase I and Phase II included Nos. 2, 5, and 6 type oils, the properties of which are summarized in Section 6.0 for Phase II. The nitrogen content of the oils varied from essentially zero to greater than 0.5%. Other properties, such as API gravity, viscosity, heating value, and Conradson carbon also varied over the normal ranges for oil fuels. The burners tested in Phase I included steam, air, rotary cup and pressure atomization. All Phase II testing was done on steam or air atomized burners.

The baseline nitrogen oxides emissions from oil fuel are plotted in Figure 4-4 as a function of boiler test load. The fire-tube boiler data, from Phase I, shown as a cross-hatched area due to large number (14) of data points, were insensitive to boiler load, combustion air temperature and excess oxygen level and were between 56 and 168 ng/J (100 and 300 ppm). The watertube boiler nitrogen oxides emission data shown in Figure 4-4 did not vary significantly with test load, but were dependent upon fuel nitrogen content, burner size and excess oxygen level, as is discussed later in this report.

Nitrogen oxides emissions from No. 2 oil fueled watertube boilers were typically about 56 ng/J (100 ppm). In two cases emissions approached 112 ng/J (200 ppm) on a No. 2 oil fired boiler. Emissions were found to be insensitive to excess oxygen for both preheated and ambient-temperature combustion air.

Burner heat release rate and fuel nitrogen content were found to influence NO_x emissions for No. 5 and 6 oil fueled boilers. The larger burners, 85 to 130 GJ/hr (80 to 123 10^6 Btu/hr), had nitrogen oxides emissions from 140 ng/J (250 ppm) to over 336 ng/J (600 ppm). The smaller burners, 10 to 50 GJ/hr (9.5 to 47 10^6 Btu/hr), produced from 85 to 170 ng/J (150 to 300 ppm) of NO_x. Nitrogen oxides emissions from No. 5 and 6 oils were generally affected by the excess O_2 level as discussed in Section 5.1.1.

4.1.3 Natural Gas Fuel

The analyses of the natural gas fuels tested in Phase II are contained in Section 6.0. The properties of all the natural gases tested were similar. The methane contents varied from 88 to 97% and ethane proportions were between 1.8 and 5.8%. The fuel heating values ranged from 0.0364 to 0.0391 GJ/m^3 (976 to 1050 Btu/ft^3).

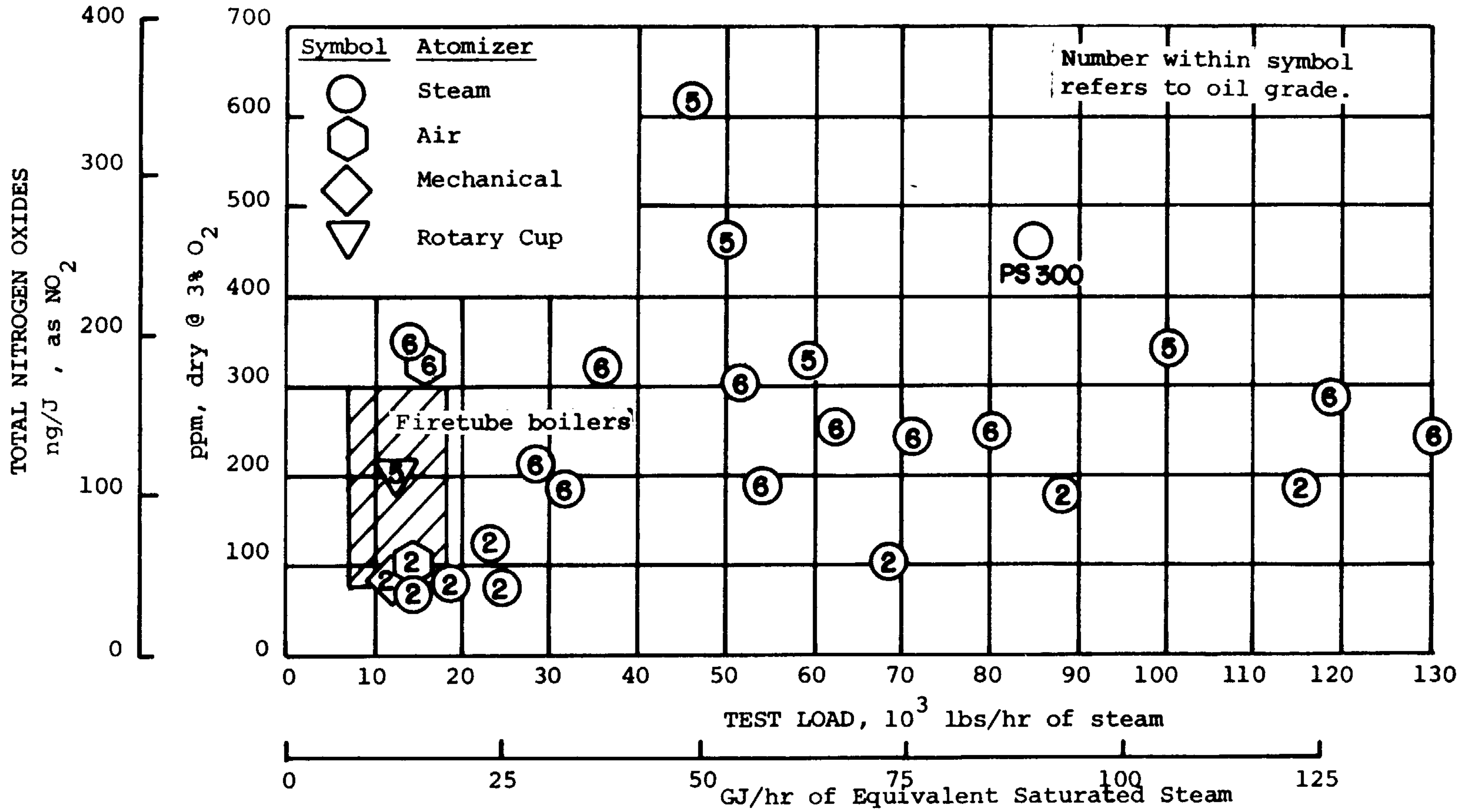

Figure 4-4. Baseline total nitrogen oxide emissions for oil fired boilers.

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The natural gas fired boilers tested in the program were nearly all equipped with ring type burners. The only exceptions were the two corner-fired boilers used for Tests 75 and 77, that had natural gas nozzles which could be tilted for steam temperature control and the boiler used for Tests 153-155 that utilized a single burner comprised of three multi-orifice gas nozzles. The natural gas ring burners operated at various pressure levels, depending upon gas pressure available at the site and burner design.

The NO_x emissions for natural gas-fired boilers were found to be dependent in varying degrees upon furnace type, excess oxygen level, combustion air preheat temperature, burner size and firing rate. The baseline NO_x emissions for large and small size boilers are presented in Figure 4-5. A large number of small firetube boilers, 7.4 to 21 GJ/hr (7 to 20 10^3 lbs/hr steam flow), were tested in Phase I and each individual test point could not be shown on Figure 4-5, since many boilers had practically the same concentration. These 10 tests are represented by the cross-hatched area. No firetube boilers were tested during Phase II.

The natural gas fired firetube boilers all had baseline NO_x emissions between 25 and 50 ng/J (50 and 100 ppm) and showed little dependence of nitrogen oxides on excess oxygen level (see Section 5.1). The natural gas fired watertube boilers without combustion air preheaters (indicated by simple squares) showed only a slight dependence of nitrogen oxides on excess oxygen; while for boilers with preheated air (shown by crossed squares) the influence of excess O_2 on NO_x was significant. Natural gas fired watertube boilers with ambient temperature combustion air had baseline nitrogen oxides emissions of 36 to 57 ng/J (70 to 111 ppm). These boilers were generally small, less than 95 GJ/hr capacity (90,000 lb/hr steam flow). NO_x emissions from natural gas

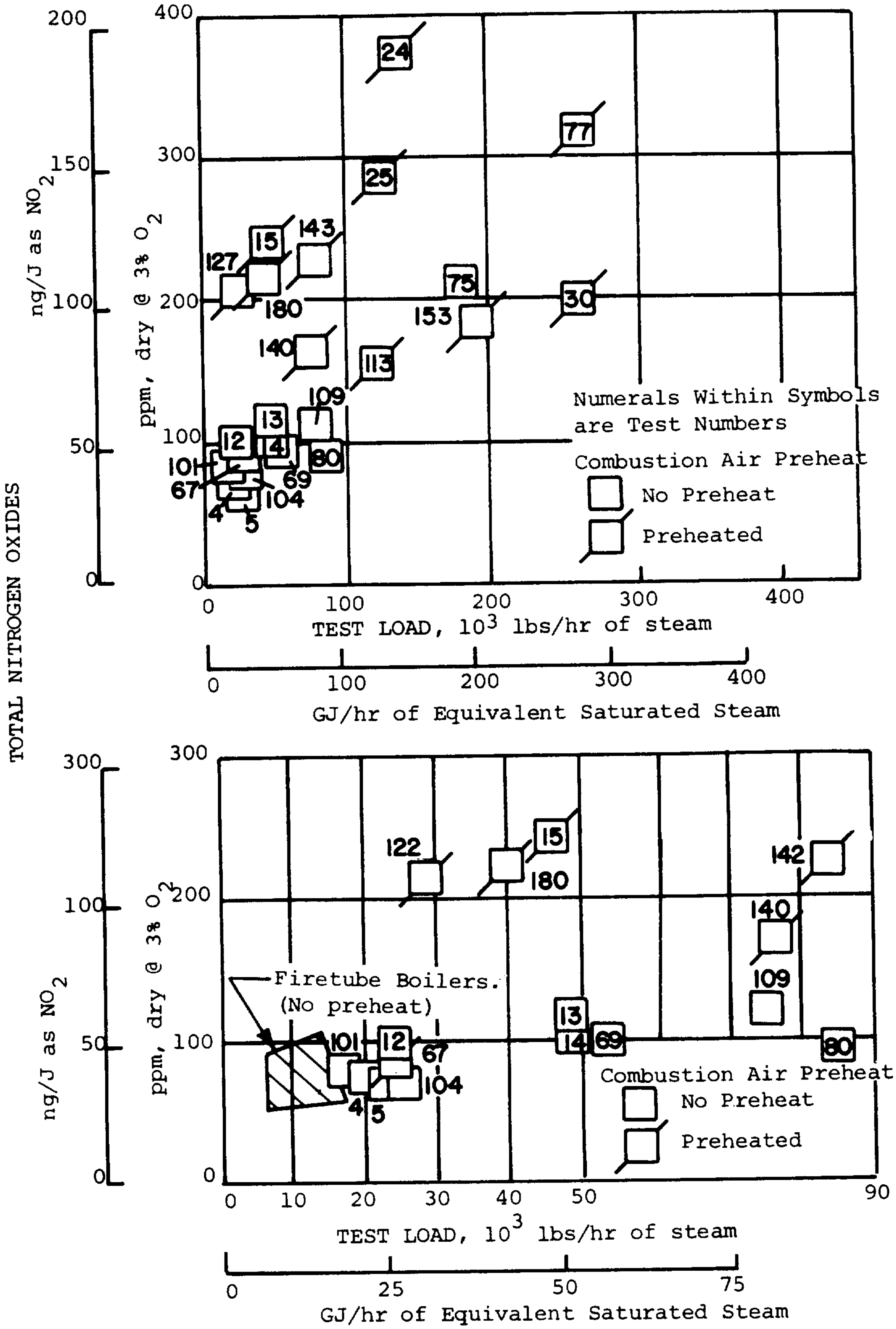

Figure 4-5. Baseline total nitrogen oxides emissions for natural gas fired boilers.

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fired boilers equipped with air preheaters were between 46 and 191 ng/J (90 and 375 ppm). Figure 4-5 indicates that nitrogen oxides emissions increased with test load for the watertube boilers.

4.1.4 Mixed Fuels

An additional objective of the Phase I and Phase II field measurements was to collect data on the level of nitrogen oxides emitted when a mixture of fuels was burned. The properties of the secondary fuel may materially affect NO_x emissions, especially since waste material fuels sometimes are high in organic nitrogen content. Six sets of measurements were made where a secondary fuel was burned and the results are listed in Table 4-2.

In Test No. 23, the fuel was a mixture of No. 5 oil and a small amount of refinery gas. The refinery gas contained about 25% hydrogen and 30% methane. In Test No. 74 the proportion of refinery gas was increased to 50%, and the nitrogen oxides emissions increased by 26%, even though the excess oxygen was lower. This might have been due to the refinery gas having a high nitrogen content that varied with time, but unfortunately, it was impractical to obtain for analysis a sample of the refinery gas.

When a quantity of wet tree bark, about 18 metric tons (20 English tons) per hour, was fired with No. 6 oil in Test No. 29-1, the nitrogen oxides concentration increased by 6%, even though the excess oxygen level had decreased.

In Test No. 32 burning pure coal produced nitrogen oxides levels of about 485 ng/J (800 ppm). When a 70-30 combination of coal and No. 6 oil was burned nitrogen oxides became very sensitive to the excess oxygen level and varied between 423 and 513 ng/J (710 and

Table 4-2. NITROGEN OXIDES EMISSIONS FROM MIXED FUELS

Test No.	Test Load, GJ/hr	Mixed Fuel Type	Burner Type	Excess O_2, %	NOx ng/J	NOx ppm
23-1	93	92% #5 Oil & 8% Refinery Gas	Steam/Ring	8.0	96	172
74-1	93	50% #5 Oil & 50% Refinery Gas	Steam/Ring	6.5	116	217
29-5	422	#6 Oil	Steam	9.5	224	400
29-1	422	#6 Oil & Wet Bark	Steam	9.0	238	425
32-4	338	Coal	Cyclone	3.4	489	800
32-2	424	Coal	Cyclone	3.2	483	790
72-3	431	70% Coal & 30% #6 Oil	Cyclone/ Steam	3.6	513	860
72-4	338	70% Coal & 30% #6 Oil	Cyclone/ Steam	3.4	423	710
71-1	422	50% Coal & 50% #6 Oil	Cyclone/ Steam	3.7	468	797
156-2	422	Coal	Pulv.	8.6	216	353
159-6	443	50% Coal & 50% #6 Oil	Pulv./Steam	8.9	177	302
190-3	14	Natural Gas	Ring	3.2	29	56
200-3	15	#6 Oil	Air	2.9	91	162
204-1	16	50% #6 Oil & 50% Natural Gas	Air/Ring	3.3	59	111
207-1	169	Natural Gas & Refinery Gas	Spud	3.7	97	192

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860 ppm). A 50-50 mixture of coal and No. 6 oil resulted in a slight reduction of 3.5% in nitrogen oxides emissions below those from pure coal, however, there was insufficient testing time remaining to investigate how sensitive this particular fuel mixture was to the excess oxygen level.

A 50-50 mixture of coal and No. 6 oil in Test No. 159 resulted in 14% lower nitrogen oxides emissions than with coal alone as in Test No. 156. This reduction was probably due to the lower overall nitrogen content of the fuel mixture. The coal was analyzed to be 1.5% nitrogen and the oil was found to contain 0.33% nitrogen.

Tests 190, 200, and 204 were conducted on natural gas, No. 6 oil, and a 50-50 mixture of the two. Natural gas firing resulted in 30 ng/J (59 ppm) of nitrogen oxides. Oil firing gave 91 ng/J (162 ppm). Emissions from the fuel mixture were an average of the two levels at 59 ng/J (111 ppm).

For Test No. 207 the fuel was a mixture of natural and refinery gases. The fuel composition averaged 48% methane, 36% hydrogen, and 11% ethane. Baseline NOx emissions were 97 ng/J (192 ppm). Unfortunately, this was the only fuel burned in the boiler so no comparisons can be made.

The limited amount of mixed fuels testing does not allow a firm conclusion to be drawn. However, it does appear that nitrogen oxides emissions may decrease when the total amount of nitrogen contained in the composite fuel is reduced by mixing fuels having a high and a low nitrogen content.

4.2 PARTICULATE EMISSIONS

The baseline solid (filterable) particulate emissions from the oil- and coal-fired boilers that were tested during Phases I and II are discussed in the following sections. The solid particulate emissions and the total particulate emissions (including both the solid particulates and the condensed vapors) from coal and oil fuels tested in Phase II are listed in Table 4-1.

4.2.1 Coal Fuel

For many of the coal burning boilers particulate measurements were made downstream of a dust collector, because upstream sampling was not possible due to the absence of satisfactory sampling stations. Test numbers 32, 131, 134, and 169 were conducted upstream of dust collectors and are indicated as such in Figure 4-6 by the shaded data points. When comparing particulate emissions from coal fuel, one should be aware of whether the measurements were made downstream or upstream of a dust collector.

Figure 4-6 illustrates solid particulate emissions as a function of boiler load for coal fuel. As the data indicate, the particulate emissions are not dependent significantly upon boiler load. The highest particulate emissions were measured during Test 31, 4300 ng/J (10 lb/10^6 Btu). The boiler can burn tree bark as a supplement fuel to pulverized coal. The high particulate level was measured during Phase I immediately following a period of bark burning. Emissions were high due to either residual bark particles in the flue gas or to the extremely high ash content of the coal fuel. An ultimate analysis of the coal revealed it was over 17% ash and had a low heating value. The same boiler was tested during Phase II (Test 156), this time with a coal of approximately 15% ash but with a higher heat content. Particulate emissions were significantly

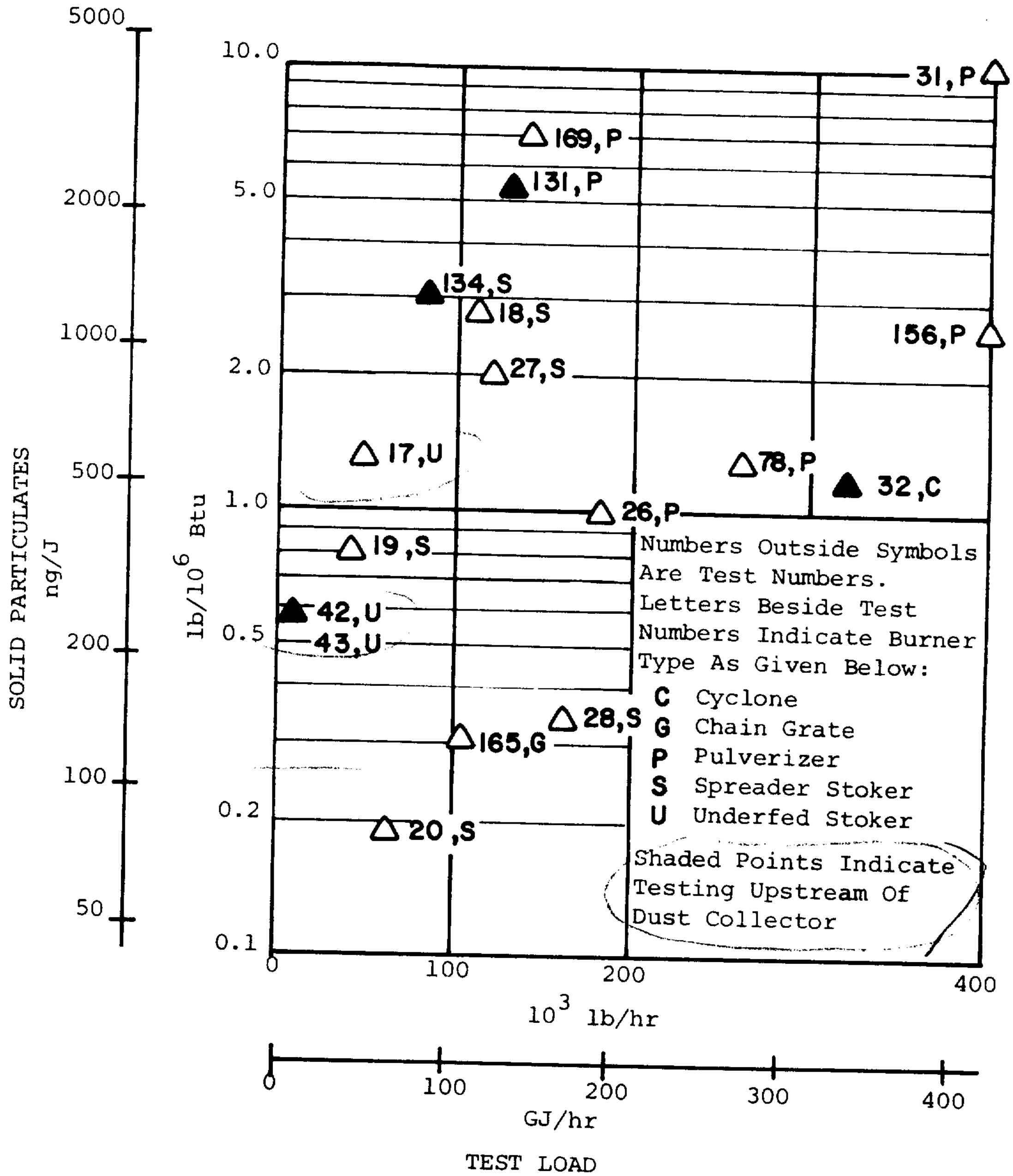

Figure 4-6. Baseline solid particulate emissions, coal fuel.

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lower at 1120 ng/J (2.6 lb/10^6 Btu). The boiler had not been fired with any appreciable amount of tree bark prior to this second set of measurements, and the particulates could have been lower because of the absence of residual bark fly ash, as well as from firing a lower ash content coal.

Particulate levels for other pulverized coal fired boilers ranged between 430 and 3000 ng/J (1.0 and 7.0 lb/10^6 Btu).

Spreader stoker fired boilers had a large range of particulate emissions levels. Test 20 had the lowest emissions of the group of 82 ng/J (0.19 lb/10^6 Btu), and Test 18 had the highest emissions of 1250 ng/J (2.9 lb/10^6 Btu). Test 134 on a spreader stoker had even higher particulates, but these data were taken upstream of the dust collector.

The boiler equipped with the chain grate burner, Test 165, had relatively low particulates of 133 ng/J (0.31 lb/10^6 Btu). This boiler was operating with a very high excess O_2.

Test No. 32 was on a cyclone-fired unit for which the particulates were measured before the dust collectors, rather than after. The level of 516 ng/J (1.2 lbs/10^6 Btu) was no higher than that of the other units that were measured after a dust collector.

Generally, baseline particulate emission levels from coal fired boilers were found to be independent of the boiler size and dependent upon the fuel ash content. To a lesser extent, particulates were also dependent upon burner design. The correlation between particulates and fuel ash content is further discussed in Section 6.0.

4.2.2 Oil Fuel

Figure 4-7 presents solid particulate emissions plotted versus boiler load. The particulates generally increased in going from light to heavy oils, but were independent of boiler size and burner type. Particulates from No. 2 oil-fired boilers were between 4.3 and 14.6 ng/J (0.01 and 0.034 lb/10^6 Btu). The levels from No. 5 oils were 10.3 and 36.6 ng/J (0.024 to 0.085 lb/10^6 Btu). No. 6 fuel oil fired boilers produced the highest particulate emissions; 16.8 to 155 ng/J (0.039 to 0.36 lb/10^6 Btu).

The total particulate loading was found to be highly dependent upon the fuel ash content. This correlation is discussed in Section 6.0.

4.2.3 Gaseous Fuel

Gas fired boilers very seldom operate with luminous flames where the combustion of elemental carbon is occurring and soot or coke particles are formed by incomplete combustion. The particulate emissions data taken during Phase I for natural gas fired boilers and shown on Figure 4-8 were low, typically between 1.7 and 3.0 ng/J (0.004 and 0.007 lbs/10^6 Btu) as would be expected from non-luminous gas flames. No particulate testing was conducted on gas fired boilers during Phase II.

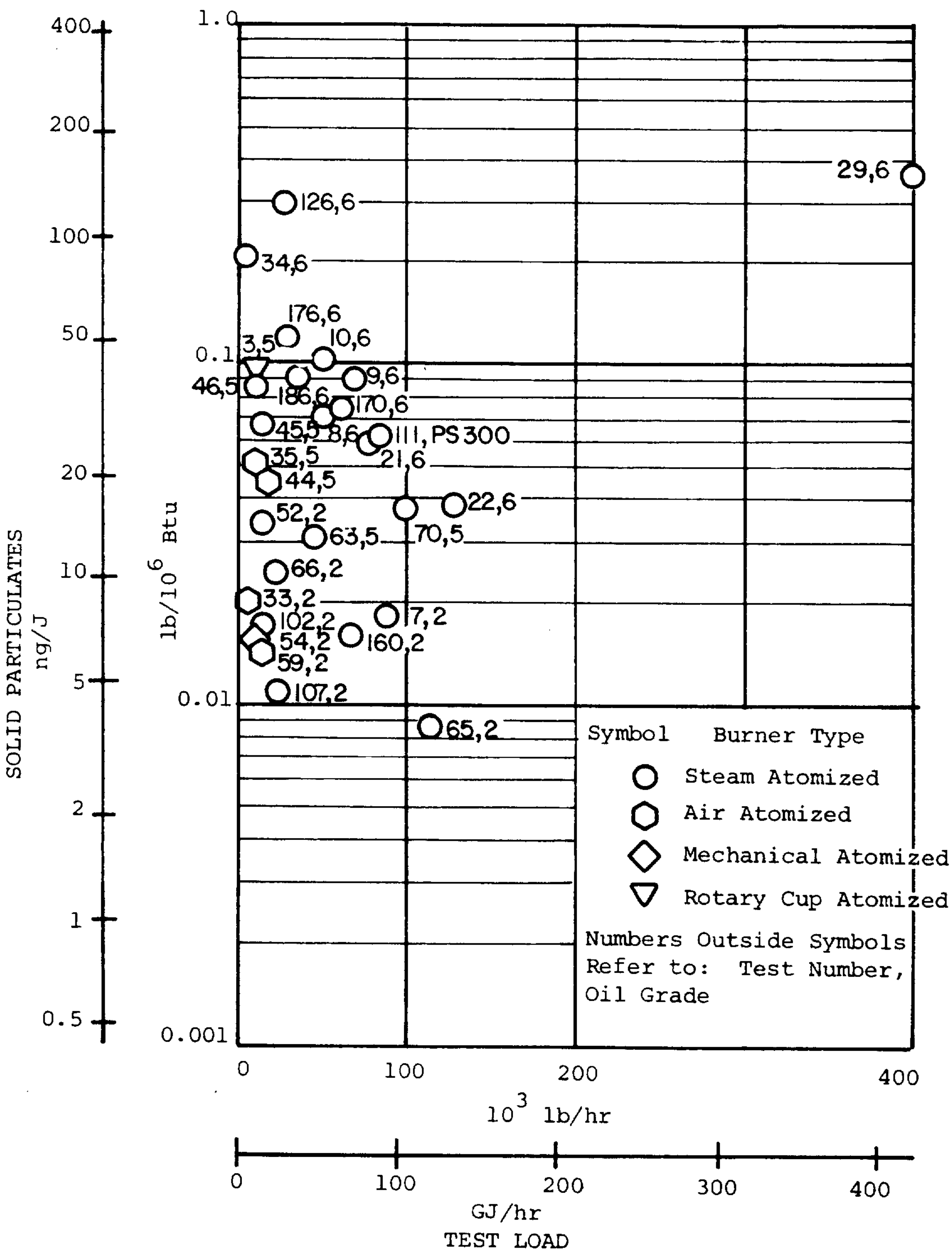

Figure 4-7. Baseline solid particulate emissions. Oil Fuel.

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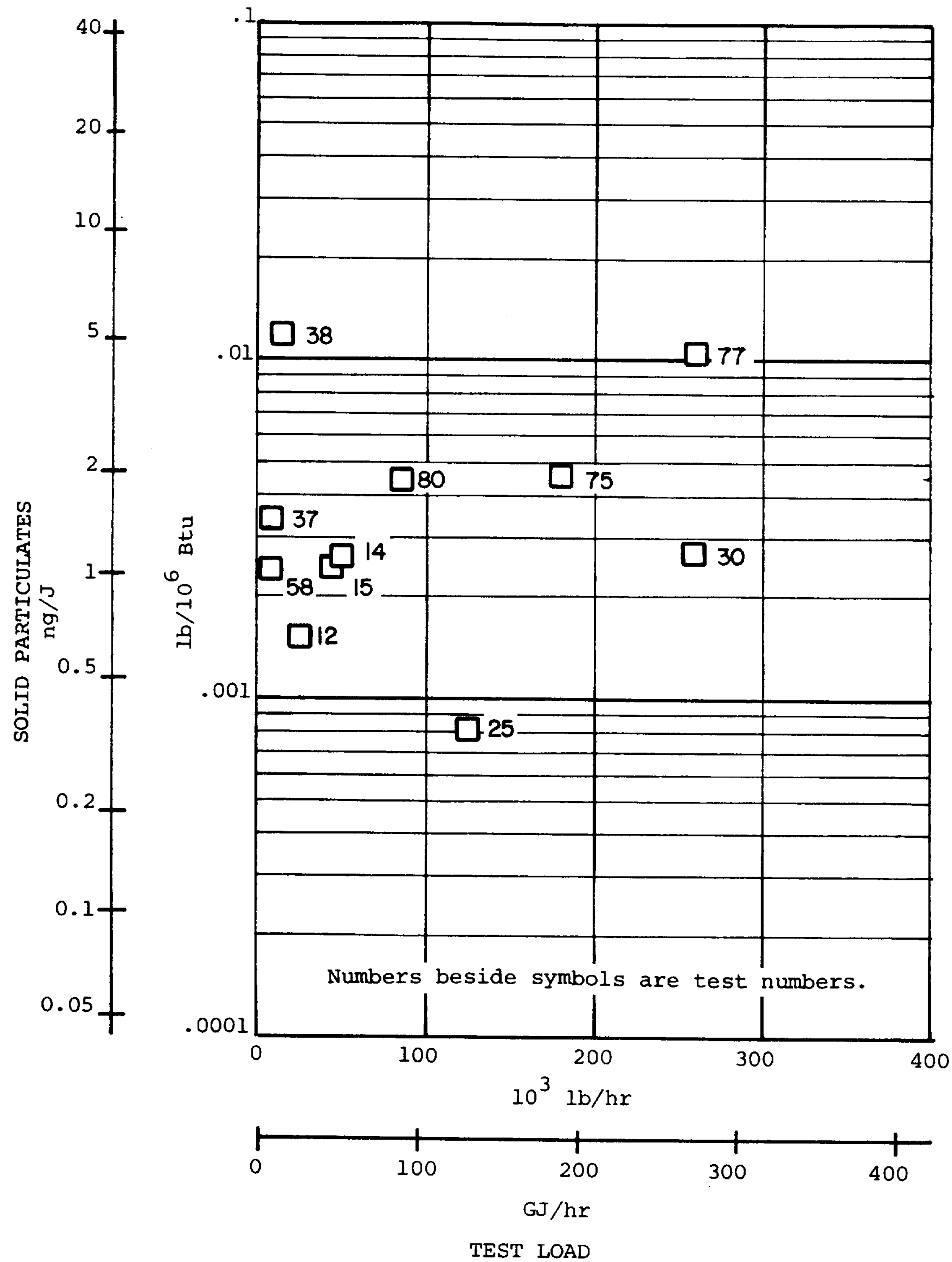

Figure 4-8. Baseline solid particulate emissions. Natural gas fuel.

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4.3 PARTICULATE SIZE

The particulate sizing portion of the field test included thirty runs on ten different boilers with and without combustion modification. Sixteen of the runs also involved the measurement of the toxic element content of the flue gas and fly ash. Sixteen of the measurements were with oil fuel and fourteen with coal fuel. The particulate sizing was done on the basis of aerodynamic diameter, as is explained in Subsection 3.2. (In Phase I the sizing was done on the basis of optical size using an electron microscope. The Phase I results are discussed in Subsection 4.7 of Reference 1.)

A low speed flow type of cascade impactor that is described in Subsection 3.5 was used to measure particulate aerodynamic diameters. It consisted of five stages having nominal cut points at diameters of 2.5, 1.5, 1.0, 0.5, and 0.25 μm, and a final filter to catch particulates that passed through the stages. The aerodynamic diameter discussed here is the diameter of a spherical particle of unit density that is collected with 50% efficiency by the impactor stage. The symbol used for this diameter is D_{50}. A cyclone was added upstream of the first stage of the impactor to collect particulate larger than 2.5 μm when coal was the test fuel.

In order to forestall particulate rebound and reentrainment, the flue gas flow speed through the impactor was reduced to about two-thirds nominal, and this reduced flow increased the aerodynamic diameters of the stages.[6] The points plotted on the graphs in this section are the aerodynamic diameter cut points of the stages that actually existed during the test.

The proportion of particulates in three size categories for the toxic tests with oil and coal fuels are listed in Table 4-3. The size category of five-tenths of a micrometer or less was selected because of what is shown about particle size on Figure 4-9. Particles that are less than 0.5 μm in size tend to be inahled and then exhaled,

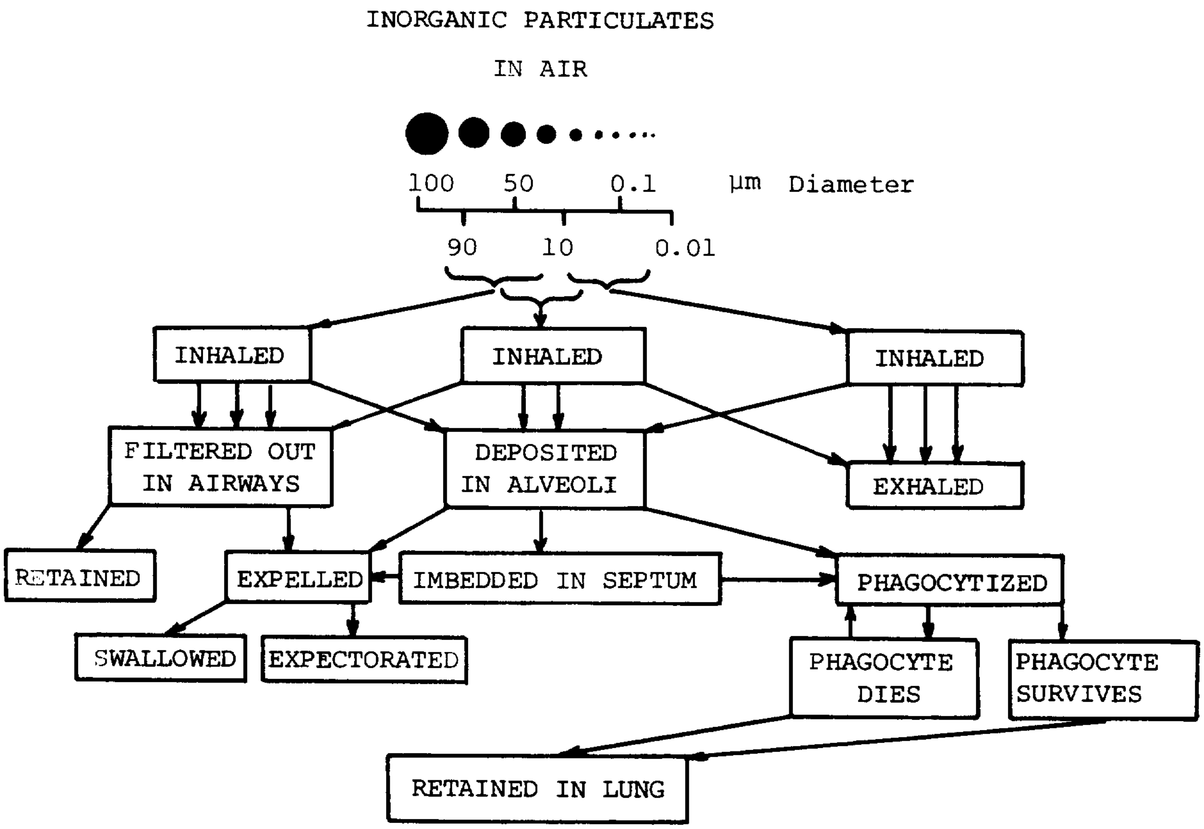
Table 4-3. DISTRIBUTION OF PARTICULATE SIZE WITH BASELINE CONDITIONS

OIL FUEL

Test No.	Test Location	Load GJ/hr (10^3lb/hr)	Burner or Oil Type	Proportion of Total Weight of Catch: Particles Inhaled Then Exhaled <0.5 μm %	Particles In The "Fine" Particulate Size Range <3 μm %	Particles Reducing Visibility by Mie Scattering 0.4-0.7 μm %	Soot Included	Test Conditions
111	27	90 (85)	PS300	60	81	10	No	Baseline
121-9	29	76 (72)	No. 6	10	68	8	Yes	Baseline with light soot
121-10		76 (72)	No. 6	15	70	19	Yes	Baseline with light soot
121-11		76 (72)	No. 6	3	30	3	Yes	Baseline with heavy soot
130	28	32 (30)	No. 6	7	49	6	No	Baseline
162-36	36	65 (62)	No. 2	1	26	1	No	Baseline
171-6A	20	53 (50)	No. 6	40	73	2	Yes	Baseline
171-6B		53 (50)	No. 6	37	67	2	Yes	Baseline
171-8		54 (51)	No. 6	35	65	2	Yes	Baseline
170-5		68 (64)	No. 6	32	62	3	No	Higher Load
176-5	37	34 (32)	No. 6	32	58	1	No	Baseline

COAL FUEL

Test No.	Test Location	Load GJ/hr (10^3lb/hr)	Burner or Oil Type	<0.5 μm %	<3 μm %	0.4-0.7 μm %	Soot Included	Test Conditions
139-5	30	87 (82)	SpStk	0.7	8	<1	No	Baseline, Upstream of Cyclone
156-2	13	422 (400)	Pulv.	2	30	3	No	Baseline, Downstream of Cyclone
166-3	35	116 (110)	ChGrt	11	24	6	No	Baseline, Downstream of Dust Collector
166-5		111 (105)		46	65	13	Yes	
166-6		111 (105)		25	33	3	Yes	
166-7		110 (116)		6	30	2	Yes	
166-9		106 (100)		5	22	2	Yes	
166-10		116 (110)		5	25	4	Yes	
169-1	31	148 (140)	Pulv.	3	30	1	Yes	Baseline, Upstream of Dust Collector
169-2		148 (140)		1	30	<1	Yes	Baseline, Downstream of Dust Collector
169-3		148 (140)		1	11	3	Yes	Baseline, Upstream of Dust Collector
169-4		148 (140)		1	31	2	Yes	Baseline, Downstream of Dust Collector
169-6		148 (140)		<1	17	<1	Yes	Baseline, Downstream of Dust Collector



Source: "The Pneumoconioses -- Diagnosis, Evaluation and Management." Committee on the Pneumoconioses, Council on Occupational Health, American Medical Association, Chicago, 1963.

Figure 4-9. Schematic presentation of the biological fate and effects of inhaled inorganic particulates.

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rather than deposited in the alveoli. They do not build up readily in the airways and possibly are not a serious health hazard. Figure 4-9 also shows that particulates between 0.5 μm and 50 μm in diameter are inhaled and either filtered out in the airways, deposited in the alveoli or exhaled in various amounts. In this size range particles 3 μm or less are the most hazardous.[7,8]

When analyzing the impactor data it is assumed that all of the mass caught upon an impaction stage consists of material having aerodynamic diameters equal to or greater than the D_{50} for that stage, and less than the D_{50} for the next higher stage. For the first stage, or the precutter cyclone when one is employed, it is assumed that all of the captured particulate have aerodynamic diameters greater than, or equal to the D_{50} for that stage or cyclone, but less than an arbitrarily large diameter of 50 μm for oil fuel and 100 μm for coal fuel.

The combustion of oil fuel produced a larger proportion of particulates having an aerodynamic diameter less than 3 μm than did coal fuel. Thus, more of the particulate emissions from oil is inhaled and then exhaled (24%), retained in the respiratory passages (67%), and involved in reduced visibility (7%) than from coal. Coal fly ash generally was larger in size than was oil fly ash.

The chain grate type of coal burner at Location No. 35 produced more fine particulate (about 36%), than did the pulverizer at Location No. 31 (about 24%). The greater proportion of fine particulate being from the chain grate, rather than the pulverizer was unexpected. The difference in particulate size between the chain grate and pulverizer is not explained easily by the difference in the size of the coal fired. One would expect that the larger size crushed coal that was fired on the chain grate would yield the larger particulate, but this was not so.

At 10 μm diameter and less the order was reversed. The pulverizer produced a greater amount of particulate having a diameter less than 10 μm (50%) than did the chain grate (35%). These data are similar to those reported in Reference 9 where 30% of the particulate from a pulverizer was under 10 μm while only 10% from a spreader stoker was under 10 μm in diameter. At 10 μm the pulverized coal produced a greater proportion of smaller size particulate than did the crushed coal.

There was little difference in the proximate analyses of the two coals burned at Location 31, Test 169 and Location 35, Test 166. The averages of the three proximate analyses of the coals was as follows:

	Coal		Bottom Ash	
Location No.	35	31	35	31
Test No.	166	169	166	169
Inerts, %	13	11	49	95
Volatile Matter, %	38	39	4	5
Fixed Carbon, %	44	44	45	<1
Heat of Combustion, J/g	26,835	25,576	--	--

However, the proximate analyses of the two ashes were far different. The inerts content of the bottom ash from Test 169 was much higher than that from Test 166, while the carbon content was practically zero. The pulverizer burner completely burned out the carbon leaving both a bottom ash and fly ash that was almost entirely uncombustible mineral. This type of ash remained or agglomerated into larger size particulates than did the ash from the chain grate that was 45% carbon.

The smallest proportion of fine particulate was 8% from a spreader stoker tested as part of the combustion modification task. There was no ash analysis nor was the soot blown during this test, so there can be no direct comparison, as in Tests 166 and 169 above.

It was not surprising, however, that a spreader stoker that burned crushed coal partly in suspension, as did the pulverizer, and partly on a grate, as did the chain grate, would produce relatively few fine particulates and many large particulates.

When the test was run to measure the toxic elements content of the flue gas, e.g., trace metals and polyorganic material, the soot was collected. Just prior to the start of this latter type of test the soot blowers were operated to clean the boiler. Then, just before the end of the particulate collection the soot blowers were operated again to dislodge the soot that had been deposited during the test. The results of the toxic element testing are discussed in Reference 5.

Test No. 121 at Location 29 illustrate a size effect of soot blowing during a test. For test runs 121-9 and 121-10 the soot blowing was timed so only the soot deposited during the run was caught by the impactor. For run 121-11, an operational problem caused about 18 hours of soot accumulation to be caught, rather than the 4 hour accumulation of runs 121-9 and 121-10. The result was that the submicron particulates constituted only 3% of the total catch, and a great many more large-size particulates were caught. Apparently there was a significant growth in the size of soot particles by agglomeration over a period of time.

The cascade impactor data are listed in Table 4-4. The data points and the distribution of aerodynamic diameter for the baseline type tests are discussed in this subsection and the data from the combustion modification tests are discussed in Subsection 5.4.2. When reducing the particulate size data the convention was employed that assumes that the largest particulate present in the flue gas from oil fuel was 50 μm and from coal fuel was 100 μm.[6] Thus, a cumulative proportion of 100% was deemed to occur at an aerodynamic diameter (D_{50}) of 50 or 100 μm.

Table 4-4. CASCADE IMPACTOR DATA SUMMARY

Test No.	Loc. No.	Fuel Type	Burner Type	Test Load $GJ \cdot hr^{-1}$	Impact. Flow $cm^3 \cdot s^{-1}$	Actual D_{50} of Stage No. 1 µm	2 µm	3 µm	4 µm	5 µm	D_{50} Cycl. µm	Cyclone, Stage and Filter Catch: Cyclone mg	Stage No. 1 mg	2 mg	3 mg	4 mg	5 mg	Filter mg	Total Catch mg	Comments
111	27	PS300	Steam	90	35.4	2.9	1.7	1.2	0.58	0.29	--	None	0.368	0.148	0.240	0.272	0.216	0.864	2.11	Baseline
112	27	PS300	Steam	90	37.7	2.8	1.7	1.1	0.56	0.28	--	None	0.038	0.246	0.444	0.296	0.304	M	1.33	Filter destroyed
130	28	No. 6	Steam	31	11.8	5.0	3.0	2.0	1.0	0.4	--	None	2.064	1.152	0.896	0.880	0.734	0.32	6.19	Baseline
121-9	29	No. 6	Steam	76	17.8	4.1	2.4	1.6	0.81	0.41	--	None	1.00	1.08	1.21	0.992	0.489	0.436	5.17	Light soot
121-10	29	No. 6	Steam	74	20.0	3.85	2.31	1.54	0.77	0.38	--	None	1.82	2.20	0.616	1.06	2.37	0.560	8.62	Light soot
121-11	29	No. 6	Steam	126	17.9	4.1	2.4	1.6	0.81	0.41	--	None	11.7	2.62	1.84	1.64	0.848	0.349	18.99	Heavy soot
133-5	30	Coal	Spread	53	46.5	2.5	1.5	1.0	0.5	0.25	10.9	75.1	8.33	5.49	0.488	0.396	0.528	0.12	99.5	Baseline
154-2	13	Coal	Pulv.	420	51.5	2.5	1.4	0.96	0.43	0.24	10.4	52.6	57.7	34.2	8.82	6.69	3.04	0.236	163	Baseline
166-3	35	Coal	Grate	116	24.6	3.5	2.1	1.4	0.70	0.35	15.6	10.39	1.056	0.780	0.660	0.340	0.600	0.572	14.60	Baseline no soot
166-5	35	Coal	Grate	111	22.2	3.6	2.2	1.5	0.73	0.35	15.8	32.3	6.54	2.75	1.176	0.714	32.20	33.91	109.8	Toxic with soot
166-6	35	Coal	Grate	111	25.5	3.4	2.0	1.4	0.68	0.34	14.7	30.01	6.18	2.32	1.01	1.33	0.916	13.74	55.51	Toxic with soot
166-7	35	Coal	Grate	116	23.6	3.5	2.1	1.4	0.71	0.35	15.3	13.06	3.22	4.60	1.38	1.21	0.772	1.22	25.46	Toxic with soot
168-8	35	Coal	Grate	103	23.6	3.5	2.1	1.4	0.71	0.35	15.3	10.82	0.200	0.276	0.472	2.10	3.26	1.29	18.42	Low NOx, no soot
168-9	35	Coal	Grate	106	24.1	3.5	2.1	1.4	0.70	0.35	15.2	19.99	3.30	4.01	0.936	0.692	1.304	1.24	31.48	Toxic with soot
168-10	35	Coal	Grate	116	24.1	3.5	2.1	1.4	0.70	0.35	15.2	34.15	0.768	3.42	2.58	1.20	4.88	1.59	48.53	Toxic with soot
162-5	36	No. 2	Steam	58	28.3	3.2	1.9	1.3	0.64	0.32	--	None	96.9	7.55	0.408	0.756	0.008	0.368	105.6	Lower load
162-11	36	No. 2	Steam	65	28.3	3.2	1.9	1.3	0.64	0.32	--	None	5.60	0.148	0.064	1.032	0.024	0.192	79.6	Low NOx
162-35	36	No. 2	Steam	65	28.3	3.2	1.9	1.3	0.64	0.32	--	None	10.6	3.57	0.788	0.62	0.034	0.20	15.842	Baseline
169-1	31	Coal	Pulv.	149	23.7	3.53	2.12	1.41	0.71	0.35	15.3	289.2	48.02	92.46	55.95	33.24	6.48	11.91	537.27	Toxic, Upstream dust collector
169-2	31	Coal	Pulv.	148	25.7	3.39	2.03	1.36	0.678	0.339	15.4	64.49	32.55	26.90	19.60	4.82	2.15	0.600	151.112	Toxic, Downstream dust collector
169-3	31	Coal	Pulv.	148	25.7	3.39	2.03	1.36	0.678	0.339	14.7	67.83	5.49	2.89	2.05	2.74	1.58	0.336	82.52	Toxic, Upstream dust collector
169-4	31	Coal	Pulv.	148	26.4	3.35	2.01	1.34	0.669	0.335	14.5	72.39	35.20	32.00	19.42	6.73	3.04	0.203	168.99	Toxic, Downstream dust collector
169-6	31	Coal	Pulv.	149	23.7	3.53	2.12	1.41	0.71	0.35	15.3	71.89	40.63	20.96	8.11	1.36	1.02	0.156	144.13	Toxic, Downstream dust collector
171-5A	20	No. 6	Steam	53	26.1	3.36	2.02	1.35	0.67	0.34	--	None	0.588	0.616	0.332	0.172	0.140	1.160	3.008	Baseline, Toxic
171-6S	20	No. 6	Steam	53	27.6	3.27	1.96	1.31	0.66	0.33	--	None	1.052	0.480	0.256	0.172	0.068	1.172	3.200	Baseline, Toxic
171-8	20	No. 6	Steam	54	26.1	3.36	2.02	1.35	0.67	0.34	--	None	1.060	0.501	0.256	0.168	0.108	1.120	3.213	Baseline, Toxic
170-5A	20	No. 6	Steam	68	29.3	3.18	1.91	1.27	0.64	0.32	--	None	1.792	0.852	0.512	0.164	0.256	0.288	3.864	Baseline
175-52	20	No. 6	Steam	67	34.5	2.93	1.76	1.17	0.59	0.29	--	None	3.824	1.660	0.924	0.372	0.312	3.158	10.250	Registers
176-5	37	No. 6	Steam	34	22.6	3.62	2.17	1.45	0.72	0.36	--	None	2.812	1.616	0.668	0.456	0.312	2.700	8.564	Baseline
179-4	37	No. 6	Steam	34	22.7	3.61	2.17	1.44	0.72	0.36	--	None	3.112	1.372	0.596	0.332	0.196	2.344	7.952	Low NOx

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The size distribution from all of the baseline oil fuel tests are shown in Figure 4-10. Test No. 121 is not included, because it was primarily a toxic element test and soot was blown on all three runs. In general the heavy oils, No. 6 and PS 300, had the greatest proportion of particulates in the fine particulate size range below 3 μm, and the No. 2 fuel the least proportion. Typically two-thirds of the particulates from the residual type oils were 3 μm or smaller in size while only about 30% of the particulates from Test No. 162 with No. 2 oil were below 3 μm. The light oil also had a lower total concentration of particulates. As is shown in Figure 4-7, the concentration of No. 2 oil particulate was about 15 ng/J, while the concentration of No. 6 oil particulates was about 390 ng/J.

The five individual runs on chain grate-fired coal that were made on successive days at Location No. 35 are depicted on Figure 4-11. All of the measurements were made downstream of the dust collector, since the dust collector was built into the back-pass of the boiler and the flue gas up stream of the collector was not accessible.

There were two types of distribution. One distribution was convex with the proportion increasing rapidly up to 1 or 2 μm and then tending to level out. The other was an s-shaped distribution, where the proportion increased rapidly between 2 and 3 μm and then leveled out.

The baseline data from Test No. 169 on a pulverized coal-fired boiler at Location 31, are entered on Figure 4-12. The triangles with the base down and connected by the solid curve are data points taken upstream of the cyclone dust collector. The inverted triangles and dashed curves are data taken downstream of the dust collector. The striking feature compared to Figure 4-11 is the much smaller proportion of fine particulate.

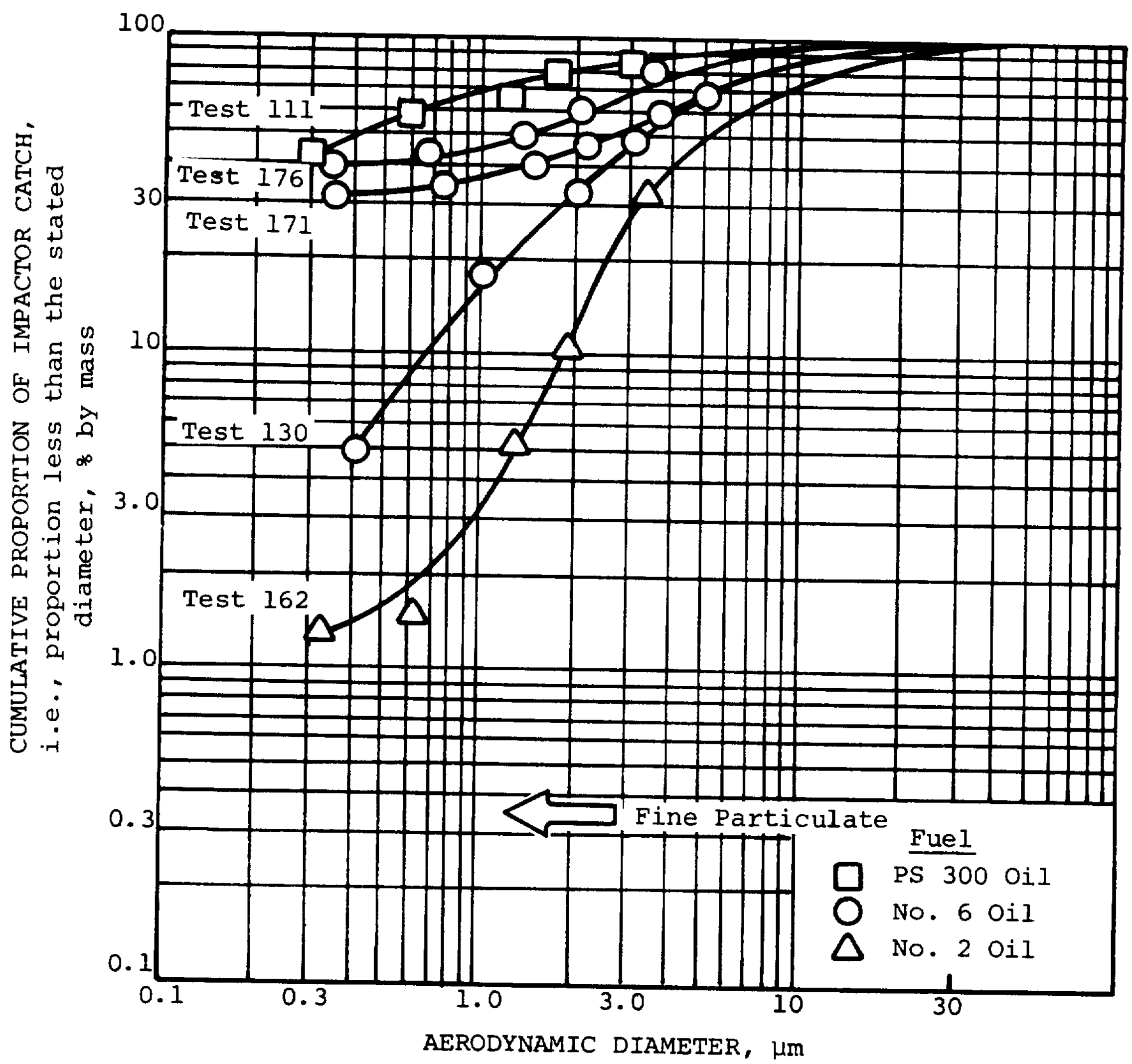

Figure 4-10. Baseline particulate size distribution, oil fuel.

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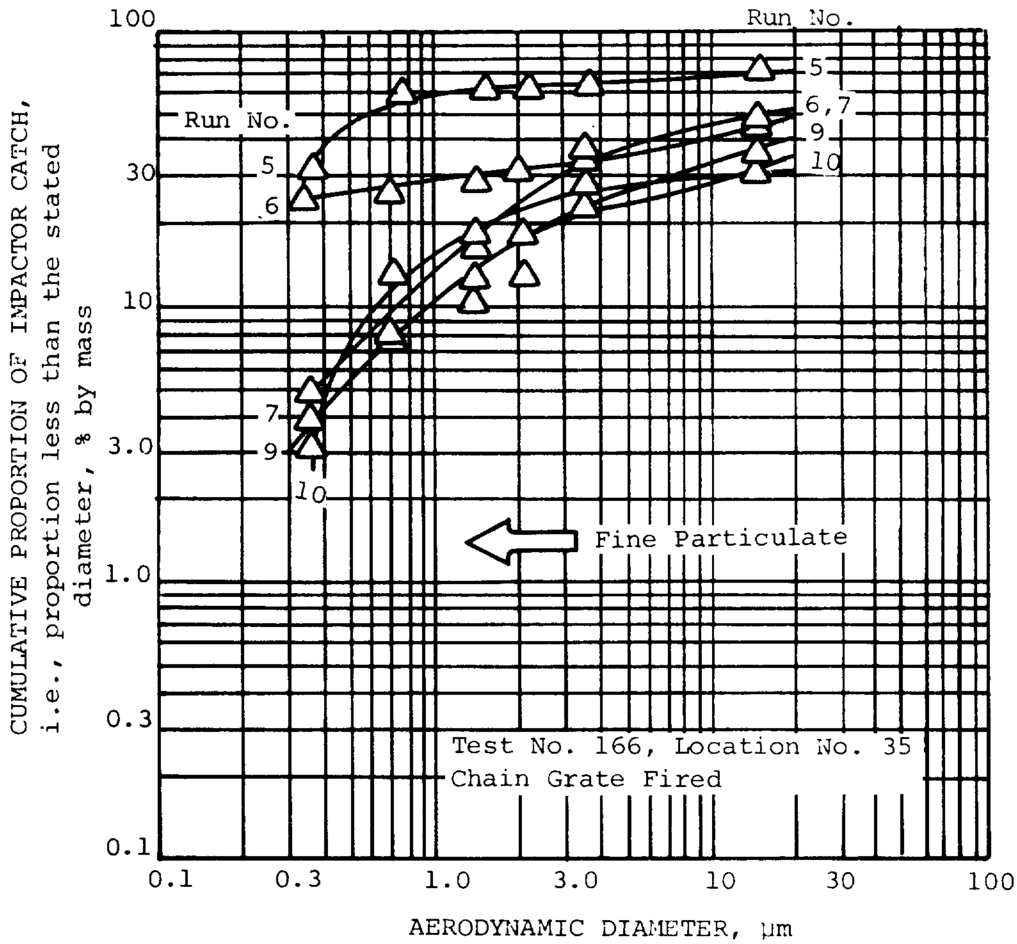

Figure 4-11. Baseline particulate size distribution, coal fuel.

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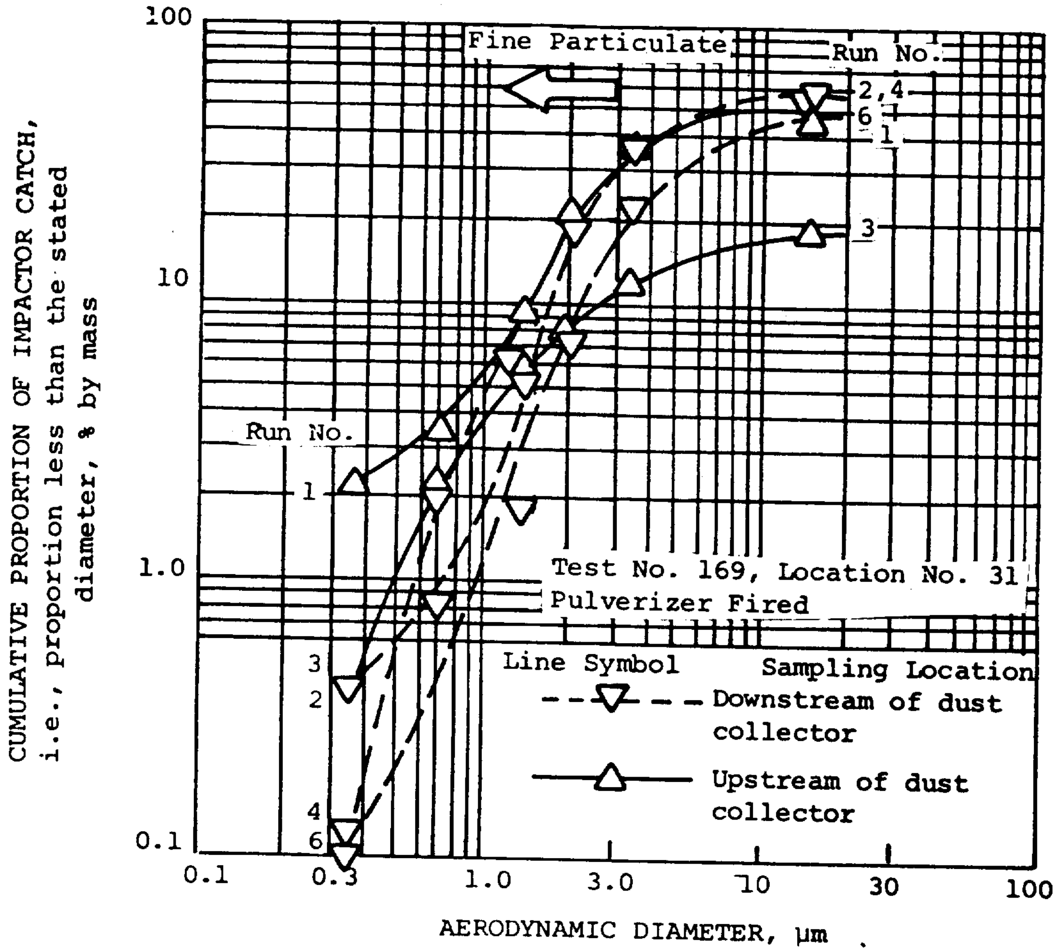

Figure 4-12. Baseline particulate size distribution, pulverized coal fuel.

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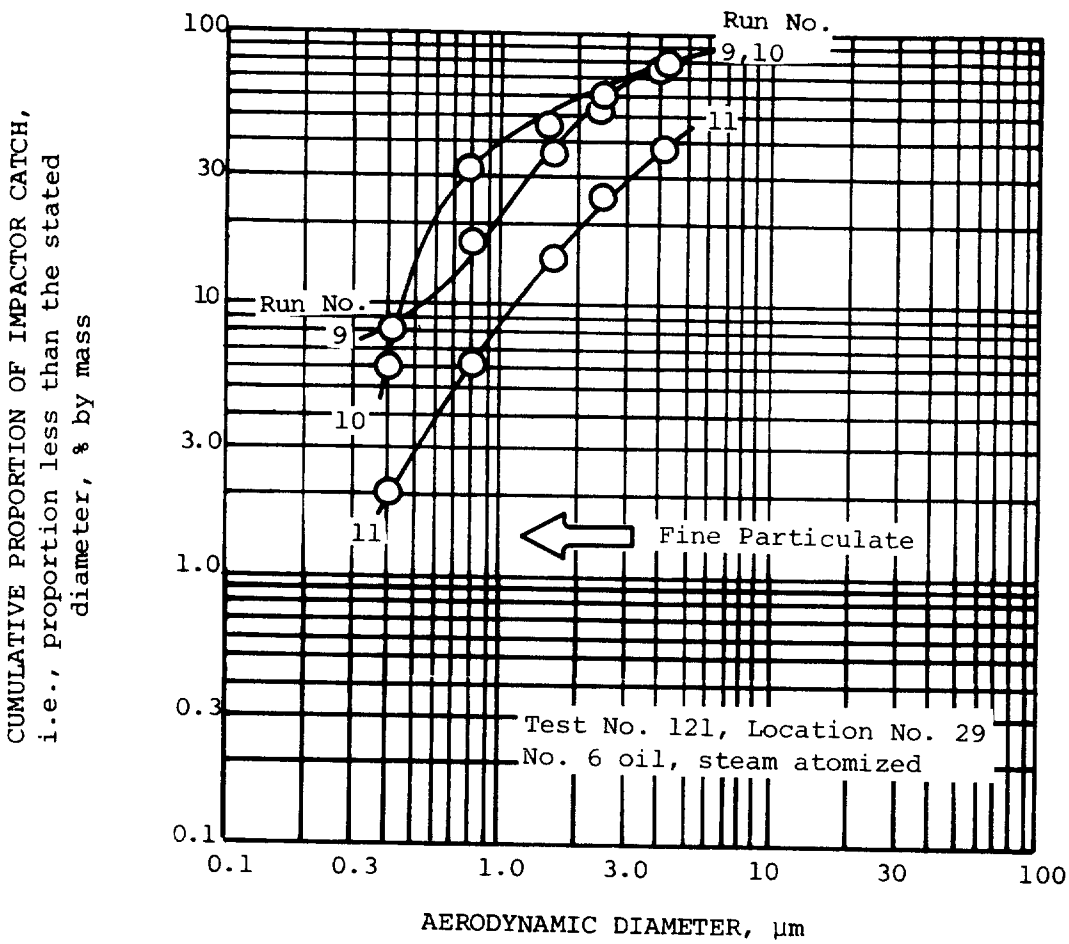
The proportion of fine particulate downstream of the dust collector, on the average, was larger than the proportion upstream, being 26% and 21% respectively. The difference was caused, no doubt, by the dust collector removing more of the larger particulate than the smaller. The amount of particulates in the 0.5 μm diameter or less was much smaller across the board than the amount from the chain grate and from oil fuel. The entire particulate size spectrum definitely was weighted toward the larger particulate sizes.

As with Test No. 166 there were two types of distribution: one convex with a rapid increase in the cumulative proportion up to about 2 μm and the other s-shaped. The distribution type was not unique to whether the sample was collected upstream or downstream; both locations had both types of distribution.

The findings of the size measurements for Tests 121 and 170 with No. 6 oil fuel are plotted on Figures 4-13 and 4-14. It is assumed arbitrarily that 100% of the impactor catch was 50 μm or smaller in diameter; although the largest cut point of the impactor was about 4 μm. The significant difference between these oil data and the coal data shown in the two preceeding figures was that the proportion of submicron and fine particulate from oil burning was greater than that from coal by a factor of about 10.

Test No. 121 in Figure 4-13 illustrates the size effect of soot blowing during a test. For test runs 121-9 and 121-10 the soot blowing was timed so only the soot deposited during the run was caught by the impactor. For run 121-11, an operational problem caused about 18 hours of soot accumulation to be caught, rather than the 4 hour accumulation of runs 121-9 and 121-10, and the total catch shown in Table 4-4 was 18.99 mg. The result was that the submicron particulates constituted only 3% of the total catch, and a great many more large-size particulates were caught. Apparently there was a significant growth in the size of soot particles by agglomeration over a period of time.



Test No. 121, Location No. 29
No. 6 oil, steam atomized

Figure 4-13. Baseline particulate size distribution, No. 6 oil fuel.

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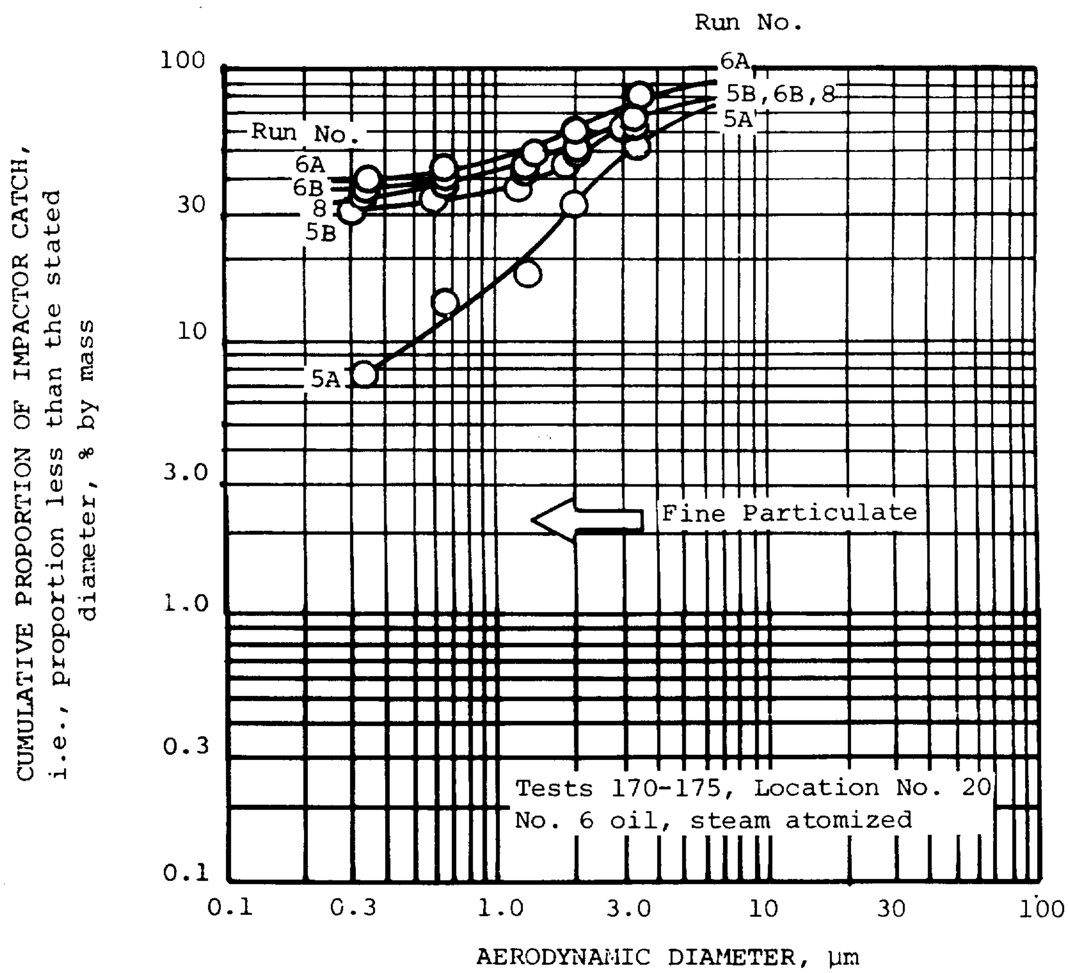

Figure 4-14. Baseline particulate size distribution, No. 6 oil.

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The proportion of the submicron size particulate 0.5 μm or less in diameter and of the fine particulate 3.0 μm or less were about the same from the two runs with light soot. At a diameter of 1.0 μm there was considerable difference in the proportion, but this difference did not persist beyond 2.0 μm.

During Tests 170 through 175 shown on Figure 4-14, the fine particulate proportion ranged only from 25% to 33%, with the exception of Run No. 5A. At 0.5 μm diameter there was moderate scatter of the data. The relatively large proportion of the total mass on the filter stage of Run 175-5B that is shown in Table 4-4 may be due to particulate rebound and reentrainment. The data are typical of what would happen if some of the larger particles that belonged on the second through the fourth stages had rebounded and ended up on the filter stage at the outlet end of the impactor. There is no ready explanation of the relatively large total catch of Run No. 175-5B nor of the small filter catch of Run No. 170-5A.

Figure 4-15 illustrates the effectiveness of a dust collector in removing the larger particles from the flue gas. The two curves are the size distribution before a mechanical dust collector and the size distribution after it. After the dust collector approximately 30% of the particulates were less than 3.0 microns whereas only 11% were less than three microns before the dust collector. Sixty percent of the catch was less than 100 microns after the dust collector compared to 18% before the dust collector.

The method in which the coal was fed into a furnace was found to have an effect on the particulate size. The size distribution for a given type of coal feed was similar from furnace to furnace. This similarity is illustrated in Figure 4-16. The upper two solid curves are for Locations 13 and 31, both of which fired pulverized coal from different sections of the country but the size distributions were similar.

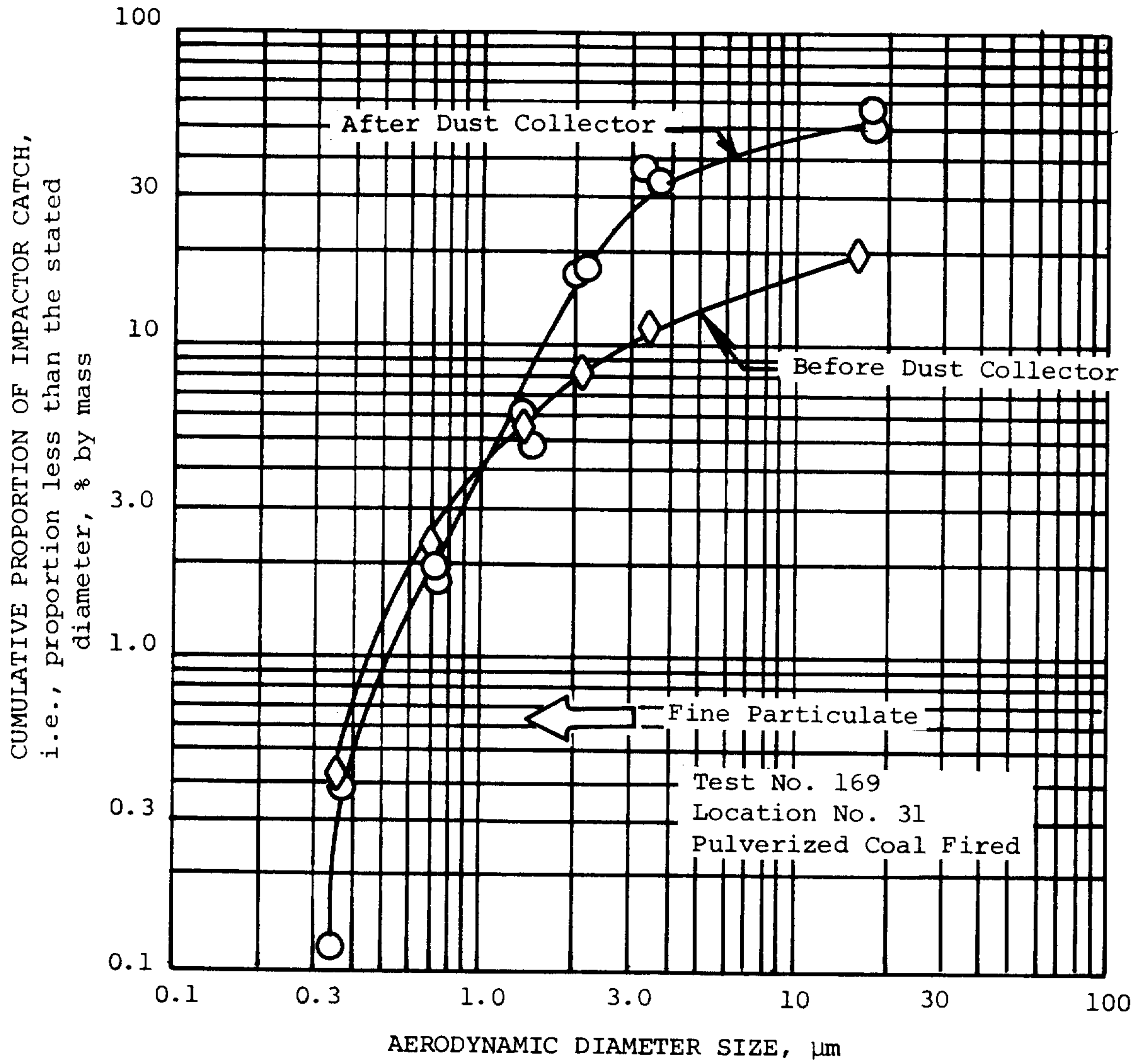

Figure 4-15. Effect of a dust collector on particulate size distribution.

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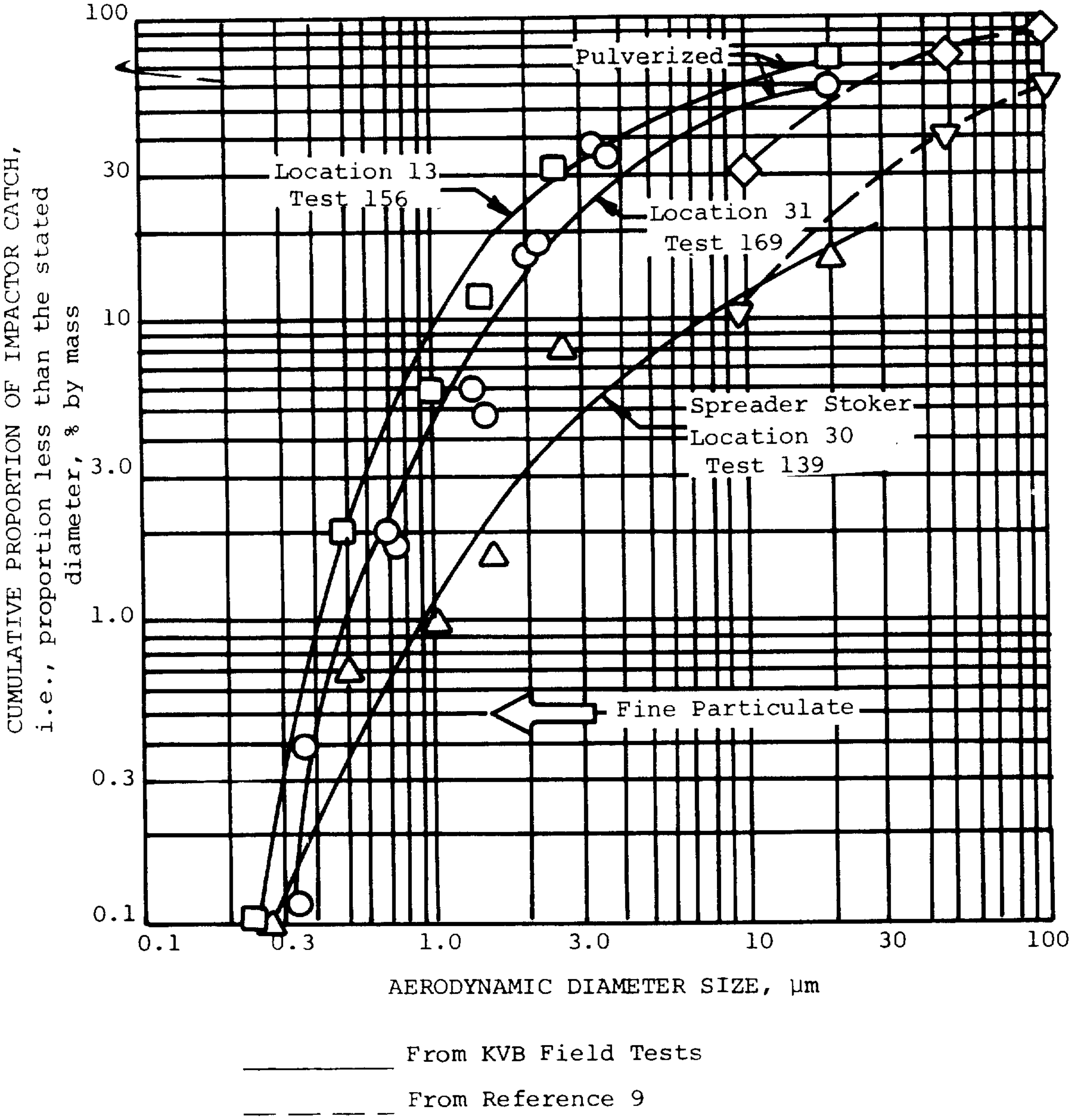

Figure 4-16. Effect of coal size and burner on particulate size distribution.

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The lower solid curve is from a spreader stoker at Location 30 that burned crushed, rather than pulverized, coal. The crushed coal fly ash had a much smaller proportion of fine particulate. For example, with the pulverized coal about 30% of the fly ash was less than 3 μm in diameter, while with the crushed coal only about 5% was less than 3 μm in diameter.

This finding that the coal feed method had an effect on the fly ash size is consistent with data published in Reference 9. These data are plotted on Figure 4-16 too and are connected with dashed lines. The absolute level of the proportions differ in some respects, but the spreader stoker data also showed a lesser proportion of small-sized particulate than did the data for the pulverized coal.

4.4 HYDROCARBON EMISSIONS

Hydrocarbon (HC) emissions measured as methane (CH_4) at baseline conditions with both natural gas and oil fuels are listed in Table 4-1 and were generally in the zero to 14 ng/J (0 to 75 ppm) range. The two highest baseline values measured were 35.4 and 101.8 ng/J (200 and 575 ppm), and both of these were natural gas fueled firetube boilers. Ideally, the hydrocarbon emissions should be near zero, indicating that no unburned fuel is being lost up the smoke stack.

The single highest baseline hydrocarbons emissions measurement with oil fuel was 14.6 ng/J (75 ppm) from a firetube boiler. The highest hydrocarbon emissions from an oil fuel fired watertube boiler were 6.8 ng/J (35 ppm).

The test data indicated that natural-gas-fired firetube boilers tended to emit a greater concentration of hydrocarbon than did watertube furnace type boilers burning natural gas, oil, or coal. This higher concentration may be caused by the rapid quenching of the products of combustion by the relatively cool walls of the furnace tube.

4.5 CARBON MONOXIDE EMISSIONS

The carbon monoxide (CO) emissions for industrial boilers were normally near zero although in a few test cases the emissions reached significant levels. The presence of over 100 ppm carbon monoxide in the flue gas indicates either low overall excess oxygen, air/fuel maldistribution, or burner problems.

Oil-fueled boilers typically had no carbon monoxide emissions, because oil fuels generally are fired with higher excess air or oxygen to avoid smoke emissions. One exception was the boiler used for Test 107. Baseline CO emissions were 139 ng/J (407 ppm). Carbon monoxide emissions were reduced to 38 ng/J (110 ppm) via adjustments made by the boiler manufacturer, but the CO emissions could not be eliminated entirely. The air to fuel ratio was set by adjusting the air bias control by positioning the damper on the inlet to the forced draft fans according to a curve issued by the boiler manufacturer. Carbon monoxide was present at all damper adjustments, even when the forced draft fan dampers were fully open. Observation of the oil flame during the tests showed that it was very bright and that it impinged upon the relatively cold water walls of the furnace. The completion of oxidation of carbon monoxide may have been hindered by the quenching effect of the cold walls or, the impact of the burning combustion gases with the walls may have prevented thorough fuel and air mixing. After the test, the oil burner tip was carefully inspected and no sign of wear or orifice restriction was seen. It was noted that the brick work between the furnace and backpass had holes in it. Possibly the incompletely burned gases escaped through these holes.

Carbon monoxide emissions from coal fired boilers were generally found to be less than 74 ng/J (200 ppm). The units that did produce CO were equipped with spreader stoker, underfed stoker, and chain grate type coal burners. Pulverized and cyclone coal burners produced no CO at baseline conditions.

Baseline carbon monoxide emissions from natural gas fired boilers were typically 62 ng/J (200 ppm) or less. In a few cases, emissions exceeded this level. In one instance during Phase I testing, a firetube boiler emitted greater than 620 ng/J (2000 ppm) CO.

4.6 SULFUR OXIDES EMISSIONS

Total sulfur oxides emissions for coal- and oil-fired boilers ranged from near zero to as high as 1530 ng/J (1800 ppm). The level of sulfur oxides emission was dependent solely upon the sulfur content of the fuel. A sulfur content of 1.0% in an oil fuel resulted in approximately 390 ng/J (500 ppm) of sulfur oxides emission. For coal, 1.0% sulfur in the fuel gave about 765 ng/J (900 ppm) of the pollutant. The relationship between fuel sulfur content and sulfur oxides emissions is further discussed in Section 6.0.

4.7 BOILER EFFICIENCY

Boiler thermal efficiencies were determined by the ASME Heat Loss Method using on-site measurements of the fuel and flue gas compositions.[10] The efficiency of steam generating equipment determined within the scope of the ASME Code is the gross efficiency and is defined as the ratio of the heat absorbed by the working fluid to the heat input. This definition disregards the equivalent heat in the power required by the auxiliary apparatus external to the envelop. The abbreviated efficiency calculation considers only the major heat losses and only the chemical heat in the fuel as the input.

Baseline efficiencies for coal-fired boilers ranged from 72 to 88% and average 81%. The oil-fired boilers exhibited efficiencies between 72 and 88% and average 83%. Gas fueled boilers had efficiencies from 70 to 85% with an average of 81%. One of the major factors affecting the efficiency of individual boilers was the excess oxygen level. A reduction of one percentage point in excess O_2 (about a 5% reduction in excess air) generally improved efficiency by about one-half a percentage point.

Baseline efficiencies were also dependent upon the type of boiler equipment. Older boilers were generally in poorer physical condition and lacked efficiency-enhancing design features, such as economizers and air preheaters. Hence, the older boilers exhibited lower efficiency levels. The larger capacity boilers were more efficient than smaller units probably due to design factors. The type of burner had an influence on efficiency, especially in the case of coal-fired units. Cyclone and pulverizer units had much higher efficiency levels than the chain grate and underfed stokers.

The effect on boiler efficiency of combustion modifications is shown in Figure 1-3 and it was determined primarily by the level of excess air required. If the amount of combustion air could be lowered along with changing burner registers or taking burners out of service, the efficiency was improved. If an operational change resulted in a higher excess air requirement, efficiency was degraded. In either case, the magnitude of the change was typically in the 1 to 3% range. The effects of combustion modifications on efficiency are discussed further in Section 5.5.

4.8 PLUME OPACITY

In addition to measuring the concentration of solid and condensible particulates in the flue gas, the opacity of the smoke plume was observed. The opacity measurement was made using the EPA Method 9.

The data taken during three of the observations are tabulated in Tables 4-4 through 4-6. Starting at Location No. 37 the observations were made at fifteen second intervals for a six minute long portion of the baseline total particulate measurement period. The data in Tables 4-4 and 4-6 were taken at fifteen second intervals. Prior to Location 37 the observation was made at five minute intervals over a two or three hour period of emission testing. Table 4-7 is a sample of the data from this prior type of observation.

An attempt was made to correlate the opacity measurements with the concurrent particulate concentration measurements. This correlation was unsuccessful, and a reason is that the fifteen-second observation interval was started too late in the program to get sufficient data to make a meaningful correlation.

Table 4-5. PLUME OPACITY OBSERVATIONS

Test No. 188-1 **Location No.** 38 **Fuel Type** No. 6 Oil

Test Load 38 GJ/hr, 36 10^3 lb/hr **Sun Position** Southeast

Solid Particulate Concentration 55.0 ng/J, 0.128 lb/10^6 Btu

Total Particulate Concentration 58.5 ng/J, 0.136 lb/10^6 Btu

Obs. No.	Time	Opacity %	Wind Speed m/s	Wind Direction	Sky Con.
1	11:21:00	10	2-3	SE	PCldy
2	11:21:15	10	2-3	SE	PCldy
3	11:21:30	10	1-2	SE	PCldy
4	11:21:45	5	2-3	SE	PCldy
5	11:22:00	10	2-3	SE	PCldy
6	11:22:15	20	1-2	SE	PCldy
7	11:22:30	10	1-2	SE	PCldy
8	11:22:45	10	1-2	SE	PCldy
9	11:23:00	15	2-3	SE	PCldy
10	11:23:15	15	2-3	SE	PCldy
11	11:23:30	5	2-3	SE	PCldy
12	11:23:45	10	2-3	SE	PCldy
13	11:24:00	10	4-5	SE	PCldy
14	11:24:15	10	2-3	SE	PCldy
15	11:24:30	5	2-3	SE	PCldy
16	11:24:45	5	2-3	SE	PCldy
17	11:25:00	15	1-2	SE	PCldy
18	11:25:15	20	3-5	SE	PCldy
19	11:25:30	20	3-5	SE	PCldy
20	11:25:45	10	3-5	SE	PCldy
21	11:26:00	15	3-5	SE	PCldy
22	11:26:15	20	2-3	SE	PCldy
23	11:26:30	10	2-3	SE	PCldy
24	11:26:45	5	5-6	SE	PCldy
25	11:27:00	5	2-3	SE	PCldy
26	11:27:15	10	3-5	SE	PCldy
27	11:27:30	10	2-3	SE	PCldy
28	11:27:45	5	3-5	SE	PCldy
29	11:28:00	5	2-3	SE	PCldy

Average Opacity = 11%

PCldy = Partly Cloudy

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Table 4-6. PLUME OPACITY OBSERVATIONS

Test No. 203-7 **Location No.** 19 **Fuel Type** No. 6 Oil

Test Load 15 GJ/hr, 14 10^3 lb/hr **Sun Position** Southwest

Solid Particulate Concentration 18.1 ng/J, .042 lb/10^6 Btu

Total Particulate Concentration 20.2 ng/J, .047 lb/10^6 Btu

Obs. No.	Time	Opacity %	Wind Speed m/s	Wind Direction	Sky Con.	Obs. No.	Time	Opacity %	Wind Speed m/s	Wind Direction	Sky Con.
1	3:30:00	5	0	-	HSun	1	4:31:00	5	0-1	W	Clear
2	3:30:15	5	0	-	HSun	2	4:31:15	5	1-2	W	Clear
3	3:30:30	5	0-1	E	HSun	3	4:31:30	5	1-2	W	Clear
4	3:30:45	5	0-1	SE	HSun	4	4:31:45	5	0-1	W	Clear
5	3:31:00	5	0-1	E	HSun	5	4:32:00	5	1-2	SW	Clear
6	3:31:15	5	0-1	E	HSun	6	4:32:15	5	1-2	SW	Clear
7	3:31:30	10	0-1	E	HSun	7	4:32:30	5	1-2	SW	Clear
8	3:31:45	5	0-1	E	HSun	8	4:32:45	10	1-2	SW	Clear
9	3:32:00	5	0-1	E	HSun	9	4:33:00	5	1-2	SW	Clear
10	3:32:15	10	0-1	SE	HSun	10	4:33:15	5	1-2	SW	Clear
11	3:32:30	5	0-1	E	HSun	11	4:33:30	5	1-2	SW	Clear
12	3:32:45	5	0-1	E	HSun	12	4:33:45	5	1-2	SW	Clear
13	3:33:00	5	0-1	E	HSun	13	4:34:00	5	1-2	SW	Clear
14	3:33:15	5	0-1	E	HSun	14	4:34:15	5	1-2	SW	Clear
15	3:33:30	5	0	-	HSun	15	4:34:30	5	1-2	SW	Clear
16	3:33:45	5	0	-	HSun	16	4:34:45	5	1-2	SW	Clear
17	3:34:00	5	0	-	HSun	17	4:35:00	5	1-2	SW	Clear
18	3:34:15	5	0-1	E	HSun	18	4:35:15	5	1-2	SW	Clear
19	3:34:30	10	0-1	E	HSun	19	4:35:30	5	1-2	SW	Clear
20	3:34:45	5	0-1	E	HSun	20	4:35:45	5	0-1	SW	Clear
21	3:35:00	5	0-1	E	HSun	21	4:36:00	10	0-1	SW	Clear
22	3:35:15	5	0-1	E	HSun	22	4:36:15	10	0-1	SW	Clear
23	3:35:30	10	0-1	E	HSun	23	4:36:30	10	0	-	Clear
24	3:35:45	5	0-1	E	HSun	24	4:36:45	5	0-1	SW	Clear

Average Opacity = 6%

HSun = Hazy Sunshine

Table 4-7. PLUME OPACITY OBSERVATIONS

Test No. 179-4 Location No. 37 Fuel Type No. 6 Oil

Test Load 34 GJ/hr, 32 10^3 lb/hr Sun Position Southwest

Solid Particulate Concentration 34.8 ng/J, 0.081 lb/10^6 Btu

Total Particulate Concentration 41.3 ng/J, 0.096 lb/10^6 Btu

Obs. No.	Time	Opacity %	Wind Speed m/s	Wind Direction	Sky Con.	Obs. No.	Time	Opacity %	Wind Speed m/s	Wind Direction	Sky Con.
1	1500	5	2-3	SE	Clear	27	1725	5	1-2	NW	Cldy
2	1505	5	2-3	SE	Clear	28	1730	5	1-2	W	Cldy
3	1510	5	4-5	SE	Clear	29	1735	5	1-2	W	Cldy
4	1515	5	4-5	SE	Clear	30	1740	5	1-2	W	Cldy
5	1520	5	4-5	SE	Clear	31	1745	5	0-1	W	Cldy
6	1525	5	4-5	SE	Clear	32	1750	5	0-1	W	Cldy
7	1530	5	5-6	SE	Clear	33	1755	5	2-3	SW	PCldy
8	1535	5	4-5	SE	Clear	34	1800	5	1-2	SW	PCldy
9	1540	5	5-6	SE	Clear						
10	1545	5	5-6	SE	PCldy		Average Opacity = 5%				
11	1550	5	5-6	SE	PCldy						
12	1555	5	4-5	SE	PCldy						
13	1600	5	4-5	SE	PCldy						
14	1605	5	4-5	SE	PCldy						
15	1610	5	4-5	SE	PCldy						
16	1615	5	4-5	SE	PCldy						
17	1620	5	4-5	W	Cldy						
18	1625	5	4-5	W	Cldy						
19	1630	5	4-5	W	Cldy						
20	1650	5	4-5	W	Cldy						
21	1655	10	4-5	W	Cldy						
22	1700	10	4-5	W	Cldy						
23	1705	5	4-5	NW	Cldy						
24	1710	5	4-5	W	Cldy						
25	1715	5	2-3	W	Cldy						
26	1720	5	1-2	W	Cldy						

Cldy = Cloudy PCldy = Partly Cloudy 6001-43

4.9 NITROGEN DIOXIDE EMISSIONS

About one hundred measurements of the ratio of nitrogen dioxide (NO_2) to total nitrogen oxides (NO_x) at base load were made and many of them are plotted in Figure 4-17. Nitrogen dioxide percentages for oil fuel were typically about 1% to 5% of the total nitrogen oxides with an average percentage of about 2%. Typical nitrogen dioxide percentages for coal were about 1% to 6% with an average value of 2.8%. For gas fuel the typical percentages were 3% to 13%, and the average of 4.5% was the highest of the three fuels. A commonly accepted ratio heretofore has been 5%, but this value would appear to be too high for coal and oil fuels.

The amount of nitrogen dioxide was determined by taking the difference between a measurement of the total nitrogen oxides and the nitric oxide concentrations. In several instances the measured percentages of nitric oxide were zero, e.g. Tests 27 and 190, or abnormally high, e.g., Tests 38 and 122. There is no rationalization based on the mechanism of nitrogen oxides formation to explain these extreme values.

The cause could have been differing operating conditions. A likely cause was a combination of instrumentation error and readout error. The uniformity of the temperature of the heated sample line, the stability of the nitrogen oxides analyzer and the objectivity of the crewman in estimating a representative value from a constantly-changing trace on a pen recorder tape all affect the magnitude of the small difference between the nitric oxide and total nitrogen oxides measurements. For gas testing where the total nitrogen oxides concentrations frequently are less than 30 ng/J (100 ppm), there is a very small absolute difference.

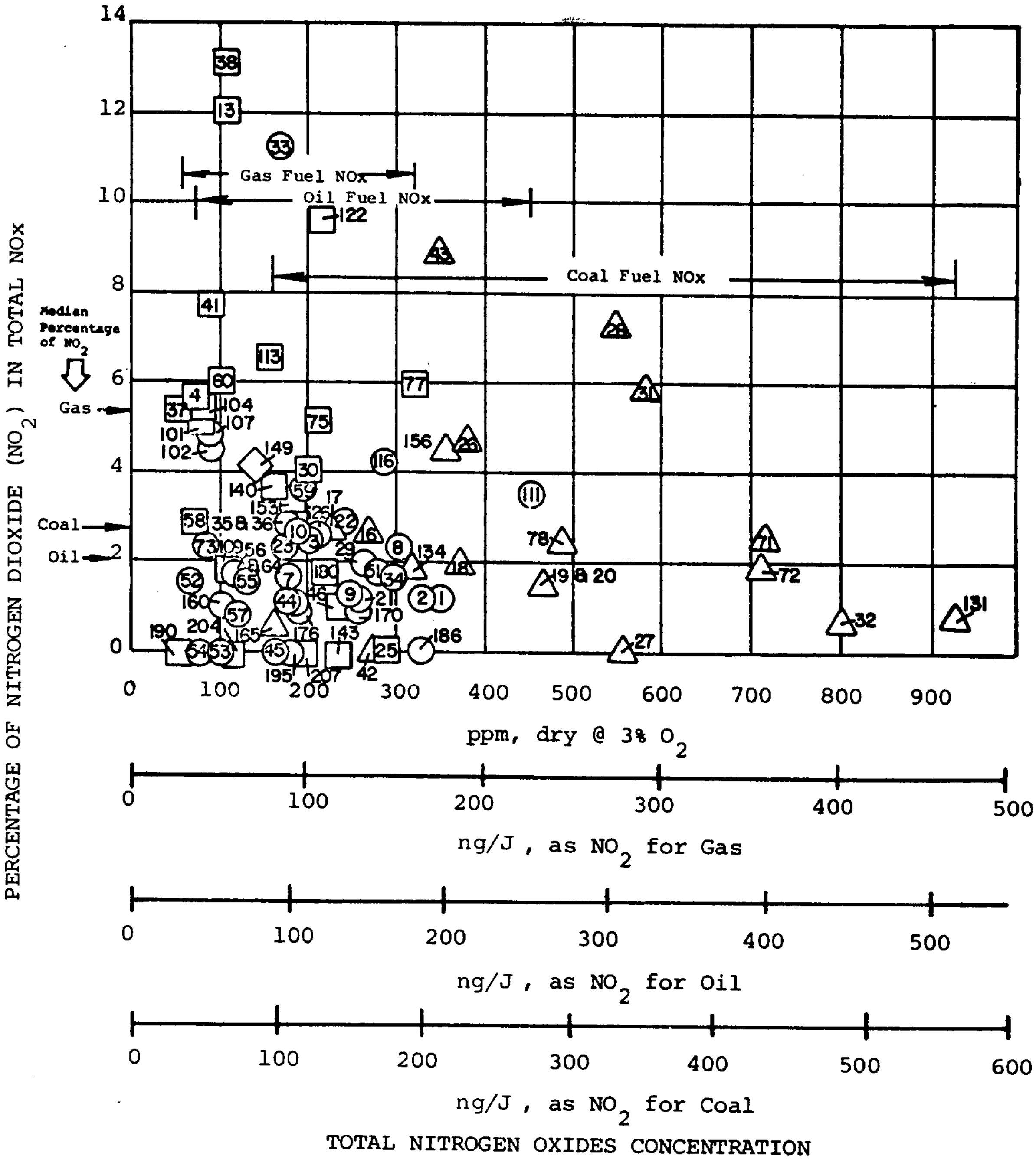

Figure 4-17. Percent of nitrogen dioxide in total nitrogen oxides concentration.

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SECTION 5.0

COMBUSTION MODIFICATION TEST RESULTS

The overall objective of the program was to determine the effectiveness of known combustion modification methods in reducing the nitrogen oxides emissions from industrial boilers. Phase I of the program primarily concerned the emissions of boilers operating normally; although some testing of simple combustion modifications was done. The findings of Phase I were analyzed and the results used a guide in selecting the types of combustion modification to be used in Phase II.

During Phase II three major categories of combustion modification were investigated. These categories were the following and the methods of combustion modification that were used in each category are listed in Table 5-1.

1. Mixture Ratio Variation: (1) Vary the overall fuel/air mixture ratio (e.g., reduce average excess air level); (2) vary the local fuel/air mixture ratio in the furnace.

2. Enthalpy Variation: Reduce the level and/or duration of the peak gas temperatures in order to reduce the pollutant formation rates.

3. Input Variation: Limit the input of the chemical source from which the pollutant is derived in the boiler.

The postulated effect of the combustion modification technique that causes the lower nitrogen oxides emissions is tabulated in the right-hand column of the table.

Table 5-1. COMBUSTION MODIFICATION METHODS AND EFFECTS

CATEGORY AND METHOD	EFFECT
1. Mixture Ratio Variation	
o Excess air level	o Varies the overall fuel/air mixture ratio
o Staged combustion air	o Creates local fuel/air ratio stratification by bypassing air and delays complete combustion
o Burners-out-of-service	o Creates local fuel/air ratio stratification by bypassing air and delays complete combustion
o Burner register adjustment	o Controls swirl level and the local rate of fuel/air mixing
2. Enthalpy Variation	
o Combustion air temperature	o Influences peak gas temperature level and duration
o Flue gas recirculation	o Reduces peak gas temperature level and duration
o Firing rate	o Affects fuel heat release rate per unit volume, and gas heat loss rate
3. Input Variation	
o Fuel oil temperature/viscosity	o Controls atomization characteristics, e.g., drop size and vaporization rate
o Fuel type switching	o Reduces sulfur and/or nitrogen oxides emissions from the fuel
o Burner tune-up	o Assures performance according to design specifications
o Fuel oil atomization method and pressure	o Control local fuel/air mixing rates by varying drop size distribution and overall fuel spray shape

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During Phase I and II fifty-four individual tests were run on the effectiveness of combustion modification. The tests are listed in Table 5-2. As the table indicates, tests were run using coal, oil, natural gas and mixed fuels.

In order to find the combustion modification capabilities that were needed it was necessary to include boilers located at widely separated sites within the continental United States, as is shown in Figure 2-1. This dispersal of test boilers had the added advantage that the effect of the geographical variation in fuel properties could be included in the testing. The boiler capacities ran from a minimum of 18 GJ/hr (17×10^3 lb/hr) of equivalent saturated steam to a maximum of 580 GJ/hr (550×10^3 lb/hr).

The measurements that were made are listed by test number in Tables 1-1 and 4-1. In the balance of this section the results of the analysis of the measurements are discussed. Not every combustion modification test listed on Tables 1-1, 4-1, and 5-2 is discussed individually in this section. Those where the test results followed the general trend usually are not discussed specifically. The practice is to select one or two tests that illustrated the trend, or deviated from the trend, and discuss these.

Table 5-2. COMBUSTION MODIFICATION TEST SUMMARY,

PHASE I AND PHASE II TESTS

Combustion Modification	Test Number	Test Location	Test Fuel Type	Boiler Capacity GJ/hr	$(10^3$ lb/hr)
Staged Air	136	30	Coal	132	(125)
	161	36	No. 2 Oil	211	(200)
	168	35	Coal	227	(215)
	183	38	Natural Gas	47	(45)
	188	38	No. 6 Oil	47	(45)
	193	19	Natural Gas	18	(17)
	198,203	19	No. 6 Oil	18	(17)
Burners Out Of Service	6	7	No. 5 Oil	90	(85)
	9	18	No. 6 Oil	95	(90)
	15	9	Natural Gas	63	(60)
	21	18	No. 6 Oil	110	(105)
	22	18	No. 6 Oil	169	(160)
	30	9	Natural Gas	316	(300)
	63	2	PS 300 Oil	62	(59)
	68	2	PS 300 Oil	69	(65)
	119	29	No. 6 Oil	158	(150)
	124	28	Natural Gas	74	(70)
	128	28	No. 6 Oil	74	(70)
	133	31	Coal	274	(260)
	147	32	Natural Gas	127	(120)
	151	33	Refinery Gas	580	(550)
	159	13	Coal & No. 6 Oil	528	(500)
Burner Register Readjustment	7	17	No. 2 Oil	116	(110)
	10	16	No. 6 Oil	69	(65)
	26	12	Coal	237	(225)
	30	9	Natural Gas	317	(300)
	70	2	PS 300 Oil	132	(125)
	77	12	Natural Gas	338	(320)
	78	12	Coal	338	(320)
	141	32	Natural Gas	137	(130)
	148	32	Natural Gas	133	(120)
	154	34	Natural Gas	264	(250)
	174	20	No. 6 Oil	84	(80)
Variable Combustion Air Temperature	115	29	Natural Gas	158	(150)
	118	29	No. 6 Oil	158	(150)
	125	28	Natural Gas	74	(70)
	130	28	No. 6 Oil	74	(70)
	142	32	Natural Gas	137	(130)
	144	32	Natural Gas	127	(120)
	155	34	Natural Gas	264	(250)
	177	37	No. 6 Oil	42	(40)
	182	38	Natural Gas	47	(45)
	189	38	No. 6 Oil	47	(45)
Flue Gas Recirculation	192	19	Natural Gas	18	(17)
	197,202	19	No. 6 Oil	18	(17)
Fuel Oil Viscosity	120	29	No. 6 Oil	158	(150)
	129	28	No. 6 Oil	74	(70)
	173	20	No. 6 Oil	84	(80)
	178	37	No. 6 Oil	42	(40)
Burner Tune-up	106	1	Natural Gas	31	(29)
	108	1	No. 2 Oil	31	(29)
	110	27	Natural Gas	106	(100)
	112	27	PS 300 Oil	106	(100)
Fuel Atomization	2	19	No. 6 Oil	18	(17)
	44	19	No. 6 Oil	18	(17)
	52	19	No. 2 Oil	18	(17)
	163	36	No. 2 Oil	211	(200)

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5.1 MIXTURE RATIO MODIFICATION

5.1.1 Excess Oxygen or Air

One form of combustion modification that was applied to almost all boilers measured in both Phases I and II was the reduction of the amount of excess air or oxygen that was being fired. It was found that, in general, industrial boilers were being fired with more than adequate excess air in order to assure complete combustion and provide a margin of safety to the operator. Utility boilers, on the other hand, typically are fired with a smaller margin of excess air, but they are more closely monitored by the operating personnel and do not suffer the wide variations in demand that industrial boilers do.

This form of combustion modification was found to be most effective for coal-fueled boilers and slightly less effective for oil and natural gas-fueled boilers. This is illustrated in Figure 5-1 which shows the reduction in the nitrogen oxides emissions that were obtained during several of the tests by reducing the amount of excess oxygen being fired. As the amount of excess oxygen was lowered, the nitrogen oxides level fell most steeply and consistently when the fuel was coal. The amount of excess oxygen fired on the average also is indicated on the figure for each of the three fuels, and the average for coal of 8.7% is a good deal higher than for oil or natural gas.

5.1.1.1 Coal Fuel -

The effects of the level of excess oxygen on the total nitrogen oxides emissions for coal fuel are depicted in Figures 5-1 and 5-2. Figure 5-1 illustrates the absolute nitrogen oxides levels as a function of excess oxygen, while Figure 5-2 shows the nitrogen oxides reduction factor plotted versus the reduction in excess oxygen from the highest oxygen level at which NO_x was measured.

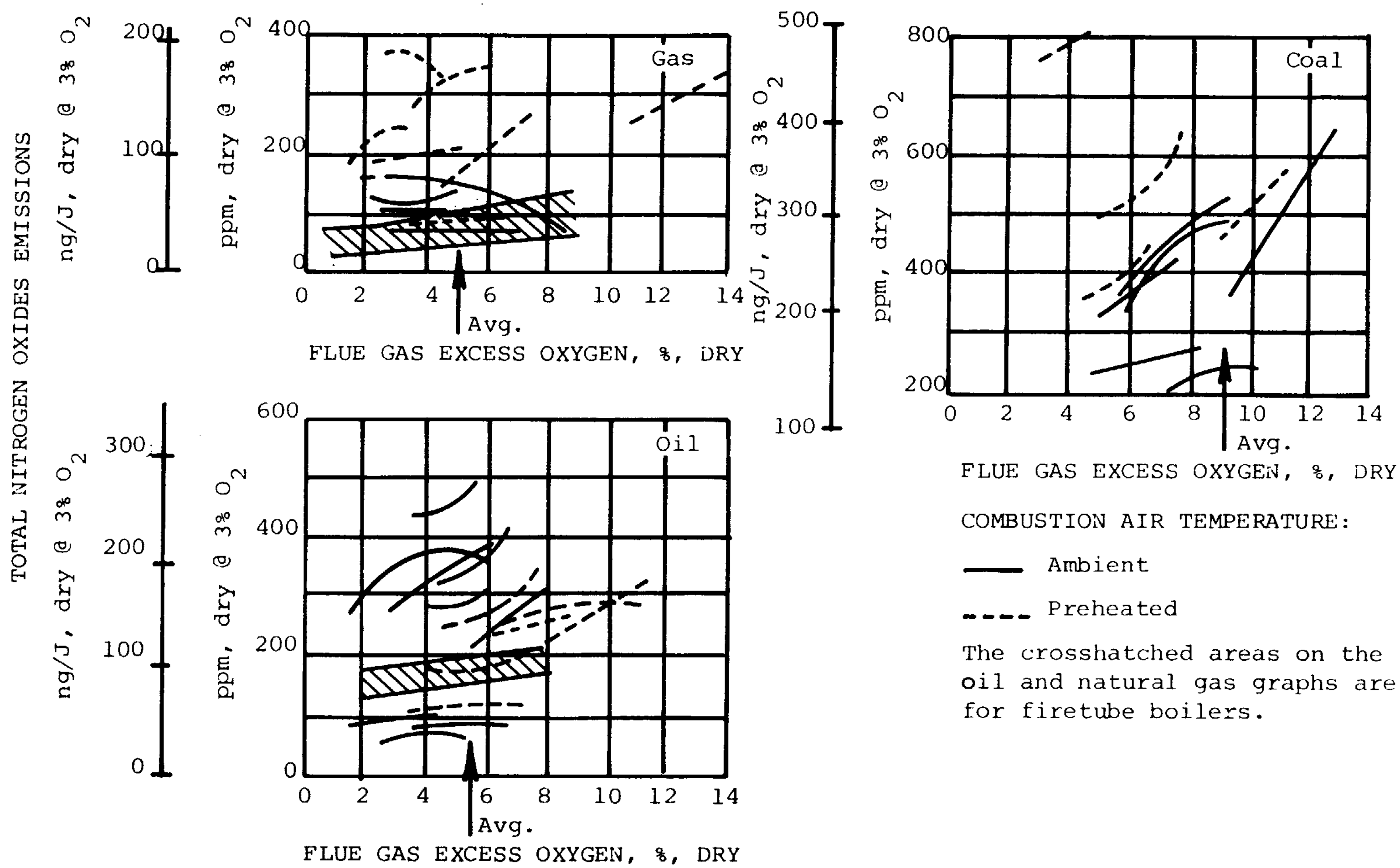

Figure 5-1. Reduction in total nitrogen oxides emissions due to a decrease in excess oxygen.

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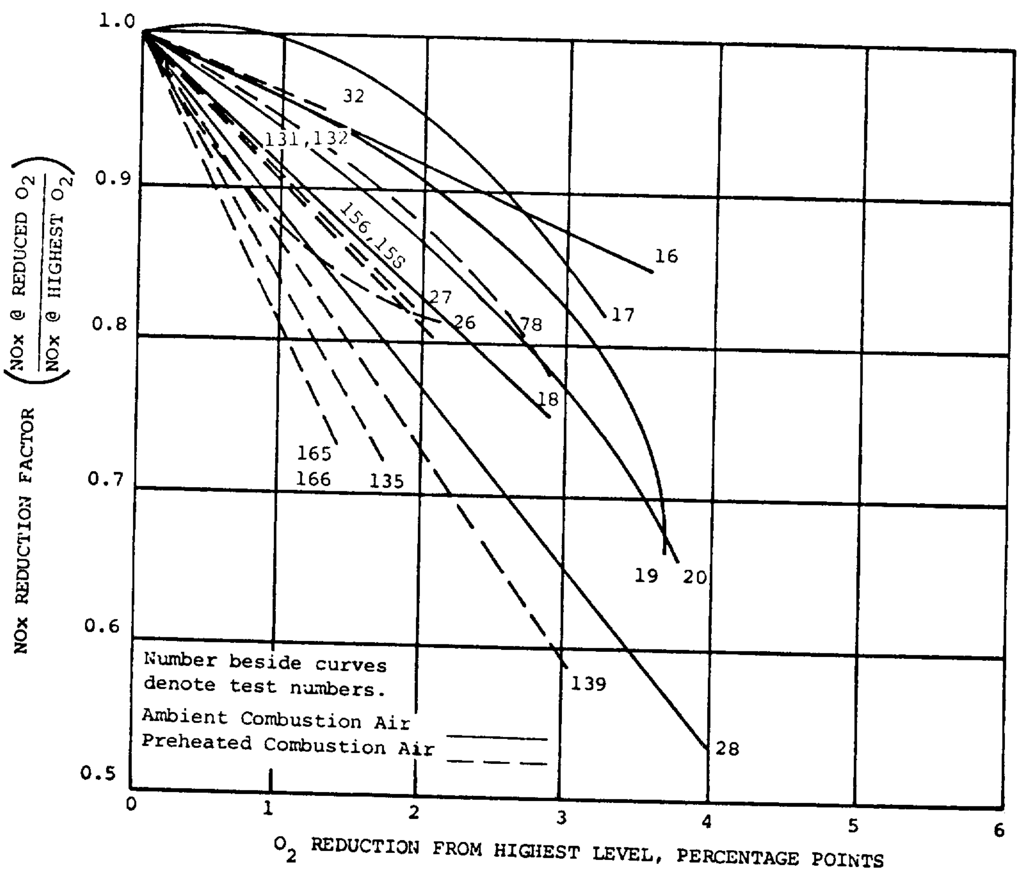

Figure 5-2. Reduction in total nitrogen oxide emissions due to a reduction in excess oxygen, coal fuel.

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Figure 5-1 shows that the effect of reducing the excess oxygen was relatively large, running approximately at 31 ng/J (60 ppm) change in nitrogen oxides emissions for each one percent change in excess oxygen. The normalized curves of Figure 5-2 summarizes the reductions in emissions brought about by reducing excess oxygen. The effect was similar whether or not the combustion air was preheated. A decrease in excess oxygen/air always resulted in a steady decrease in nitrogen oxides emissions.

The highest level of excess oxygen that is referred to in the abscissa title is the level to which the excess was raised at the start of the test. For example the small graph labeled "coal" in Figure 5-1 indicates that in one test the excess oxygen was raised to almost 13% and then reduced to about 9%.

This consistent decrease in the nitrogen oxides emissions during all tests was unique to coal, since the nitrogen oxides emissions occasionally increased with a decrease in excess oxygen with oil and gas fuels. A very effective form of combustion modification would be to fire coal-fueled boilers with less excess air.

5.1.1.2 Oil Fuel -

Figures 5-1 and 5-3 illustrate the effect of changes in the level of excess air, expressed as excess oxygen, on the total nitrogen oxides emissions from oil fuel firing. The data for both heated combustion air and ambient temperature combustion air indicated that the total nitrogen oxides emissions for No. 2 oil were less affected by excess oxygen level and averaged about 6 ng/J (10 ppm) change for each one percent change of excess oxygen. The type of oil burned is listed in Table 4-1 and in Table 7-1. The data for the Nos. 5 and 6 fuel oils with both preheated and ambient air showed a greater influence of excess oxygen on nitrogen oxides emissions than did the data for No. 2 oil.

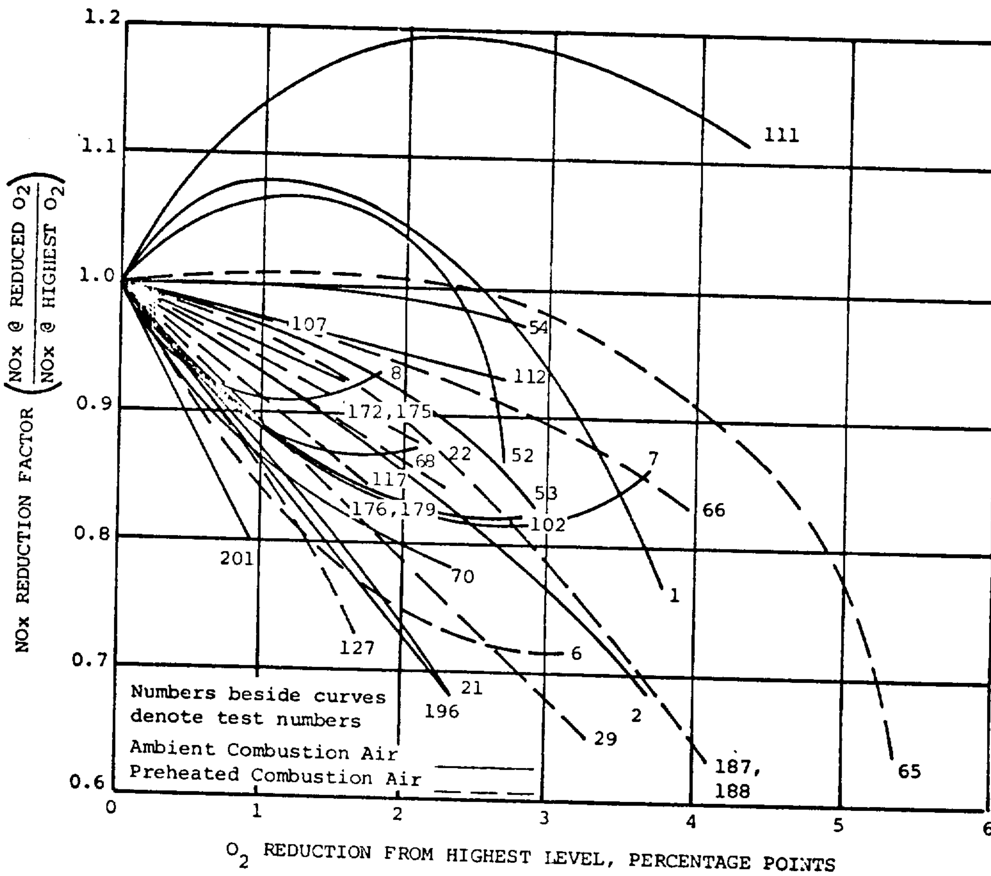

Figure 5-3. Reduction in total nitrogen oxide emissions due to a reduction in excess oxygen, oil fuel.

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An average change in nitrogen oxides emissions of about 11 ng/J (20 ppm) for each one percent change of excess oxygen level was observed for watertube boilers during both Phase I and Phase II. The change for firetube boilers measured in Phase I and shown on the figure as a shaded area averaged about 3 ng/J (6 ppm) for each one percent change of excess oxygen.[4] Generally, when the absolute level of the total nitrogen oxides was less than 100 ng/J (200 ppm), the sensitivity of the nitrogen oxides to excess oxygen change was very small.

In most instances the nitrogen oxides decreased steadily as the excess oxygen was reduced. However, in two cases in Phase I and two more in Phase II, nitrogen oxide emissions first increased, then peaked and finally decreased as the excess oxygen was lowered. Examples of this behavior shown in Figure 5-3 are Test No. 1 (with No. 6 oil), Test No. 111 (with PS 300 oil) and Test No. 65 (with No. 2 oil).

This behavior is typical of a burner where the fuel and air are well mixed prior to ignition. The nitrogen oxides emissions from a "pre-mixed" burner first increase then decrease when the level of excess air or oxygen is reduced.

5.1.1.3 <u>Natural Gas Fuel</u> -

The influence of the excess air/oxygen level on natural gas-fueled boilers is illustrated in Figure Nos. 5-1 and 5-4. Both the Phase I and Phase II measurements with ambient temperature combustion air showed that the effect of excess oxygen changes on nitrogen oxides was varied. However, the preheated combustion air data evidenced a stronger effect of excess oxygen level on nitrogen oxides emissions than did the data for the unheated combustion air. The change in nitrogen oxides concentration with excess oxygen varied from about 3 to 20 ng/J (5 to 70 ppm) change for each one percent

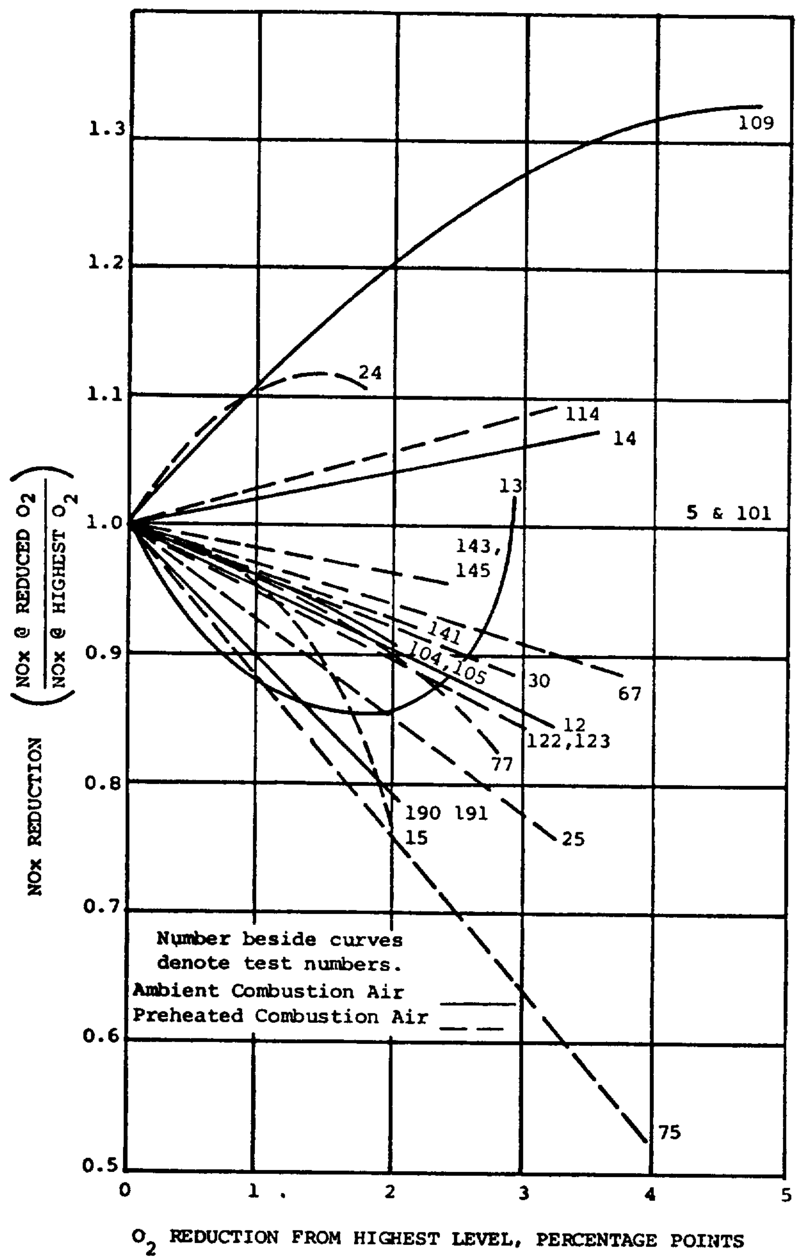

Figure 5-4. Reduction in total nitrogen oxide emissions due to a reduction in excess oxygen, natural gas fuel.

6001-43

change in excess oxygen level. The variations in dependency were brought about by physical differences between boilers. The heat absorbing characteristics of the furnace, slight differences in burner design, and burner air register position could have all combined to produce the inconsistent excess air effect.

As with oil fuel, in most instances the nitrogen oxides emissions decreased steadily as the excess oxygen level was decreased. In four instances, Tests 14 and 109 with ambient temperature combustion air and Tests 24 and 114 with heated combustion air, however, the nitrogen oxides emission levels increased as the excess oxygen was decreased.

5.1.1.4 Firetube Boilers -

The test results showed that the nitrogen oxides emissions from firetube boilers was less sensitive to the excess oxygen level than it was from watertube boilers. Figure 5-5 presents the firetube boiler data that were taken during Phase I (no firetube boilers were measured during Phase II). The change in emissions for firetube boilers averaged about 3 ng/J (6 ppm) for each one percent change of excess oxygen.[4] Generally, when the absolute level of the total nitrogen oxides was less than 110 ng/J (200 ppm), the nitrogen oxides emissions were insensitive to a change in excess oxygen. Test No. 34 conducted with No. 6 oil fuel did show some dependency of nitrogen oxides emissions on excess oxygen. However, the test results may not be typical, because the No. 6 oil was run as a special test fuel for this program using a boiler and atomizer that actually were designed for a lighter oil.

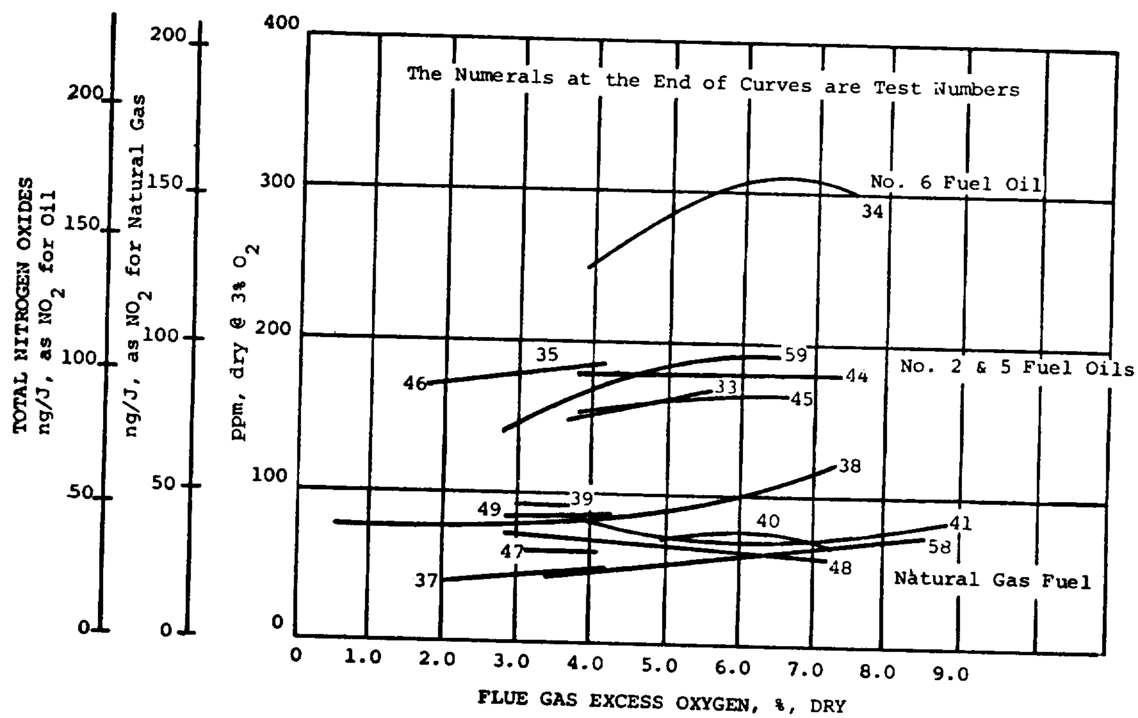

Figure 5-5. Reduction in total nitrogen oxides emissions due to a reduction in excess oxygen. Firetube boilers.

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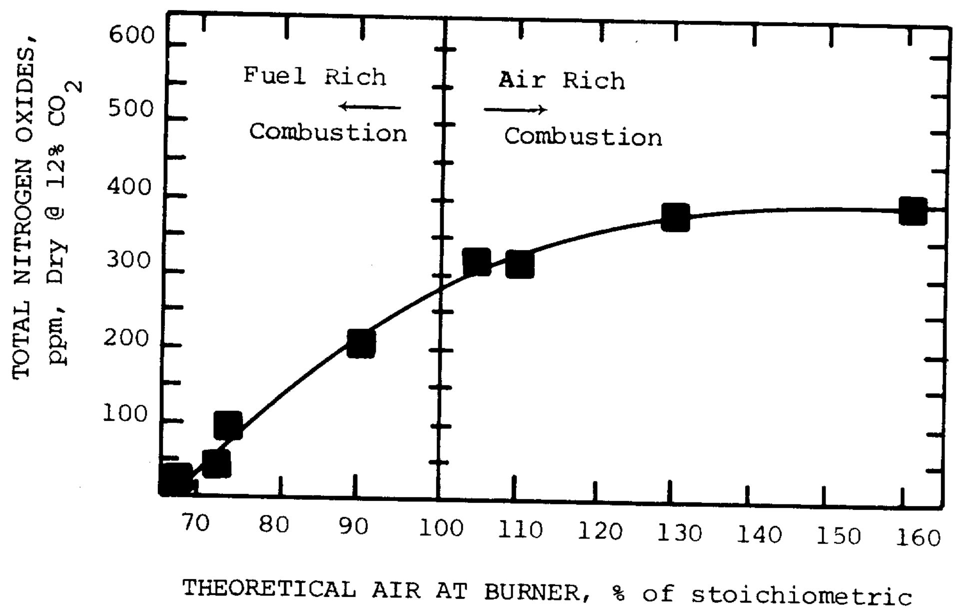
5.1.2 Staged Combustion

Three different methods of staging the combustion air were investigated during the program. The term "staged combustion" denotes a method of modifying the combustion whereby the air is injected into the combustion zone in stages, rather than all of it entering with the fuel through the burner. When a portion of the air is injected through ports located above the burners, it commonly is called "overfire air." When the fuel to one of the burners is turned off and only air is injected through the burner, it is called "burners-out-of-service." When the air is staged through ports located in the furnace walls downstream of the burner, it will be called "sidefire air." Front or side-mounted ports often are called "NO_x Ports."

In addition to limiting the formation of thermally generated nitrogen oxides, staged combustion also limits the conversion of fuel-bound nitrogen to nitrogen oxides. The mechanism for the fuel-bound nitrogen conversion is not highly temperature sensitive, so a combustion modification which reduces only the bulk gas temperature will not greatly limit the conversion. Staged firing, however, also reduces the available oxygen in the combustion zone near the burner, and thus it is effective in limiting the conversion of fuel-bound nitrogen. This effect is illustrated by Figure 5-6 from the work of Turner, et al.[11] showing the theoretical nitric oxide emissions as a function of the percentage of stoichiometric air at the burner throat. The parameter that is used in discussions of staged combustion is the "theoretical air at the burner" defined in percent of the stoichiometric ratio of fuel to air as follows:

$$\text{Theoretical Air at Burner, \% of Stoichiometric} = \frac{(\text{Fuel/Air})_{\text{stoichiometric}}}{(\text{Fuel/Air})_{\text{actual}}} \times 100$$

$$= \frac{(\text{Air/Fuel})_{\text{actual}}}{(\text{Air/Fuel})_{\text{stoichiometric}}} \times 100$$



Fuel-bound nitrogen content = 0.35%

Figure 5-6. Reduction in nitrogen oxides emissions due to reduction of combustion air at the burner.(11)

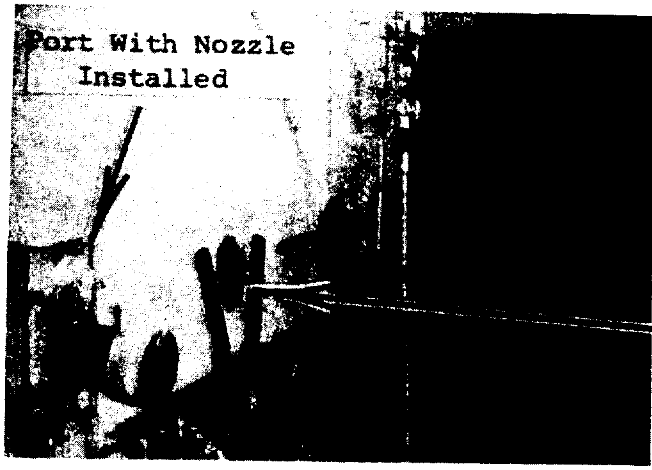
6001-43

The data in Figure 5-6 indicate a sharp decrease in nitrogen oxides emissions for fuel-rich combustion, and this reduction has been achieved with industrial boilers during the current series of tests. The objective of the staged combustion air tests was to operate the burner in a fuel-rich, rather than an air-rich mode, i.e., the left side of the 100% theoretical air point. However attaining fuel-rich operation in actual practice sometimes was difficult, because if the combustion became too fuel-rich, the carbon monoxide and/or smoke emissions increased.

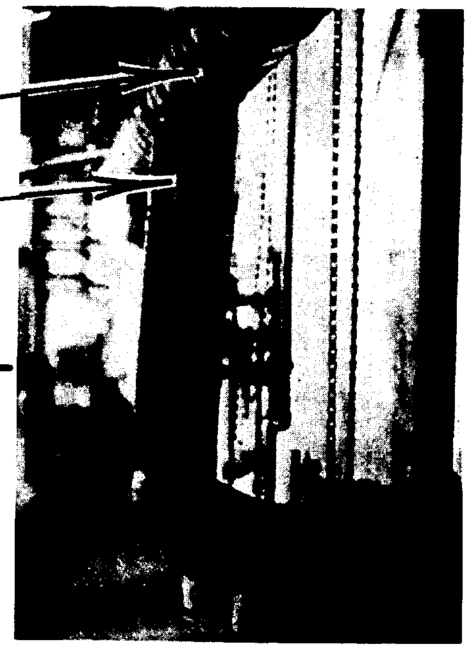
5.1.2.1 Sidefire Air -

During Phase II two boilers were modified to allow the addition of air in stages downstream of the burner and two units were tested which had been manufactured with sidefire air capability. The first unit to be modified was a 47 GJ/hr (45,000 lb/hr of saturated steam flow) vertical type watertube boiler at Location 38 for Tests 183 and 188. It had a single Peabody brand oil and gas burner that fired either natural gas or No. 6 oil. In addition the unit was equipped with an air preheater which preheated the combustion air to a temperature of 450 K (350°F).

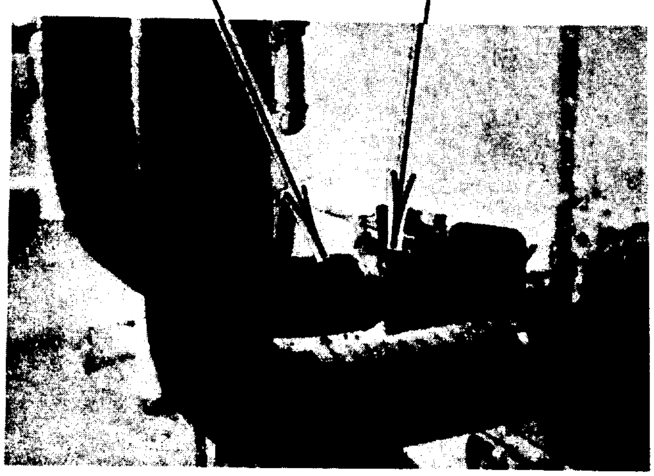
The sidefire installation is pictured in Figure 5-7. A 36 centimeter diameter manifold pipe was run along each side of the boiler and was connected to a fan mounted on the floor at the left rear of the boiler. The manifold is pointed out in the picture in the center photograph of Figure 5-7 and a schematic diagram is shown in Figure 5-8. Four flexible fabric pipes were connected to each manifold and these could be connected to the five overfire air ports that had been cut into the furnace side walls on each side. Two of these downcomers also are shown attached to the manifold and to the ports in the center photograph.



FURNACE WALL SHOWING PORT INSTALLATIONS



AIR SUPPLY MANIFOLD AND TWO DOWNCOMERS



DETAIL OF ATTACHMENT OF DOWNCOMERS TO PORT NOZZLE

Figure 5-7. Staged air installation at Location No. 33.

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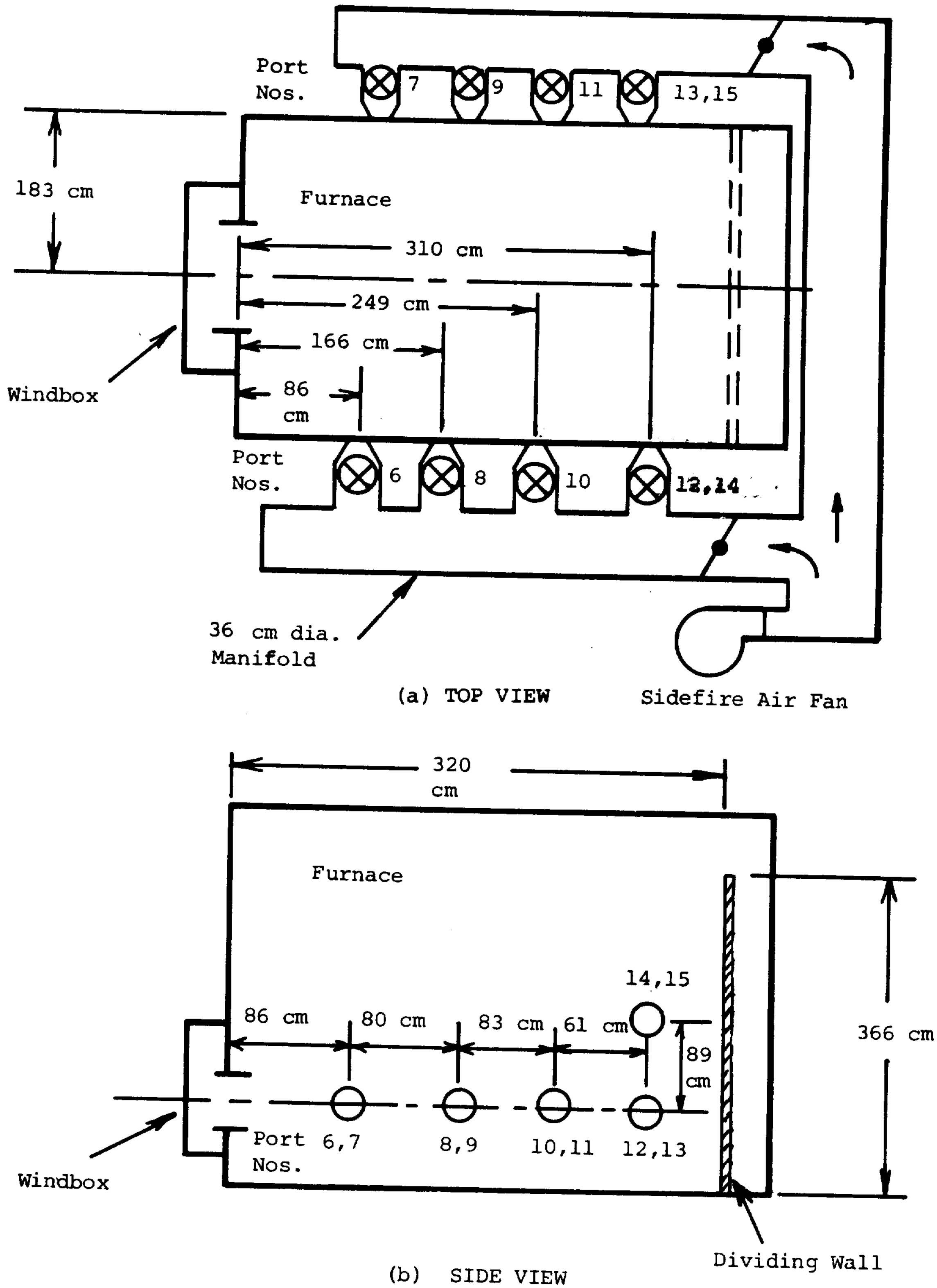

Figure 5-8. Schematic diagram of staged air system installed at Location No. 38.

Two of the ten ports cut into the boiler wall are seen in the photograph in the upper left of Figure 5-7. The first one has the sidefire air nozzle installed. The second port has a plug inserted to close it off while it is not being used. The third and fourth ports have downcomers attached. The details of the attachment of the downcomers to the sidefire air nozzles is depicted in the lower photograph.

The amount of sidefire air going to each downcomer was controlled by butterfly valves installed in each of the two legs of the manifold and in the upper section of each downcomer.

Staged combustion air tests were conducted on this unit with both natural gas and No. 6 oil firing.

At the baseline load setting of 42.7 GJ/hr (40,500 lbs/hr steam flow) while firing natural gas the unit operated with 1.9% excess oxygen and emitted 112 ng/J (220 ppm, dry @ 3% O_2) of nitrogen oxides. The carbon monoxide emission levels were zero. During the staged air tests the amount and location of the injection of the sidefire air addition was systematically varied while the total amount of combustion air was held constant. Due to process demands it was not possible to hold the load constant and it varied as follows: Tests 180 and 183, 88% of capacity; Test No. 184, 96%, and Test No. 185, 71%. The test results are presented in Figures 5-9, 5-10, and 5-11.

For comparison, the effect of burner stoichiometry on nitrogen oxides emissions with no staged air also is plotted with dotted circle symbols in Figure 5-9 for a load of 88% of capacity. The staged air port numbers and locations are shown in Figure 5-8. The data in Figure 5-9 indicate the following:

(1) except for the ports located above the burner axis (ports 14 and 15) the nitrogen oxides emissions exhibited little sensitivity to the location of the sidefire air addition,

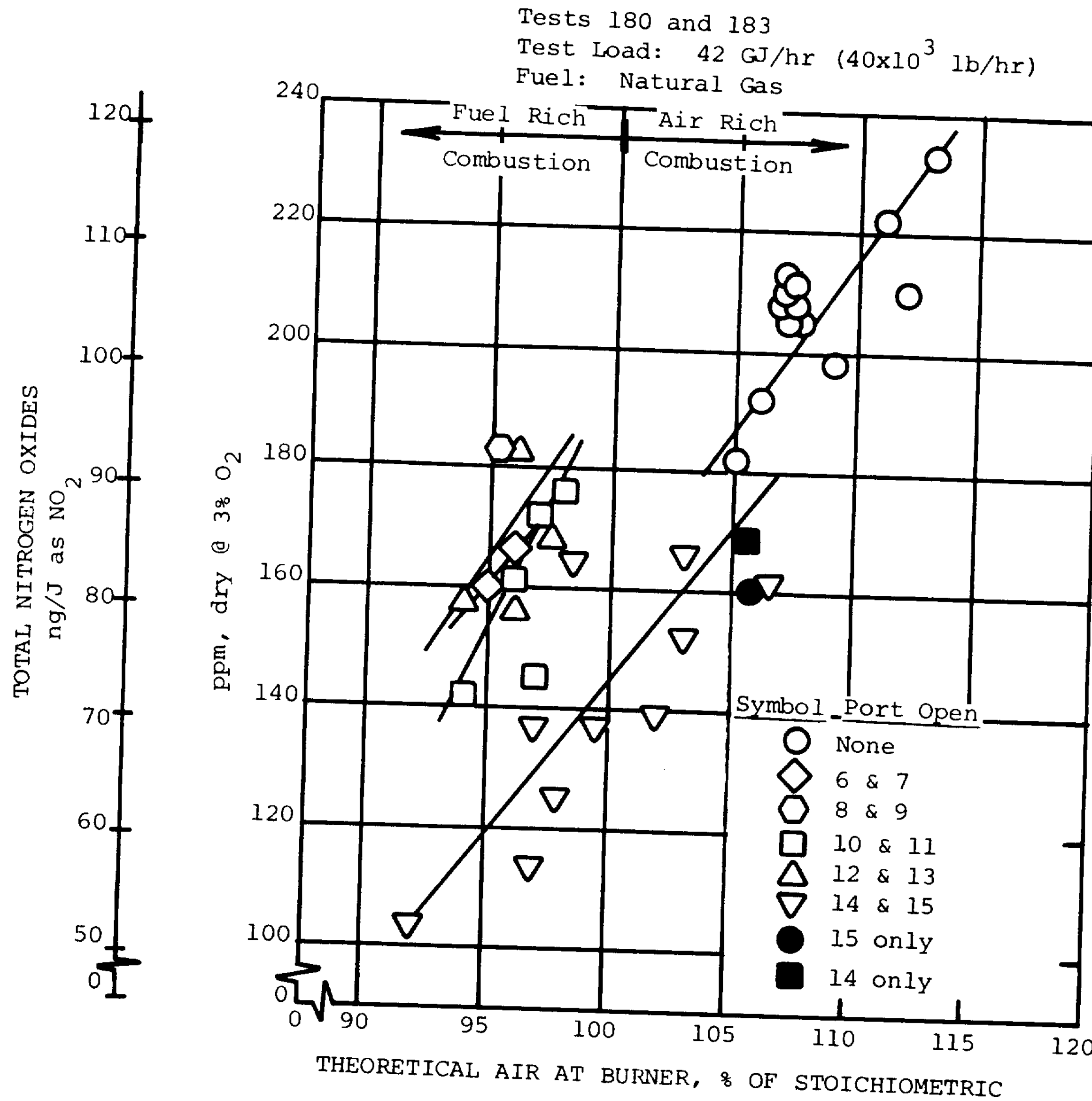

Figure 5-9. Reduction In Total Nitrogen Oxides At Constant Total Excess Air Due To Staged Combustion Air, Natural Gas Fuel.

6001-43

(2) the sidefire air ports 14 and 15 located above the burner axis were the most effective in reducing nitrogen oxides,

(3) the nitrogen oxides reduction with sidefire air addition was a strong function of the theoretical air at the burner, i.e., the percentage of the required stoichiometric air.

The nitrogen oxides emissions were reduced on the average of 32% when sufficient air was staged to create a theoretical air ratio of 98% at the burner (an increase in the burner equivalence ratio 98% to 108%). The carbon monoxide emissions were generally under 30 ng/J (100 ppm) except when ports 14 and 15 were used. In this case carbon monoxide levels were frequently in the range of 80-300 ng/J (250-950 ppm) when the burner air ratio was less than unity.

Similar results were obtained at a lower load setting of 71% of capacity or 34 GJ/hr (32,000 lb/hr steam flow), and they are plotted in Figure 5-10. The nitrogen oxides reduction achieved was somewhat less, being 43% for a load of 71% of capacity compared to a reduction of 54% for the baseline load of 88% of capacity.

The relative insensitivity of the nitrogen oxides emissions from natural gas to the location of the staged air addition except for the extreme upper rear was somewhat surprising. It was suspected that there was insufficient momentum in the sidefire air jet to cause complete mixing of the staged air with the primary combustion products. To further investigate this, all of the staged air was added through only one port rather than two opposed ports, in order to increase the sidefire air penetration. As the solid symbols in Figure 5-9 show, when port 14 or 15 alone was used no discernible differences in nitrogen oxides emissions were observed.

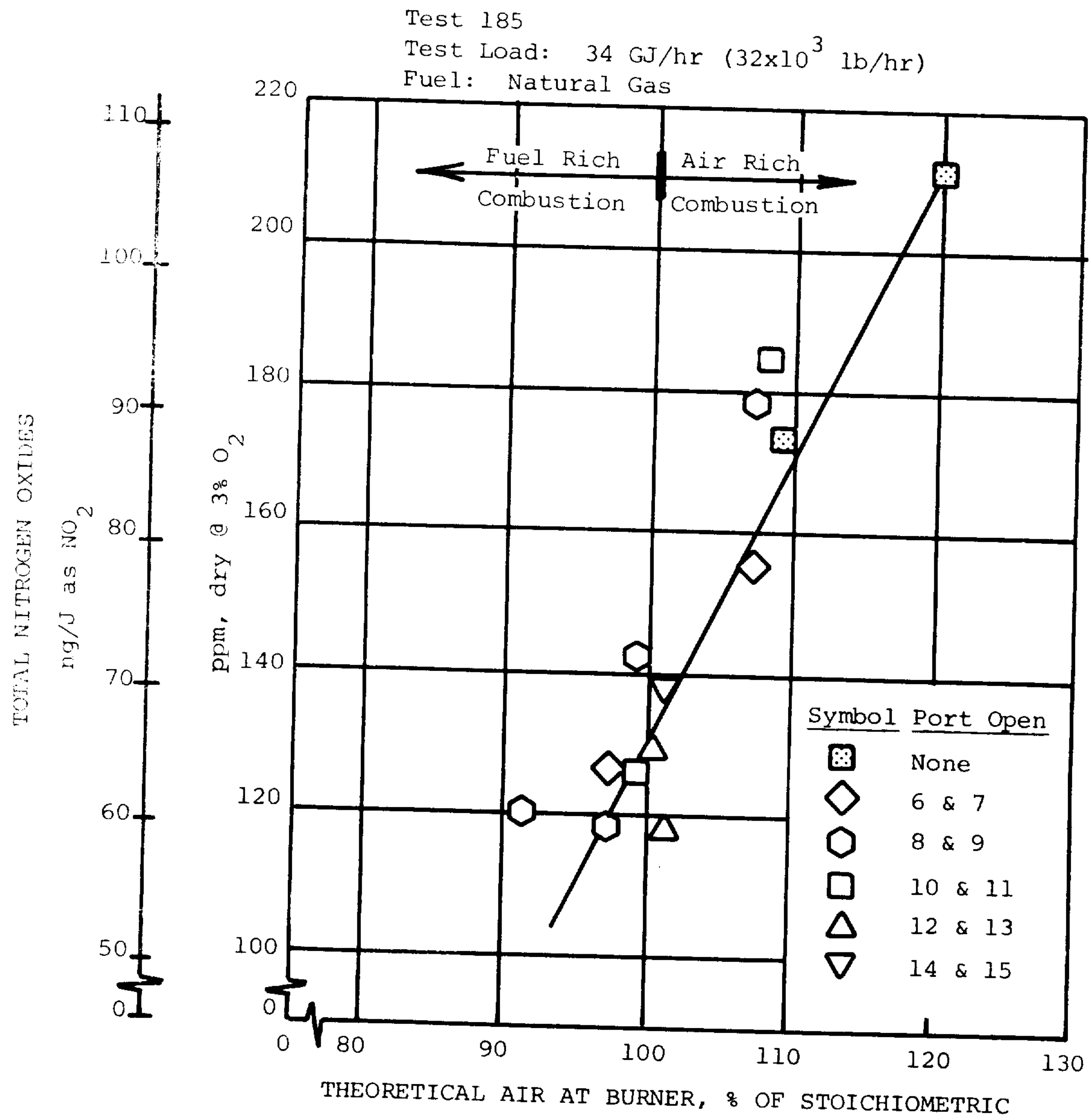

Figure 5-10. Reduction in total nitrogen oxides emissions due to staged combustion air, natural gas fuel.

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Further tests were conducted at a high load of 96% of capacity where the staged air was added through four side ports in order to increase the total amount of staged air, thus operating with a lower level of theoretical air at the burner.

The results of the test series are summarized below:

Test No.	Fig. No.	Test Load % of Capacity %	Number of Ports Open	Lowest Theoretical Air at Burner %	Reduction in NO_x Below Baseline Level %
180, 183	5-9	88	2	93	54
185	5-10	71	2	98	43
184	5-11	96	4	90	49

In Test No. 184 with four ports open it was possible to reduce the theoretical air at the burner to 90%, i.e., to 90% of the stoichiometric amount, and to achieve a nitrogen oxides reduction of 49%. The fact that the greatest nitrogen oxides reduction were achieved at the lowest levels of theoretical air was deemed to support the conclusion that, with natural gas firing in this unit, the nitrogen oxides reductions were determined primarily by the burner equivalence ratio rather than by the location at which the staged air was added.

The results of the staged air tests with oil firing at Location 38 are shown in Figure 5-12. While firing No. 6 oil, the baseline emissions from the boiler at Location 38 were 183 ng/J (326 ppm) of nitrogen oxides and zero carbon monoxide at an excess oxygen level of 3%. The total particulate emissions were 45.6 ng/J (0.106 lb/10^6 Btu) at this baseline condition. As had been found with gas firing, the theoretical air at the burner was an important factor in correlating the nitrogen oxides emission. Nitrogen oxides reductions on the order of 50% of the baseline level were achieved when the theoretical air at the burner was reduced to 100%.

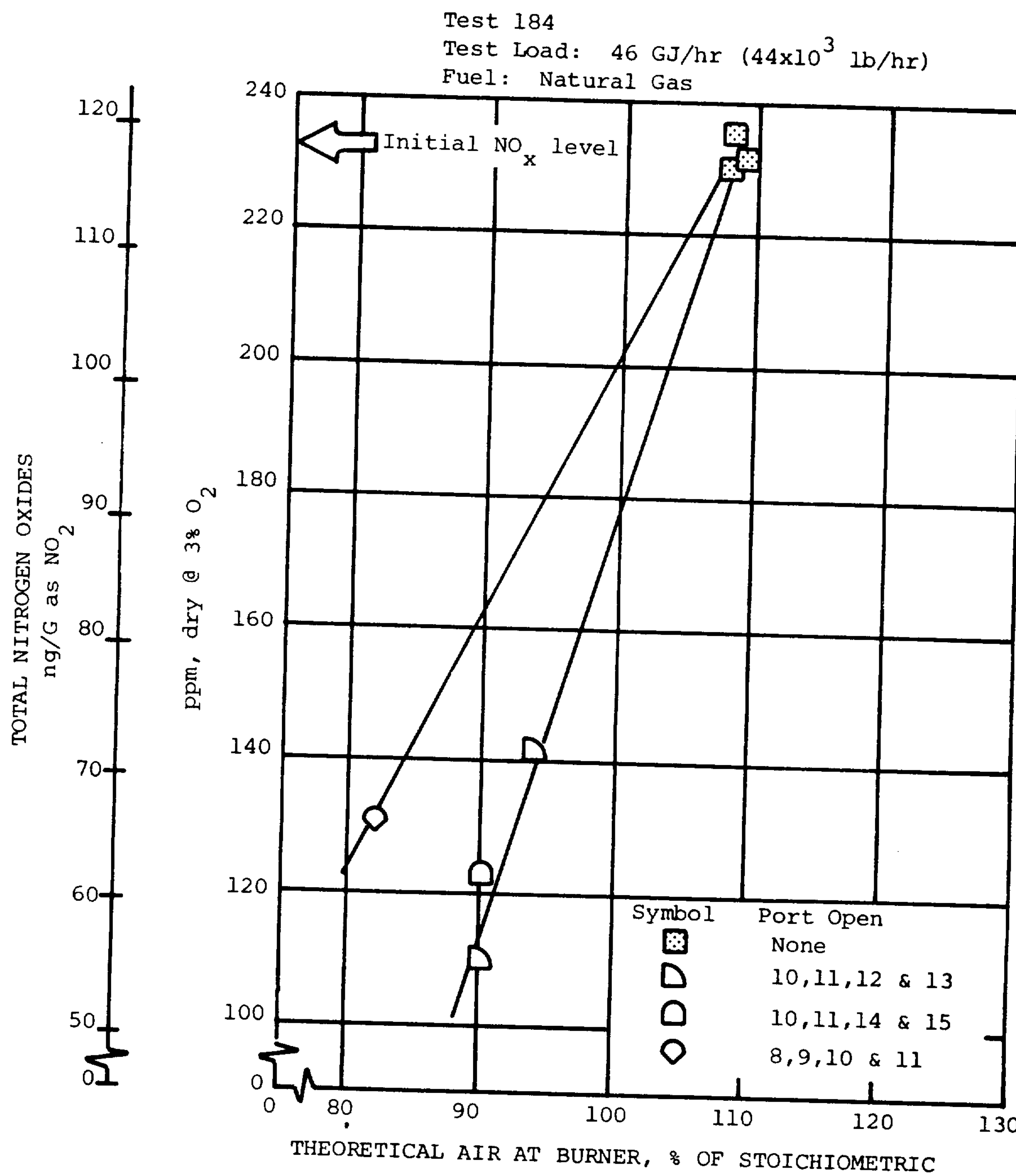

Figure 5-11. Reduction in total nitrogen oxides emissions due to staged combustion air, natural gas fuel.

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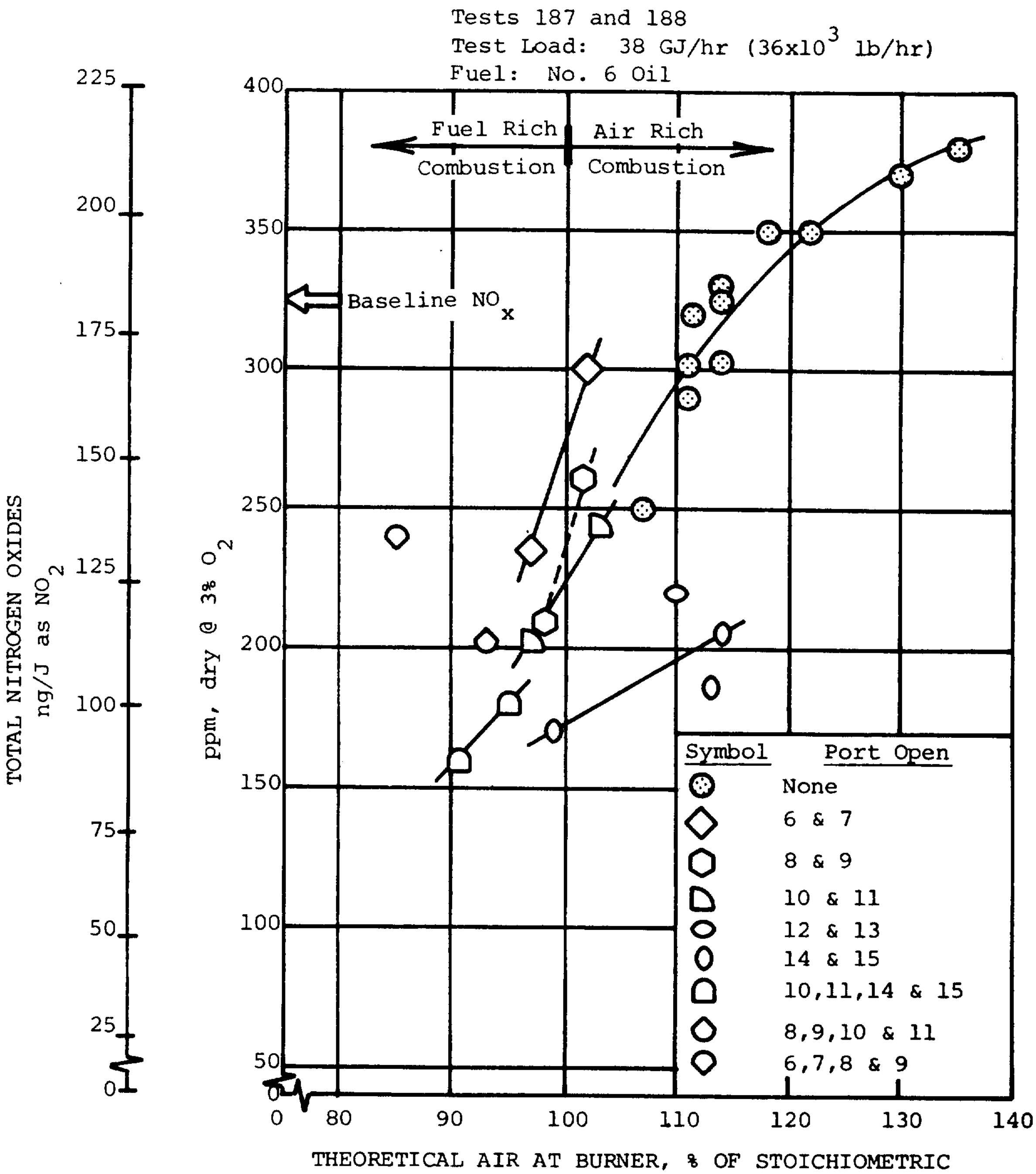

Figure 5-12. Reduction in total nitrogen oxides emissions due to staged combustion air, No. 6 oil fuel.

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As with natural gas, the curve of nitrogen oxides emissions with staged air that is shown in Figure 5-12 was essentially an extension of that obtained merely by reducing the overall excess air with no staged air ports open. The main effect of the staged air appeared to be the suppression of the carbon monoxide and smoke while allowing operation of the burner in a fuel-rich mode.

Although the proportion of the stoichiometric air that was injected through the burner was a major parameter, there was a definite effect of the location of the sidefire air addition on the nitrogen oxides emissions with oil firing. The testing showed that the nitrogen oxides reductions increased as the point of staged air addition was moved farther away from the burner. This can be explained in that moving the injection point away from the burner provided a more gradual heat release and a longer residence time of the products of combustion in a fuel-rich region. The delayed heat release rate resulted in overall lower temperature levels and a reduction in the production of thermal nitrogen oxides. The longer residence time under fuel-rich conditions allowed a greater fraction of the fuel nitrogen compounds to be reduced to molecular nitrogen rather than oxidized to nitrogen oxides and, thus, reduced the conversion of fuel-bound nitrogen to nitrogen oxides. In fact, the insensitivity of the nitrogen oxides reductions to the location of the staged air addition with natural gas firing, suggests that the major effect of staged firing with oil in this unit was to suppress the conversion of fuel bound nitrogen, rather than to suppress the formation of thermal nitrogen oxides.

During all the sidefire air tests with No. 6 oil firing, the carbon monoxide emissions were less than 7 ng/J (20 ppm), with the exception of one test run No. 188-10 where the carbon monoxide emissions reached a level of 74 ng/J (218 ppm).

The effect of sidefire air on particulate emissions was also investigated. A relatively large decrease in nitrogen oxides was achieved with only a moderate increase in particulates. The baseline Test 186-1 (no sidefire air) had total particulate emissions of 45.6 ng/J (0.106 lb/10^6 Btu). With sidefire air addition through ports 14 and 15, such that the theoretical air at the burner was 99% (overall excess oxygen level held constant at about 3%), the total particulate emissions increased by 28% to 58.5 ng/J (0.136 lb/10^6 Btu). The nitrogen oxides emissions were reduced by 50% from the baseline value of 183 ng/J (326 ppm).

The second boiler modified for sidefire air was a D-type watertube unit rated at 18.5 GJ/hr (17,500 lb/hr steam flow) at Location 19. Tests were conducted with both natural gas and No. 6 oil firing during Tests 193, 198, and 203.

The furnace walls were of tangent-tube construction so it was not practicable to install sidefire ports in the wall of the furnace. The staged air was introduced into the furnace by four steel tubes that were pushed through holes cut into each of the four corners of the front face of the windbox. Flexible fabric ducts were attached to the end of each steel tube to supply air from the staged air manifold to each tube. The manifold was attached to an staged air fan mounted beside the boiler on the floor of the boiler house. The four tubes are shown in the retracted position in the picture in the lower left of Figure 5-13.

The photographs in the upper left and center are side and front views of the windbox with the tubes fully inserted. The vertical, rectangular structure at the right shoulder of the engineer in the center picture is the flue gas recirculation duct. With this arrangement the effect of simultaneous staged air and flue gas recirculation could be determined.

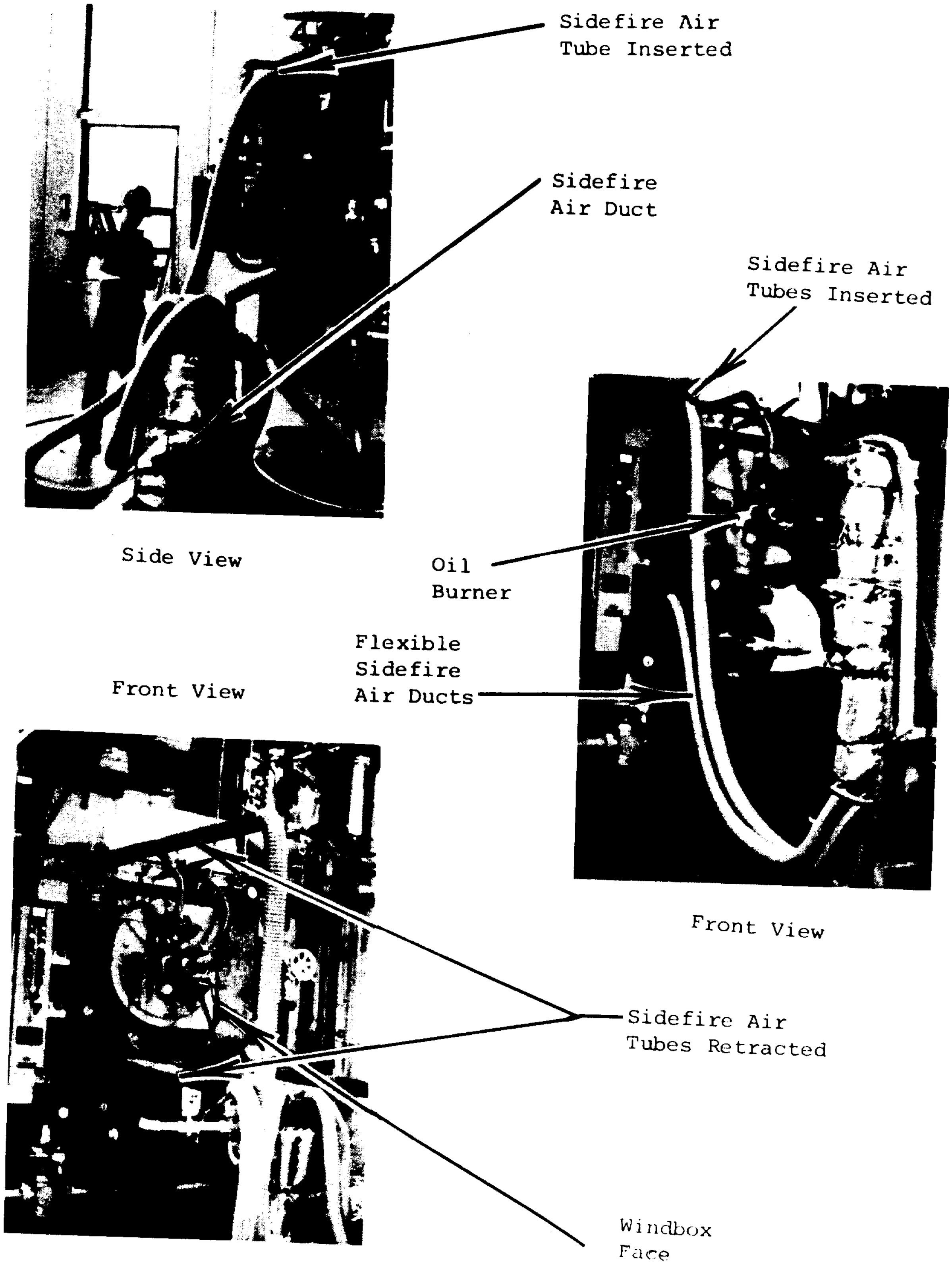

Figure 5-13. Staged air installation at Location No. 19.

Each of the four air sidefire air tubes could be inserted to a depth of up to 122 cm (4 ft) into the furnace. The ends of the tubes were constructed such that the staged air was injected into the flame from the side. When air was not being blown through a tube it was fully retracted to prevent its being melted by the nearby flame. The quantity of air being staged was controlled by a butterfly valve in the manifold.

A pitot tube was positioned in the staged air duct to determine the quantity of sidefire air that was passing though it. The load and overall excess oxygen level were held constant and the amount and the point at which the staged air was added were varied. In addition, the No. 6 oil tests were conducted with both steam and air atomization.

Figure 5-14 illustrates the effect of staged air in terms of the theoretical air at the burner on nitrogen oxides emission levels for natural gas fuel at Location 19. The shaded data points on the right are the tests with no staging of the air. Without staged air the minimum nitrogen oxides level was 28 ng/J (54 ppm) at an theoretical air of 109%. Adding the air in stages allowed the burner to be operated fuel rich with a theoretical air of between 67% and 77%. With the sidefire air tubes inserted 30 cm from the burner nitrogen oxides emissions were 33 to 39 ng/J (65 to 77 ppm), which is a significant increase above baseline levels. As the sidefire air tubes were moved further downstream from the burner the nitrogen oxides emissions decreased. The reason that nitrogen oxides emissions first increased above the baseline with sidefire air appears to be that the sidefire air was introduced too near the burner and, thus, the air was not in fact added in stages. The lowest level of nitrogen oxides emissions attained with staged air was achieved with the tubes 122 cm into the furnace; the nitrogen oxides was 27 ng/J (53 ppm). This was an insignificant reduction from baseline conditions. Further reductions may have been possible if the air could have been introduced further downstream of the burner.

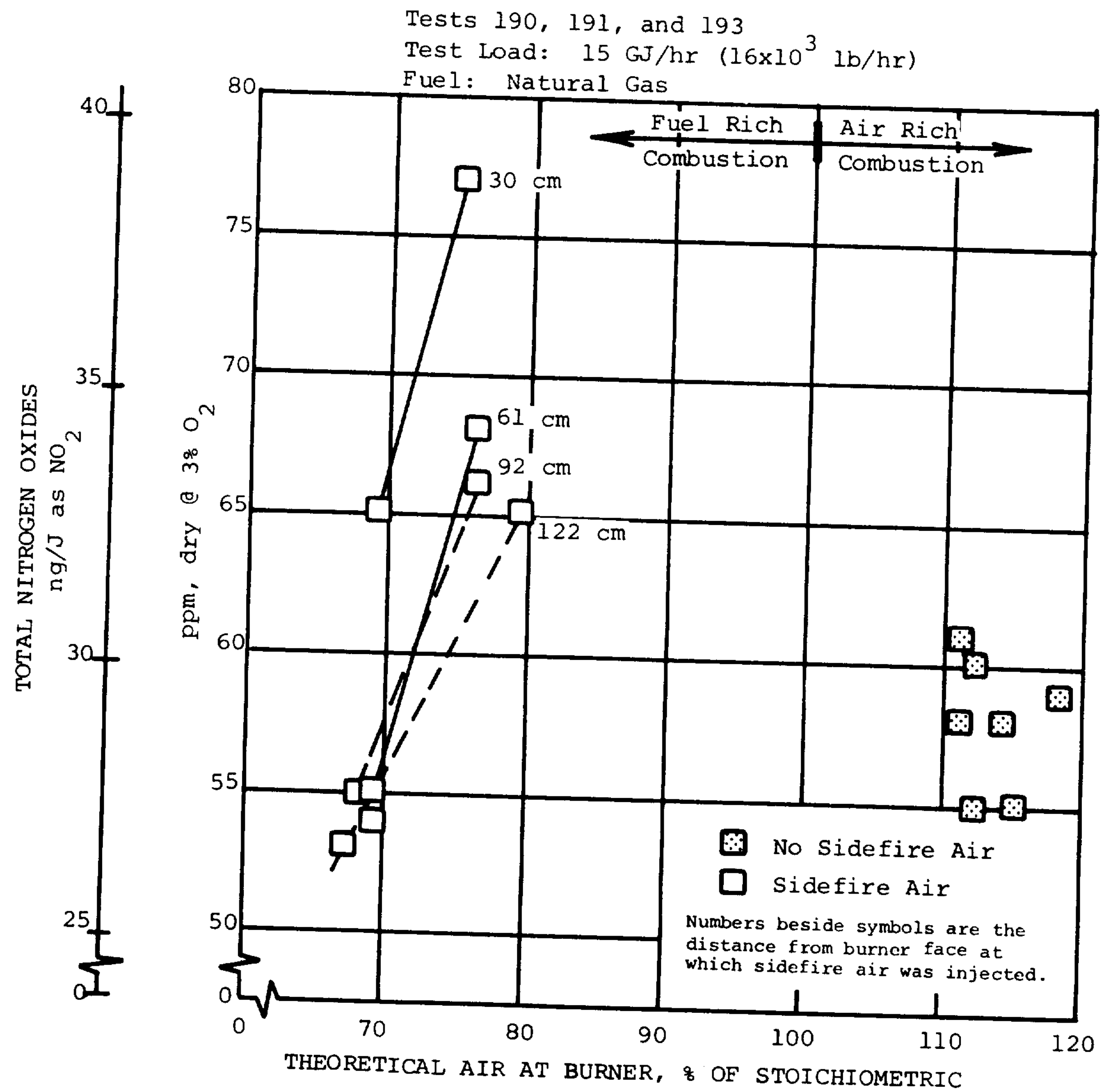

Figure 5-14. Reduction in total nitrogen oxides emission due to staged combustion air, natural gas fuel.

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The effect of sidefire air on nitrogen oxides emissions for No. 6 fuel oil firing at Location 19 is presented in Figures 5-15 and 5-16 for air and steam atomization respectively. Again the nitrogen oxides data grouping at the left is from baseline and excess oxygen variations alone. The lowest nitrogen oxides emission level without staged combustion air was 77.4 and 69.6 ng/J (138 and 124 ppm) for air and steam atomization at burner air levels of 103% to 110% respectively. With sidefire air the burner was operated with fuel-rich burner air levels between 77% and 86%. As with gas fuel the effect of the sidefire air was dependent upon the position of the tubes within the furnace. Inserting the tubes 122 cm into the furnace resulted in the lowest nitrogen oxides emissions of 73 and 61 ng/J (120 and 108 ppm) for air and steam atomization, respectively. These levels represent a reduction of 13% from baseline conditions without staged air for both the air and steam atomizing techniques. For air atomization the effect of the sidefire air tube position on nitrogen oxides emissions was less pronounced than for steam atomization. With air atomization, emissions varied within a range of about 8 ng/J (15 ppm) as the tubes were moved from the minimum to the maximum insertion. When the fuel was atomized with steam the nitrogen oxides emissions changed by about 17 ng/J (30 ppm) as the air insertion point was changed.

Staged air was more effective with No. 6 oil than natural gas (recall that for natural gas the nitrogen oxides emissions were essentially the same or increased above the baseline values). This indicates that:

(1) the fuel/air mixing characteristics for this burner may by different for natural gas and No. 6 oil with effective staging being obtained 122 cm from the burner with oil firing or

(2) the differences in fuel/air mixing were such that the fuel bound nitrogen conversion to NO was suppressed with little effect on the thermal NO formation.

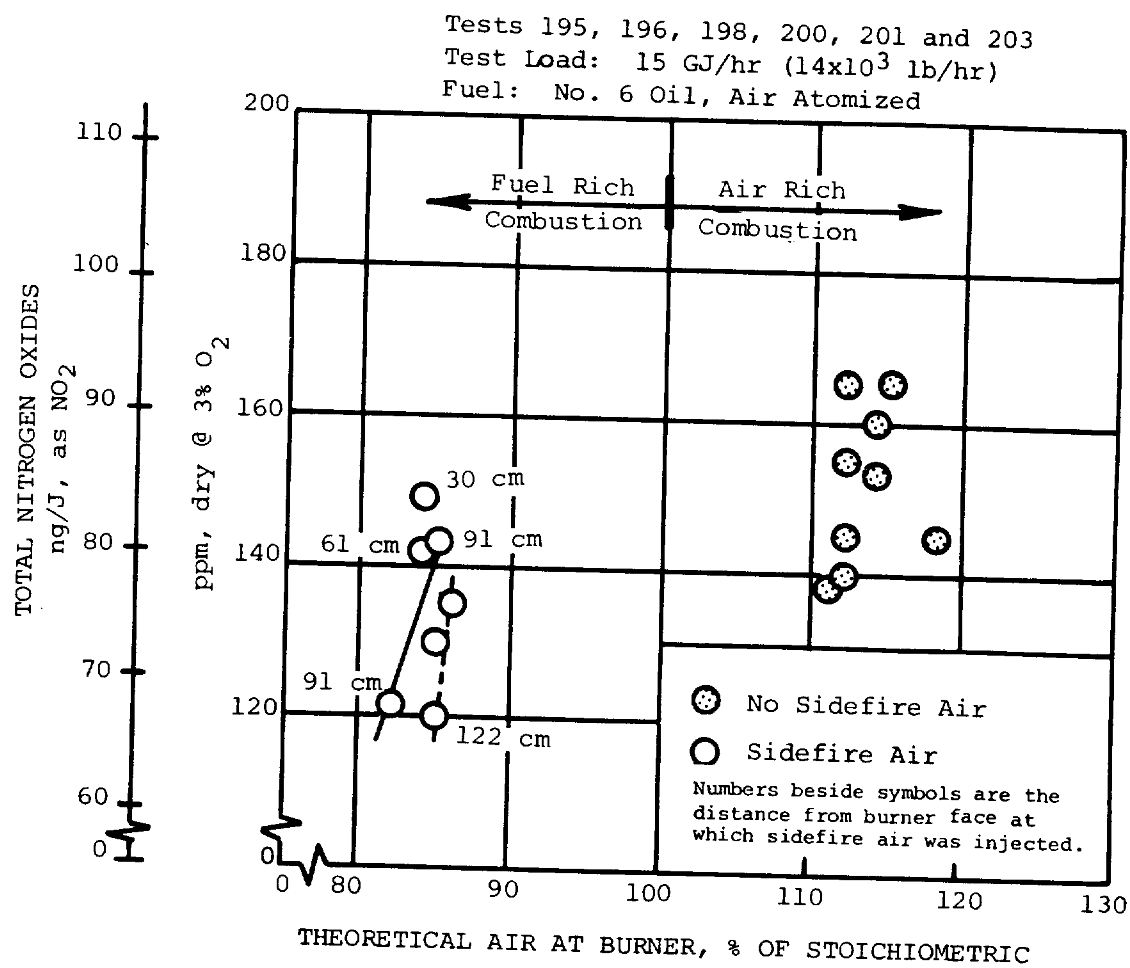

Figure 5-15. Reduction in total nitrogen oxides due to staged combustion air, No. 6 oil fuel.

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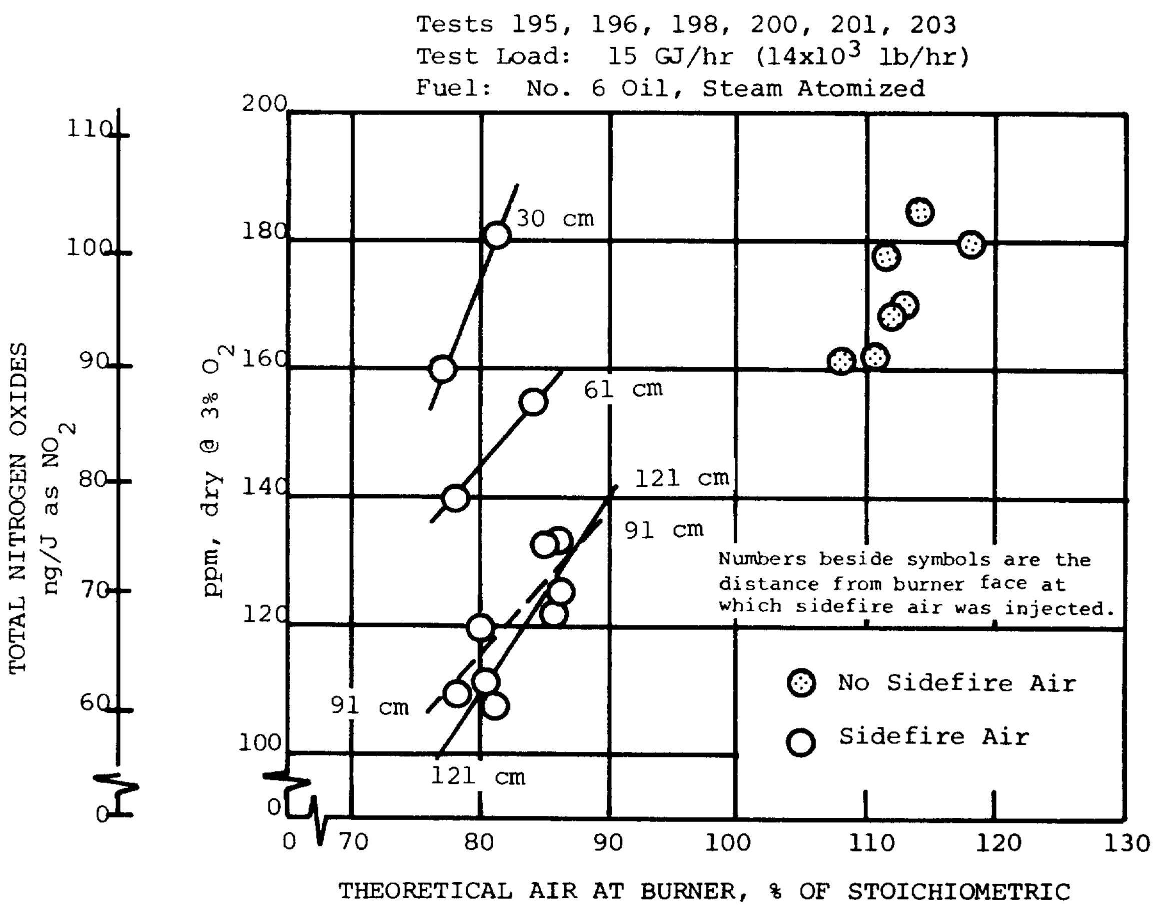

Figure 5-16. Reduction in total nitrogen oxides due to staged combustion air, No. 6 oil fuel.

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Using staged air with steam atomization resulted in lower total particulate emissions. The baseline level was 13.3 ng/J (0.031 lb/10^6 Btu) and the particulates with the staged air tubes 122 cm into the furnace were 11.6 ng/J (0.027 lb/10^6 Btu). The reverse occurred with air atomization. Baseline particulates were 13.3 ng/J (0.031 lb/10^6 Btu) while the concentration with sidefire air was 20.2 ng/J (0.047 lb/10^6 Btu). It is not certain why the trends were different with steam and air atomization.

Two boilers at Locations 39 and 36, which were manufactured with staged air capabilities, also were tested. The unit at Location 39 was a new watertube boiler rated at 211 GJ/hr (200,000 lb/hr steam flow). The boiler utilized a single gas spud burner and was fired with a mixture of natural gas and refinery gas. A single forced draft fan supplied both the burner and the sidefire air duct. The staged air was supplied from one side of the furnace through two ports located approximately one-fourth of the furnace length from the burner.

The effect of burner equivalence ratio on nitrogen oxides emissions at 80% and 48% rated load are presented in Figure 5-17. As in the previous graphs the shaded symbols are nitrogen oxides data obtained by varying the excess oxygen level without staging the combustion air and the open symbols represent staged air tests. It should be noted that during these staged air tests it was not possible to hold the overall excess air level constant while varying the burner theoretical air. At a load of 80% of capacity the nitrogen oxides emissions were 83 ng/J (164 ppm) at an air-rich burner air of 128%. As the excess oxygen was decreased, nitrogen oxides emissions increased and peaked at a burner air level of about 110%. Fuel-rich firing conditions (burner air levels less than 100%) were reached with staged air and nitrogen oxides emissions reached the lowest level of 58 ng/J (114 ppm) at an air level of 82%. (This represents a reduction on the order of 40%.) Carbon monoxide emissions were high, between 93 and 620 ng/J (300 and 2000 ppm) at low burner air levels.

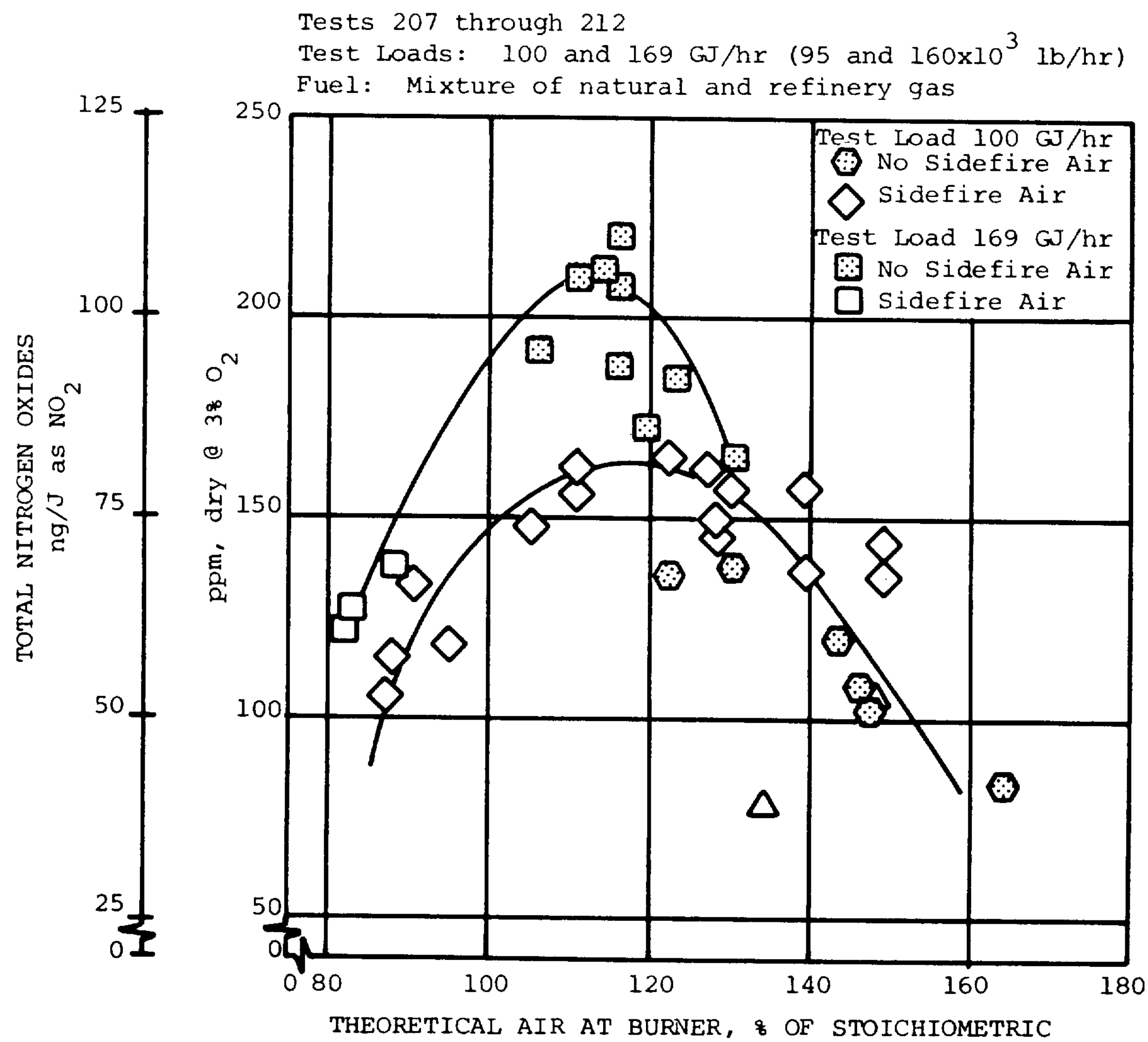

Figure 5-17. Reduction in total nitrogen oxides due to staged combustion air, mixture natural and refinery gas.

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At a test load of 48% of capacity, i.e., 100 GJ/hr (95,000 lb/hr steam flow) nitrogen oxides emissions increased as conditions became less air-rich when the theoretical air at the burner was lowered from 164%. Nitrogen oxides emissions were a maximum 85 ng/J (166 ppm) at a burner air level of about 118% and then decreased as the combustion approached fuel-rich conditions. The nitrogen oxides emissions with staged air were lowered to 106 ppm at a burner air level of 86%; however, the carbon monoxide emissions were greater than 620 ng/J (2000 ppm) which is unacceptably high.

The effectiveness of staging the air for reducing nitrogen oxides was not as great as simply firing air-rich. The lowest nitrogen oxides level of 44 ng/J (86 ppm) was achieved with zero staged air and a burner air level of 164%. Operating with fuel-rich staged air conditions, however, was better in terms of the boiler efficiency than with high excess oxygen. For example, the boiler efficiency was about 83% when staged air was used to obtain burner air levels of 90% and nitrogen oxides levels in the 56 to 61 ng/J (110 to 120 ppm) range. On the other hand, operating with burner air levels of 164% and a nitrogen oxides emissions of 44 ng/J (86 ppm), resulted in an 81% efficiency.

The effectiveness of staged air in reducing nitrogen oxides emissions from this boiler is further illustrated in Figure 5-18 which shows the reduction of nitrogen oxides that was achieved in terms of the excess oxygen, rather than theoretical air parameter. This figure indicates that at overall excess oxygen levels less than 5.5%, the staged air addition was effective in reducing the nitrogen oxides emissions below that obtained without staged air. When the overall excess level is below 5.5%, the burner is operating with a theoretical burner air level greater than 100%, i.e., fuel rich. When the overall excess oxygen level is greater than 5.5% the use of staged air increases the nitrogen oxides emissions. This

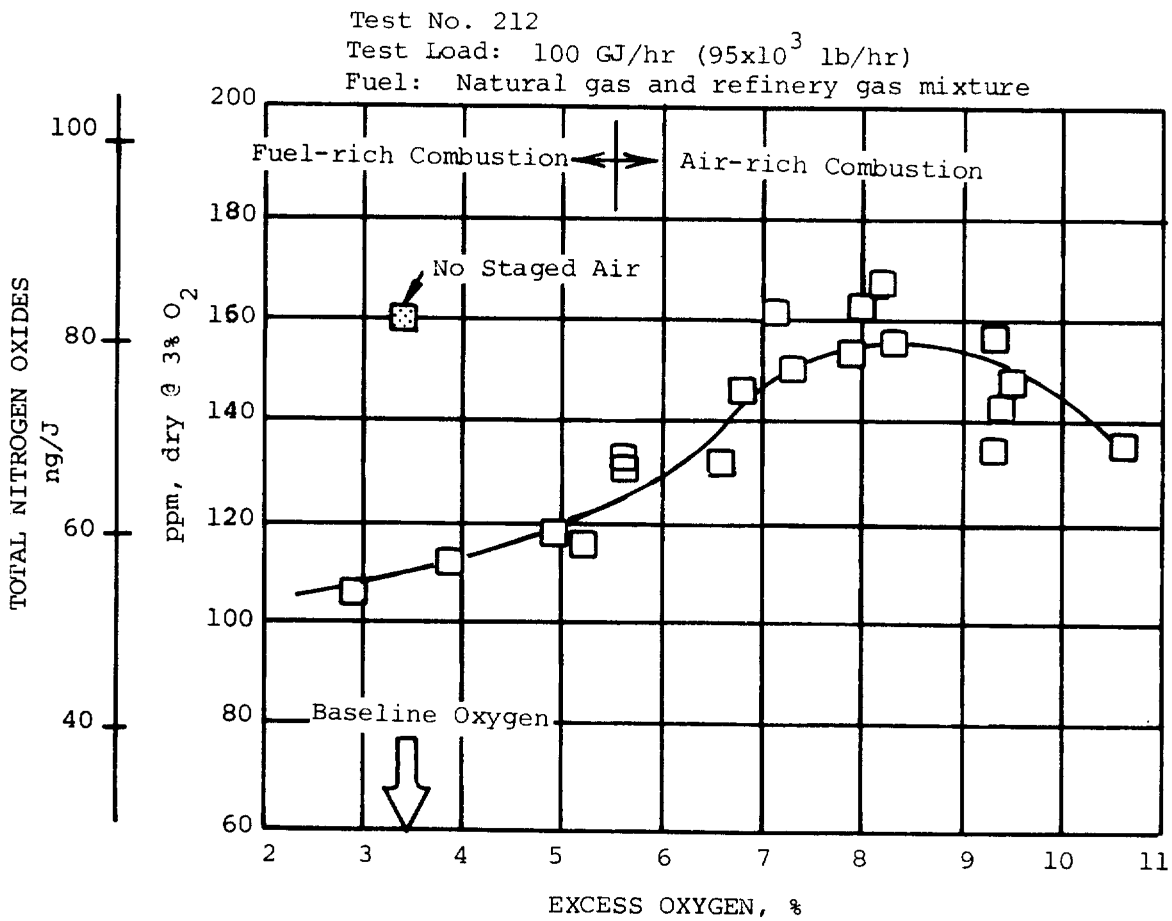

Figure 5-18. Effect of excess oxygen on total nitrogen oxides emissions with and without staged air.

6001-43

may be caused by increased fuel and air mixing due to the proximity of the sidefire air port to the burner.

The 211 GJ/hr (200,000 lb/hr steam flow) watertube boiler at Location 36 also had staged air capabilities. The unit had a single steam atomized burner with a 96.5 cm (38 inch) diameter throat and fired No. 2 fuel oil. The sidefire air port was located approximately 3.61 meters (12 feet) downstream of the burner [furnace length was 10.5 meters (34.5 feet)].

Staged air tests were conducted at three different loads, 38, 63, and 80 GJ/hr ($36x10^3$, $60x10^3$, and $76x10^3$ lb/hr steam flow). During each of these test series the overall excess oxygen level was held constant and the amount of air supplied to the burner varied by changing the sidefire air damper position. With the sidefire air damper open 100% the nitrogen oxides emissions were reduced by 10%.

The effect of the amount of staged air on nitrogen oxides is shown in Figure 5-19 in terms of the degree of being open of the sidefire air port. The data are plotted as a function of damper position as sufficient instrumentation was not available to determine the theoretical burner air level. However, approximate calculations based on the static pressure in the ducts and the duct areas indicate that the theoretical air level at the burner with the sidefire air damper 100% open was on the order of 72%.

The reason that only a 10% reduction in nitrogen oxides emissions was realized with substantial amounts of staged air at Location 36 probably was that the test loads were low. At the low-load settings the fuel and air mixing is reduced due to the decreased pressure drop across the burner. This reduced mixing has the effect of naturally "staging" the combustion. The effectiveness of staging the combustion additionally with sidefire air then would be expected to be diminished at low loads. Additionally, the burner heat release rate per unit heat absorption area is reduced at low loads, and this reduction tends to decrease the flame temperature which also causes lower nitrogen oxides emissions.

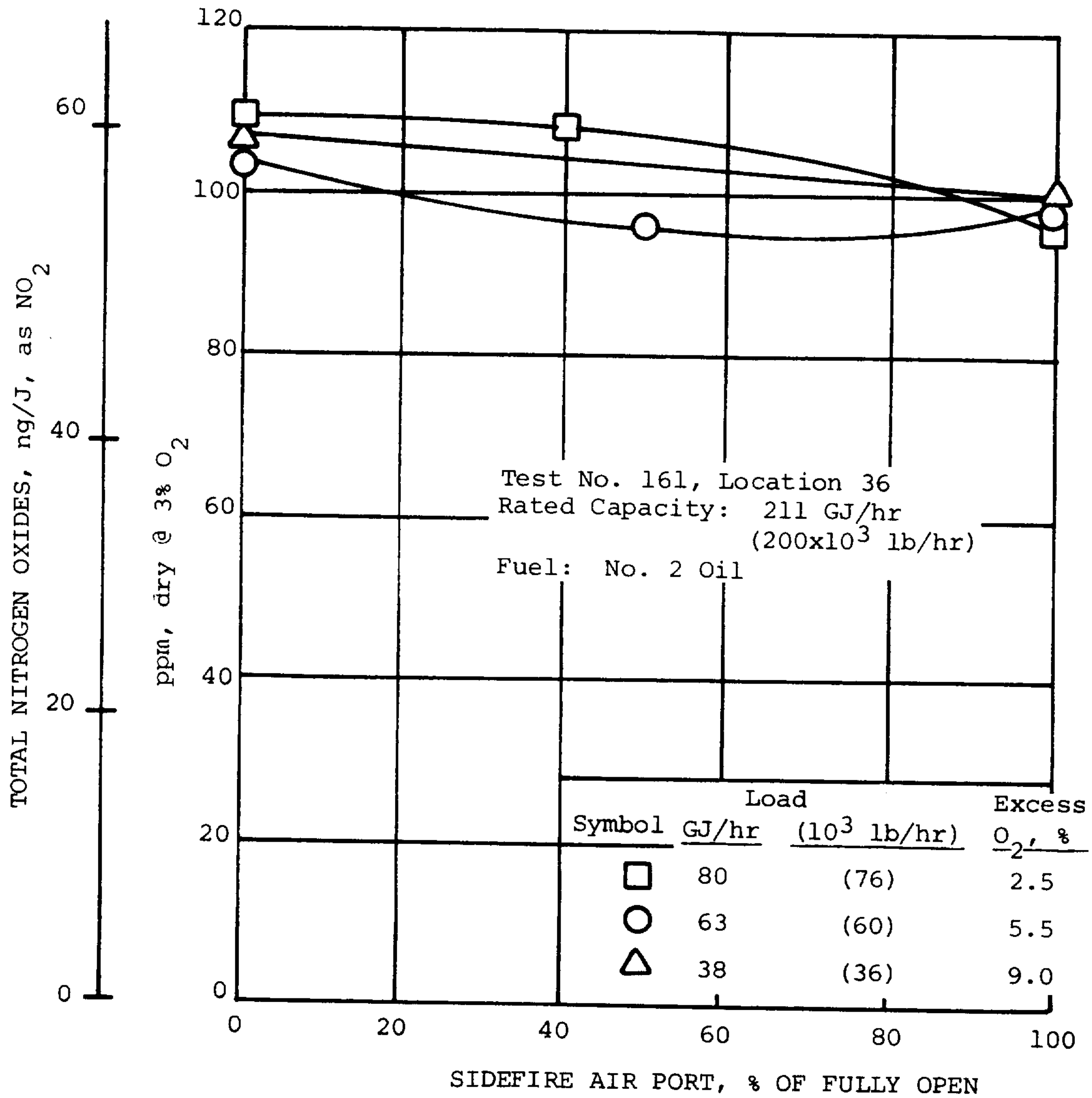

Figure 5-19. Effect of staged air on total nitrogen oxides emissions.

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5.1.2.2 Overfire Air -

On stoker fired coal units, air ports are conventionally located over the coal injection ports and inject air into the flame zone above the grate. The purpose of this overfire air is to promote turbulence in the vicinity of the flame zone to assist in obtaining complete carbon burnout within the furnace. During the program varying this overfire air was investigated as a nitrogen oxides control technique. In addition, three of the stoker fired units had the equivalent of overfire air ports in the form of auxiliary oil or gas burners located above the grate. The effectiveness of using these auxiliary burners as overfire air ports was also investigated.

The boiler at Location 30 was a spreader stoker rated at 132 GJ/hr (125,000 lbs/hr steam flow). Overfire air injection ports were located at two different heights on the furnace front and back walls. The lower air ports were always open and the air flow to the upper ports could be controlled. A single natural gas burner was also located on the right hand side of the furnace and had a separate windbox with damper controls such that a portion of the coal fuel combustion air could be diverted to the gas burner port.

The baseline nitrogen oxides emissions at the normal excess oxygen level of 6.2% are 196 ng/J (320 ppm dry corrected to 3% oxygen). The overfire air injection ports in combination with the gas burner port were used to successfully reduce the baseline nitrogen oxides emissions by 26%. The overfire air injection ports alone reduced the nitrogen oxides emissions by only 8%. Either these ports were located too far from the primary flame zone or, they did not have sufficient air flow capacity to change the fuel-air ratio of the primary flame.

The 227 GJ/hr (215,000 lb/hr steam flow) unit at Location 35 was coal fired with a traveling chain grate type stoker with forty-six overfire air nozzles mounted above the chain grate. Air was supplied to these nozzles by a separate overfire air fan. Also, four Peabody oil burners were installed in a single horizontal row on the boiler front wall. Primary combustion air was supplied under the grate and to the oil burner windbox by a forced draft fan. Increasing the overfire air flow on this unit increased the nitrogen oxides emissions on the order of 10%.

However, in comparison to other coal fired stoker units, the nitrogen oxides emissions from this boiler were unusually low with baseline emissions of 100 ng/J (164 ppm, dry at 3% O_2) at 60% load and an excess oxygen level of 9.5%. Visual examination of the furnace during the tests revealed low intensity combustion flames of a very lazy and random nature at these low loads where testing had to be conducted. The combination of the lazy flames, low load, and a large furnace could result in low nitrogen oxides emissions, with an increase in nitrogen oxides as the turbulence and mixing is enhanced with the addition of overfire air.

During Test No. 28 of Phase I a spreader stoker coal fired unit was tested that had the equivalent of overfire air in the form of auxiliary oil burner throats. When these were used as overfire air ports, nitrogen oxides reduction of 20-25% were obtained with satisfactory boiler operation (see Ref. 4, Subsection 4.1.1).

5.1.2.3 <u>Burners-Out-Of-Service</u> -

The third form of staged combustion achieved by adding the combustion air to the flame zone in stages involved taking one or more burners out of service.

The burner-out-of-service modification on multiple burner boilers entails terminating the fuel flow, but not the air flow, to one or more of the burners while maintaining the same overall fuel flow by increasing the fuel flow at the other burners.

During Phase I, the eight burner-out-of-service tests which were conducted focused primarily on determining the most effective burner pattern to be implemented. These results showed that:

- A square burner pattern (rows and columns) is more effective than a staggered pattern. This is probably a result of better mixing between burners in the regular pattern than in the staggered arrangement. This allows in-service burners to be operated more fuel rich with subsequent mixing of the remaining combustion air from the out-of-service burner.
- Removing a burner in the top row from service is more effective than removing a bottom row burner.
- Removing inner rather than outer burners is more effective. Operation at lower excess oxygen levels is possible due to better mixing of the air from the burner out of service with the combustion products from the operating burners.

Seven additional burner-out-of-service tests were conducted on six multiple burner boilers during Phase II. Burner register changes were investigated to optimize burner-out-of-service performance during these tests. In addition, the effect of burner equivalence ratio on emissions and performance was investigated. The results of these tests are summarized in Table 5-3.

The Phase II burner-out-of-service tests showed that nitrogen oxides reductions on the order of 25-40% could be attained with gas or oil fuels, with no change in efficiency and minor increases in carbon monoxide levels. However, on the oil fired units where particulate data were obtained, the particulate emissions increased substantially (65-100% on tests during Phase I and 170% for series 119).

Table 5-3. BURNERS-OUT-OF-SERVICE SUMMARY

Test No.	Burner Pattern	Out-of-Service Burner	Capacity GJ/hr (10^3lb/hr)	Fuel	Test Load GJ/hr (10^3lb/hr)	Excess O_2 %	Approx. Burner Equiv. Ratio	NOx dry @ 3% O_2 ng/J(ppm)	Efficiency %	Air Register Positions (% Open)	% Reduction
119-1		None	158(150)	No.6 Oil	73(69.5)	5.5	0.75	139(248)	87	Normal positions	--
119-2		None			74(70)	5.2	0.76	145(258)	--	1: 30/55% open	--
119-3	0 2	2			71(67)	6.8	1.37	107(191)	--	2: 30/55% open	23
119-4		2			74(70)	6.0	1.45	99.3(177)	--		29
119-5	0 1	2			74(70)	7.1	2.12	96(171)	--	Burner #2 registers	31
119-6		2			74(70)	5.4	1.52	104(186)	86	opened to 100%/95%	25
122-1		None	74 (70)	Nat. Gas	31(29)	5.7	0.74	108(211)	83	100% open	--
123-2		None			31(29)	3.7	0.84	85(166)	85	100% open	--
124-1	0 0 0	2			31(29)	5.4	0.92	62(122)	83	#2 50% open	42
124-3	1 2 3	2			30(28)	5.5	0.91	70(138)	--	#2 50% open	35
124-5		2			32(30)	5.3	1.05	49 (96)	83	#2 75% open	55
127-2		None	274(280)	No.6 Oil	32(30)	6.75	0.69	139(248)	--	100% open	--
127-3		None			30(28)	4.9	0.78	101(180)	87	100% open	--
128-1		2			31(29)	5.9	1.10	125(223)	86	100% open	Reductions due primarily to excess oxygen level
128-4	0 0 0	2			32(30.5)	5.7	1.11	129(230)	--	100% open	
128-5	1 2 3	2			32(30)	4.8	1.16	105(188)	86	100% open	
128-2		2			30(28)	6.7	0.95	154(274)	--	100% open	
128-6		2			31(29)	6.35	1.06	137(244)	--	#2 75% open	
128-3		2			31(29)	5.9	0.91	167(298)	--	#2 50% open	
146-1		None	127(120)	Nat. Gas	64(61)	4.0	0.83	106(207)	--	Normal: 50% 60%/60% 60%	--
147-1		3			66(63)	4.0	0.99	105(206)	--	#3 closed to 30%	0.5
147-2	0 0	3			66(63)	3.2	1.03	97(190)	--	#3 closed to 30%	6
147-3	3 4	3			64(61)	4.6	0.96	108(212)	--	#3 closed to 30%	(+2.4)
147-4		4			65(62)	4.0	0.95	107(209)	--	#4 closed to 20%	(+1)
147-5	0 0	4			65(62)	3.2	1.00	101(198)	--	#4 closed to 20%	4
147-6	1 2	4			65(62)	2.6	1.01	95(186)	--	#4 closed to 20%	10
147-7		3,4			65(62)	4.4	1.12	74(146)	--	#3, #4 closed to 20%	29
147-8		3,4			64(61)	4.4	1.12	80(155)	--	#3, #4 closed to 20%	25
151-1	0 0 0 0	None	580(550)	Ref. Gas	481(456)	5.5	0.76	86.6(149)	--	No register changes	--
151-2	5 6 7 8	None			506(480)	4.7	0.79	84.3(145)	--		--
151-4	0 0 0 0	2			450(427)	6.4	0.82	71.5(123)	--		17
151-5	1 2 3 4	2,4			433(410)	7.3	0.90	52.3 (90)	--		40
133-1	0 3 0 4	None	274(260)	P.C.	70(66)	7.2	0.67	668(1011)	81	No register changes	--
133-2	0 1 0 2	3,4			66(63)	7.5	1.30	408(618)	81		39
156-2	0 0 0 7 8 9	None	528(500)	P.C.	422(400)	8.6	--	216(353)	--	--	--
159-1	0 0 0 4 5 6	4,5,6*		P.C. + No.6 Oil	433(410)	9.2	--	209(357)	--	--	--
159-6	0 0 0 1 2 3	7,8,9**			422(400)	8.9	--	177(302)	--	--	--

*P.C. fired in 7,8,9; Oil fired in 1,2,3
**P.C. fired in 4,5,6; Oil fired in 1,2,3

The results obtained during test series 119 shown in Figure 5-20 are typical of the results obtained during Phase II. These tests were conducted on a 158 GJ/hr (150,000 lb/hr) watertube boiler fired by No. 6 oil through two burners in a vertical arrangement. During these tests the fuel flow to the top burner was terminated and the theoretical air level of the in-service burner varied by controlling the total air flow and/or the register setting of the out-of-service burner. The maximum load obtainable with the top burner out of service was 74 GJ/hr (70,000 lb/hr steam flow). These tests resulted in nitrogen oxides reductions of 29-31% with the top burner out of service. Adjusting the out-of-service burner register had little effect on the results. Opening the top burner register which increased the burner air level of the in-service burner required the excess oxygen level to be raised to 7.1% in order to prevent smoking. Also, the particulate emissions were 2.7 times higher with the top burner out of service and the boiler heat loss efficiency dropped from 87% to 86%.

A three burner boiler with a horizontal burner pattern was tested with natural gas during test series 124. The middle burner was taken out-of-service and the middle register used along with the total air flow to control the level of the air at the burner of the in-service burners, with the overall excess oxygen held constant at 5.5%. The nitrogen oxides emissions were reduced by 55% with this configuration as seen in Figure 5-21. The efficiency remained at 83% with burners out of service and the carbon monoxide emissions only increased to 16 ng/J (50 ppm) at the maximum nitrogen oxides reduction condition.

If the fuel and air going through a burner are well mixed, one expects the level of the theoretical air at the operating burners to be the controlling parameter for nitrogen oxides formation. This control is apparent for the multi-jet ring burner of test series 124

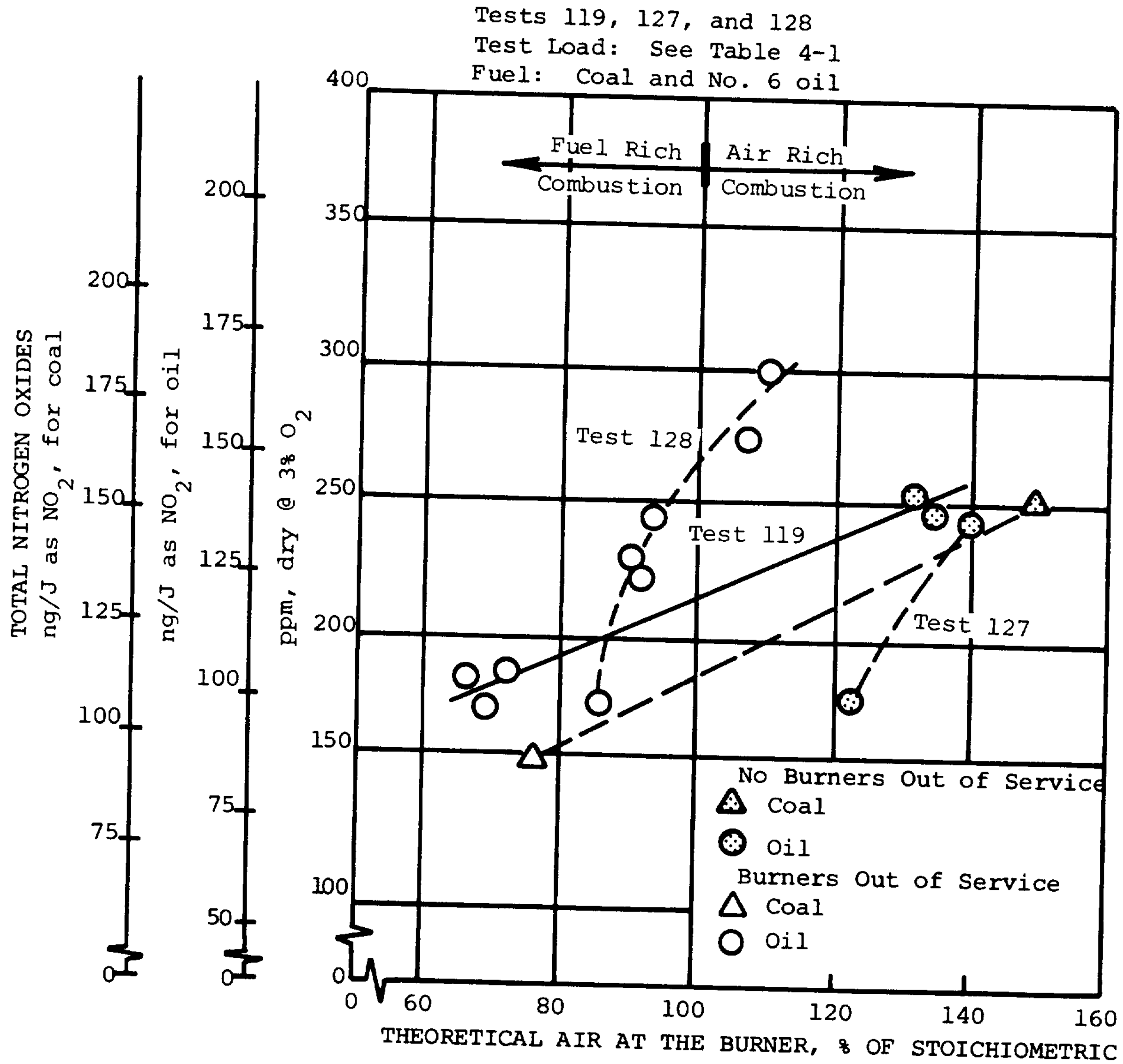

Figure 5-20. Reduction in total nitrogen oxides due to burners out of service, coal and oil fuels.

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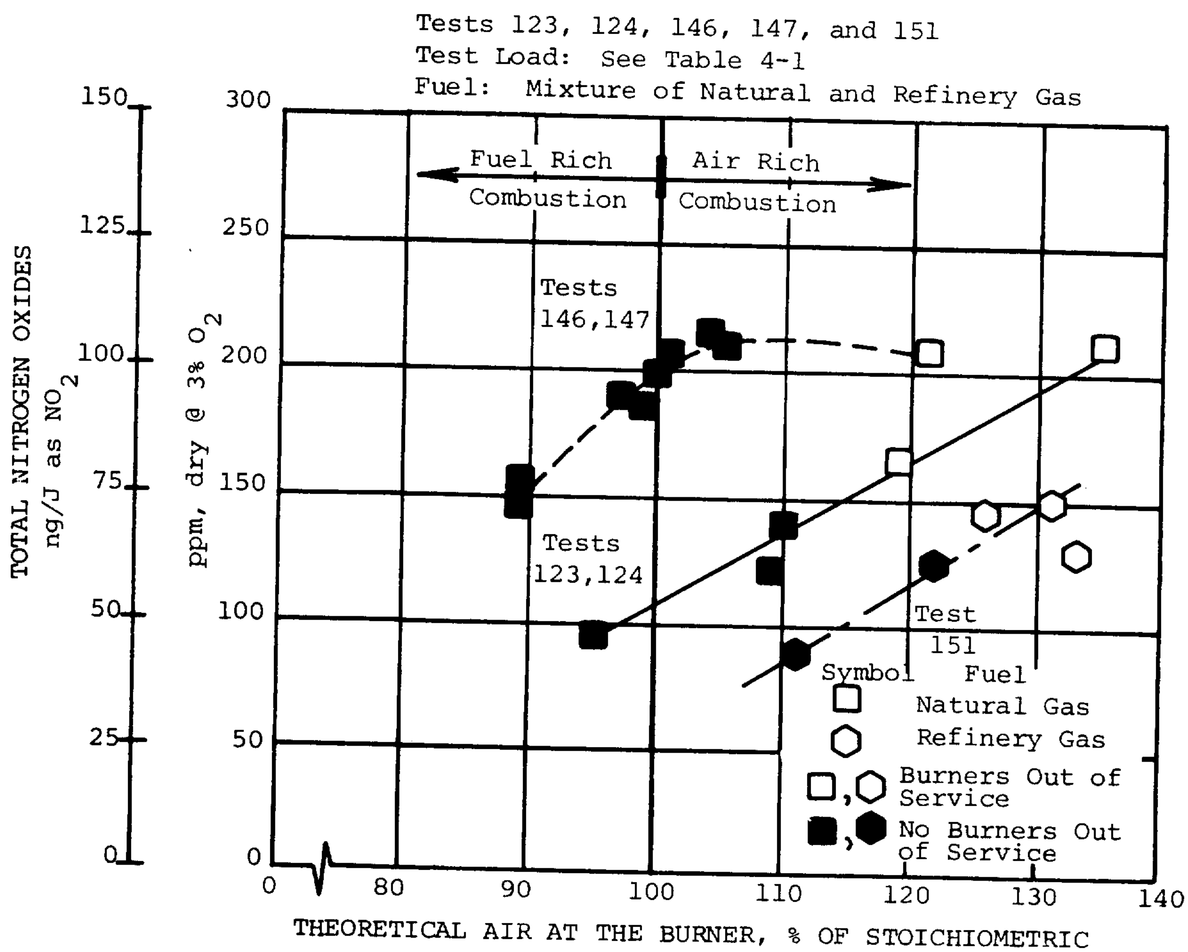

Figure 5-21. Reduction in total nitrogen oxides due to burners out of service, mixture natural and refinery gas fuel.

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the results of which are plotted on Figure 5-21. Figure 5-21 also shows a good correlation of the natural gas nitrogen oxides emissions data with the burner theoretical air level whether the theoretical air level is obtained by low-excess-air-firing of all the burners or by taking a burner out-of-service.

The same three burner unit discussed above also was fired with No. 6 oil with the center burner out of service during test series 127. As is illustrated in Figure 5-20, the nitrogen oxides was not reduced during this test series with oil fuel as it had been with natural gas fuel. The nitrogen oxides emissions were not a strong function of the in-service burner theoretical air level but rather of the overall excess air in the boiler. This dependence would occur if the fuel and air mixing did not occur in a short distance from the burner, but actually on a length scale comparable to the burner spacing or furnace length. For this case, removing a burner from service would not have grossly altered the fuel and air mixing process in the furnace, and the nitrogen oxides emissions would have been primarily dependent on the overall excess air level in the boiler (e.g. the burner was naturally staged).

A four burner boiler with a square burner pattern, two rows and two columns, was tested in series 133 with pulverized coal fuel. As indicated in Table 5-3, a 40% reduction in nitrogen oxides emissions from 618 to 378 ng/J (1011 and 618 ppm) was achieved by removing the top two coal burners from service and using the burner ports for air injection. The carbon monoxide emissions were zero for all tests and boiler efficiency did not change from the baseline condition of 81% when the top burners were taken out of service.

A smaller unit with a square burner pattern was tested with natural gas in series 147. With either one of the top burners out of service, nitrogen oxides emissions were reduced to about 100 ng/J or at most 10%. This change appeared to be due to a reduction in overall excess air level and not necessarily to a change in the burner theoretical air level due to removing a burner from service. When the top two burners, numbers 3 and 4, were removed from service, the reduction in burner theoretical air was a dominant factor and the nitrogen oxides emissions were reduced to about 75 ng/J or by 25% with little change in carbon monoxide emissions.

During test series 151, burners were removed from service from an eight burner boiler firing refinery gas. Removing a bottom center burner (#2) from service resulted in 17% reductions in nitrogen oxides emissions with no increase in carbon monoxide levels. When an additional bottom burner was removed (#4), a 40% reduction in nitrogen oxides was realized; although there was an increase in the carbon monoxide levels from less than 35 ng/J to 139 ng/J.

Since modifications to the fuel delivery systems were not possible, this limited the scope of testing during Phase II to low load setting on the units. Testing at these low loads can limit the effectiveness of "burners-out-of-service" in the following ways:

1. The air pressure drop across the burner is reduced which can result in reduced fuel/air mixing rates in the near-burner region.
2. Mixing between in-service and out-of-service burners will be reduced due to the decreased momentum. This can result in too much heat transfer from the fuel-rich region precluding CO and smoke burn-out upon mixing with the air from the out-of-service burner.

On existing units without modifications to the fuel delivery system, operation with burner out of service requires that the unit be derated. The load limit is determined by the number of burners removed from service. If actually applied as a nitrogen oxides control technique, modification to the fuel delivery systems of the in-service burners would be required to allow operation at full load, such as increasing the oil burner tip orfice and fuel line sizes.

5.1.2.4 Other Staged Air Test Results -

The staged air results obtained from the oil and gas fired units can be compared to previous studies of "staged combustion" in single burner commercial and industrial type boilers that have been conducted. The application of staged combustion to an 883 kw (90 boiler horsepower) firetube-type combustor was studied by Muzio, et al.,[12] and Turner and Siegmund[11] applied staged combustion to a 490 kw (50 boiler horsepower) Cleaver Brooks firetube boiler.

In the studies conducted by Muzio, et al., the "staged" air was injected downstream of the burner through sidefire ports located along the sides of the combustor or through a water-cooled rear boom. The results of this study indicated that:

1. Staged combustion resulted in 20% to 25% reductions in nitrogen oxides while firing No. 6 oil. (The burner was operated with a theoretical burner air level of 93% and 17% overall excess air.)

2. Downstream air injection increased nitric oxide unless it was injected at least 1.5 combustor diameters downstream from the oil nozzle. This result indicates that for the particular burner studied, the near-burner flame was effectively "naturally staged" without any deliberate method of staging the combustion. [The same appears to have been true of the unit at Location 19 that was investigated during test series 190 to 206 of Phase II.]

In the studies by Turner and Siegmund, the staged air was added to the combustion gases through a rear injector. The location at which the air was added was fixed. The length of the combustion section was increased by 0.9 meters (3 feet) and provision was made to vary the amount of cooling of the burner combustion products prior to adding the air. With the 490 kw (50 boiler horsepower) unit fired with residual oil, their results showed:

1. Nitrogen oxides reductions on the order of 33% were achieved.

2. The amount that the combustion products were cooled prior to adding the staged air did not significantly affect the level of nitrogen oxides reduction.

3. The nitrogen oxides reductions were obtained without smoke emissions becoming a problem.

The differences in the results of these studies further indicates the variability between boilers and the influence that this can have on the successful application of a nitrogen oxides reduction technique.

5.1.3 Air Register Adjustments

During Phase I and Phase II the local air/fuel mixture ratio was controlled by varying the burner air register settings. Air registers on face-fired boilers typically consist of a group of interconnected vanes oriented so that they all move simultaneously. This movement varies the area and angle through which the air enters the burner, providing control of the air flow rate and degree of swirl. The area and direction are usually changed simultaneously by a lever mechanism, so that a decreasing flow area is accompanied by increased air speed and swirl. On most of the small single burner boilers tested, the vanes on the register were bolted or tack-welded in a fixed position, thus the effect of swirl could not be investigated. On the large single burner or multiple burner boilers a single adjustable register usually was utilized. The boilers at Locations 32, 36, 29 utilized a single burner with dual registers which could be manually adjusted to control the flow rate and swirl of the secondary and tertiary air.

Experience with multi-burner boilers has shown the most important effect of air register adjustments to be the altering of the air flow distribution between the burners. The swirl effect on the NOx production of an individual burner usually appeared to be relatively small. At constant air flow, closing an air register should increase the swirl, resulting in increased mixing and a shorter, more intense flame. However, this increased swirl had less effect on NOx production than did the change in air flow rate.

Table 5-4 summarizes the results of tests run on face-fired boilers where the excess air and load were held practically constant, while the air register settings were changed. The column entitled "Burner Pattern" shows the number and arrangement of the burners and registers.

The data for face-fired boilers presented in Table 5-4 incorporate two effects: (1) effect of swirl, (2) effect of air distribution among the burners in multiple burner units. The effect of swirl on nitrogen oxides emissions can be seen in the data from tests 30, 70, and 10. Opening the registers (e.g., reducing the swirl level) for both Tests 30 and 70 resulted in slight increases in nitrogen oxides emissions. For Test 10 opening the registers from the 65/65 position to the 100/100 position also caused the nitrogen oxides emissions to increase, although a portion of the increase was due to an inadvertent increase in the excess oxygen level.

The effect of swirl can be explained by considering the general flow patterns of a swirling flame as shown in Figure 5-22.

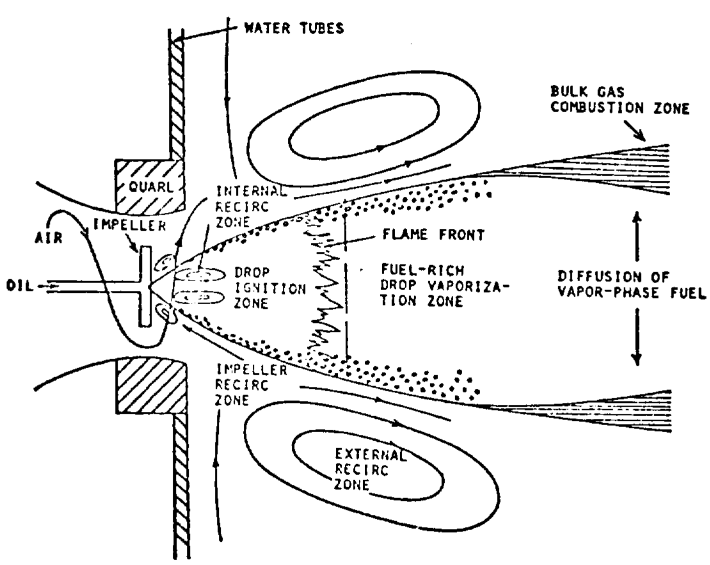

Figure 5-22. Idealized flame flowfield.

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Table 5-4. EFFECT OF AIR-FUEL MIXING BY CHANGING THE AIR REGISTER SETTING

Face-Fired Boilers

Test Run Number	Fuel Type	Test Load GJ/hr (10^3 lb/hr)	O_2 %	Burner Pattern	Register Setting % Open	NOx Meas ng/J (ppm)	NOx Change %	Comments	Major Effect
30-14	NG	273 (259)	3.0	0 0	70	100 (197)	--	Baseline	
30-19	NG	268 (254)	2.8	0 0	100	104 (204)	+3.5	All 4 registers reset	
70-11	#2	106 (100)	6.6	0	50	215 (383)	--	Baseline	Swirl decreases as register is opened.
70-10	#2	106 (100)	6.6		100	227 (405)	+5.7		
10-2	#6	57 (54)	4.7		65/65	104 (186)	--	Baseline	
10-12	#6	52 (49)	3.9	0 0	100/45	98 (174)	-6.5		
10-10	#6	54 (51)	5.2		100/100	128 (228)	+22.6		
7-10	#2	93 (88)	5.7	0	100/100	99 (177)	--	Baseline	Redistribution of air among burners with changes in register setting
7-13	#2	87 (82)	6.6	0	100/70	101 (180)	+1.7		
143-3	NG	88 (83)	4.4		$\frac{50}{60}$ $\frac{60}{60}$	117 ([illegible]30)	--	Baseline	
148-1	NG	87 (82)	4.2	0 0	$\frac{45}{40}$ $\frac{40}{50}$	101 (199)	-13.4	Bottom closed more than top	
148-3	NG	87 (82)	4.0	0 0	$\frac{45}{30}$ $\frac{40}{40}$	97 (190)	-17.4	Bottom closed further	
148-4	NG	87 (82)	4.7		$\frac{45}{30}$ $\frac{40}{30}$	111 (218)	-5.2	Bottom closed further	

At a fixed air flow, as the registers are closed the level of swirl increases. This increased swirl will cause increased mixing between the burning gases of both the external recirculating flow and the internal recirculating flow. The gases comprising the external recirculation zone are bulk gases at the relatively low bulk gas temperatures, having had heat removed by radiation to the cooler water walls; whereas, the gases in the central recirculation zone are combustion products near their adiabatic flame temperature. Thus if the state of the swirling flow is such that an increase in swirl predominantly increases the mixing between the burning gases and gases from the external recirculation zone, the nitrogen oxides emissions would be expected to decrease due to the quenching effect of the cooler external bulk gases. In a flow regime where increased swirl primarily effects the mixing of the internal recirculation zone one would expect increasing nitrogen oxides emissions with increased swirl. It appears that the burners tested during Phase I and Phase II were operating in a region where opening the registers (decreasing swirl) primarily increased the mixing with the internally recirculating gases thus causing an increase in nitrogen oxides emissions.

On multiburner units changing air register settings on individual burners not only changed the swirl at the burner but also, and most important, changed the air distribution between the burners. On a unit with two rows of burners, top and bottom, closing the bottom row will reduce the air flow to the bottom (while increasing its swirl) and increase the flow to the top row. This will have the following effect on the nitrogen oxides formation:

- The bottom rows will tend to produce less nitrogen oxides per burner due to the reduction in the local excess air level at the burner.
- The increased swirl at the bottom burners will also tend to reduce nitrogen oxides formation; based on the Phase I and Phase II data.

The nitrogen oxides formation in the top burners will tend to increase due to the increased local oxygen levels at the top burners.

For Test No. 7 it appears that the increase in oxygen level at the top burner was the predominant effect resulting in an overall slight increase (1.7%) in nitrogen oxides emissions. For Tests 143 and 148 the opposite was found. Initially, as the registers were closed the nitrogen oxides emissions decreased indicating that the increased swirl and decreased local oxygen levels at the bottom row were the predominant factors. However a point was reached where further closing of the bottom registers (Test 148-4) resulted in an increase in nitrogen oxides emissions from 107 to 122 ng/J (190 to 218 ppm). Presumable this was due to the increased oxygen levels at the top burners becoming the more important factor.

Particularly interesting results were obtained from tests conducted on a dual register (Peabody type HT) burner with an 84 cm (33 inch) diameter throat operating on natural gas. The dual air register design consisting of conical registers at the rear of the burner which determine the amount and swirl of the center air (secondary) and cylindrical registers just upstream of the burner throat which determine the amount and swirl of the outer (tertiary) air. The ring burner injects gas radially into the swirling air streams. Figure 5-23 shows a diagramatic sketch of the burner.

The dual register design allows extreme flexibility in tailoring flame shape to a particular furnace geometry. Test series 140 and 141 involved adjusting the registers to reduce the flow resistance to the center air passage relative to the outer air passage. The normal register settings had both the secondary (center) and tertiary (outer) air registers set at the sixth notch out of a total of 13 notches (13 is full open). Table 5-5 summarizes the effect of these air register adjustments on nitrogen oxides and carbon monoxide emissions and the differential pressure, ΔP, between the windbox and furnace.

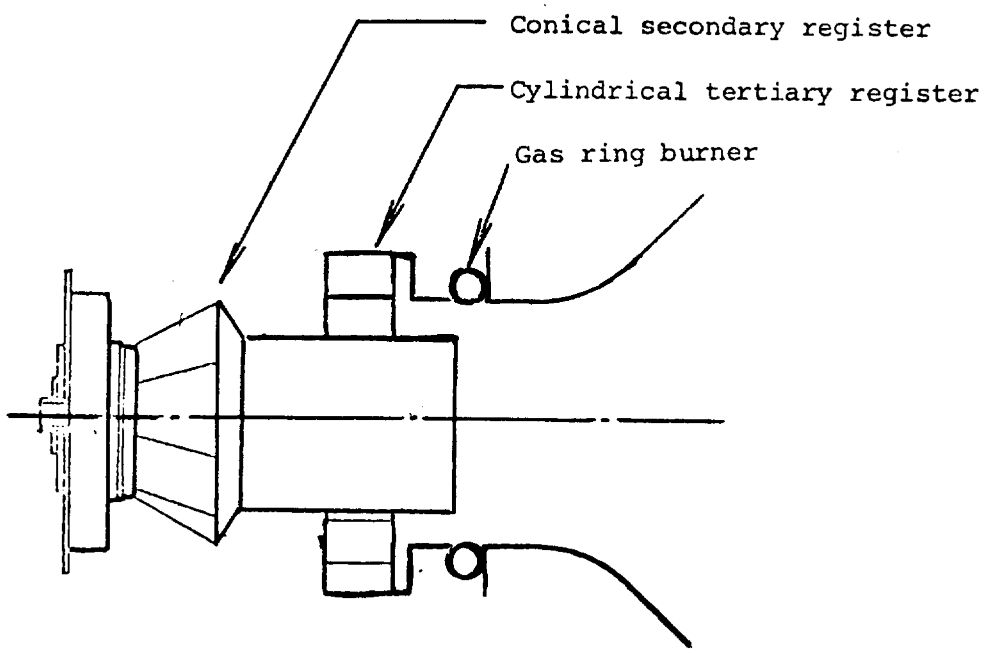

Figure 5-23. Peabody HT dual register burner

Table 5-5. EFFECT OF DUAL REGISTER ADJUSTMENTS ON NOx AND CO EMISSIONS

Test	Load GJ/hr (10^3lb/hr)	Excess O_2 %	Register Setting secondary/ tertiary*	NOx % Change	NOx ng/J (ppm @ 3% O_2)	CO ng/J (ppm @ 3% O_2)	ΔP kPa (IWG)
140-2	81 (77)	7.1	6/6	--	83 (163)	70 (227)	1.69 (6.8)
141-5	85 (81)	6.7	7/6	+20	100 (196)	0 (0)	2.32 (9.3)
141-6	84 (80)	6.7	7/5	+43.5	119 (234)	18 (58)	2.86 (11.5)

* a setting of 13 is fully open (radial flow)

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One would expect that opening the secondary register, with all other variables fixed, would result in a decrease in the differential pressure between the windbox and furnace. As is apparent from Table 5-5 this was not found to be the case and the differential pressures increased. This can be explained as follows: As more air is diverted to the center passage (secondary air) the relative velocity between the natural gas jets and the tertiary air decreases. The gas jets will not be deflected downstream as much by the tertiary air, thus penetrating closer to the center line of the burner. The flame will then be moved closer to the burner throat, and the density change and its effect on the central recirculation zone will increase the flow resistance through the throat. This change in flame location also results in a more intense flame with increased nitrogen oxides production.

The effect of air register adjustments on emissions is presented in Figures 5-24 and 5-25. The registers are adjustable in a range of zero to 100%, with a setting of zero corresponding to fully-closed while 100% is fully-open with the register vanes radial to the burner center. In Figure 5-24 the tertiary air register setting is constant at 70% and emissions vary as the secondary air register is adjusted. Emissions increase from 250 ppm to a maximum of approximately 265 ppm as the secondary setting is increased from 50 to 70%. Then emissions drop sharply to 236 ppm as the secondary setting is further increased to 90%. Figure 5-25 shows that emissions increase as the tertiary register is moved from 60 to 85% with a secondary setting of either 55 or 70%. The highest total nitrogen oxides reading of 292 ppm was obtained with secondary and tertiary air register settings of 70 and 85%, respectively.

Test Run Nos. 174-1 thru 174-16
Rated Capacity: 84 GJ/hr (80×10^3 lb/hr)
Test Load: 66 GJ/hr (63×10^3 lb/hr)
Fuel: No. 6 Oil
Excess O_2: 3.5%

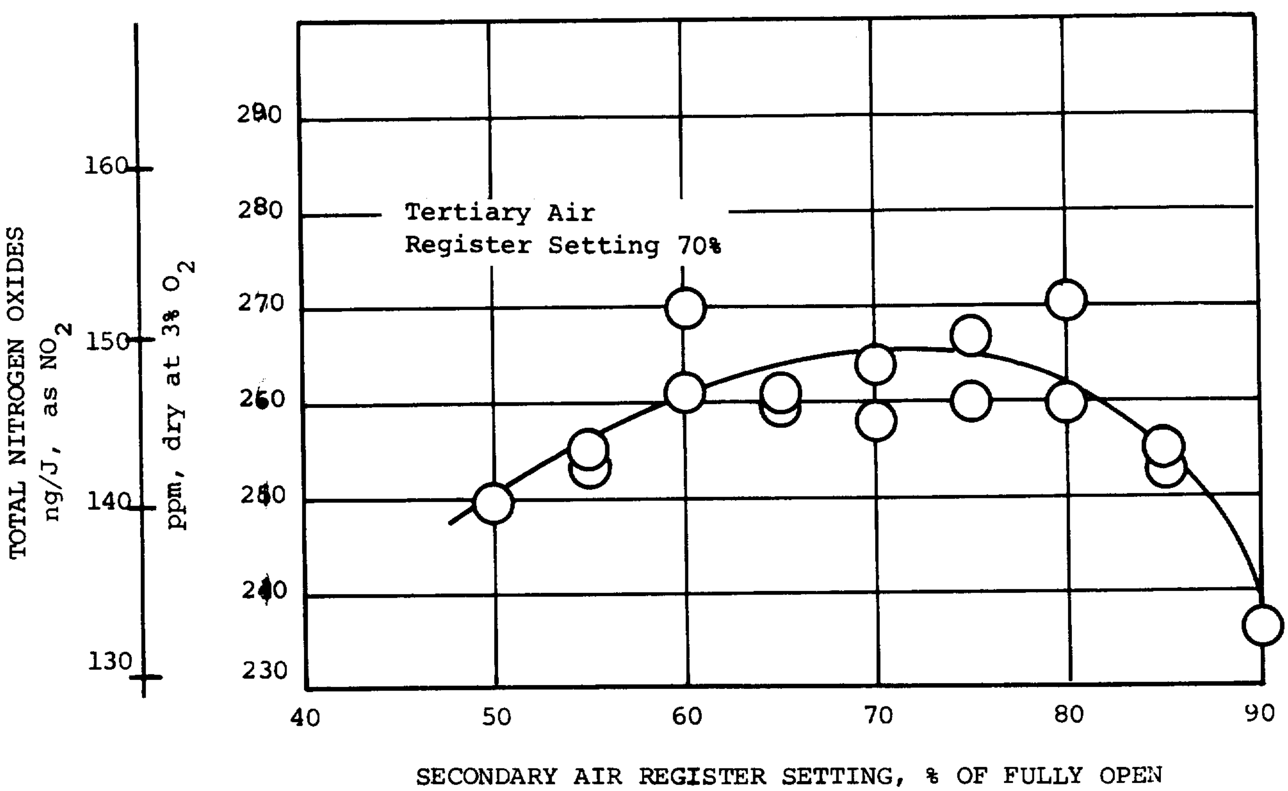

Figure 5-24. Effect of secondary air register setting on total nitrogen oxides emissions.

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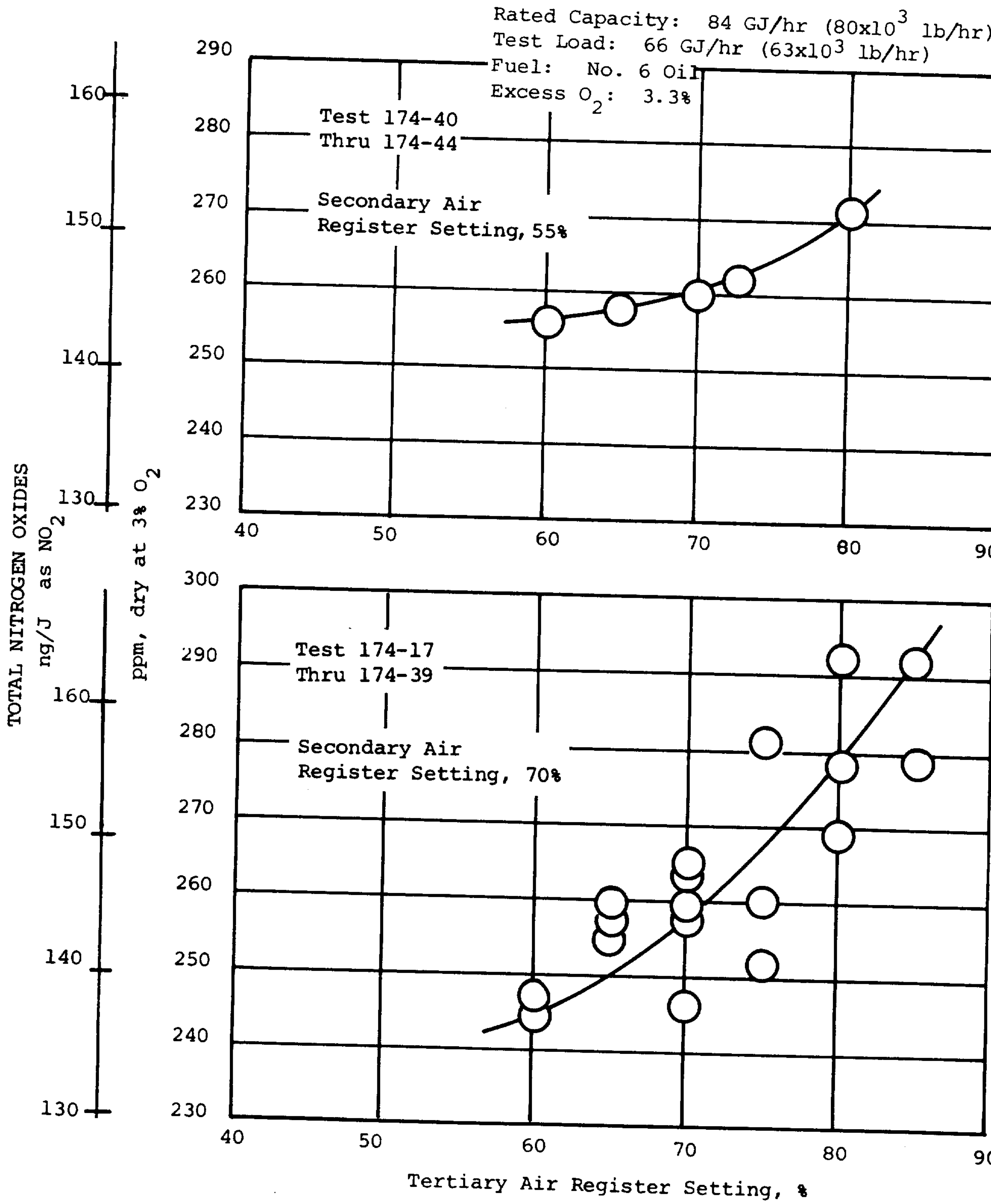

Figure 5-25. Effect of tertiary air register setting on total nitrogen oxides emissions.

The effect of secondary damper position on NOx emissions and smoke levels is shown by the results of testing done at Location No. 36 and presented in Figure 5-26. In addition to the secondary damper percentage open, an approximate ratio of secondary to primary air flow is noted on the ordinate. Opening the secondary damper to its 100% open position decreased the amount of primary air, resulting in decreased fuel air mixing rates near the burner and a 22% reduction in nitrogen oxides emissions. However, the reduction in nitrogen oxides was obtained through a tradeoff in smoke level. The smoke level increased by three Bacharach smoke numbers.

A couple of tests were performed to investigate the effect of secondary register position (swirl) on the NO_x emissions from the unit. Due to the low air velocities through the burner at low loads, at which the test series was conducted, register setting (or swirl) had no effect on the emissions.

In general the tests involving air register adjustments on these face-fired boilers have shown the following:

- Decreasing swirl (opening registers) on single register burners tended to increase NO_x emissions by 3 to 20%.
- The major effect on NO_x of register adjustments on multiple burner units is due to an alteration of the air distribution between the individual burners, and not to changes in swirl.
- On dual register burners the major effect of register adjustment on NO_x emissions appears to be the redistribution of air between the secondary and tertiary air passages with swirl playing a minor role.

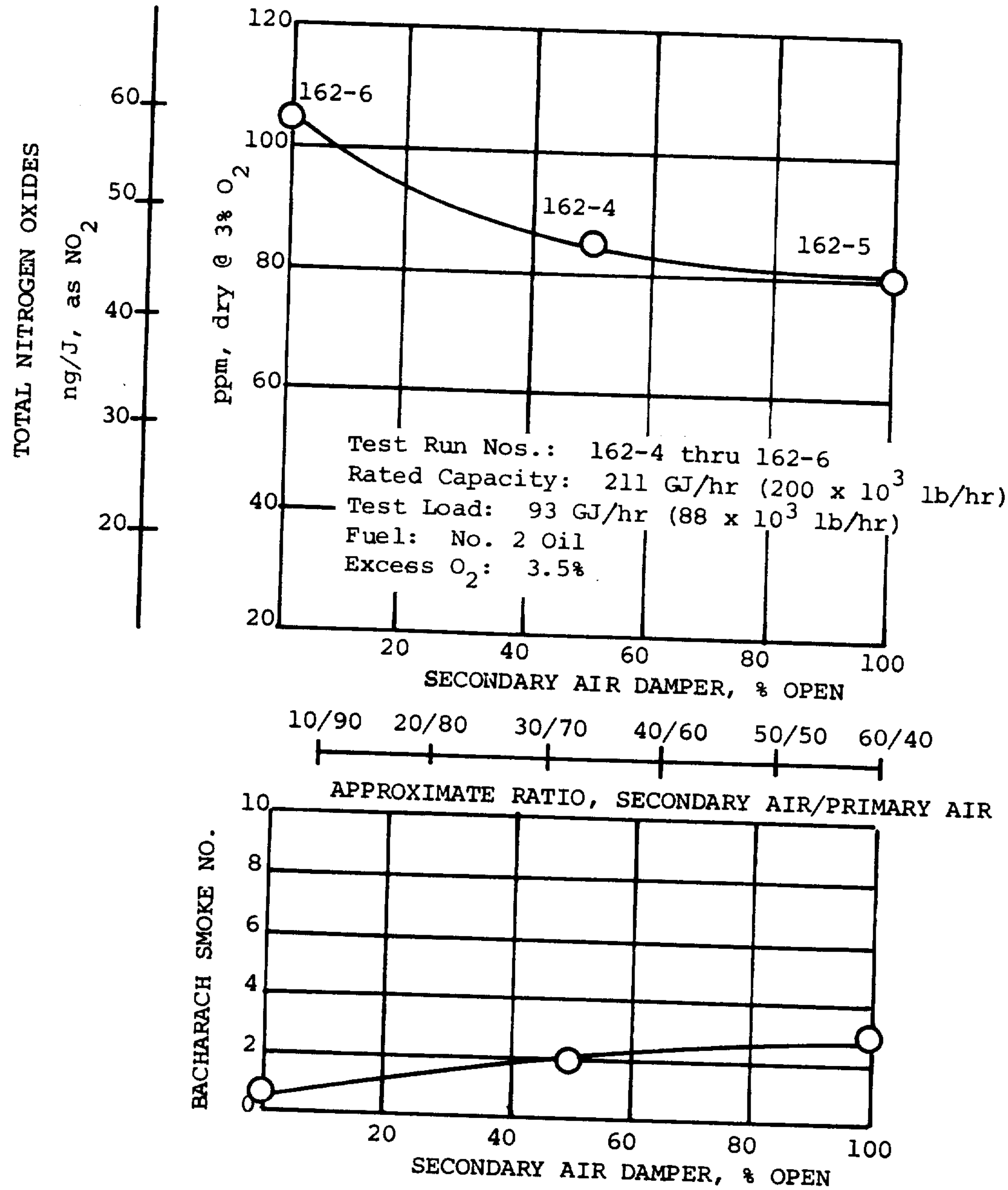

Figure 5-26. Effect of secondary air damper position on total nitrogen oxides emissions and smoke level.

6001-43

5.2 ENTHALPY MODIFICATION

5.2.1 Combustion Air Temperature

Boilers that have combustion air preheat are usually found in sizes above 53 GJ/hr (50,000 lbs steam/hr) and preheat air temperatures typically are in the range of 400 K to 600 K (250° to 650°F). The level of combustion air preheat has a direct effect on the temperatures in the combustion zone. For example a 50 K decrease in air temperature results in approximately a 25 K reduction in the adiabatic combustion temperature which can have a direct impact on the formation of thermal nitrogen oxides. Figure 5-27 (from Ref. 13) shows a prediction of the kinetic effect of the combustion air temperature on nitrogen oxides formation. The calculations predict a reduction in thermal nitrogen oxides formation of 0.5% per 1 K (27% per 100°F) decrease in air preheat. Since the air preheat temperature primarily affects the thermal nitrogen oxides formation it is expected that preheat will have its greatest effect, in terms of percent change, on fuels with low fuel nitrogen contents (e.g. natural gas and distillate oils).

During Phase II, combustion air temperature was varied on six separate units. However at three locations, Nos. 28, 29, 32, the air temperature only could be increased by a maximum of 8 K due to the nature of the air preheater system. When this was done the nitrogen oxides increased. The other three units had capabilities for varying the combustion air temperature on the order of 100 K (150°F). The results for the latter three boilers are presented in Figure 5-28 for both natural gas and oil fuels together with the results from Test No. 177 where the temperature was varied by only 50 K. The shaded points in Figure 5-28 represent the normal air temperatures for the units. Except for the test series 177, nitrogen oxides emissions decreased by about 22 ng/J (45 ppm) per 50 K decrease in combustion air temperature.

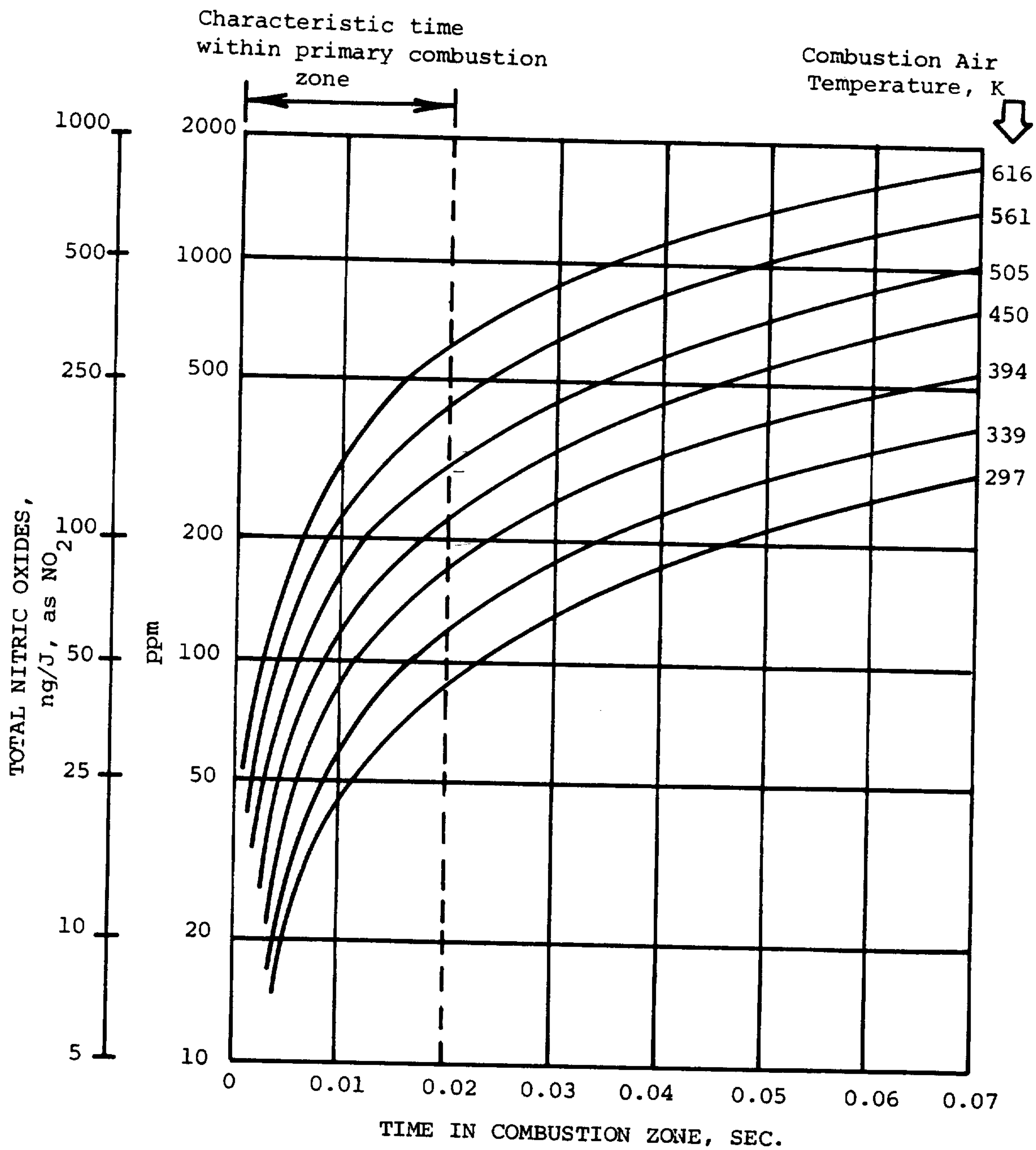

Figure 5-27. Effect of combustion air temperature and time within the primary combustion zone on total nitric oxides formation

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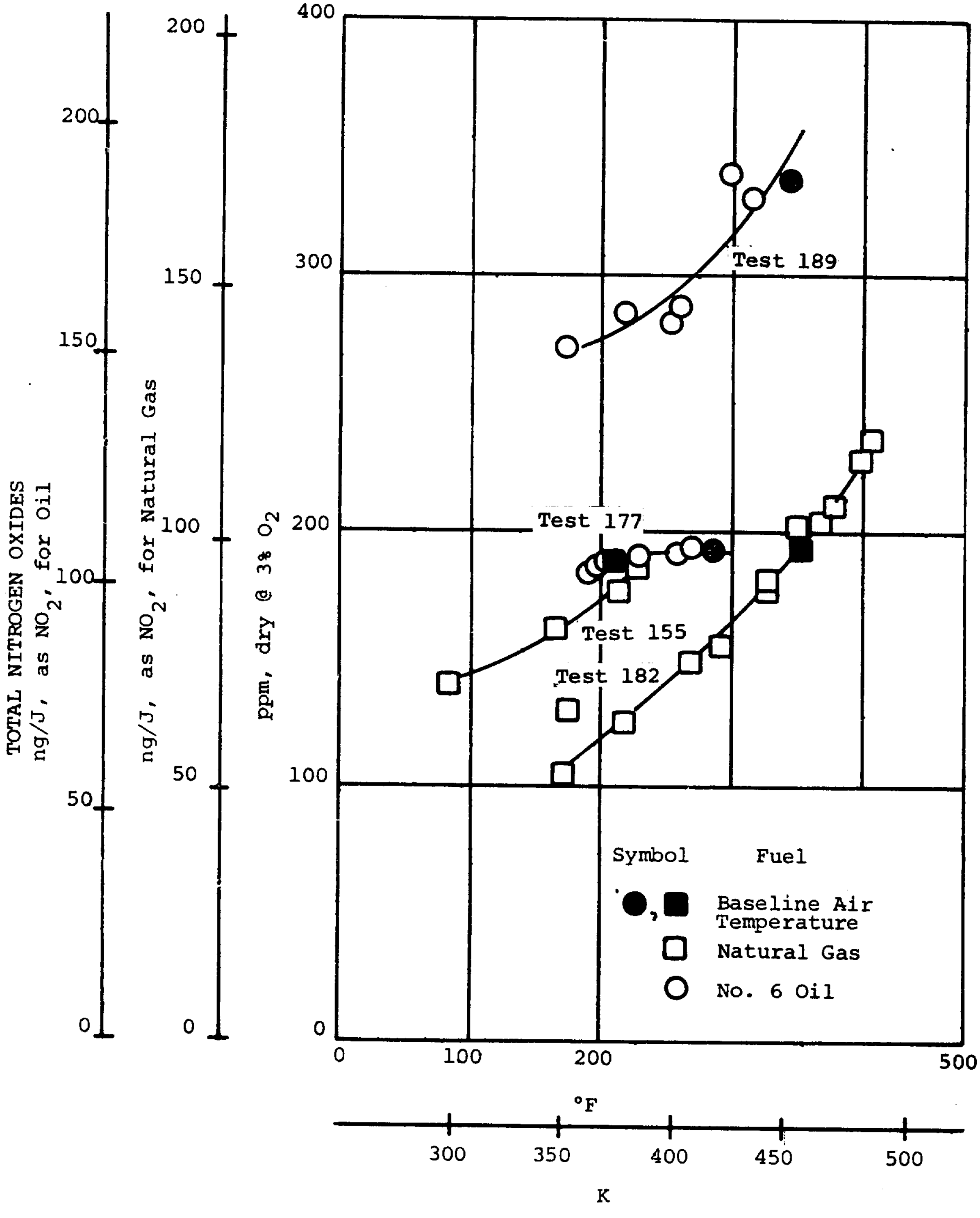

Figure 5-28. Effect of combustion air temperature on total nitrogen oxides emissions, gas and oil fuels

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Test series 155 was performed on a 264 GJ/hr (250,000 lb steam/hr) gas-fired, watertube unit. The test conditions were 211 GJ/hr (200,000 lb/hr steam flow) and 2.6% excess oxygen. Reducing the combustion air temperature from the normal 389 K (240°F) to 300 K (80°F) dropped the NO emissions by 25% or by 14 ng/J (29 ppm) per 50 K change in preheat temperature.

During test series 182 the combustion air temperature was varied over the range of 550 K to 480 K (167°F to 408°F) on a gas-fired watertube boiler rated at 47 GJ/hr (45,000 lb/hr steam flow). The NO emissions were quite sensitive to air temperature over this range exhibiting an increase of 26 ng/J (50 ppm) per 50 K (90°F) increase in combustion air temperature.

The effect of combustion air temperature with No. 6 oil firing was also investigated on the same 47 GJ/hr watertube boiler during test series 189. The nitrogen oxides emission decreased by 20 ng/J (66 ppm) (20%) as the combustion air temperature was reduced from about 430 K to 350 K (320°F to 175°F). This corresponded to a sensitivity of 23 ng/J (41 ppm) increase in nitrogen oxides per 50 K (90°F) increase in air preheat temperature which was similar that observed while firing natural gas. A similar effect was not expected since changes in air preheat primarily effect the thermal nitrogen oxides formation and the nitrogen oxides emissions from No. 6 oil are due in a large part to the conversion of the fuel nitrogen to nitrogen oxides.

Nitrogen oxides emissions varied by only 3.7 ng/J (6 ppm) per 50 K increase in the 42 GJ/hr (40,000 lb/hr) unit tested during series 177. The unit was firing No. 6 oil at a load of 34 GJ/hr (32,000 lb/hr steam flow) with a normal air preheat temperature of about 95 K (200°F). It appeared that the thermal nitrogen oxides emissions, as opposed to the fuel nitrogen NO_x emissions, were initially low for this test and that changes in air preheat temperature had a small effect on the overall nitrogen oxides formation.

Reducing the air preheat temperatures as a means of reducing nitrogen oxides emissions will result in a decrease in the boiler efficiency of about 2.5% per 50 K increase in stack temperature. Thus, it will be necessary to increase the effectiveness of the boiler heat exchange components, e.g., increase economizer area, in order to maintain overall boiler efficiency if this is used as an nitrogen oxides control technique.

5.2.2 Flue Gas Recirculation

Testing of utility size boilers has established that the recirculation of flue gas into the combustion air reduces flame temperatures in the furnace and is similar in concept to other low enthalpy firing techniques, such as reduced combustion air preheat. The effectiveness of flue gas recirculation on utility boilers in reducing the thermal nitrogen oxides emissions is dependent upon burner heat release rate and the type of fuel being fired. Generally nitrogen oxide emissions from gas fuels are more affected by recirculation than are the emissions from oil or coal fuels. The reason is deemed to be that with oil and coal fuels the nitrogen oxides formation resulting from the conversion of fuel nitrogen to nitrogen oxides are significant, and they are influenced but little by flue gas recirculation.

For the flue gas recirculation investigation the watertube furnace boiler at Location No. 19 was modified following the Phase I testing. The flue gas recirculation tests achieved reductions in nitrogen oxides of 73% and 36% with natural gas and No. 6 fuel oil firing, respectively. Reductions typically had not been so large in utility boilers.

The boiler was the watertube furnace design with a rated capacity of 18.5 GJ/hr (17,500 lb/hr steam flow), and the majority of testing was done at a load of approximately 15 GJ/hr. Ambient temperature combustion air was fed to a single burner by a forced draft fan. Natural gas fuel was injected through a ring type burner.

The No. 6 oil fuel at an approximate temperature of 375 K (200°F) could be atomized by either air or steam. Saturated steam at a pressure of 1.14×10^6 Pa (150 psig) was generated and the stack gas temperature was approximately 530 K (500°F).

The flue gas recirculation installation is pictured in Figure 5-29. The flue gas was drawn from the bottom of the smoke stack by a flue gas recirculation fan as indicated in the photograph. The flue gas was pumped through the recirculation duct and up into the right hand side of the windbox through a windbox addition that had been fabricated.

The windbox had been lengthened to accommodate the flue gas inlet and an additional set of registers was installed within the lengthened section to give the flue gas swirl before it mixed with the combustion air. The combustion air came in through the top of the windbox and through the original burner registers. The amount of flue gas being recirculated was controlled by a butterfly valve located in the recirculation duct.

Tests 192, 197, and 202 were conducted with natural gas, steam-atomized No. 6 oil, and air-atomized No. 6 oil fuels. Test 206 was also run in which the fuel was a 50/50 combination of natural gas and air atomized No. 6 oil fuel.

The results for the gas fuel tests (Test 192) are presented in Figure 5-30 wherein nitrogen oxides emissions are plotted as a function of the percentage of the flue gas recirculation. The percentage of the recirculation is defined here as the mass of the recirculated flue gas divided by the sum of the mass of the recirculated gas and the mass of the combustion air. Baseline total nitrogen oxides emissions were 31 ng/J (60 ppm) with no recirculation. Adding approximately 20% flue gas recirculation reduced emissions by 50%, down to 15 ng/J (30 ppm). Emissions

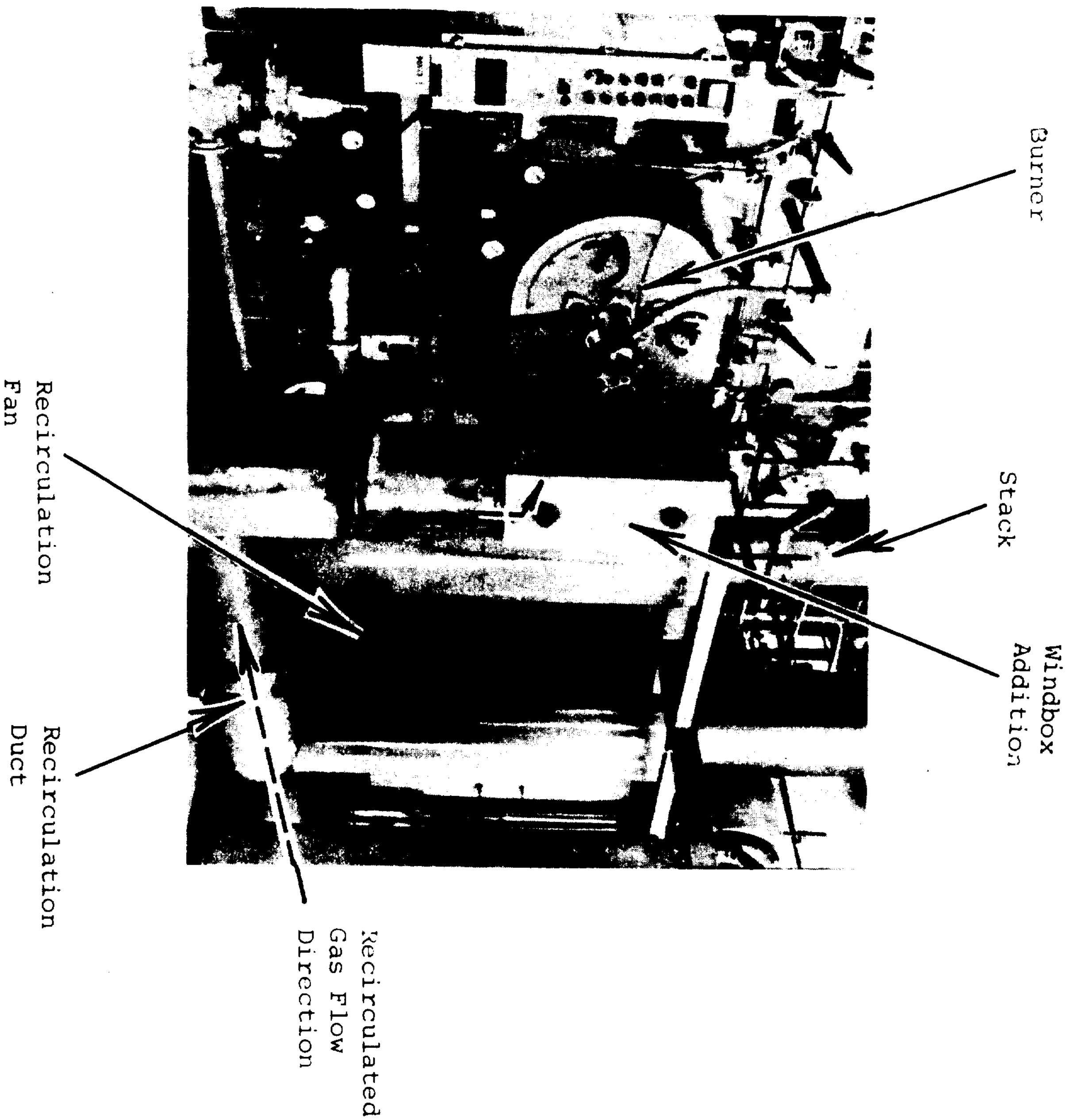

Figure 5-29. Flue gas recirculation installation at Location No. 19 for Test Nos. 192, 197, and 202.

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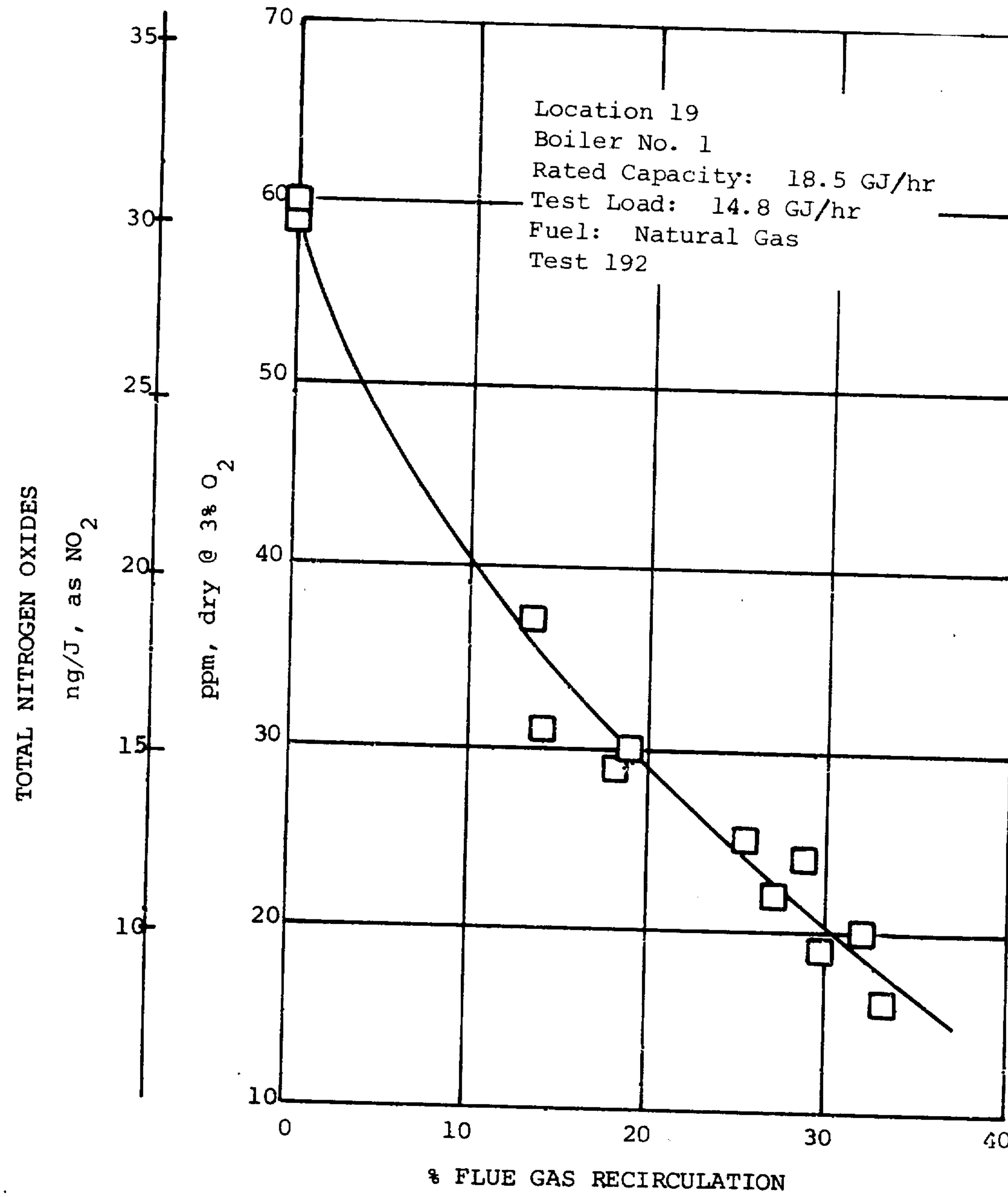

Figure 5-30. Effect of flue gas recirculation on the total nitrogen oxides emissions, natural gas fuel.

6001-43

were lowered to a minimum of 8 ng/J (16 ppm), for a total nitrogen oxides reduction of 73%, by introducing 33% flue gas recirculation. Variations in the excess air level effected NOx emissions only slightly.

The effects of flue gas recirculation on nitrogen oxides emissions from No. 6 fuel oil firing are illustrated in Figure 5-31. Test 197 was conducted with steam atomization and Test 202 with air atomization. Baseline nitrogen oxides emissions with steam atomization were 95 ng/J (170 ppm) at the nominal excess oxygen of 3%. Adding 20% flue gas recirculation lowered steam atomized No. 6 oil nitrogen oxides emissions by 15% to 81 ng/J (145 ppm). By reducing the excess oxygen to 2%, the nitrogen oxides emissions with 20% recirculation were dropped to a minimum of 74 ng/J (132 ppm), representing a total reduction of 50% for steam atomization.

The effects of flue gas recirculation on the total nitrogen oxides emissions from air atomized No. 6 oil with the nominal excess oxygen level were not quite as pronounced. Baseline emissions with 3% excess oxygen were 90 ng/J (162 ppm). Using 20% flue gas recirculation reduced the nitrogen oxides by 8% to 83 ng/J (148 ppm). Using 25% recirculation resulted in a further drop to 80 ng/J (142 ppm), a total reduction of 11%. With the lower excess oxygen of 2%, the nitrogen oxides emissions were reduced further. At 18% recirculation the nitrogen oxides emissions were 71 ng/J (126 ppm). At 27.5% recirculation, emissions were lower at 65 ng/J (116 ppm). By cutting the excess oxygen still further to 1.3% and running with approximately 24% flue gas recirculation the emissions were a minimum of 58 ng/J (104 ppm), representing a total reduction of 35% from baseline conditions for air atomization. For oil firing, flue gas recirculation rates greater than 27% caused flame instability and blow-out. No test data was obtained with higher recirculation rates.

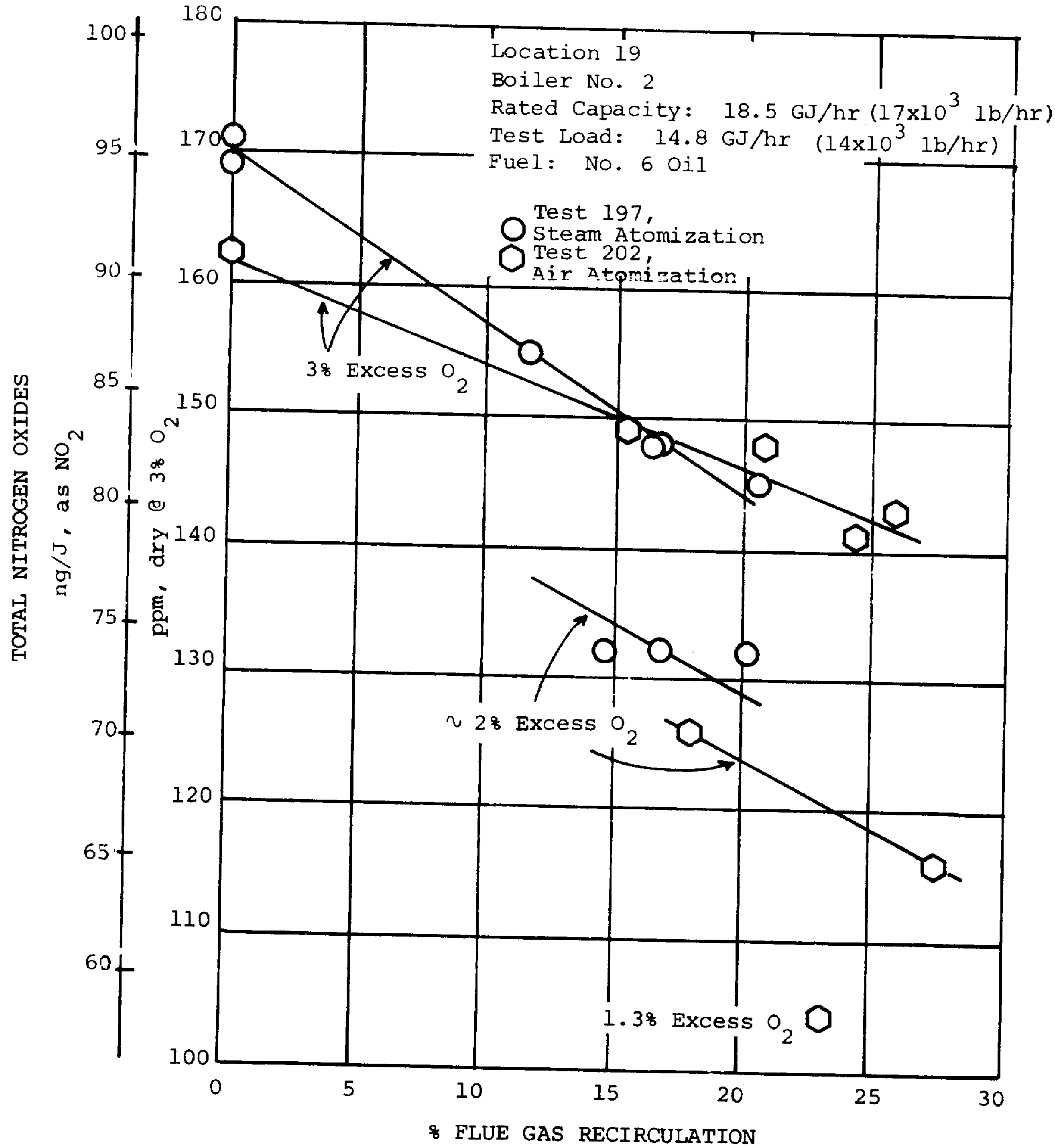

Figure 5-31. Effect of flue gas recirculation and excess oxygen level on the total nitrogen oxides emissions. No. 6 oil fuel.

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The results of flue gas recirculation on dual fuel firing are shown in Figure 5-32. Natural gas and No. 6 fuel oil were combined at a 50/50 ratio, based on fuel heat content, and fired simultaneously. Baseline nitrogen oxides emissions with the nominal excess oxygen of 3% were 69.7 ng/J (130 ppm). Using 20% recirculation at excess oxygen levels of 1.6%, 3.0%, and 3.3% reduced emissions by about 27% to 51 ng/J (95 ppm). Increasing the flue gas recirculation rate to as high as 35% resulted in no further significant reduction in nitrogen oxides emissions.

The results of all the testing are summarized in Figure 5-33. The nitrogen oxides reduction is plotted versus the flue gas recirculation rate. Recirculation was most effective in reducing nitrogen oxides emissions from natural gas fuel firing. This can be expected because gas nitrogen oxides emissions occur solely from the thermal fixation of atmospheric nitrogen at elevated temperatures. The flame temperature reducing potential of the recirculated combustion products is fully realized.

The effectiveness of flue gas recirculation is not as great for No. 6 fuel oil firing. The reason is that a significant fraction of the total nitrogen oxides emissions is due to the low temperature conversion of fuel nitrogen. In addition, oil fuel combustion is slower in relation to the intense burning of natural gas from a highly mixed ring type burner. The oil fuel goes through three major processes before it is burned, i.e., atomization, vaporization, and mixing. In the course of these processes a significant amount of natural recirculation of combustion products within the flame zone occurs and the flame is self-cooled. The effect of flue gas recirculation on the gas and oil fuel mixture is less than for gas alone, yet greater than for oil alone.

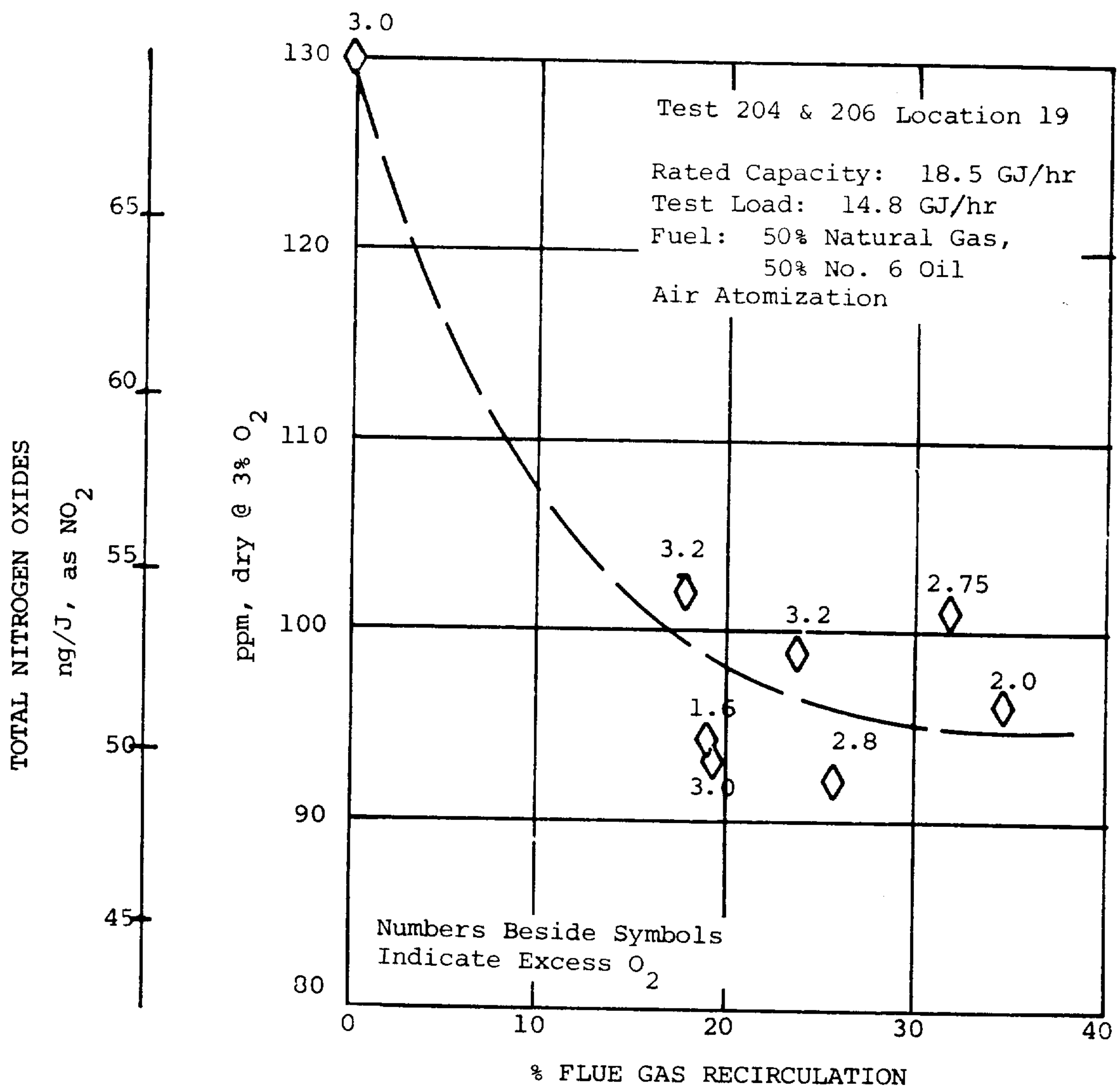

Figure 5-32. Effect of flue gas recirculation on the total nitrogen oxides emissions. Mixed natural gas and No. 6 oil fuels.

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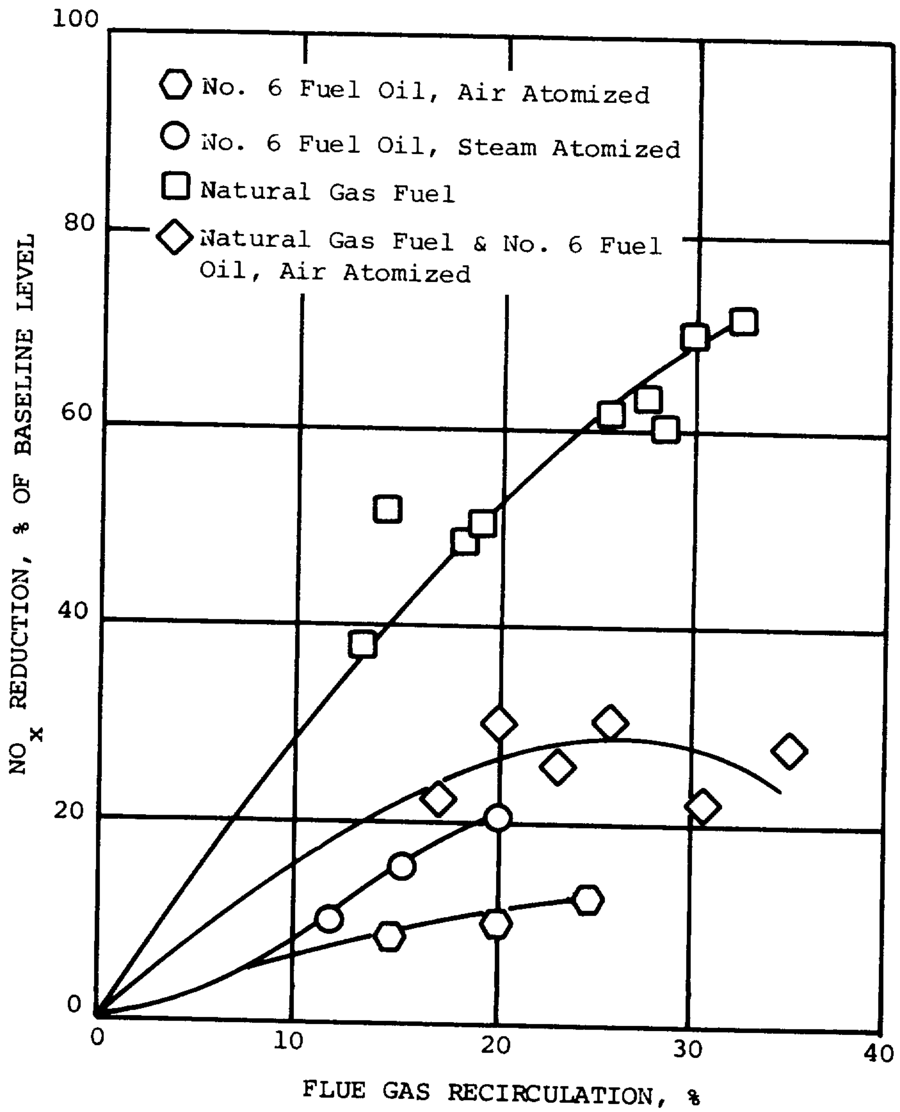

Figure 5-33. Summary of flue gas recirculation test results with normal excess air.

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Testing was done to evaluate the effect of flue gas recirculation on particulate emissions. Baseline solid particulates for steam atomized No. 6 fuel oil were 8.6 ng/J (0.020 lb/MBtu). Operating with 16.5% flue gas recirculation on steam atomized No. 6 oil resulted in a particulate level of 9.5 ng/J (0.022 lb/MBtu). With air atomization, the baseline solid particulates were 10.8 ng/J (0.025 lb/MBtu). No particulate tests were conducted while firing with air atomization and flue gas recirculation.

The boiler used for Tests 149 through 152 was a combined cycle unit consisting of a natural gas-fired turbine and a supplementary fired watertube boiler. The boiler could use as an oxidant either the gas turbine exhaust containing approximately 17% oxygen by volume at 630 K (680°F) or slightly heated atmospheric air at approximately 340 K (150°F). Using turbine exhaust was a form of flue gas recirculation. Refinery gas was used as the boiler fuel, and the specifications of this fuel are listed on Table 6-1.

With air as the boiler fuel oxidizer, baseline nitrogen oxides emissions were 76.0 ng/J (149 ppm) at an excess oxygen of 5.5%. Baseline nitrogen oxides emissions with turbine exhaust as the oxidizer were 74 ng/J (146 ppm) at an excess oxygen of 5.1%. The boiler emissions with turbine exhaust were not as low as might be expected; since this type of firing is very similar to flue gas recirculation, and flue gas recirculation has proved to be effective in reducing nitrogen oxides emissions. An uncertain factor was that there was a significant amount of nitrogen oxides produced by the gas turbine that entered the boiler with the turbine exhaust.

In order to assess the effect that the nitrogen oxides in the turbine exhaust had on the stack emissions from the boiler, the mass flowrate of nitrogen oxides into the boiler and out of the stack has to be determined. However, previous studies[11] have shown that the nitrogen oxides entering with the turbine exhaust often is decomposed to free nitrogen by the combustion process, rather than passing through the boiler as nitrogen oxides. Therefore, it is not possible to directly assess this inlet nitrogen oxides effect for these tests, since it was not possible during the testing to determine the degree to which the nitrogen oxides in the turbine exhaust was decomposed. Using the emissions data taken while operating the boiler with air, the effect was approximated, and the results of this approximation are shown in Figure 5-34.

At a nominal baseload of 485 GJ/hr (460,000 lb/hr steam flow) the nitrogen oxides emissions measured in the boiler exhaust were 59.9 kg/hr (132 lb/hr). The nitrogen oxides emissions measured in the boiler intake (turbine exhaust) were 24.5 kg/hr (54 lb/hr). By difference, the nitrogen oxides produced by the boiler fuel combustion were approximately 35.4 kg/hr (78 lb/hr). The baseline boiler nitrogen oxides emissions with air as the oxidizer were 76 ng/J, which is equivalent to approximately 52.2 kg/hr (115 lb/hr). The resulting reduction in nitrogen oxides emissions in going from air as an oxidant to turbine exhaust as an oxidant was 16.8 kg/hr (37 lb/hr), a reduction of 32.2%.

5.2.3 Firing Rate

The KVB field crew found that it is common in industry to have additional boiler capacity that is not used in the day-to-day production. Sometimes these boilers are used for standby in case of breakdown and sometimes they are installed to provide for an occasional high demand and/or future growth. When there is additional capacity available, the use of a reduced firing rate to lower the nitrogen oxides emissions from a boiler is a possible control strategy for some boilers.

The effect of firing rate on the level of nitrogen oxides emissions was investigated in Phases I and II by raising and lowering the boiler load from the base load point of 80% of nameplate capacity.

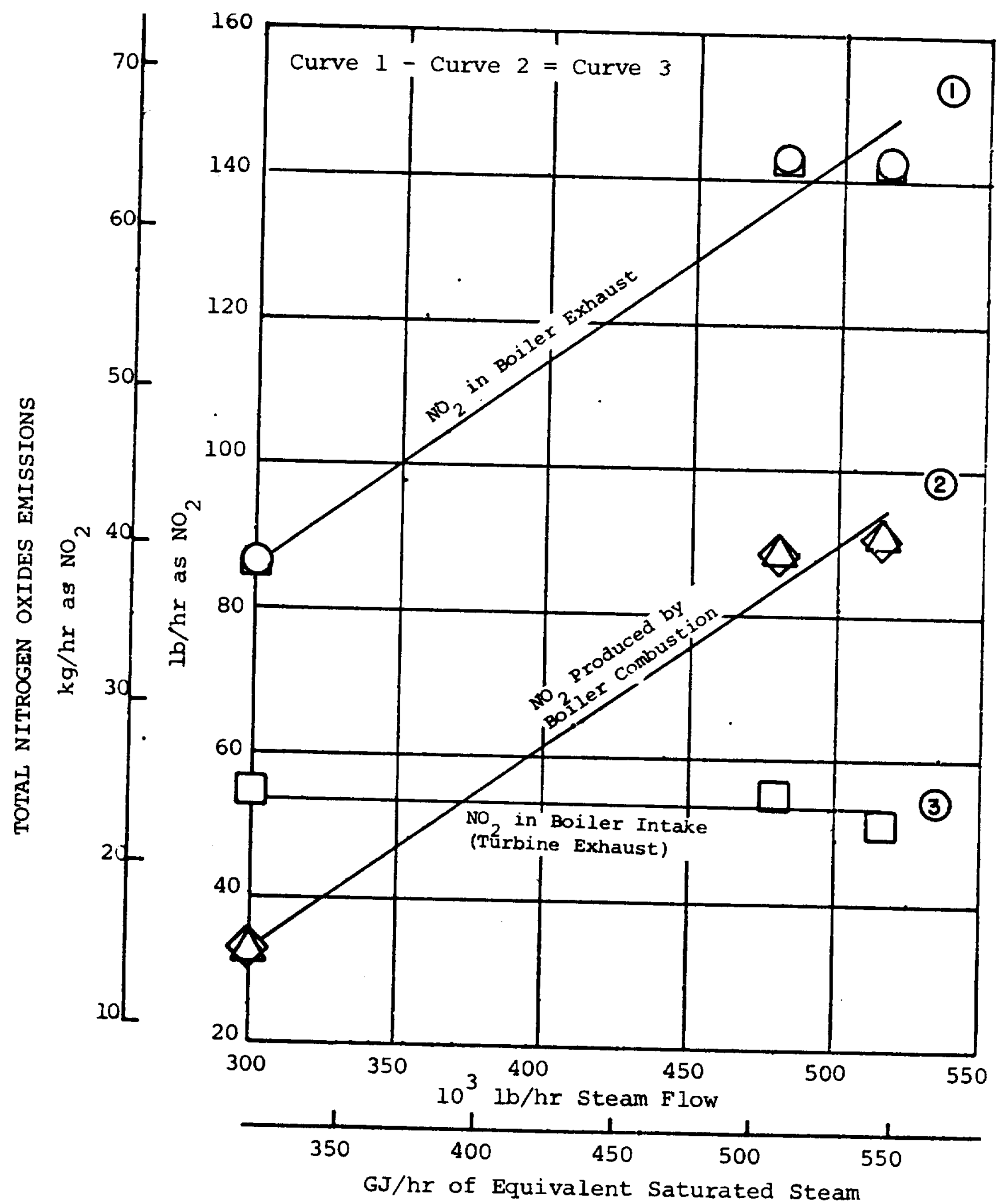

Figure 5-34. Reduction in total nitrogen oxides emissions in a combined cycle boiler.

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The boiler control settings, including the level of excess oxygen fired, were normal for each load. In general, changing the firing rate did not have a strong effect on nitrogen oxides emissions, however. Usually the NOx reduction effect of lowering the load was nullified by the increase in excess air at the reduced load that was called for by the boiler firing procedure. The net result was that the nitrogen oxides emissions either did not change significantly or even increased at the lower firing rate.

Watertube gas-fired boilers were relatively insensitive to load changes unless they had air preheaters. The measurements from Tests Nos. 15, 25, 77, 146, 154, and 180 that are plotted on Figure 5-35 are the data collected from boilers with preheated combustion air. The nitrogen oxides dropped about 26 ng/J (50 ppm) as the firing rate dropped from 85% of capacity to 60% of capacity for Tests 15, 25, and 77. For Tests 146, 154, and 180 the reduction was not quite as great, only a 5 ng/J (10 ppm) reduction in going from 85% to 60% of capacity. A combination of lower air preheat temperatures, poorer fuel-air mixing, reduced heat release per unit heat transfer area, and the resulting lower temperature of the combustion products probably caused these decreases in total nitrogen oxides production.

Generally, coal fired watertube boilers showed an increase in nitrogen oxides emissions when operating below 60% capacity. This increase usually coincided with an increase in the excess air level. Oil-fired boilers showed little or no relationship between nitrogen oxides emissions and firing rate.

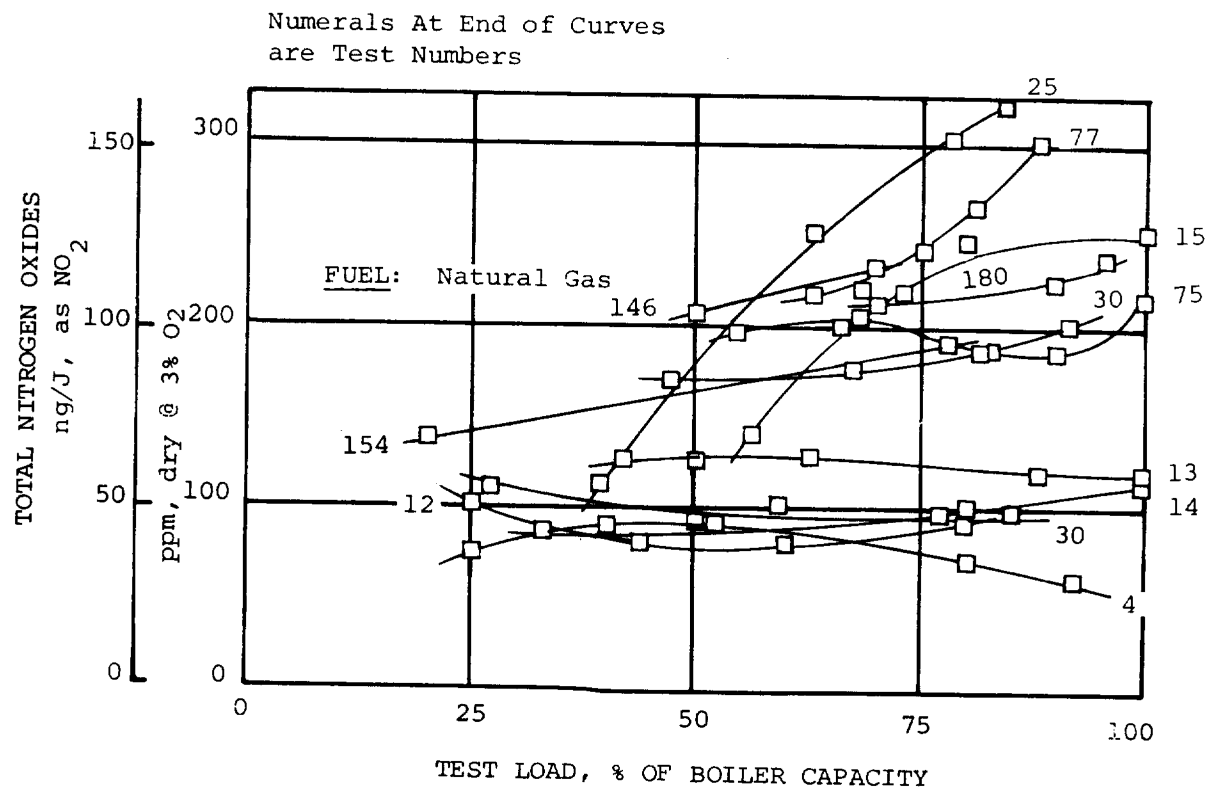

Figure 5-35. Effect of firing rate on total nitrogen oxides emissions, natural gas fuel.

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5.3 INPUT MODIFICATION

5.3.1 Fuel Properties

5.3.1.1 Fuel Nitrogen Content -

There are two important mechanisms for the formation of nitrogen oxides. One is thermal fixation of atmospheric nitrogen, and the other is conversion of nitrogen compounds in the fuel. The magnitude of the potential fuel nitrogen effect is about 730 ng/J (1300 ppm) of nitrogen oxides for complete conversion of 1% nitrogen (by weight) in a typical oil. For coal, the fuel nitrogen per volume of flue gas at a given oxygen content is greater, and the corresponding figure is about 1200 ng/J (1900 ppm) of NO_x per 1% nitrogen in the coal. Actually, only partial conversion of the fuel nitrogen occurs and the percent conversion depends on the fuel nitrogen content and the availability of oxygen. The percentage conversion is high for low nitrogen oil and decreases with increasing nitrogen content.[14]

The fuel nitrogen content of residual oils used in industrial and utility boilers ranges from 0.1 to 1.0% by weight. Distillate oils are less than 0.2% in nitrogen content. Crude oils, which contain distillate and residual fractions, are intermediate. Shale oils have nitrogen contents as high as 2.5%, and pyrolytic oils made from waste materials could conceivably contain 5% or more of nitrogen. The nitrogen content of bituminous coals can vary from as low as 0.8% up to 3.5%. The oils tested during this program varied in nitrogen content from 0.002 to 0.77% by weight. The nitrogen contents for the No. 2 oils were from 0.006 to 0.045%, the No. 5 oils were from 0.10 to 0.52%, and the No. 6 oils were from 0.26 to 0.46%. One oil which is designated by the refiner as PS 300 had a fuel nitrogen of 0.77%. This oil has other properties similar to a No. 5 oil. The nitrogen contents of the majority of coal fuels tested during this program varied from 1.29 to 1.80% by weight as fired. Two coals had fuel nitrogens of 0.83 and 0.94%.

The baseline nitrogen oxides emissions as a function of fuel nitrogen content are plotted as circles connected by a solid line in Figure 5-36. Not all data points were included since a lot of the data were nearly identical and would lie on the top of the points shown. The oil fuel Tests 63 and 68, which are inconsistent with the remaining data, are PS 300 oil tests conducted with nearly ambient temperature fuel oil at the burner instead of the 71 to 82°C (160 to 180°F) typical for No. 5 oils. The dashed curve is a fit to empirical data from an in-house KVB, Inc. laboratory investigation of the influence of oil fuel nitrogen on NO emissions.[14] The KVB laboratory curve is nitric oxide concentration measurements versus fuel nitrogen content for 130% of theoretical air at the burner. The percent theoretical air for the measurements of this study are written beside each data point. The Phase I and II data are slightly above the KVB laboratory curve. The intercept at zero fuel nitrogen content is the thermal NO contribution, and the slope of the curve is the contribution of converted fuel nitrogen. This interpretation leads to the conclusion that for normal operating conditions with oil fuel the thermal NO for the tests shown was in the 34 to 110 ng/J (60 to 200 ppm) range and the fuel nitrogen conversion averaged 46%.

The thermal NO and fuel nitrogen conversion in the field-tested boilers were similar to the laboratory burner used for the subscale study. This further indicates a lack of nitrogen oxides variation with unit size for oil fuel. Other investigators have reported similar values of fuel nitrogen conversion.[15,16] Sufficient data were not collected to allow evaluation of fuel nitrogen conversion under off-stoichiometric conditions; however, the KVB laboratory tests discussed above showed a reduction in fuel nitrogen conversion to about 20% for fuel rich combustion.

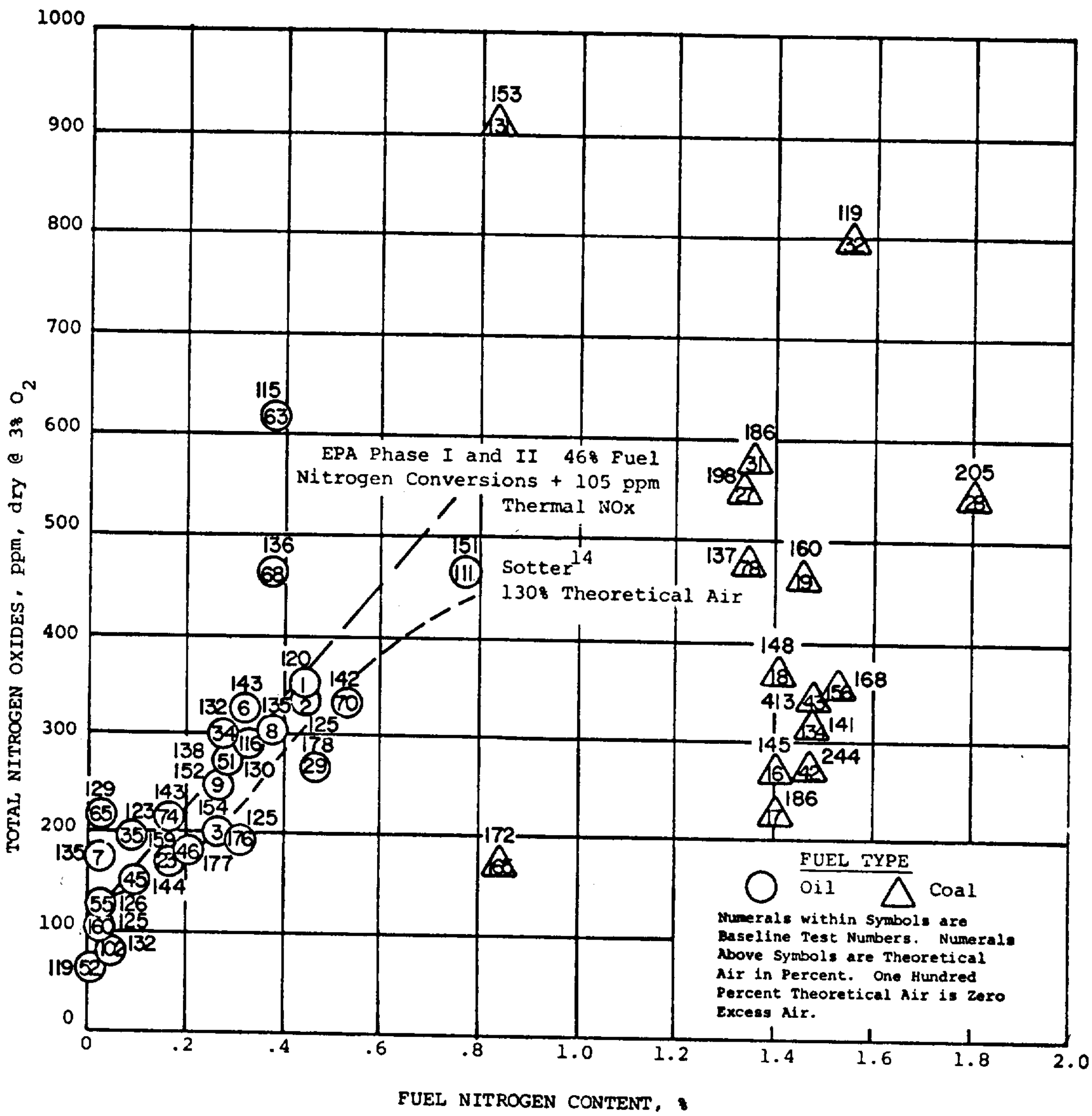

Figure 5-36. Effect of fuel nitrogen content on total nitrogen oxides emissions.

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During Phase I, fuel oils of varying nitrogen contents were burned in the same type boiler at four test locations. Table 5-6 summarizes these data. At Location 19 changing from No. 2 oil with 0.006% nitrogen to No. 6 oil with 0.44% nitrogen resulted in a 43% conversion of the fuel nitrogen to nitrogen oxides for air-atomized tests and 51% conversion for steam-atomized tests. Tests conducted at Location 23 with air-atomized No. 5 and 6 oils with fuel nitrogen contents of 0.28 and 0.27%, respectively, resulted in 44% conversion of the fuel nitrogen to nitrogen oxides for the No. 5 oil and 52% conversion for the No. 6 oil. Similar air atomized tests conducted at Location 24 on No. 5 oil with 0.20% fuel nitrogen resulted in 41% conversion of the fuel nitrogen to nitrogen oxides. The test series conducted at Location 26 when No. 2 oil with 0.02% fuel nitrogen and No. 5 oil with 0.1% fuel nitrogen were burned both with air and steam atomizers resulted in 60% and 56% fuel nitrogen conversion to nitrogen oxides, respectively. The average for these tests is 50% fuel nitrogen conversion which agrees quite well with the average of 46% for all the Phase I and Phase II data.

Figure 5-38 also presents nitrogen oxides emissions plotted versus fuel nitrogen content for the coal fuel tests. The data indicate that no dependence of NOx emissions upon coal fuel nitrogen, per se, exists. Other factors including furnace geometry, excess air, firing rate, burner type and possibly additional fuel properties are all contributing to the variations in nitrogen oxides production.

The majority of coals exhibited fuel nitrogen contents of between 1.29 and 1.80% and the NOx emissions ranged from 122 to 490 ng/J (200 to 800 ppm). When a western coal with 0.83% nitrogen was fired in a pulverizer unit for Test 131, nitrogen oxides emissions were higher than any other coal test; 563 ng/J (922 ppm).

Table 5-6. EFFECT OF FUEL OIL GRADE ON TOTAL NITROGEN OXIDES EMISSIONS AND CONVERSION OF FUEL NITROGEN TO TOTAL NITROGEN OXIDES EMISSIONS

Location Number	Test No.	Fuel	Burner Type	NOx dry @ 3% O_2 ppm	Excess O_2 dry, %	Fuel Nitrogen Content, Wt. %	Fuel Nitrogen Conversion, %
19	1	#6 oil	Steam	350	3.6	0.44	51
19	2	#6 oil	Air	334	4.4	0.44	43
19	52	#2 oil	Steam	65	3.6	0.006	100*
19	53	#2 oil	Air	97	3.0	0.006	100*
19	54	#2 oil	Pressure	80	4.3	0.006	100*
23	64	#2 oil	Air	127	6.8	0.015	100*
23	51	#5 oil	Air	275	6.3	0.28	44
23	34	#6 oil	Air	298	5.4	0.27	52
24	73	#2 oil	Air	84	3.1	0.014	100*
24	46	#5 oil	Air	186	3.2	0.20	41
26	56	#2 oil	Air	116	8.0	0.020	100*
26	57	#2 oil	Steam	118	8.0	0.020	100*
26	44	#5 oil	Air	173	7.3	0.10	60
26	45	#5 oil	Steam	161	6.7	0.10	56

*Fuel nitrogen content was too low to determine a realistic conversion percentage. The conversion was near 100%.

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The western coal differed significantly from the other coals not only in nitrogen content, but in oxygen content. This western coal contained 12.5% oxygen while the other coals averaged about 7%. It is theorized that the high oxygen content in intimate contact with the fuel nitrogen enhanced the low temperature conversion of fuel nitrogen to nitrogen oxides and contributed significantly to the overall high nitrogen oxides level.

For Test 165 the nitrogen oxides emissions were the lowest of any coal-fired boiler; 100 ng/J (164 ppm). The fuel averaged about 0.94% nitrogen and the fuel oxygen was 9.9%. It is believed that the low nitrogen oxides emissions are related to the furnace geometry and the nature of the combustion process. The boiler was equipped with a traveling stoker chain grate burner which combusts large coal particles at a relatively slow rate. The combustion equipment was in poor condition. Visual examination of the furnace during the tests revealed low intensity combustion flames of a very lazy and random nature. The addition of overfire air actually improved the mixing of fuel and air and resulted in an increase of nitrogen oxides. The excess air was extremely high and the heat release rate per unit volume was comparatively low, 0.496 [$GJ \cdot hr^{-1} \cdot m^{-3}$ (0.013×10^6 $Btu \cdot hr^{-1} \cdot ft^{-3}$)], considering the rated boiler capacity.

5.3.1.2 <u>Temperature</u> -

The effect of oil temperature, or viscosity, on nitrogen oxides emissions was investigated at five locations during the course of the program. In all cases the tests were conducted with steam atomized No. 6 fuel oils over a temperature range of 69°C to 121°C (157°F to 250°F). As seen in Figure 5-37 no consistent trend was observed, although in all cases the changes in nitrogen oxides emissions were less than 10%.

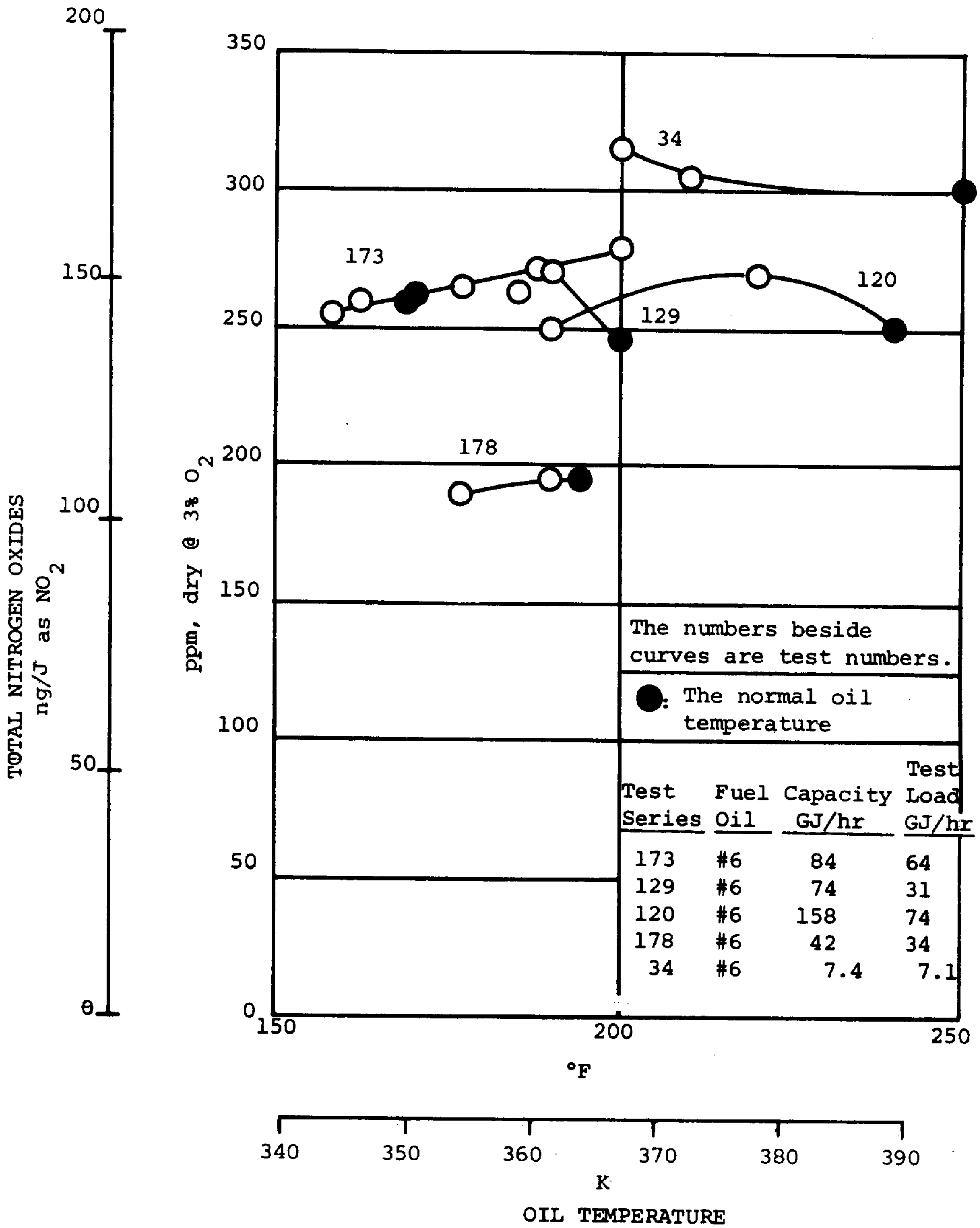

Figure 5-37. Effect of fuel oil temperature on total nitrogen oxides emissions

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The main property change due to increasing the oil temperature is the reduction of the viscosity; for a typical No. 6 oil the viscosity will drop from 400 SSU to 110 SSU as the temperatures is increased from 240 K to 365 K (150°F to 200°F). Number 5 and 6 oils are normally atomized in the viscosity range of 150 to 300 SSU. Fundamentally, as the temperature decreases and the viscosity increases the energy required to overcome viscous effects increases, and this detracts from the energy available for droplet breakup resulting in coarser atomization. This is minimized somewhat in steam or air atomizers which produce much smaller drop sizes than their mechanical counterparts since the energy contained in the atomizing gas stream can be independent of the quantity of liquid being atomized. Thus, one would not expect nitrogen oxides emissions to be greatly dependent on oil temperature or viscosity for air or steam atomized systems.

Another field test crew from KVB, Inc. tested a twin boiler at Location 38 for the effect of fuel oil temperature on particulate emissions.(15) They found that the particulate emissions as indicated by the mass monitor showed a 57% decrease with increasing oil temperature as shown in Figure 5-38 and a further decrease with increase oil atomization pressure.

5.3.2 Burner Characteristics

5.3.2.1 Burner Tune-up -

The effect on total nitrogen oxides emissions of tuning the burner was determined by first measuring the emissions from a boiler that had not been tuned for a year or so. The local serviceman for the burner manufacturer then was brought in and he tuned the boiler to the manufacturer's specifications. Tuning involved examining the nozzle for worn tips, adjusting the spray angle to make sure unburned fuel did not strike the side or rear walls of the furnace and adjusting the flame length so it did not wash the side or rear walls. Much of this is done by means of adjusting the amount and swirl of the combustion air.

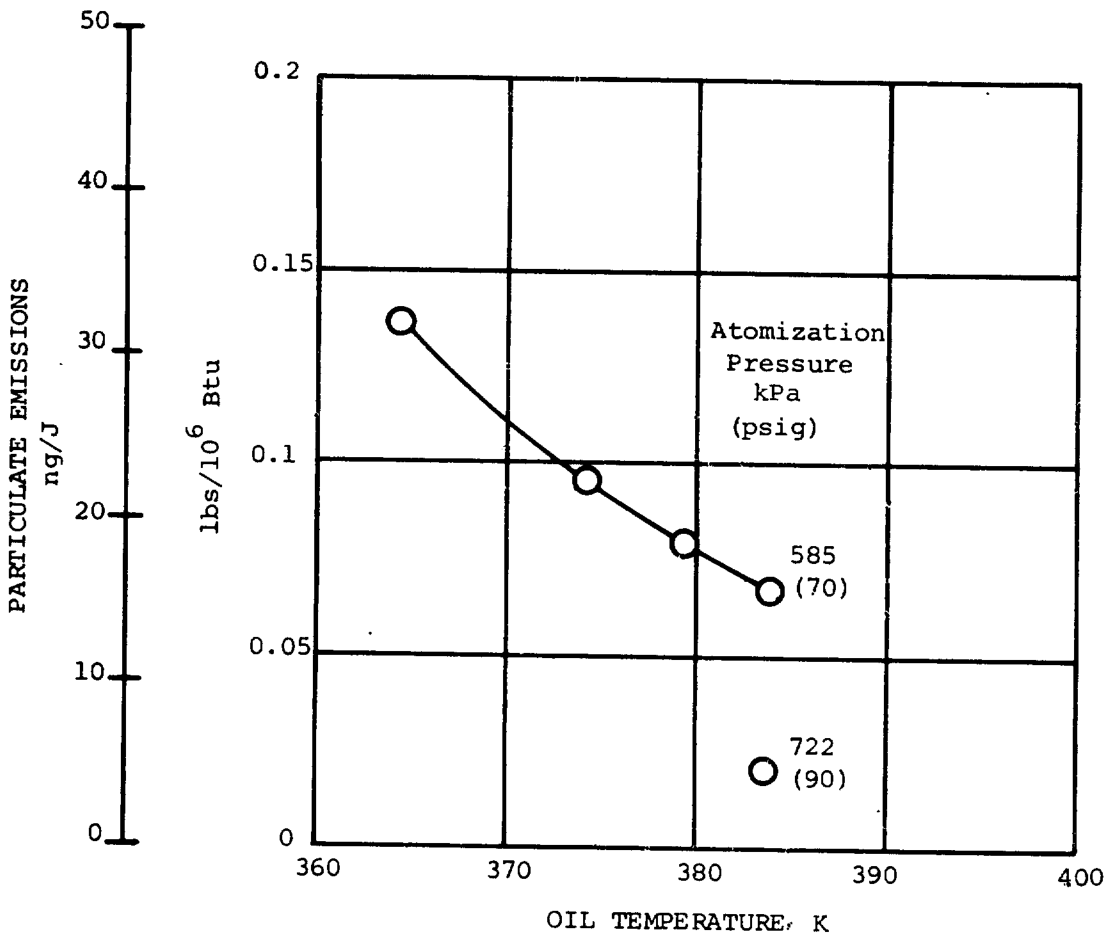

Figure 5-38. Effect of fuel oil temperature and of atomization pressure on solid particulate emissions, No. 6 oil fuel.[17]

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Oil Fuel: The chief effect of burner tune-up was a reduction in carbon monoxide emissions rather than a significant reduction of nitrogen oxides emissions. During Test 108 at Location 1, the carbon monoxide from oil fuel was reduced from 139 to 38 ng/J (407 to 110 ppm) and during Test 112 at Location 27, from 40 to zero ng/J (116 to zero ppm). During Test 108 this was accomplished by raising the excess oxygen from 2.7 to 3.8%. The increase in excess air and stack temperature compensated for the decrease in carbon monoxide in the stack gases and the heat loss efficiency did not change. After the tune-up during Test 112, it was possible to operate at a lower level of excess oxygen than originally without any carbon monoxide in the stack gases and the efficiency increased by 1% from 81 to 82%.

There was a 13% reduction in the nitrogen oxides emissions from oil fuel during Test 112 at Location 27 after tune-up, but no reduction during Test 108 at Location 1.

At Location 27 the particulates were relatively unaffected, increasing by about 5%. At Location 1, however, the particulate emissions increased substantially, i.e., doubled, after tune-up. This increase may have been due to the impingement of the flame on the water walls of this particular boiler. Even after tune-up there was a substantial amount of impingement and the relatively cold water walls may have quenched the flame and increased the creation of unburned carbon particles. The spray angle was very large and there was not time during the test for the burner manufacturer to secure and install a smaller angle burner tip for test purposes.

However, at both locations the total particulate emission was well below the Environmental Protection Agency limit for new units of 43 ng/J (0.1 lb/MBtu) for solid particulate alone.

Natural Gas Fuel: With natural gas fuel, tuning the burner resulted in an increase in nitrogen oxides at both locations. When the excess oxygen was increased sufficiently during Test 106 at Location 1 to eliminate the carbon monoxide, the efficiency decreased due to the larger amount of excess air. For Test 110 at Location 27, however, it was possible to decrease the excess oxygen and not incur an increase in the carbon monoxide above ng/J (10 ppm) and the efficiency increased slightly.

Summary: Thus for both oil and gas fuels, if the burner was tuned to reduce the carbon monoxide to near zero and/or to improve the flame texture and color, the nitrogen oxides emissions either were unchanged or increased. Tune-up universally was successful in reducing carbon monoxide, however. Reducing carbon monoxide to near zero generally increased the heat input efficiency: e.g., 0.6 to 1.0%, because the decrease in combustibles was slightly greater than the corresponding increase in heated air exhausted up the stack.

In both instances when the fuel was oil and the particulates were measured before and after tune-up, the particulate increased rather than decreased when the burner was tuned.

It appears that the most effective way to reduce nitrogen oxides emission by burner tuning is simply to reduce the excess oxygen and accept some carbon monoxide, perhaps up to 35 ng/J (100 ppm). The remaining combustibles in the exhaust gases are offset by the decrease in excess air exhausted up the chimney and the heat loss efficiency is not affected significantly.

5.3.2.2 Coal Burners -

The data shown in Figure 4-3 have been analyzed to determine if certain types of coal burners as a class, such as underfed stokers, spreader stokers and pulverizers, emit less nitrogen oxides than other types. It was found that boilers equipped with spreader stokers and pulverizer type burners had the highest nitrogen oxides emissions. Chain grate and underfed stokers had the lowest emissions. The chain grate and underfed stokers had less intense flames and larger furnaces than the others, and this combination of less intense combustion and large furnace produced a lower level of nitrogen oxides emissions.

The chain grate burner of Test 165 produced the lowest emission levels, as Figure 4-3 indicates. Nitrogen oxides were 100 ng/J (164 ppm) and particulates were 175 ng/J (0.41 lb/MBtu). The emissions from underfed stokers were the next lowest, 134 to 208 ng/J (220 to 340 ppm) nitrogen oxides, but all boilers with this type of firing were small, less than 63 GJ/hr capacity. Spreader stokers produced nitrogen oxides emissions of 220 to 336 ng/J (360 to 550 ppm). Particulates from spreader stokers ranged from 103 to 1300 ng/J (0.24 to 3.05 lb/MBtu), depending on whether the samples were taken before or after the dust collector.

The cyclone burner of Test 32 was a high emitter of nitrogen and a low emitter of particulate. These emissions were what one would expect from the very small volume furnace and a very intense flame of this type of burner.

The highest nitrogen oxides emissions were from the pulverizer at Location 31, Tests 131 and 169. The reason for these high emissions is not known. Originally measurement error was suspected, and the field crew returned two months later and repeated the test. The results of Test 169 duplicated those of Test 131, so the high emissions appear to be real.

Particulate emissions from coal burning boilers were slightly dependent on burner type. Pulverized coal burners generally produced more particulates than stoker equipped boilers, as is discussed in Subsections 4.2 and 5.4.

5.3.2.3 Oil Burners -

The types of oil atomizers evaluated during the program were steam, air, pressure - mechanical, and rotary cup. The No. 2 oil burners were evenly divided between steam and air atomized, with one test conducted using a pressure-mechanical atomizer. The No. 5 oil burners were divided into about one-fourth steam-atomized, one-half air-atomized, and the remainder rotary cup-atomized. The majority of the No. 6 oil tests were with steam-atomized oil guns, the remainder being air-atomized. All No. 2 oil atomizers operated with ambient temperature oil at the burner. The oil and steam/air pressures at the burner varied from unit to unit; but typically, steam/air pressure was about 0.446 MPa (50 psig), and oil pressure was about 0.377 MPa (40 psig) at top load. The No. 5 oils were normally fired at from 545 to 355 K (160 to 180°F) at the burner with steam/air and oil pressures similar to the No. 2 oil atomizers. The No. 6 oils were normally fired at approximately 365 K (200°F) at the burner, and the steam/air and oil pressures at the burner were similar to No. 2 and 5 oil atomizers.

A special series of tests, Tests 1, 2, 52, 53, 54, 195, 196, 200, and 201 were run at Location 19 to investigate the effect of the oil atomization method and oil grade on the total nitrogen oxides and particulate concentrations. The boiler used was a Keeler Company packaged steam generator rated at 18.5 GJ/hr (17,500 lbs/hr steam flow) and was installed in 1970. The furnace ceiling and side walls consisted of tangent-wall tubes with a tile floor and burner wall. This saturated steam boiler operated at a nominal steam pressure of 1.14 MPa (150 psig). During this test series, both No. 6 and No. 2 fuel oils were tested with steam and air atomizing oil guns, and No. 2 fuel oil was also tested with a mechanical-pressure atomizing oil gun. Ambient temperature combustion air was used in all tests. The measurements are summarized in Table 5-7 and Figure 5-39. It should be noted that the No. 2 and No. 6 oils (Tests 1 and 2) used for these tests were the extremes in API gravity, carbon residue, ash, nitrogen, and sulfur (see Table 6-1). As a result, relatively high nitrogen oxides and particulate values were measured for Tests 1 and 2 with No. 6 oil and low values were measured for No. 2 oil.

The field test measurements from Tests 1, 2, 44, 45, 52, 53, 54, 56, and 57, which were done during Phase I are summarized in Table 5-8. This table is an excerpt of Table 4-1 of the Phase I Final Report, Reference 4.

Test No. 1: Steam-Atomized No. 6 Fuel Oil. The steam-atomized oil burner used for this test operated at the baseline load with oil pressure and temperature at the burner of 0.62 MPa (75 psig) and 93°C (200°F). The oil was atomized by steam impingement within the atomizing tip and injected into the furnace through burner tip orifices, which were similar to the common B&W Y-jet atomizer design. These tests were repeated during Tests 200 and 201 with a different shipment of No. 6 fuel oil.

As shown in Figure 5-39, the nitrogen oxides emissions increased with increasing excess oxygen up to about 5% excess oxygen where a maximum nitrogen oxides value of 213 ng/J (380 ppm) was reached and beyond this oxygen level the nitrogen oxides emissions decreased with increasing excess oxygen. The minimum excess oxygen level, below which incomplete combustion occurred, as evidenced by excessive CO emissions and a visible smoke plume, for this test was 1.6%. Particulate emissions of 65.5 ng/J (0.1524 lbs/10^6 Btu) were measured for the low air Test Run No. 1-11, which is one of the higher emission levels recorded for steam-atomized No. 6 fuel oil.

Table 5-7. EFFECT OF OIL ATOMIZATION METHOD ON TOTAL NITROGEN OXIDES, PARTICULATE EMISSIONS AND BOILER EFFICIENCY

Test No.	Oil Grade	Fuel Nitrogen (%)	Atomization Method	Test Load GJ/hr (10^3 lb/hr)	Normal[1] Excess Oxygen (%)	NO_x[2] ng/J (ppm)	Solid Particulates ng/J ($lb/10^6$ Btu)	Boiler Efficiency (%)
1[3]	No. 6	0.44	Steam	15 (14)	3.6	196 (350)	62.1 (0.1447)	85
2	No. 6	0.44	Air	16 (15)	4.4	187 (334)	125 (0.2818)	85
195[4]	No. 6	0.14	Steam	15 (14)	3.1	95 (169)	8.60 (0.020)	84
200	No. 6	0.14	Air	15 (14)	2.9	91 (162)	10.8 (0.025)	83
198	No. 6	0.14	Steam	15.1 (14.3)	3.1	75 (133)	9.90 (0.023)	82
203	No. 6	0.14	Air	14.8 (14.0)	2.9	73 (131)	18.1 (0.042)	83
44	No. 5	0.10	Air	18.6 (17.6)	7.2	99 (177)	17.5 (0.0448)	86
45	No. 5	0.10	Steam	18.3 (17.3)	6.7	90 (161)	32.0 (0.0779)	86
52	No. 2	0.006	Steam	15 (14)	3.6	36 (65)	14.6 (0.0339)	85
53[5]	No. 2	0.006	Air	15 (14)	3.0	54 (97)	5.01 (0.0163)	85
54	No. 2	0.006	Mech.	13 (12)	4.3	45 (80)	4.96 (0.0151)	85
56	No. 2	0.02	Air	16.8 (15.9)	8.0	65 (116)	-- --	85
57	No. 2	0.02	Steam	16.6 (15.7)	8.0	66 (118)	-- --	86

[1] Normal operating O_2 level defined by burner manufacturer.

[2] ppm is measured value corrected to 3% excess O_2 dry.

[3] Particulate data for Test No. 1 were taken for low air run (2.3% oxygen).

[4] A different shipment of No. 6 oil was used for Test 195, 200 than for Tests 1, 2.

[5] Particulate data for Test 53 were taken for high air run (4.3% oxygen).

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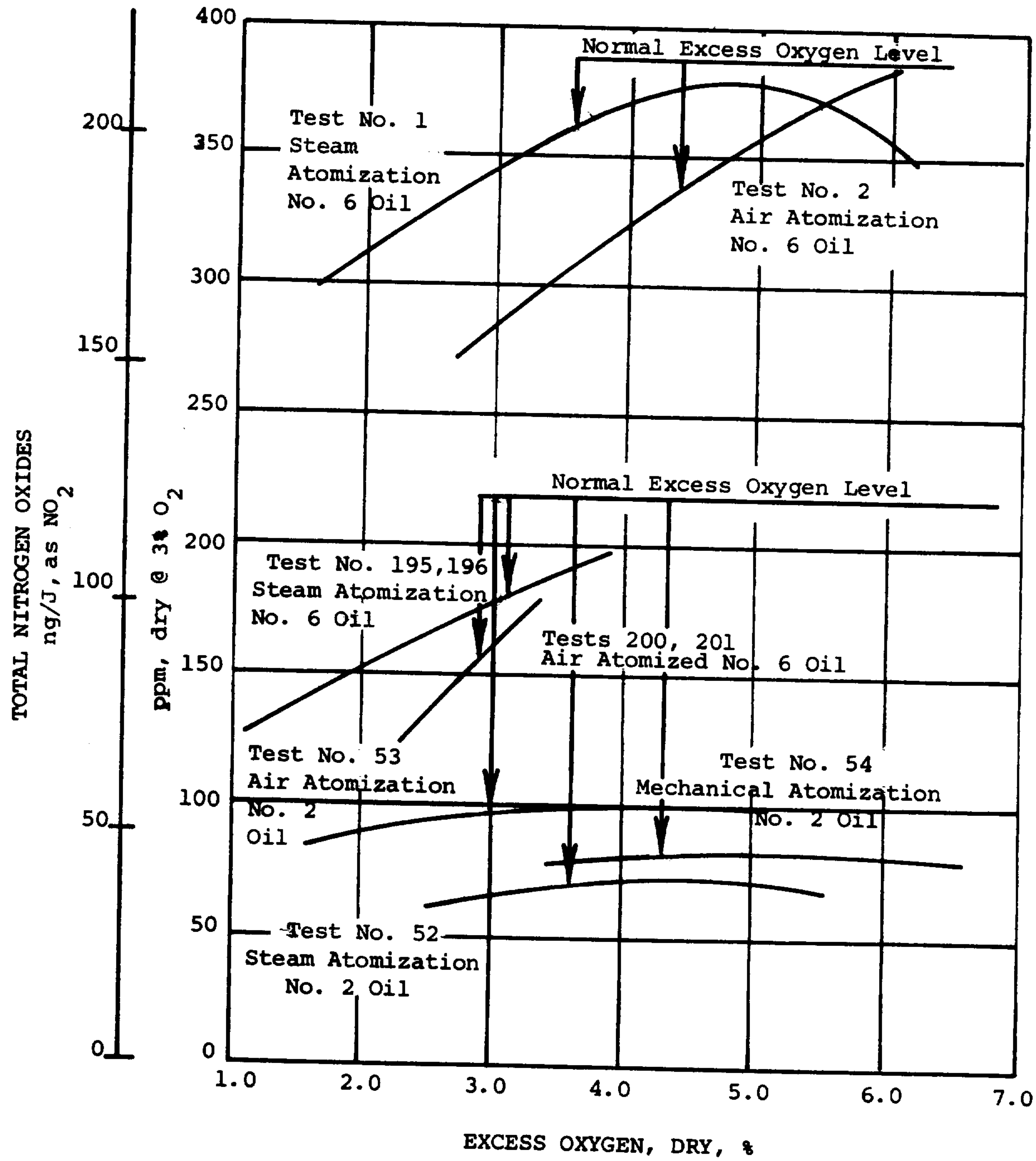

Figure 5-39. Effect of oil atomization method and excess oxygen level on the total nitrogen oxides emissions.

Table 5-8. PHASE I FIELD TEST MEASUREMENTS(4)

Test Run No.	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load (t/hr) (k#/hr)	Excess O_2 % dry	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 dry %	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
1-12	Steam	#6 Oil	Baseline	7.95 (17.5)	6.36 (14)	3.6	.806 (350)	.797 (346)	.834 (362)	13.4	0 (0)	.026 (32)	4.64 (1448)	4.56 (1424)	-	-	-	
1-8	Steam	#6 Oil	Low Load	7.95 (17.5)	2.72 (6)	11.0	.986 (428)	.961 (417)	.933 (405)	8.2	0 (0)	-	-	-	-	-	-	-
1-11	Steam	#6 Oil	Low Air	7.95 (17.5)	6.36 (14)	2.3	.763 (331)	.737 (320)	.758 (329)	14.8	.062 (45)	.022 (28)	-	-	.2743 (.1524	.2605 (.1447)	-	-
2-5	Air	#6 Oil	Baseline	7.95 (17.5)	6.81 (15)	4.4	.770 (331)	.760 (330)	.774 (336)	12.9	0 (0)	-	4.42 (1378)	4.36 (1359)	-	-	-	-
2-4	Air	#6 Oil	Low Air	7.95 (17.5)	6.36 (14)	2.8	.638 (277)	.611 (265)	.601 (261)		0 (0)	-	-	-	-	-	-	-
2-6	Air	#6 Oil	LoAtm Press.	7.95 (17.5)	6.36 (14)	4.7	.687 (298)	.675 (293)	.664 (288)	12.6	0 (0)	.053 (60)	-	-	.5238 (.2910)	.5072 (.2818)	81	-
44-4	Air	#5	Baseline	8.17 (18)	7.99 (17.6)	7.3	.408 (177)	.403 (175)	.371 (161)	10.4	0 (0)	---	2.513 (784)	2.487 (776)	.1175 (.0653)	.0806 (.0448)	86	-
44-1	Air	#5	Hi Load	8.17 (18)	9.99 (22)	5.0	.433 (188)	.426 (185)	.387 (168)	12.4	0 (0)	---	---	---	---	---	87	0.0
44-3	Air	#5	Low Load	8.17 (18)	3.41 (7.5)	7.2	.355 (154)	.350 (152)	.323 (140)	10.2	0 (0)	---	---	---	---	---	87	-
44-6	Air	#5	Low Air	8.17 (18)	7.99 (17.6)	3.6	.422 (183)	.419 (182)	.378 (164)	13.6	0 (0)	---	---	---	---	---	88	-
45-7	Steam	#5	Baseline	8.17 (18)	7.85 (17.3)	6.7	.371 (161)	.371 (161)	.357 (155)	10.9	.018 (10)	---	2.590 (808)	2.567 (801)	.1402 (.0779)	.1188 (.0660)	87	1.0
45-1	Steam	#5	Hi Load	8.17 (18)	9.99 (22.0)	4.7	.394 (171)	.385 (167)	.369 (160)	12.6	.031 (20)	---	---	---	---	---	-	-
45-3	Steam	#5	Low Load	8.17 (18)	3.22 (7.1)	6.7	.355 (154)	.346 (150)	.327 (142)	10.8	0 (0)	---	---	---	---	---	87	-
45-5	Steam	#5	Low Air	8.17 (18)	7.72 (17.0)	3.8	.350 (152)	.348 (151)	.320 (139)	13.2	.030 (20)	---	---	---	---	---	88	-
51-1	Air	#5	Baseline & Hi Load	3.18 (7)	3.04 (6.7)	6.3	.634 (275)	.622 (270)	.599 (260)	11.2	0 (0)	---	---	---	---	---	83	2.0
52-5	Steam	#2	Baseline	7.95 (17.5)	6.36 (14)	3.6	.150 (65)	.147 (64)	.147 (64)	12.6	.069 (47)	---	.199 (62)	.173 (54)	.0680 (.0378)	.0610 (.0339)	83	-
52-2	Steam	#2	Low Air	7.95 (175)	6.36 (14)	2.6	.145 (63)	.143 (62)	.145 (63)	13.1	.675 (485)	---	---	---	---	---	83	-
53-1	Air	#2	Baseline	7.95 (17.5)	6.36 (14)	3.0	.224 (97)	.224 (97)	.212 (92)	13.1	0 (0)	.002 (3)	---	---	---	---	83	-
53-6	Air	#2	Hi Air	7.95 (17.5)	6.36 (14)	4.3	.235 (102)	.230 (100)	---	12.5	0 (0)	.010 (12)	.221 (69)	.199 (62)	.0295 (.0164)	.0293 (.0163)	83	-
53-2	Air	#2	Low Air	7.95 (175)	6.36 (14)	1.6	.198 (86)	.196 (85)	.194 (84)	14.2	.272 206	.007 (9)	---	---	---	---	84	-
54-5	Mech	#2	Baseline	7.95 (175)	5.45 (12)	4.3	.184 (80)	.184 (80)	.184 (80)	12.0	0 (0)	---	---	---	.0349 (.0194)	.0272 (.0151)	80	-
54-2	Mech	#2	Low Air	7.95 (17.5)	5.45 (12)	3.7	.184 (80)	.180 (78)	.182 (79)	12.6	0 (0)	---	---	---	---	---	82	-
55-1	Air	#2	Baseline & Hi Load	4.99 (11)	5.13 (11.3)	4.7	.295 (128)	.290 (126)	.272 (118)	11.8	0 (0)	---	---	---	---	---	88	-
56-1	Air	#2	Baseline	8.17 (18)	7.22 (15.9)	8.0	.267 (116)	.263 (114)	.240 (104)	3.4	0 (0)	---	---	---	---	---	85	0.0
57-1	Steam	#2	Baseline	8.17 (18)	7.13 (15.7)	8.0	.272 (118)	.270 (117)	.242 (105)	9.6	0 (0)	---	---	---	---	---	85	1.5

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Test No. 2: Air-Atomized No. 6 Fuel Oil. At the baseline load of 15.0 GJ/hr (14,200 lbs/hr) the oil pressure and temperature at the burner were 0.36 MPa (37 psig) and 101°C (214°F) and the atomizing air pressure at the burner was 0.31 MPa (30 psig). The nitrogen oxides emissions increased by 6.6% with increasing excess oxygen over the range investigated. The flame appearance changed with excess oxygen, and the best flame characteristics occurred at the lower oxygen levels. Particulate emissions of 125 ng/J (0.2910 lbs/10^6 Btu) were measured for Test Run No. 2-6, which was substantially greater than the values obtained with steam atomization on Test No. 1.

Test No. 52: Steam-Atomized No. 2 Fuel Oil. The steam-atomized oil burner used for this test at a steam flow of 14.8 GJ/hr (14,000 lbs/hr) operated with 0.55 MPa (65 psig) pressure, ambient temperature oil and the steam pressure at the burner of 0.60 MPa (73 psig). The nitrogen oxides emissions increased with increasing excess oxygen up to about 4%, and between excess oxygen levels of 4 and 5%, the nitrogen oxides emissions appear to reach a maximum value. A visible haze from the smoke stack occurred at the lowest level of excess oxygen of 2.6%. The baseline total particulate emissions of 16.25 ng/J (0.0378 lbs/10^6 Btu) were measured for this test at an excess oxygen level of 3.6%, which is about average for steam-atomized No. 2 fuel oil.

Tests 195, 196, 200, 201. The tests were repeated with another shipment of No. 6 oil and during tests 195, 196, 200, and 201 and the results are tabulated in Table 5-7 and trends in nitrogen oxides with excess oxygen are shown in Figure 5-41. The trends obtained with this series of tests were similar to those obtained during Tests 1 and 2 with steam atomization producing about 10% more nitrogen oxides than air atomization. The difference in the absolute levels of the nitrogen oxides emission is attributable to the nitrogen content of the two different No. 6 oils. The oil of Tests 1 and 2 had a nitrogen content of 0.44% and for Tests 195, 196, 200, and 201 it was 0.14%.

Test No. 53: Air-Atomized No. 2 Fuel Oil. At the baseline steam flow of 14.8 GJ/hr the oil burner operated with 0.29 MPa (27 psig) oil pressure, ambient oil temperature and 0.26 MPa (23 psig) atomizing air pressure. The NOx emissions increased with increasing excess O_2 up to about 4.0% O_2 beyond which the NOx was relatively constant at 101 ppm. Particulate emissions were 56.7 ng/J (0.0164 lbs/10^6 Btu), which is one of the lower values for air-atomized No. 2 fuel oil.

Test No. 54: Mechanically-Atomized No. 2 Fuel Oil. The mechanically-atomized oil burner used for this test operated with ambient temperature fuel oil at a burner pressure of 2.03 MPa (280 psig) for a boiler load of 12.1 GJ/hr (11,500 lbs/hr). The NOx values did not vary significantly over the excess O_2 range investigated of 3.7 to 6.6%. Particulate emissions of 8.34 ng/J (0.0194 lbs/10^6 Btu) were measured, which is one of the lower values measured for No. 2 fuel oil.

The No. 6 oil data presented in Figure 5-40 show steam atomized fuel oil burners to have slightly higher NOx emissions than air atomized burners for normal operating excess oxygen levels. As the excess O_2 level is increased, both of the NOx emissions increase until, at 5% excess O_2, the NOx emissions for steam atomization are less than for air atomization.

The NOx emissions with No. 2 fuel oil were not very sensitive to excess oxygen. Air atomization resulted in the highest NOx emissions [56 ng/J (100 ppm)] with steam atomization being the lowest NOx producer [39 ng/J (70 ppm)]. The mechanically atomized No. 2 fuel oil tests were conducted at a reduced load and yielded NOx emissions greater than the steam, but less than the air-atomized data.

The boiler efficiency did not vary measurably due to use of different oil and atomizers.

The particulate emissions for both the No. 6 and No. 2 fuel oil tests were inversely related to the nitrogen oxides emissions. For No. 6 fuel oil, atomization resulted in the lowest nitrogen oxides emissions at the normal operation oxygen level, but yielded substantially greater particulate emissions than did steam atomization. For the No. 2 fuel oil tests, steam atomization resulted in the lowest nitrogen oxides emissions and yielded the greatest particulate emissions. The air atomization test had the greatest nitrogen oxides emissions and yielded lower particulate emissions than the steam atomized test with No. 2 oil. Mechanically-atomized No. 2 fuel oil nitrogen oxides and particulate emissions were in between the air and steam results.

A second special series of tests, Tests 44, 45, 48, 56, and 47, was run at Location 26 with No. 2 and No. 5 oils with both steam and air atomization. In Tests 56 and 57 with No. 2 oil, the nitrogen oxides emissions listed in Table 5-7 for air and steam atomization were the same, whereas for Test 52, steam atomization produced significantly less nitrogen oxides emissions. With No. 5 oil in Tests 44 and 45, the emissions with air atomization were greater than with steam, rather than less, as for Tests 1 and 2 with No. 6 oil.

Tests 3 and 36 were run on a rotary cup type atomizer firing No. 5 and NSF oil, respectively. Although rotary cup oil burners once were commonplace, now they are becoming rare. The total nitrogen oxides concentrations were somewhat high for oil-fueled boilers of this small size, but not seriously so. The particulate emissions were slightly less than those of boilers burning No. 6 fuel oil.

5.3.2.4 Oil Atomization Pressure -

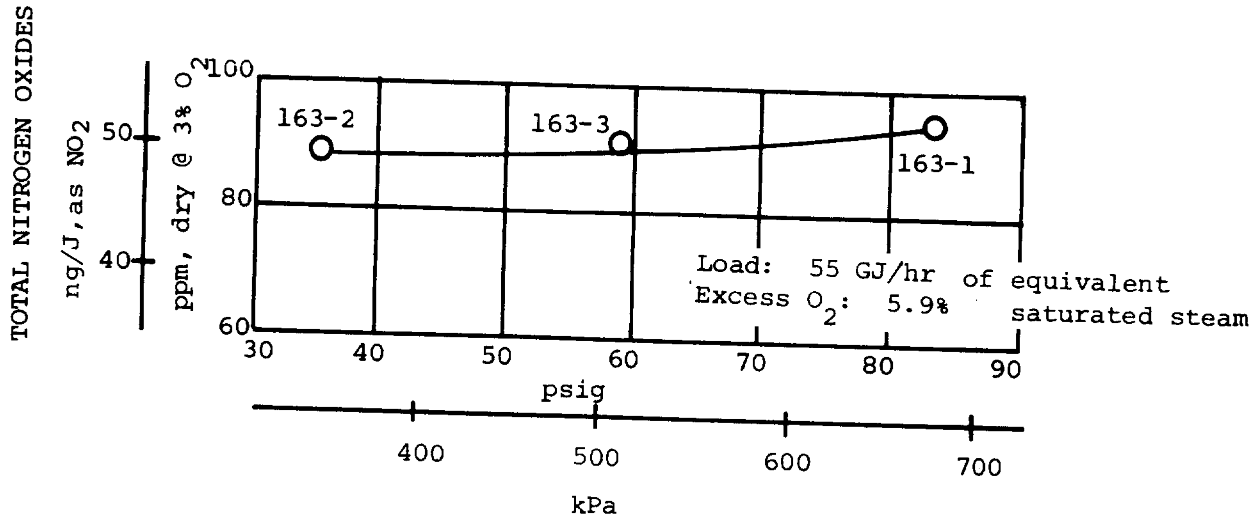
During three test series data were collected to determine the effect on nitrogen oxides emissions of changes in the pressure of the atomizing fluid. The results were that when the fuel and/or atomization pressure was increased the nitrogen oxides increased too. In the one instance where the effect on particulate emissions was measured, they decreased.

At Location 36 the pressure of the atomizing steam was varied to determine the effect of atomization pressure on the nitrogen oxide emissions. These tests were carried out in a steam-atomized watertube boiler firing No. 2 fuel oil. At a steam rate of 55 GJ/hr (52,000 lb/hr) and an excess oxygen level of 5.9%, the steam atomization pressure was varied from 340 kPa to 670 kPa (35 psig to 83 psig). The normal pressure setting at this load was 590 kPa (59 psig). The effect of nitrogen oxide emissions and smoke are shown in Figure 5-40. As the steam atomization pressure was increased over the pressure range, the nitrogen oxides emissions increased by 6% and the smoke levels decreased by two Bacharach smoke numbers.

Although the changes in the total nitrogen oxides emissions were small in these tests, the trend was consistent with that obtained previously.(4) The results of Test 2 of Phase I were that when the pressure of the atomizing air was reduced the nitrogen oxides emissions decreased.

The ASME heat loss boiler efficiency was not significantly affected by this combustion modifications, remaining at 85% throughout the tests at Location 36.

The effect of atomization pressure on nitrogen oxides and particulate emissions was investigated at length by Laurendeau, et al.(17) They tested a boiler at Location 38 that was a twin to the one tested under this program. One set of runs consisted of raising the fuel



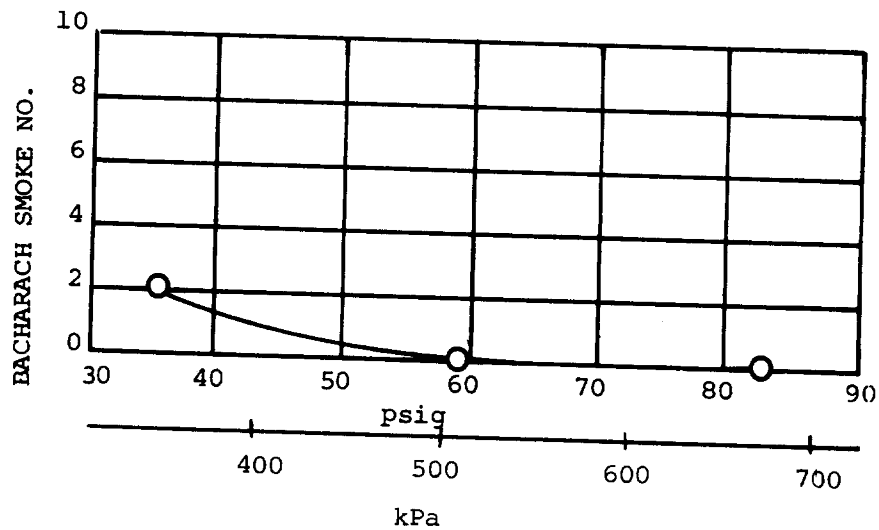


Figure 5-40. Effect of steam atomization pressure on total nitrogen oxides emissions and smoke level.

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and steam atomizing pressure while maintaining a 140 kPa (20 psig) spread between them. Raising the pressures caused the particulate emissions to decrease as is shown in Figure 5-38 when the atomizing pressure was raised from 585 to 722 kPa (70 to 90 psig). However, raising the pressure also caused the nitrogen oxides emissions to increase. At fuel and atomizing steam pressures of 515 kPa and 650 kPa (60 and 80 psig) the nitrogen oxide emissions were about 140 ng/J (250 ppm). When the pressures were raised to 700 kPa and 825 kPa (87 and 105 ppm) the NO emissions rose to about 163 ng/J (290 ppm).

5.3.2.5 Natural Gas Burners -

The majority of the industrial-sized boilers tested in Phases I and II were equipped with multijet ring type natural gas burners. This type of burner injects the gas jets radially inward (toward the burner center axis) into a swirling air stream. The ring burner produces good fuel and air mixing and the combustion starts in the fuel-rich combustion zone near the injection orifices and continues downstream of the burner throat. Ring burners have generally been found to be low nitrogen oxides producers and have the capability of operating fuel-rich over a large range of fuel flow rates with a stable flame.

Two boilers, used for Tests 75 and 77 had corner-fired furnaces which use multijet gas nozzles where the gas and air streams are injected into the boiler in parallel directions.

The boiler used for Tests 153-155 utilized a single burner comprised of three multi-orifice gas nozzles. Combustion air is supplied through primary and secondary air registers. The gas guns are located within the primary (inner) air passage and inject fuel outward into the swirling air stream at an angle of approximatley 45° from the center axis. The boilers used for Tests 149-152 and 207-212 were also fitted with gun type burners, however refinery gas was the fuel.

Because of the lack of variation in gas burner designs, no concrete conclusions could be drawn on the effect of burner design on emissions. Emissions from the boilers equipped with nozzle type burners were similar to those from boilers fitted with ring burners. Generally, nitrogen oxide emissions from natural gas fired boilers were found to be more dependent upon firing parameters, such as burner heat release rate, excess air, and combustion air temperature.

5.3.2.6 Burner Size -

The total nitrogen oxides emissions measured during the program were found to be larger when the burner size in terms of heat release level in joules per hour was large. The relationship differed for each of the three fuels, but in general it was found that the larger the burner the larger the nitrogen oxides emissions. This relationship suggests that an effective form of combustion modification would be to use two smaller burners rather than one larger one. It is recognized that coal fuel burning equipment sometimes can not be defined simply in terms of individual burners size; however, pulverized coal burners and cyclone furnaces are similar to oil and natural gas burners in that a certain portion of the fuel and air enters the furnace through a burner port.

The relationship between the nitrogen oxides emissions and the burner heat release rate or size for the natural gas and coal-fired boilers is depicted in Figure 5-41. The coal fuel data on Figure 5-41

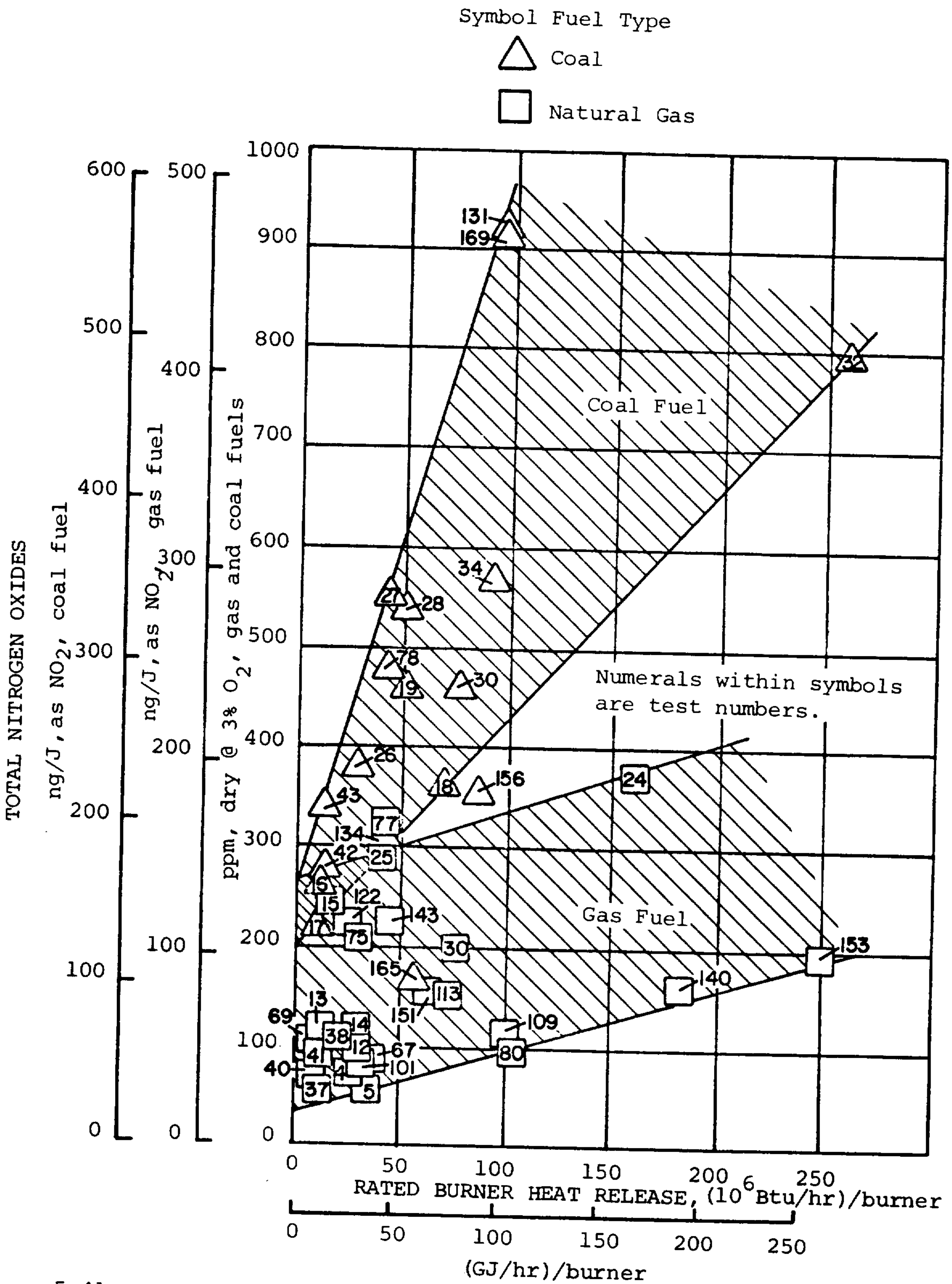

Figure 5-41. Effect of burner heat release rate on total nitrogen oxides emissions for coal and natural gas fuels.

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show a strong dependence of nitrogen oxides emissions on burner heat release level. The natural gas burner data, however, show a somewhat lower dependence of nitrogen oxides emissions on burner size than does the coal burner data.

The Phase I data[4] had been interpreted as indicating that the dependence of emissions on burner size was stronger when the combustion air was preheated than when it was not. However, during Phase II the measurements made for Tests 140 and 165 on boilers that had preheated combustion air were the same level as those taken previously for unheated combustion air. It now appears that the degree of sensitivity of nitrogen oxides emissions to burner size depends more upon the characteristics of the individual boiler than upon whether or not the combustion air is preheated.

Figure 5-42 presents the effect of burner heat release level on the total nitrogen oxides emissions for all of the oil-fired boilers tested. The two data points for No. 5 oils which have nitrogen oxides emission levels greater than 225 ng/J (400 ppm) are from tests where the fuel oil was not heated, but was near outside air temperature. Atomization was poor, and they are not considered to be representative data points.

The effect of burner heat release rate on nitrogen oxides emissions from oil fuels was not as great as previously discussed for coal fuel, but was greater than for natural gas burners with or without preheated combustion air. The type of oil atomizer did not seem to affect this relationship. The No. 2 oil burners were smaller, all being below 53 GJ/hr (50×10^6 Btu/hr), and defined the lower region of the oil data. The No. 5 and No. 6 oil burners included the complete range of burner size investigated from the smallest up to 131 GJ/hr (125×10^6 Btu/hr).

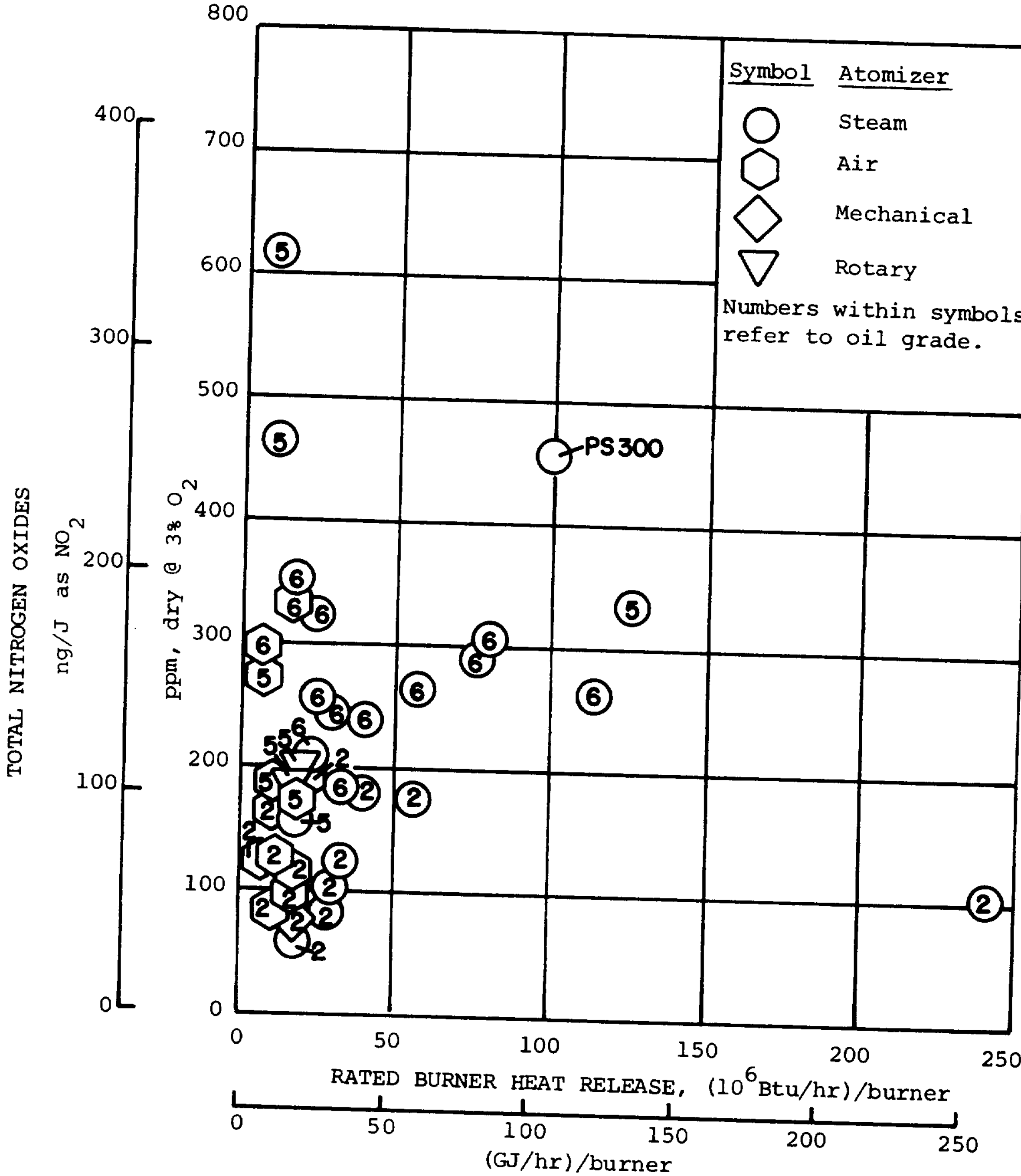

Figure 5-42. Effect of burner heat release rate on total nitrogen oxides emissions, oil fuel.

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5.3.3 Boiler Furnace Characteristics

5.3.3.1 Firetube Boilers -

A large number of firetube furnace boilers in addition to watertube furnace boilers was tested during Phase I, and the results are discussed in Subsection 5.1.1.4. Comparison of the test results showed that the emissions of nitrogen oxides from firetube boilers was less sensitive to changes in the excess air level than they were from watertube boilers when burning the same fuel.[4] The Phase II testing concentrated on watertube boilers only.

5.3.3.2 Furnace Volume and Area -

Nitrogen oxides are formed at high temperature by the combination of oxygen and nitrogen, and the length of time that the products remain at high temperature is critical to the formation of nitrogen oxides. Consequently, the furnace heat absorption volume and area were evaluated as design parameters which could influence the time/temperature history. The furnace heat absorption volume parameter was defined as the products of the furnace heat release per hour divided by the furnace volume from the burner face to the end of the furnace. The furnace heat absorption area parameter was defined as the ratio of the furnace heat release per hour to the projected wall, floor and ceiling areas of the furnace. The furnace heat absorption parameters are listed in Table 7-1 of Section 7, Test Boiler Design Characteristics, for each boiler tested in Phase II.

The heat absorption parameter data are discussed in Subsection 7.2.2 of the Phase I report,[4] and the conclusion drawn from these data was that the nitrogen oxides emissions were not dependent upon furnace heat absorption area or volume. Phase II test results support this conclusion.

5.4 PARTICULATE EMISSIONS

5.4.1 Particulate Concentration

Figure 5-43 compares the change from the baseline value in solid or filterable particulate emissions and the corresponding change in the total nitrogen oxides emissions when the different combustion modification techniques were applied. Data from both Phase I and Phase II are included. The figure is divided into quadrants. One is labeled "Best Quadrant" and a second "Worst Quadrant." The criterion for the Best Quadrant with solid particulate emissions is that the effect of the modification was to reduce the emissions of both the total nitrogen oxides and the particulates. The Worst Quadrant is when the effect was to increase both emissions.

The effect of the various combustion modification methods was as follows:

1. Reduced excess air: This was the best method because the particulate emissions decreased by as much as 30% in four out of the six tests.

2. Staged combustion air: The change in particulates was measured in three of the six staged combustion air tests. In all three instances it increased by 20 to 48% of the baseline level.

3. Burners-out-of-service: This method had the advantage that the nitrogen oxides emissions always decreased and the boiler efficiency was maintained. However, the particulate emissions always increased by from 25 to 95% of the baseline level.

4. Burner register adjustment: Readjusting the burner registers had no significant effect on the particulate emissions.

5. Reduced combustion air temperature: Only one test was run and the air temperature was increased by 11 K. The particulate emissions decreased by 53%. However, a measurement of the particulate emissions change with an air temperature reduction of 100 K was made on the boiler

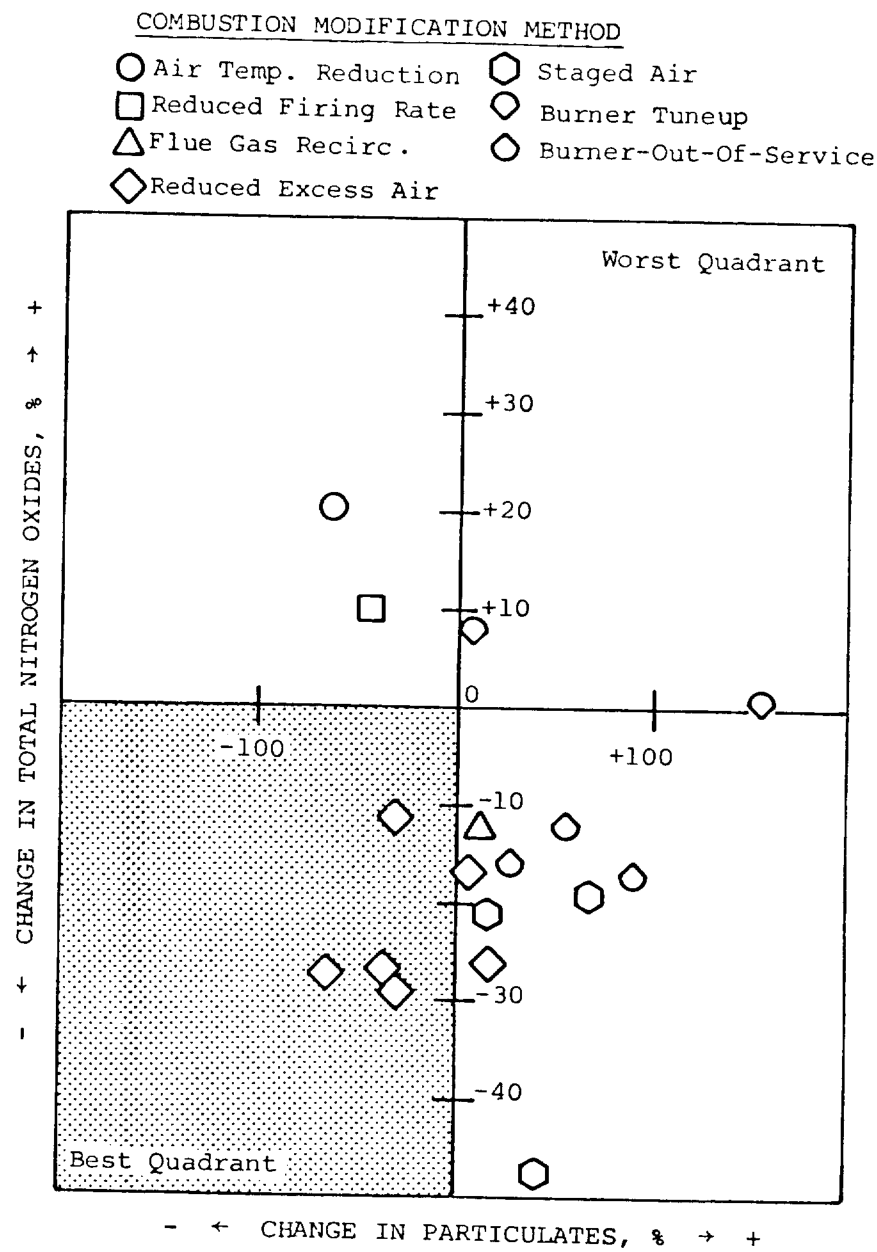

Figure 5-43. Effect of combustion modification methods on solid particulate emissions.

at Location 38 as part of the work reported in Reference 17. The results were reported in a private communication and were that no change in particulate emissions occurred.

6. Flue gas recirculation: Recirculating 25% of the flue gas resulted in a nitrogen oxides reduction of about 12% and a particulate emission increase of about 15% of the baseline levels.

7. Reduced firing rate: In the one instance where the particulates emission change was determined, the nitrogen oxides emission increased by 10% and the particulate emission decreased by 45%. This was one of the largest particulate emission decreases that was encountered.

8. Fuel oil viscosity: Another KVB, Inc. field test crew measured the particulate emissions change as the oil temperature of a twin boiler at Location 38 was increased from 351 K to 388 K. The particulate emissions "showed a pronounced decrease with increasing oil temperature."[17]

9. Burner tune-up: Tuning the burner reduced the nitrogen oxides emissions and had no effect on the particulates in Test 112. During Test 108 the emissions rose by 150%, because the tune-up resulted in increased flame impingement and quenching on the water walls. The results of Test 112 are deemed to be the more representative, since tuning the burner resulted primarily in reducing the carbon monoxide for a given level of excess air. Reducing the carbon monoxide emissions should reduce, or at the worst not affect, the particulate emissions.

10. Fuel oil atomization method: No generalized conclusions can be drawn from the five test sets that are listed in Table 5-9. There were four instances where the atomization method of a given burner was changed from steam to air. When the oil was No. 6 the particulate emissions increased by from 26 to 101% of the baseline level. For the one case when the oil was No. 2 the emissions decreased by 69%.

Table 5-9. EFFECT OF ATOMIZATION METHOD ON THE PARTICULATE EMISSION LEVELS

Test Run No.	Test Type	Oil Grade	Atom. Method	Solid Part. ng/J (lb/10^6 Btu)	Change in Particulate Emission %
1-11	Baseline	No. 6	Steam	62.1 (0.1447)	
2-6	Changed Atomization	No. 6	Air	125 (0.2818)	+101
195-1	Baseline	No. 6	Steam	8.60 (0.020)	
200-3	Changed Atomization	No. 6	Air	10.8 (0.025)	+26
198-12	Baseline	No. 6	Steam	9.90 (0.023)	
203-7	Changed Atomization	No. 6	Air	18.1 (0.042)	+83
44-4	Baseline	No. 5	Air	17.5 (0.0448)	
45-7	Changed Atomization	No. 5	Steam	32.0 (0.0779)	+83
52-5	Baseline	No. 2	Steam	14.6 (0.0339)	
53-6	Changed Atomization	No. 2	Air	5.01 (0.0163)	-69
54-5	Changed Atomization	No. 2	Mech.	4.96 (0.0151)	-69

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When the change was made from air to steam atomization on another burner, rather than from steam to air, the particulate emissions did not decrease as would have been expected from the results of Tests 1 and 2, 195 and 200, and 198 and 203. Instead the emissions from Tests 44 and 45 increased by 83%.

Apparently, the effect of atomization method on the particulate emissions is unique to each fuel-burner-boiler combination and it cannot be generalized.

12. Fuel oil atomization pressure: The results of one set of tests that are discussed in Subsection 5.3.2.3 were that an increase in the atomization pressure of 23% reduced the particulate emissions by 75%. Although this was only one test set, extensive data were taken carefully, and one can conclude that it is possible to reduce the particulate emissions by increasing the atomization pressure.

5.4.2 Particulate Size

The effect of some of the forms of combustion modification on the particulate size distribution also was determined and is discussed in this section. Table 5-10 lists the combustion modification methods that were investigated and the corresponding size distribution results.

Figure 5-44 shows the effect of the particulate size distribution of modifying the combustion of oil fuel by reducing the amount of excess air/oxygen. Test 176 was run with the baseline amount of excess oxygen of 4.3%, while Test 179 was run with 4.0% excess oxygen. Reducing the excess oxygen from 4.3% to 4.0% reduced the proportion of fine particulates from about 58% to about 50%. (The total nitrogen oxides concentration dropped from 195 ppm to 174 ppm.) Apparently the modified combustion resulted in a decrease in the proportion of the smaller and an increase in the proportion of the larger size particulates.

Table 5-10. PARTICULATE SIZE DISTRIBUTION WITH COMBUSTION MODIFICATIONS

OIL FUEL

Test No.	Test Location	Load GJ/hr (10^3lb/hr)	Burner or Oil Type	Proportion of Total Weight of Catch: Particles Inhaled Then Exhaled <0.5 μm %	Particles In The "Fine" Particulate Size Range <3 μm %	Particles Reducing Visibility by Mie Scattering 0.4-0.7 μm %	Soot Included	Combustion Modification
111	27	90(85)	PS300	60	81	10	No	None (Baseline)
112		90(85)	PS300	-	97	-	No	After Tuneup
162-36	36	65(62)	No. 2	1	26	0.8	No	None (Baseline)
162-11		63(60)	No. 2	3	40	0.9	No	Low Excess Air and Registers Reset
162-5		93(88)	No. 2	0.3	5	0.1	No	Registers Reset
176	37	34(32)	No. 6	31	60	1	No	None (Baseline)
179		34(32)	No. 6	27	50	1	No	Low Excess Air
166-3	35	116(110)	Chain Grate	11	24	5	No	None (Baseline)
166-8		116(110)	Chain Grate	18	40	13	No	Low Excess Air

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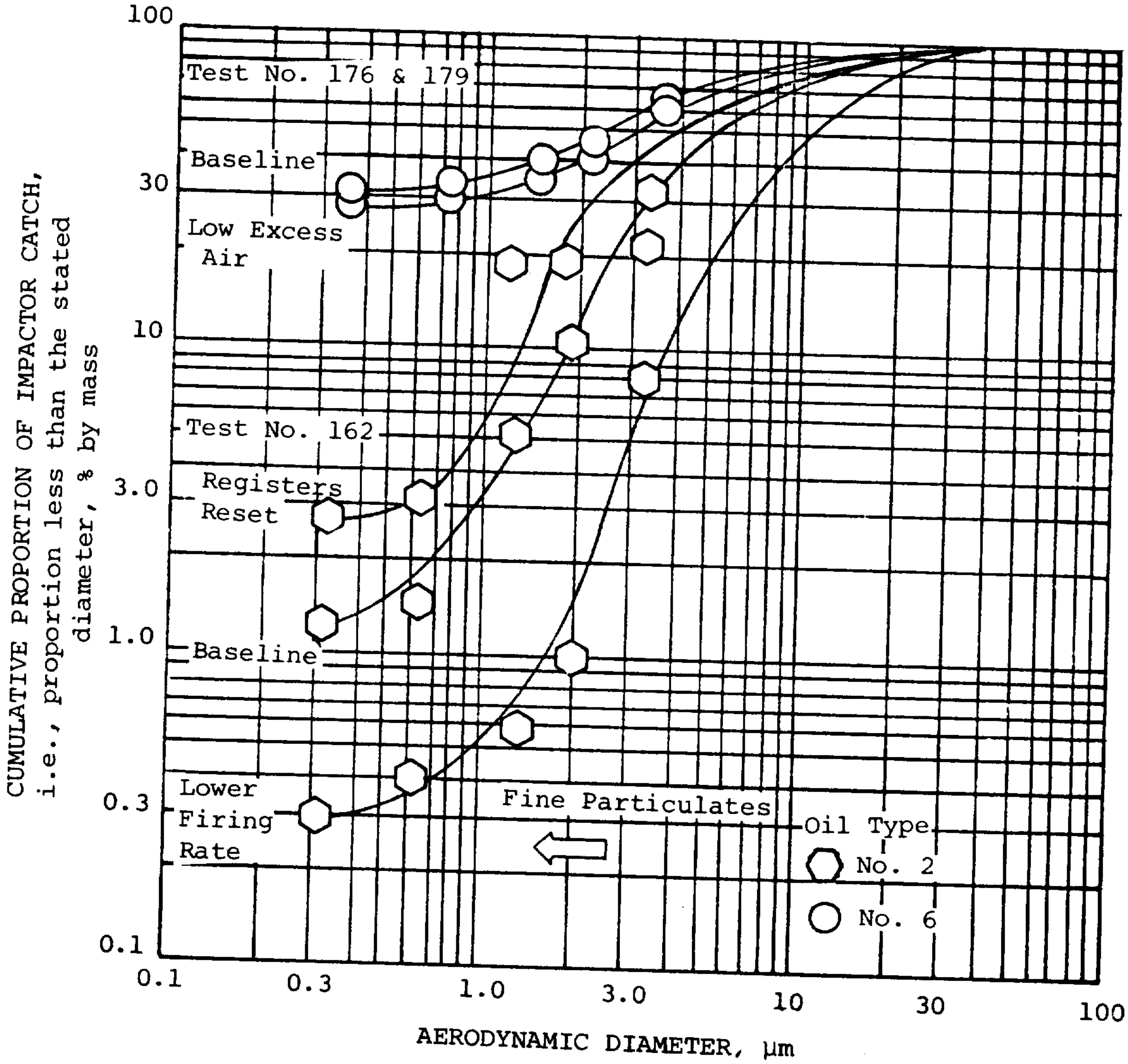

Figure 5-44. Effect of combustion modifications on particulate size. Oil Fuel.

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Also shown in Figure 5-44 is the effect on the particulate size distribution of modifying the fuel and air mixing by resetting the burner registers. The test fuel here was No. 2 oil, and the testing was done at a very low firing rate, i.e., 33% of capacity. The upper curve for Test 162 was drawn from data taken after the registers had been reset. The most striking effect was that the proportion of fine particulate rose from a baseline value of about 26% to about 40%.

When the fuel was coal burned on a chain grate the effect of reducing the excess air was different. The reduction in the percentage of excess air was 0.4. This is illustrated on Figure 5-45. Reducing the excess air raised all of the proportions of the total weight of the catch, rather than reducing them as with oil fuel.

When the firing rate of the boiler used for Test 162 was raised from a level of 65 GJ/hr that was 33% of capacity to 93 GJ/hr (47% of capacity) and the registers reset for the lowest nitrogen oxides emissions the proportion of fine particulate decreased from about 26% to about 5%.

The effect of modifying combustion by tuning the burner is illustrated in Figure 5-46. The data for the upper curve were taken before the oil burner at Location 27 was tuned and those for the lower curve were taken after. After tuning there was a larger proportion of the fine particulate. No data were available below on aerodynamic size of about 0.5 μm because the back-up filter was damaged and could not be reweighed.

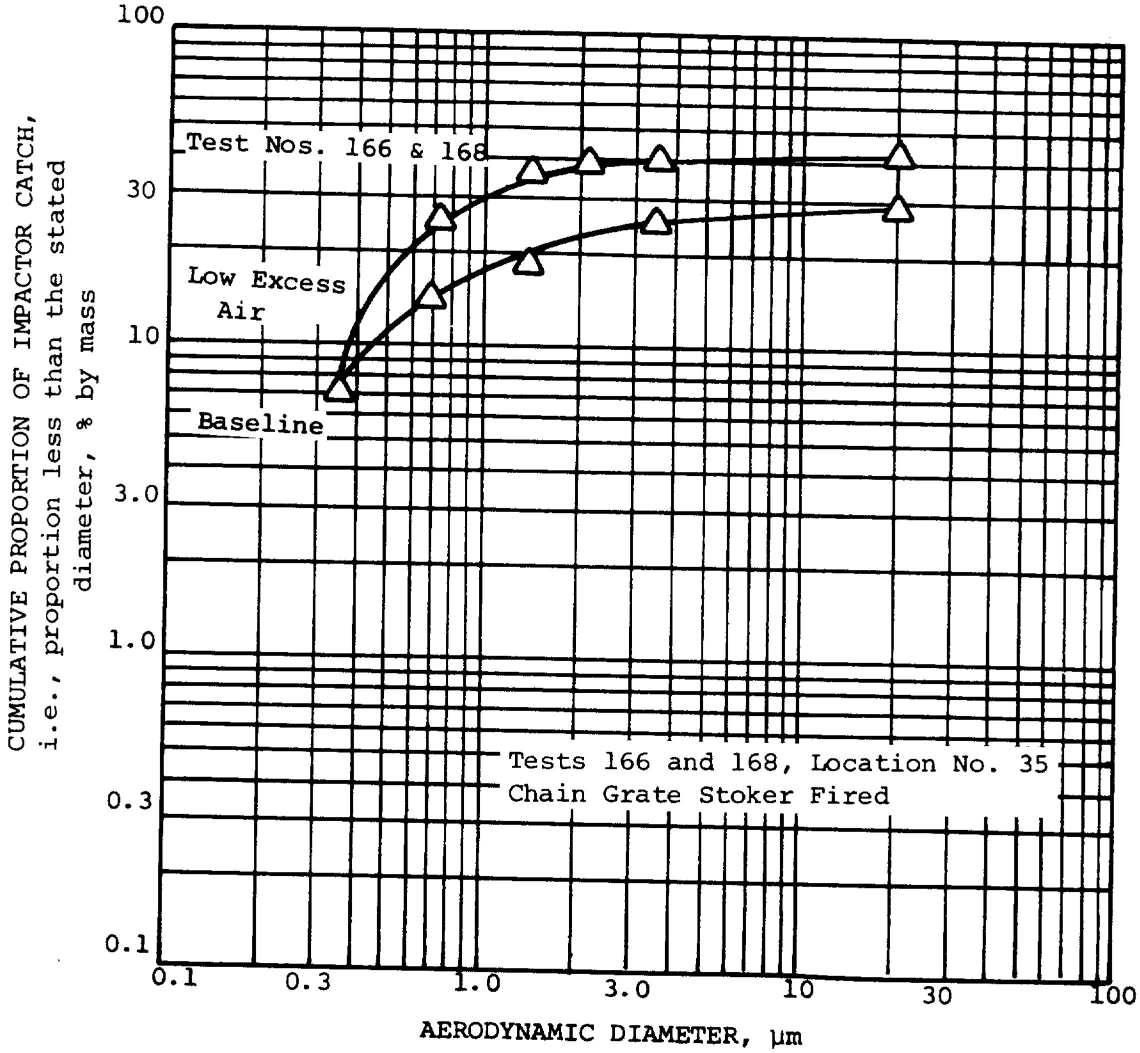

Figure 5-45. Effect of low excess air combustion modification on particulate size. Coal fuel.

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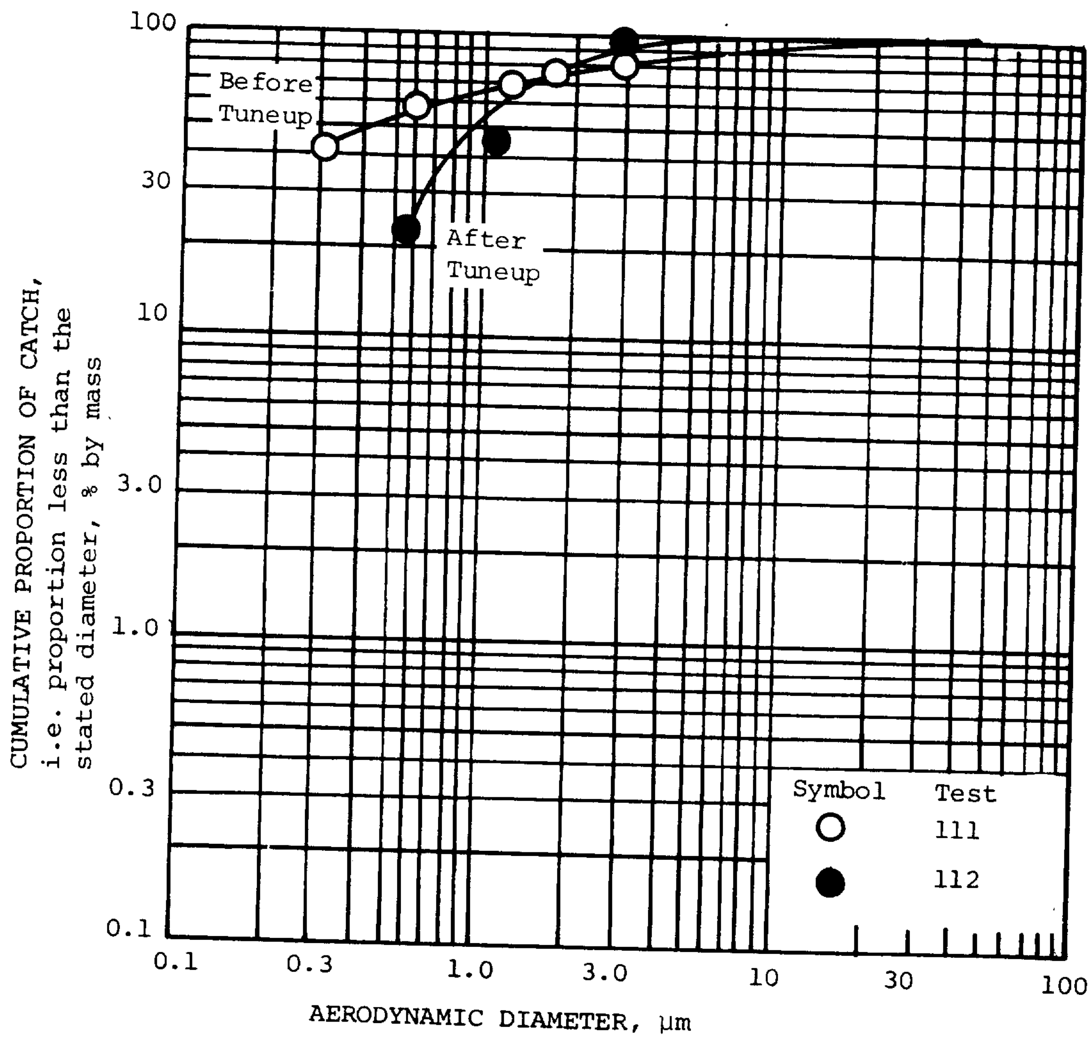

Figure 5-46. Effect of burner tune-up on particulate size, PS300 oil fuel

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5.5 BOILER EFFICIENCY

The effect of the various techniques used to reduce nitrogen oxide emissions on boiler thermal efficiency have been evaluated and are discussed in this section. The test data are from Phase II in which the nitrogen oxides reducing techniques of low excess oxygen, overfire air, burners out of service, reduced combustion air preheat, and flue gas recirculation were investigated. The data are presented in graphs wherein the percentage change of nitrogen oxides (the change in NOx resulting from a particular combustion modification divided by the baseline NOx level) is plotted versus the corresponding change in boiler efficiency.

In general, the nitrogen oxide reduction techniques of low excess oxygen firing, burners out of service, and flue gas recirculation resulted in boiler efficiencies equal to or better than baseline levels. Staged air and reduced combustion air preheat produced a degradation of efficiency.

5.5.1 Effect of Excess Air

The effect of low excess air firing on boiler efficiency is illustrated in Figure 5-47. The majority of the data points are located in the best quadrant, i.e., where a reduction in emissions is accompanied by an increase in efficiency. Efficiency was bettered by as much as 2.5% in two cases. On a coal-fired boiler reducing excess oxygen resulted in a 44% reduction in nitrogen oxide emissions along with a 2.0% increase of boiler efficiency. In three cases with gas fuel, lowering the excess oxygen resulted in an increase in emissions at a higher efficiency. This behavior of increasing nitrogen oxides with decreased oxygen is unusual and is discussed in Section 5.1.1. In two instances, lowering excess oxygen resulted in a decrease of efficiency; however, the magnitude of the changes were insignificant compared to the accuracy of the procedure used to determine them.

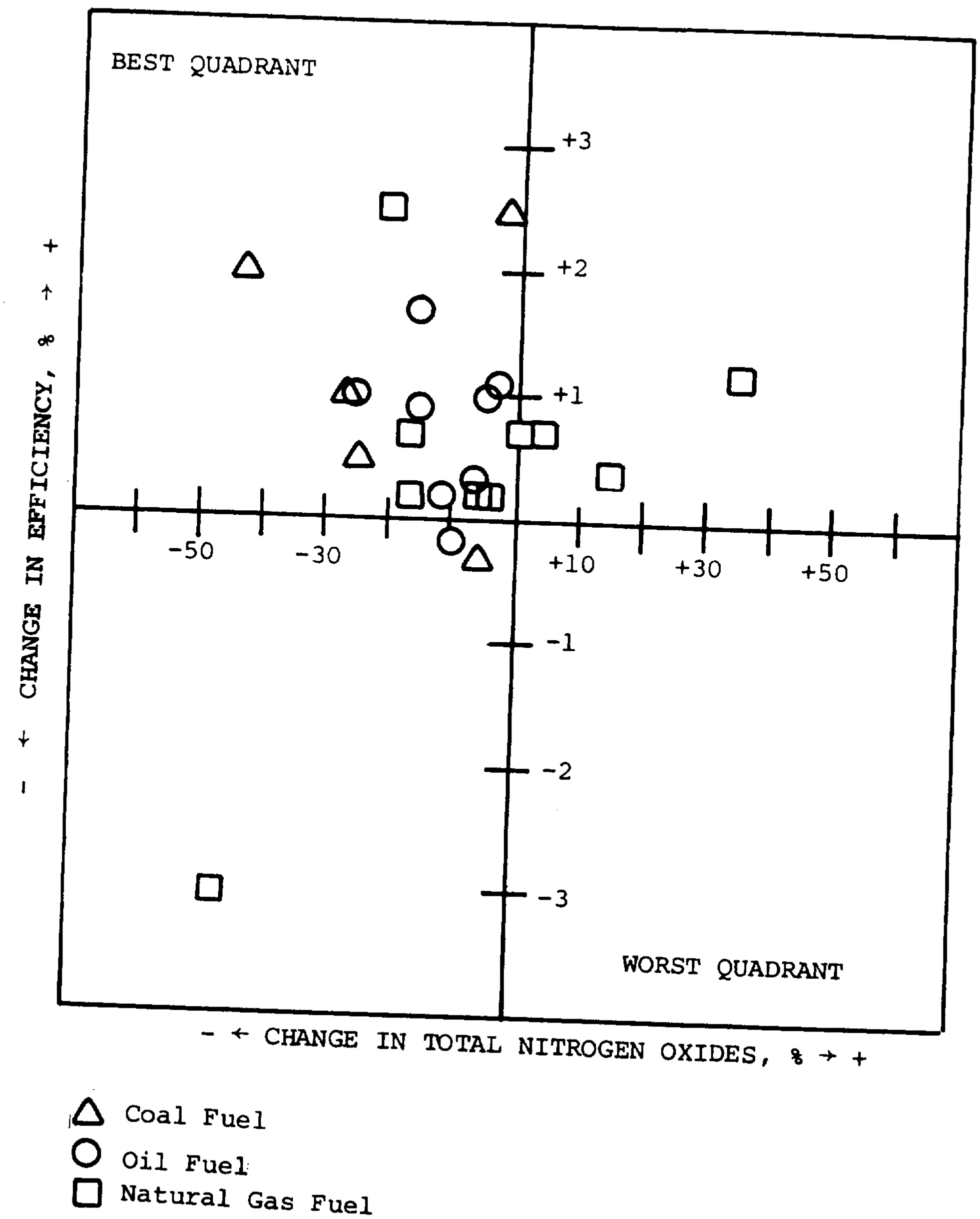

Figure 5-47. Effect on boiler efficiency of reducing the excess combustion air.

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As a whole, the efficiency of the boilers tested during Phase II responded as expected to the effects of reduced excess oxygen. In agreement with Phase I results, the degree of efficiency increase averaged to be 0.5% for each 1.0% decrease in excess oxygen.

5.5.2 Effect of Staged Air

The effect of staged combustion air on boiler efficiency is illustrated in Figure 5-48. Generally, the reduction of nitrogen oxide emissions by using staged air had a negative affect on efficiency. This behavior was to be expected since staged air normally requires that the level of excess oxygen be maintained at higher than baseline levels to assure complete combustion. This greater quantity of heated air being exhausted through the stack contributes significantly to the negative influence on efficiency. A few boilers exhibited increases in efficiency (best quadrant) when staged air was used. These boilers had staged air ports which were part of the original boiler design and were therefore more carefully sized and located.

5.5.3 Effect of Burners Out of Service

Figure 5-49 presents the effect of burners out of service on boiler efficiency. The efficiency changes were generally small, 0.6% or less, but were mostly in the positive direction. One would expect the effect of burners out of service to be similar to staged air since both techniques involve staging combustion. The quantity of test data from burners out of service is small, making it difficult to draw any concrete conclusions.

5.5.4 Effect of Combustion Air Temperature

The effect of varying the combustion air preheat temperature is shown in Figure 5-50. As expected, lowering the temperature to reduce emissions resulted in a degradation of boiler efficiency, because a reduction in air preheat was accompanied by an increase of flue gas temperature. The five instances where the efficiency increased were

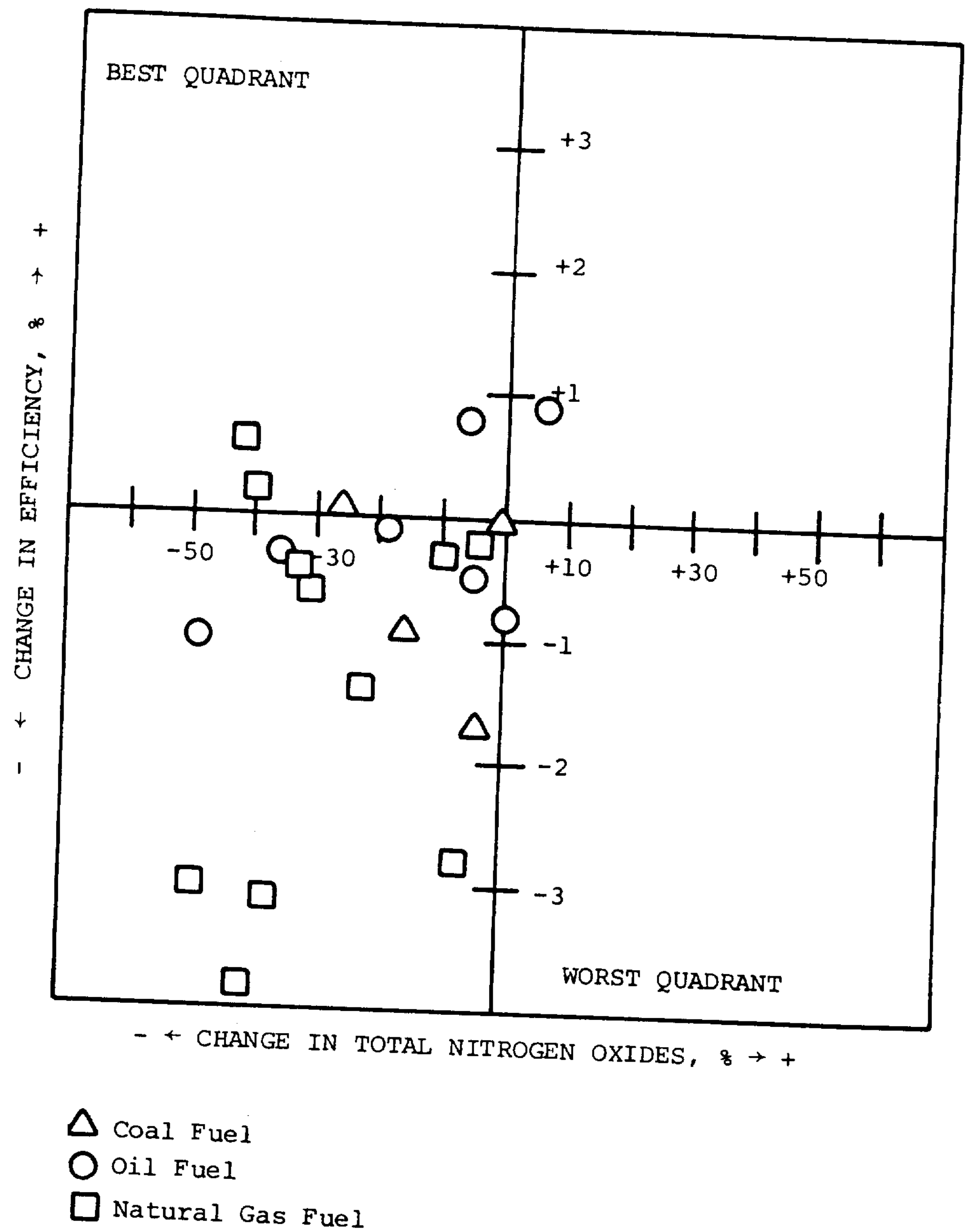

Figure 5-48. Effect on boiler efficiency of staged combustion air.

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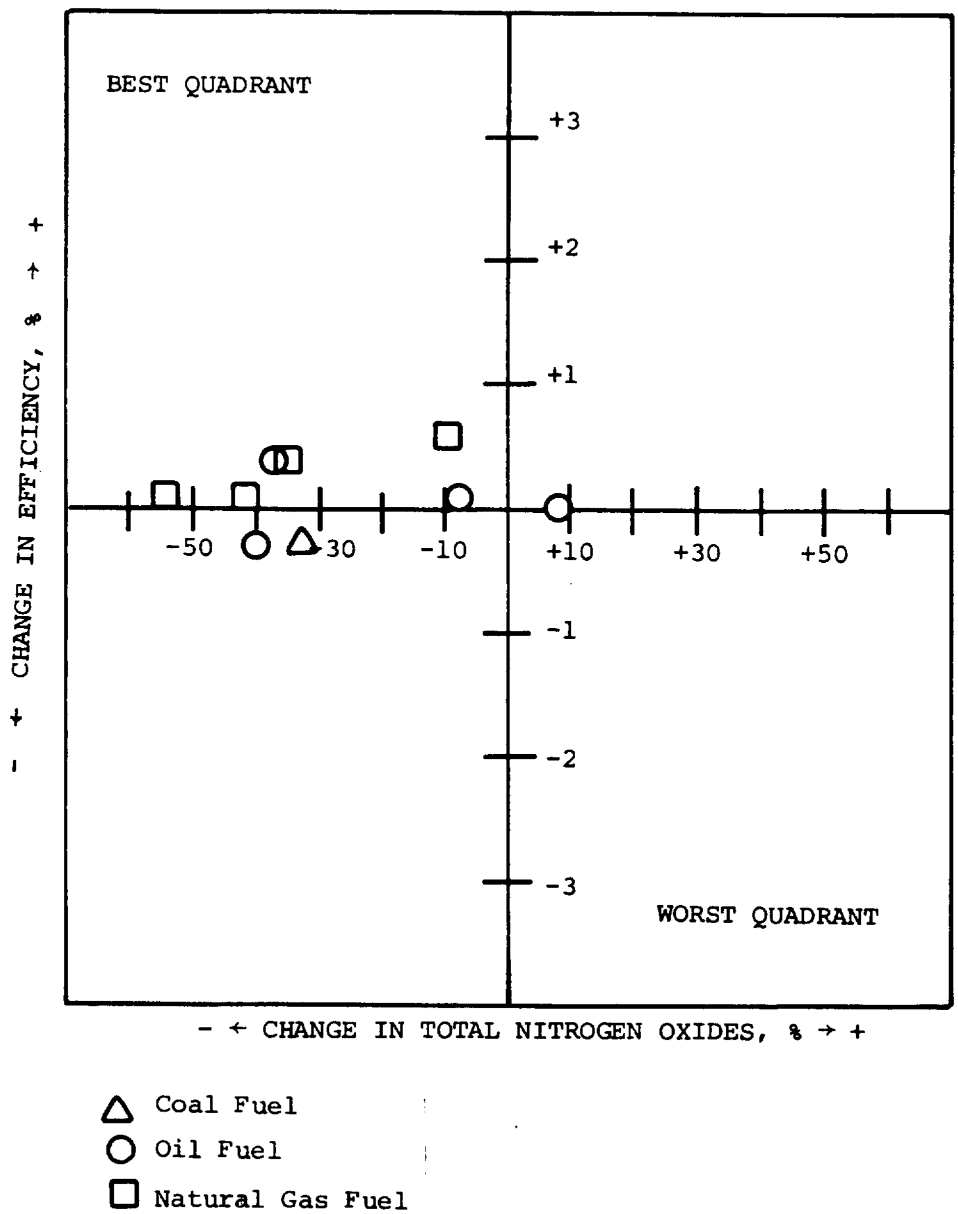

Figure 5-49. Effect on boiler efficiency of operating with burners out of service.

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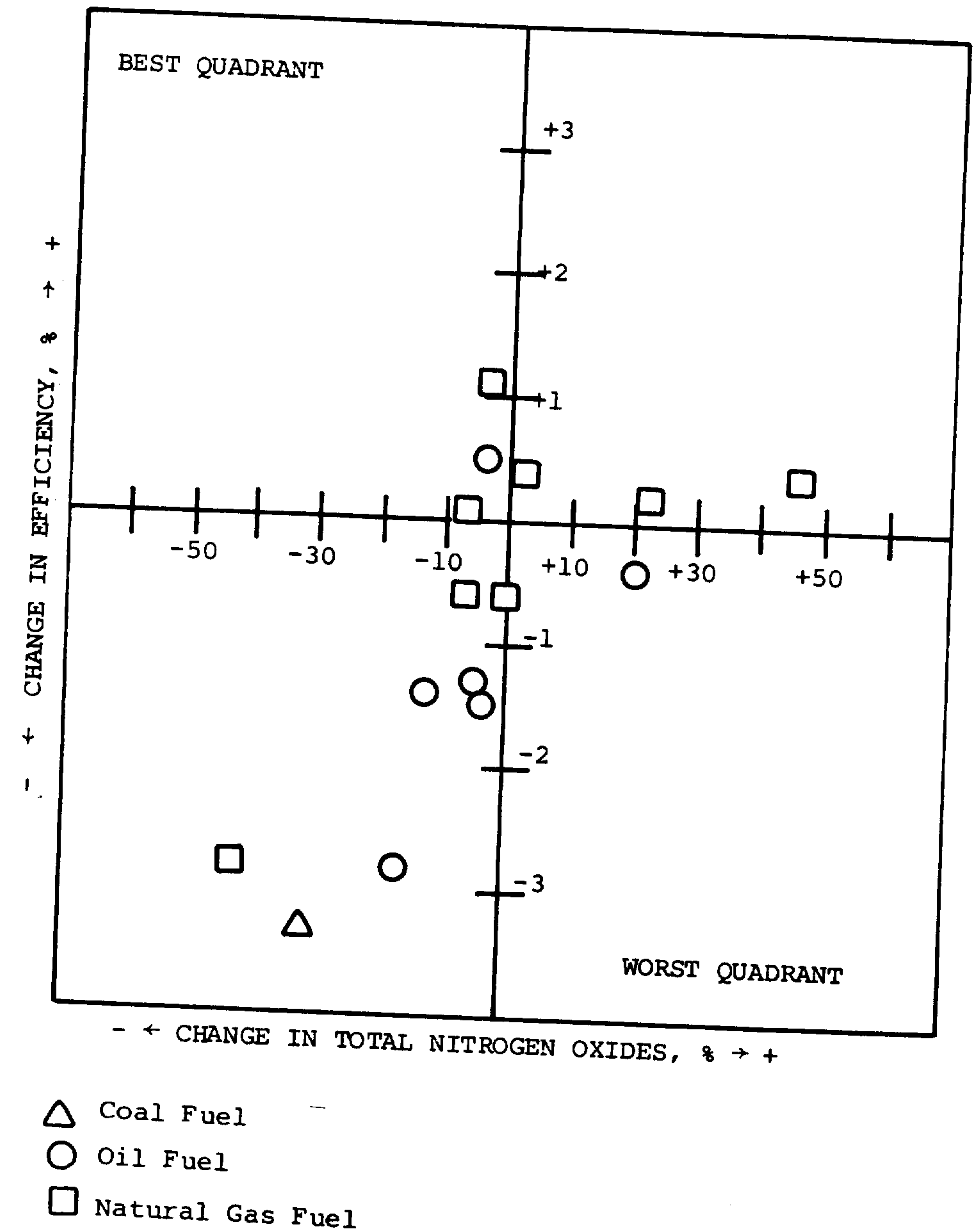

Figure 5-50. Effect on boiler efficiency of the combustion air preheat temperature.

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tests where the air temperature was raised, rather than lowered, e.g., Runs 130-1, 142-1, 118-1. Efficiency losses were as high as 3.3% with a 32% reduction of nitrogen oxides emissions from a coal-fired boiler where the air temperature was reduced from 365 K to 355 K by opening a by-pass duct (Test 138-2). If reduced air preheat is to be adopted as a permanent nitrogen oxide emissions reduction technique for a particular boiler, the stack losses can be recouped by redesigning the steam side of the boiler for more heat absorption. An example of this would be the installation or enlargement of an economizer.

5.5.5 Effect of Flue Gas Recirculation

The effects of flue gas recirculation on boiler efficiency are shown in Figure 5-51. Also illustrated are the effects of flue gas recirculation combined with staged air. Flue gas recirculation, per se, had only small effects on efficiency. The changes were 0.6% or less and varied from positive to negative. However, when sidefire air was added, efficiency dropped by about 1.5% as would be expected due to the necessary increase in excess oxygen for complete combustion.

5.6 GENERAL NITROGEN OXIDES EMISSIONS CORRELATION

A general correlation of nitrogen oxide emissions from industrial boilers was developed using the test data from Phase I and Phase II. The correlation relates nitrogen oxides emissions to three boiler operational factors. These factors are (1) the excess air level, (2) a term describing the rate of heat input, and (3) the nitrogen content of the fuel. The correlation holds for all combination of boilers and fuels tested during the program. To the knowledge of the authors of this report, this is the first of any such general correlation and is believed to be of major significance.

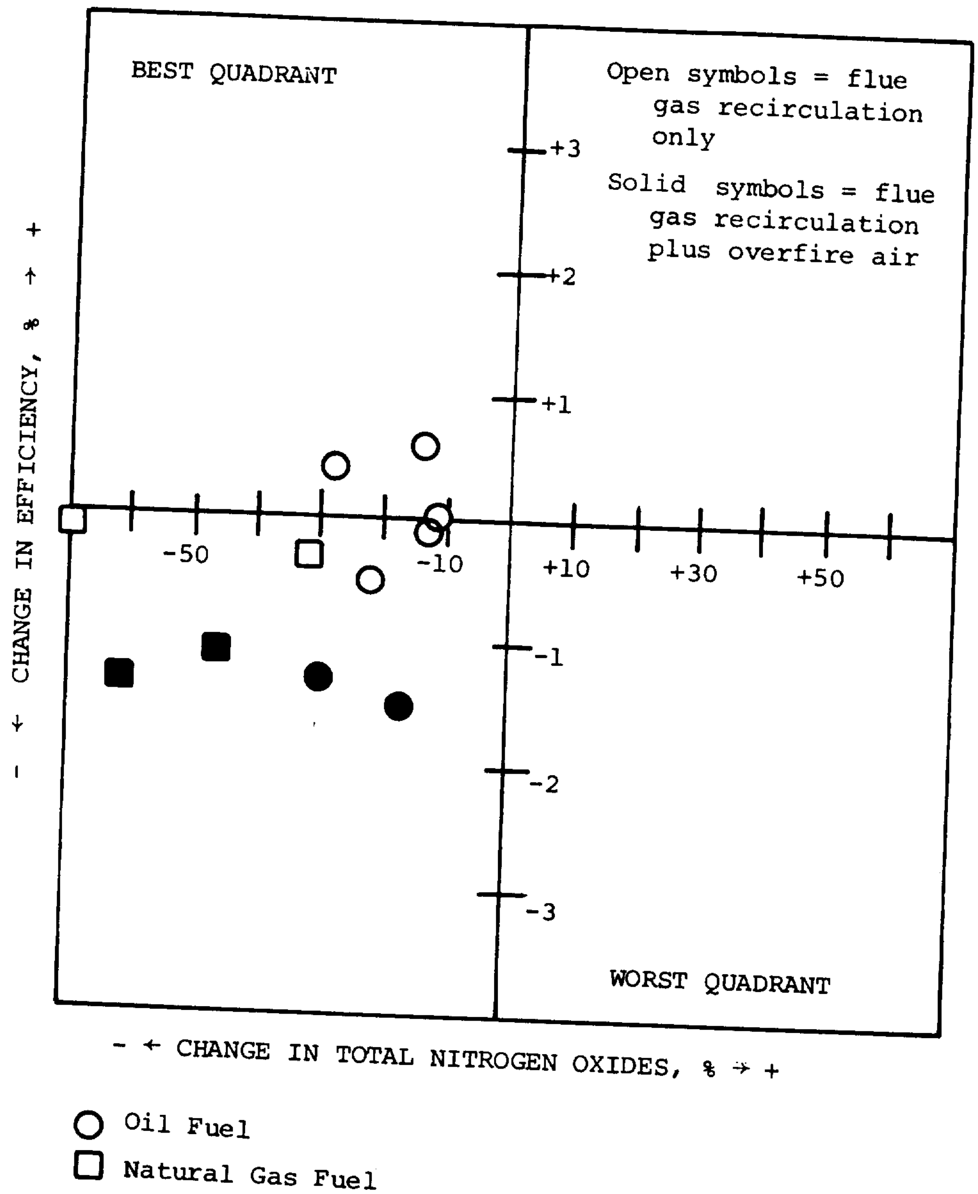

Figure 5-51. Effect on boiler efficiency of flue gas recirculation and staged combustion air.

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An overall review of nitrogen oxide emissions test data from Phase I and Phase II revealed that there was no single design or operation factor that could provide an acceptable correlation for the levels of emissions from industrial boilers. Nitrogen oxide emissions were dependent in varying degrees upon fuel properties, excess air, boiler design, boiler firing rate, combustion air temperature, etc. The effects of these factors on emissions are discussed individually earlier in this section of the report, but no one factor correlated with all of the emission trends that were encountered.

For the majority of test cases it was found that nitrogen oxide emissions consistently increased along with an increase in two factors: excess air and a factor describing the rate of heat release. This second factor was more specifically defined as the ratio of total heat release per unit furnace-heat-absorbing-area. A third factor was the fuel nitrogen content. For coal and, especially, oil fuels, nitrogen oxide emissions increased as the fuel nitrogen content became greater.

It was found that by using the rate of heat release as the basic parameter and then correcting for the excess air level and fuel nitrogen, a reasonable correlation of all the data could be achieved. The correlation parameter was formulated as the produce of the three individual factors and was as follows:

$$NO_x \doteq (1 + 46N)(TA)(Q/A)$$

where N = fuel nitrogen content, % by weight

TA = fraction of theoretical air

Q/A = heat release per unit heat absorption area, joules$\cdot$hour$^{-1}\cdot$meter^{-2}

The nitrogen factor of (1 + 46N) was developed from the field test finding that the proportion of conversion of fuel nitrogen to nitrogen oxides was 46%. This conversion factor is discussed in Sections 5.3 and 6.0. The unity portion of the term was included in the nitrogen factor to account for nitrogen oxide emissions resulting solely from the thermal fixation of atmospheric nitrogen (for example, when the fuel burned contained no bound nitrogen, as with natural gas fuel).

The fraction of theoretical air provides for the excess air effect on nitrogen oxides. One hundred percent of theoretical air is the stoichiometric air required for complete combustion under perfect conditions. Anything greater than 100% is excess air. For example, when a boiler is operated with 55% excess air the "TA" factor would be 1.55.

As mentioned above, the heat release factor is the ratio of the heat released by combustion to the furnace heat transfer area. It is the product of the full load fuel flow, fuel heating value, and the fraction of the boiler load for the test divided by the area of the furnace heat transfer surfaces surrounding the flame. This area factor is very difficult to evaluate, since a boiler furnace usually has an odd shape and a variety of waterwall tube sizes and spacings. A significant amount of scatter in the correlation data is caused by this uncertainty in the actual heat absorbing area.

The results of the correlation are presented in Figures 5-52 and 5-53, wherein the nitrogen oxide emissions level is plotted versus the correlation parameter. One variable that affects nitrogen oxides, but was not taken into consideration for the correlation, was the temperature of the combustion air. For this reason, two plots were made, one for boilers with ambient temperature combustion air and one for preheated air. The plot for preheated air has more scatter than the ambient air plot. This is because the amount of preheat temperature varied significantly and the variation in ambient temperatures was quite small. Additional scatter in the data bands may be due to different burner designs and fuel oil atomization schemes, fuel oil temperature, and coal particle size.

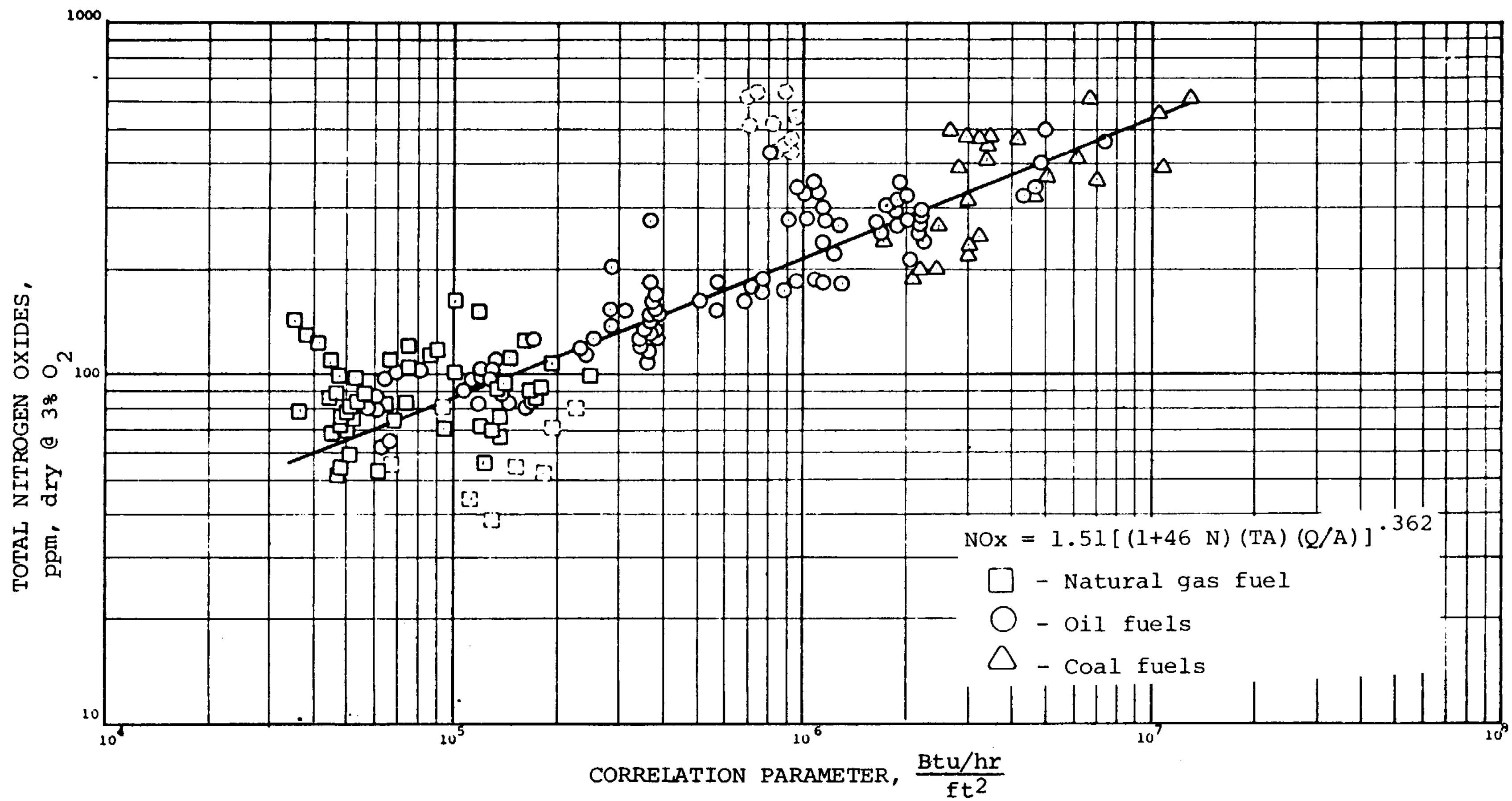

Figure 5-52. NOx correlation for boilers with ambient combustion air.

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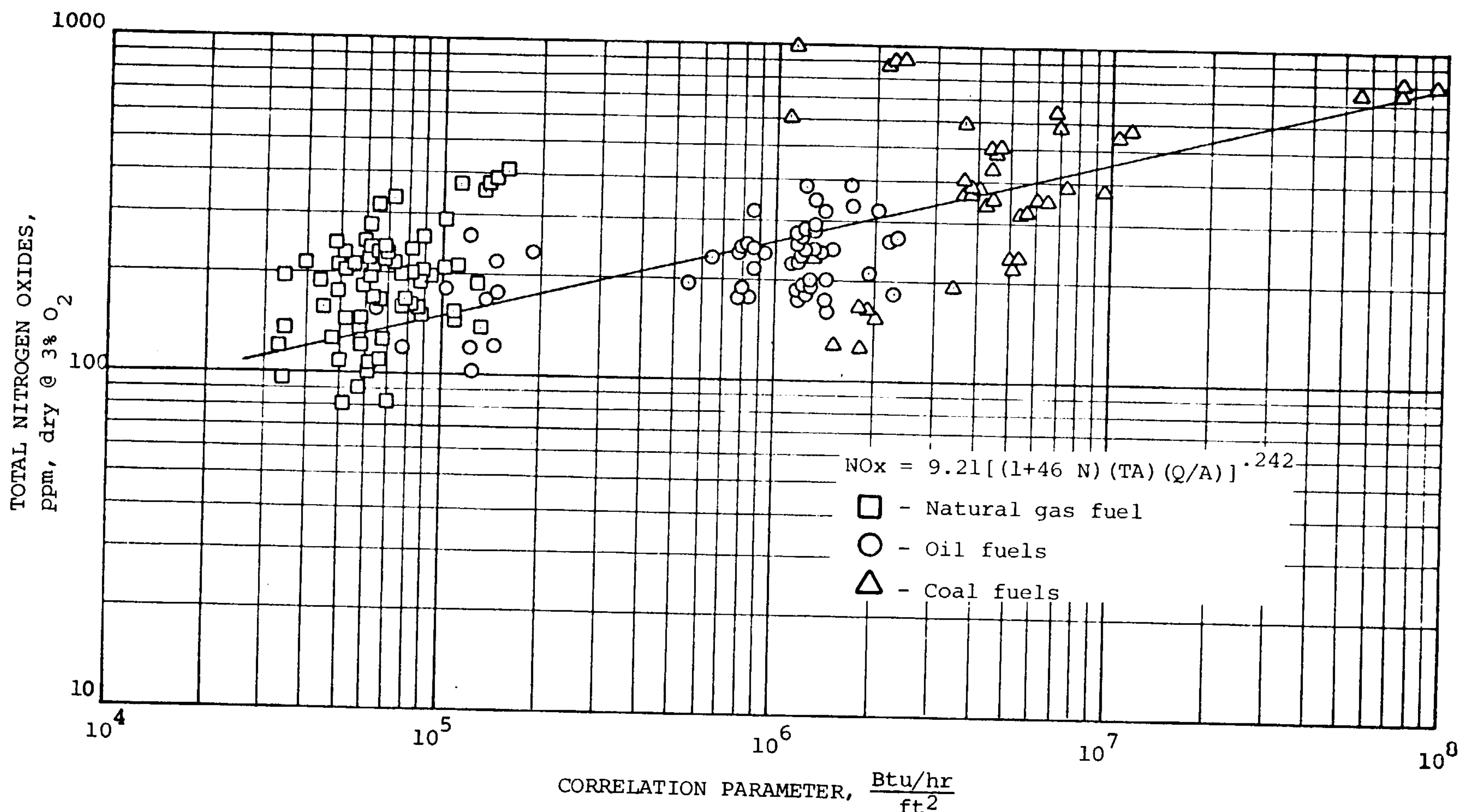

Figure 5-53. NOx correlation for boilers with preheated combustion air.

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Curves have been drawn through the data points by eye and the curves behave according to the following equations:

$$A = 1.51\ B^{0.362} \quad \text{for ambient air}$$

and

$$A = 9.21\ B^{0.242} \quad \text{for preheated air}$$

where

A = nitrogen oxides emissions in ppm, dry @ 3% O_2

$B = (1 + 46N)(TA)(Q/A)$.

SECTION 6.0

FUEL PROPERTIES

The physical form and chemical composition of the fuel have a strong effect on pollutant emissions and emission levels can be reduced readily by shifting to a different fuel. For example, oil-fueled boilers generally have lower nitrogen oxides emissions than do coal-fired boilers. A shift from residual oil to distillate oil would result in lower nitrogen oxides emissions because the fuel-bound nitrogen content of the lighter oil is less.

Gas fuel presents the simplest situation, since only gas-gas mixing is involved. Natural gas fuel is mostly methane with minor amounts of ethane and heavier constituents. Natural gas is relatively consistent and already in a state allowing easy mixing and combustion. The properties do not materially affect the emissions. An exception to this generalization may exist for process waste from chemical plants or refineries where gas streams high in organic nitrogen may be burned, or with future fuels, such as low Btu gas derived from coal.

Combustion of oil fuel is significantly more complex. It must be atomized and vaporized to burn properly; so fuel properties such as viscosity, specific gravity, volatility, ash, Conradson carbon, and heating value become important parameters. Atomization can be accomplished in different ways and can significantly affect emissions.

In evaluating the effects of oil parameters on emissions, the degree of sameness and difference from one oil to another should be considered. All oils were formed by the same basic mechanism, so crude oils have a great deal of similarity. At the same time, location-to-location differences in temperature, pressure, and raw material cause variations in chemical composition and characteristics. Typically, crude oil is further processed and segregated into fractions, classified for commercial purposes as No. 1 through No. 6, where each oil designation has a specific allowable range of properties. The result is that a given grade of oil from two sources will typically be very similar in chemical and physical properties and in nitrogen oxides emission characteristics. Variation will exist due to location differences, and these variations may sometimes be magnified by blending procedures which can result in unusual characteristics. One effect of this situation is that correlations of emissions with a particular oil property become somewhat questionable. It is not clear whether emissions and API gravity have a causal relationship or whether gravity indicates a particular oil which has a certain typical fuel nitrogen content and consequently a characteristic level of nitrogen oxides emissions. Fuel nitrogen content is known to be very important and is discussed in detail, and other properties such as ash and sulfur content are discussed because of their effect on particulates and sulfur oxide emissions.

Coal presents even more problems, since it is mined as solid material, contains more impurities, is highly variable, and must be crushed or pulverized for burning on grates or in air suspension. The difficulties of coal handling, grinding, feeding, slagging, and flyash collection can easily become the predominant design and operating problems.

6.1 NATURAL GAS

Table 6-1 lists the properties of the gaseous fuels which were tested in Phase II. Natural gas comprised the majority of the gaseous fuels. Refinery gas was tested on one boiler and a mixture of natural and refinery gas was tested in another instance.

Table 6-1. FUEL ANALYSIS SUMMARY

Gas Fuel

Test No.	Type of Gas	CH_4 %	C_2H_4 + C_2H_6 %	C_3H_6 + C_3H_8 %	C_4H_8 + C_4H_{10} %	C_5H_{12} %	C_6H_{14} %	H_2 %	CO_2 %	O_2 %	N_2 %	H_2O %	Density		Higher Heating Value	
													kg/m^3	lb/ft^3	GJ/m^3	Btu/ft^3
101	Nat.	94.52	4.26	0.20	0.062	0.032	0.032	-	0.35	0.12	0.37	0.05	0.725	0.0447	0.0388	1042
104-106	Nat.	94.52	4.26	0.20	0.062	0.032	0.032	-	0.35	0.12	0.37	0.05	0.725	0.0447	0.0388	1042
109-110	Nat.	90.00	2.90	0.40	Trace	-	-	-	0.10	-	6.60	-	0.746	0.0460	0.0364	976
113-115	Nat.	88.11	4.33	0.68	0.15	0.04	0.02	-	0.67	-	5.96	0.04	0.765	0.0472	0.0373	1000
122-125	Nat.	88.11	4.33	0.68	0.15	0.04	0.02	-	0.67	-	5.96	0.04	0.765	0.0472	0.0373	1000
140-148	Nat.	91.8	5.84	0.51	0.08	0.01	0.01	-	-	-	-	-	0.720	0.0444	0.0391	1050
149-152	Ref.	76.40	5.10	5.30	0.40	0.20	-	8.80	1.40	-	1.60	-	0.765	0.0472	0.0391	1050
153-155	Nat.	93.91	4.37	0.71	-	-	-	0.25	0.74	-	-	-	0.733	0.0452	0.0390	1047
180-185	Nat.	96.99	1.98	0.10	0.04	0.01	-	-	0.60	-	0.28	-	0.710	0.0438	0.0377	1011
190-194	Nat.	97.26	1.82	0.027	0.08	-	-	-	0.37	0.01	0.28	-	0.705	0.0435	0.0381	1023
207-212	Nat.+ Ref.	48.43	10.96	1.68	0.15	0.02	-	35.67	-	0.02	2.68	-	0.576	0.0355	0.0310	831

The natural gases were composed mostly of methane with small amounts of ethane and traces of heavier hydrocarbon gases. The methane contents varied from 88 to 97% and the ethane proportions were between 1.8 and 5.8%. The nitrogen contents of natural gases varied significantly, from zero to as high as 6.6%. Nitrogen in natural gas does not add significantly to the production of nitrogen oxides as with liquid or solid fuels. The reason is that the nitrogen is in its molecular form (N_2) as in the combustion air. Nitrogen contained in liquid or solid fuel is released in its atomic form (N) and reacts at relatively low temperatures with oxygen to form the pollutant. The heating values of the natural gases varied from 0.0364 to 0.0391 GJ/m^3 (976 to 1050 Btu/ft^3).

The refinery gas used for Tests 149 through 152 was composed of 76% methane, approximately 5% each of ethanes and propanes, and 8.8% hydrogen. The heating value was comparable to natural gas at 0.0391 GJ/m^3 (1050 Btu/ft^3).

For Tests 207-212 a mixture of natural and refinery gas was fired. The proportion of methane was comparatively low at 48%. The ethane of about 11% and 36% of the gas was hydrogen. The gas had a heating value of 0.0310 GJ/m^3 (831 Btu/ft^3).

6.2 COAL AND OIL

Coal and oil fuel properties are discussed together in this section since their characteristics influence emissions similarly. The properties of the coals and oils tested in Phase II are summarized in Table 6-2. The effects of the individual fuel properties are discussed in the following subsections.

Table 6-2. FUEL ANALYSIS SUMMARY

Coal and Oil Fuels

Test No.	Type of Fuel	Carbon, %	Hydrogen, %	Oxygen, %	Sulfur, %	Nitrogen, %	Ash, %	Moisture, %	Carbon Residue, %	Gravity, ° API	Higher Heating Value	
											GJ/kg	Btu/lb
102-103	#2 Oil	85.94	12.72	0.89	0.40	0.045	0.003	-	0.071	31.1	0.0452	19,440
107-108	#2 Oil	85.94	12.72	0.89	0.40	0.045	0.003	-	0.071	31.1	0.0452	19,440
111-112	PS 300 (#5 Oil)	86.46	10.31	1.07	1.29	0.77	0.10	-	8.50	15.1	0.0426	18,333
116-121	#6 Oil	85.95	10.21	0.22	2.74	0.31	0.03	-	-	-	0.0423	18,213
126-130	#6 Oil	No Fuel Sample Obtained For Analysis										
131-133	Coal	62.50	5.21	12.51	1.15	0.83	10.5	7.29	-	-	0.0276	11,863
134-139	Coal	68.30	4.70	11.01	1.16	1.46	9.71	3.66	-	-	0.0286	12,293
156-159	Coal	69.89	4.67	8.10	1.36	1.50	14.48	3.37	-	-	0.0286	12,300
159	#6 Oil	85.44	11.35	0.002	2.80	0.33	0.078	-	12.33	15.8	0.0432	18,580
160-164	#2 Oil	87.14	12.71	-	0.31	0.013	<0.001	-	0.027	35.1	0.0451	19,390
165-168	Coal	63.42	4.84	9.85	3.05	0.94	13.7	4.15	46.2	-	0.0276	11,873
169	Coal	62.50	5.12	12.51	1.15	0.83	10.5	7.29	-	-	0.0276	11,863
170-175	#6 Oil	86.60	10.94	0.31	1.60	0.30	0.25	-	9.00	15.1	0.0434	18,660
176-179	#6 Oil	86.17	11.55	-	1.91	0.30	0.07	-	-	-	0.0436	18,773
186-189	#6 Oil	85.10	11.10	3.12	0.19	0.49	0.08	-	8.53	25.7	0.0446	19,227
195-206	#6 Oil	86.68	12.16	0.65	0.37	0.14	0.009	-	1.61	29.2	0.0450	19,365

6.3 FUEL SULFUR CONTENT

The results of the measurements of total sulfur oxides in the flue gas are shown in Figure 6-1. The curve shows sulfur oxides concentration emitted as a function of the sulfur content of the fuel and compares it with calculated values assuming 100% conversion of fuel sulfur to sulfur oxides (SO_x). The measurements of which these data are a part indicate that the sulfur emissions were dependent almost solely upon the sulfur content of the fuel.

It is apparent that for oil fuel, practically all of the sulfur is emitted as gaseous products of combustion and an insignificant amount is contained in the fly ash or other particulates. The coal fuel data are not as consistent as the oil data, and this may indicate that the higher sulfur coals (greater than 3%, dry) have inorganic sulfate which does not convert to gaseous sulfur oxides but, rather, contributes to the particulate emissions.

Figure 6-2 shows that the ratio of sulfur trioxide (SO_3) to total sulfur oxides (SO_x) is typically 1% to 2%, except when the sulfur oxides concentration dropped below about 400 ng/J (500 ppm). The steep rise below 400 ng/J is deemed to be due to the measurement method itself, since the standard Shell-Emeryville method always yields relatively high sulfur trioxide ratios when the total sulfur oxides concentrations are below 400 ng/J. The instant of the color change when titrating is difficult to determine precisely, and only one drop of titrating solution can have a large effect on the calculated concentration of SO_3 when the absolute concentration of SO_3 is low.

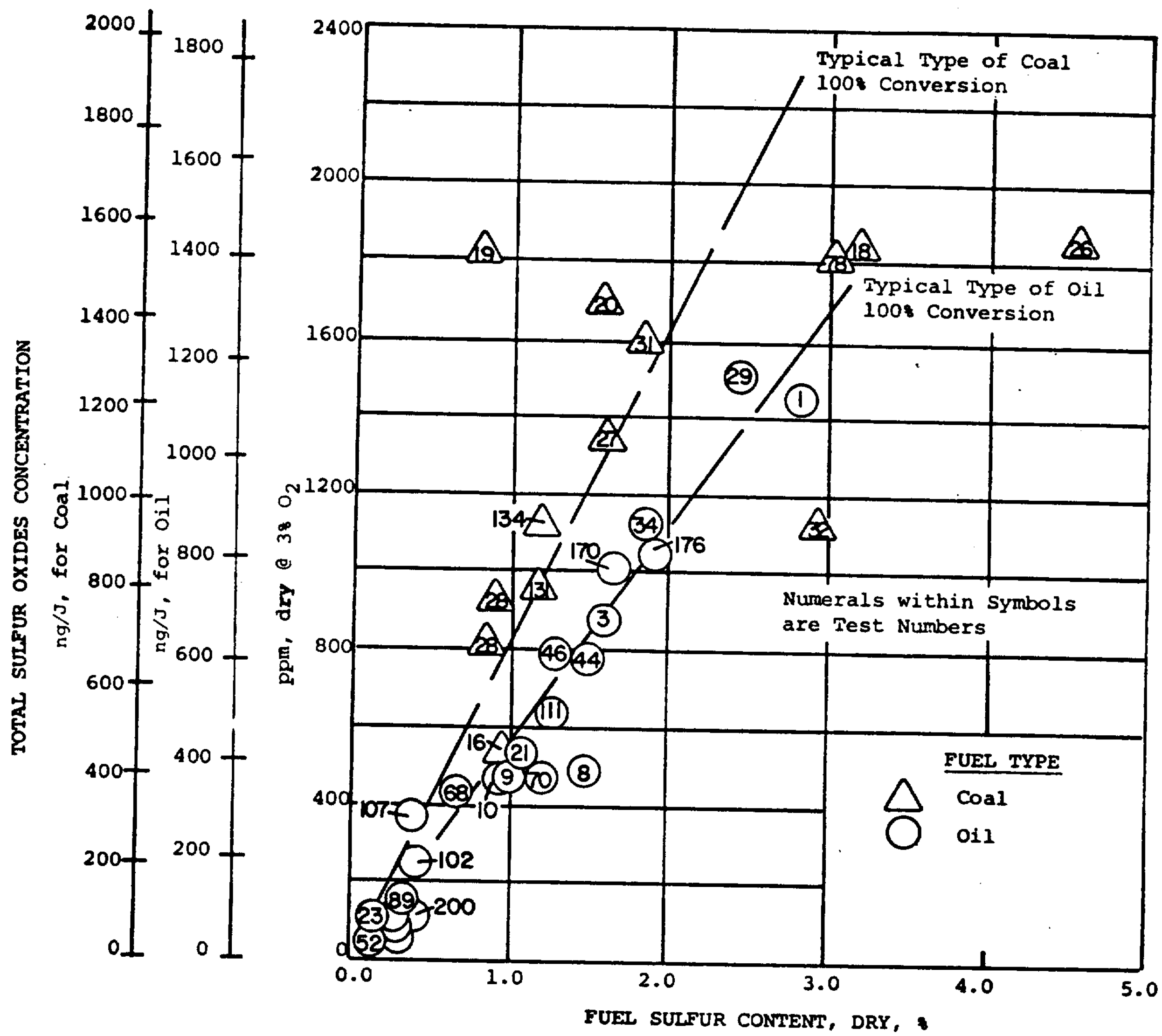

Figure 6-1. Total sulfur oxides emissions at baseload for oil and coal fired boilers.

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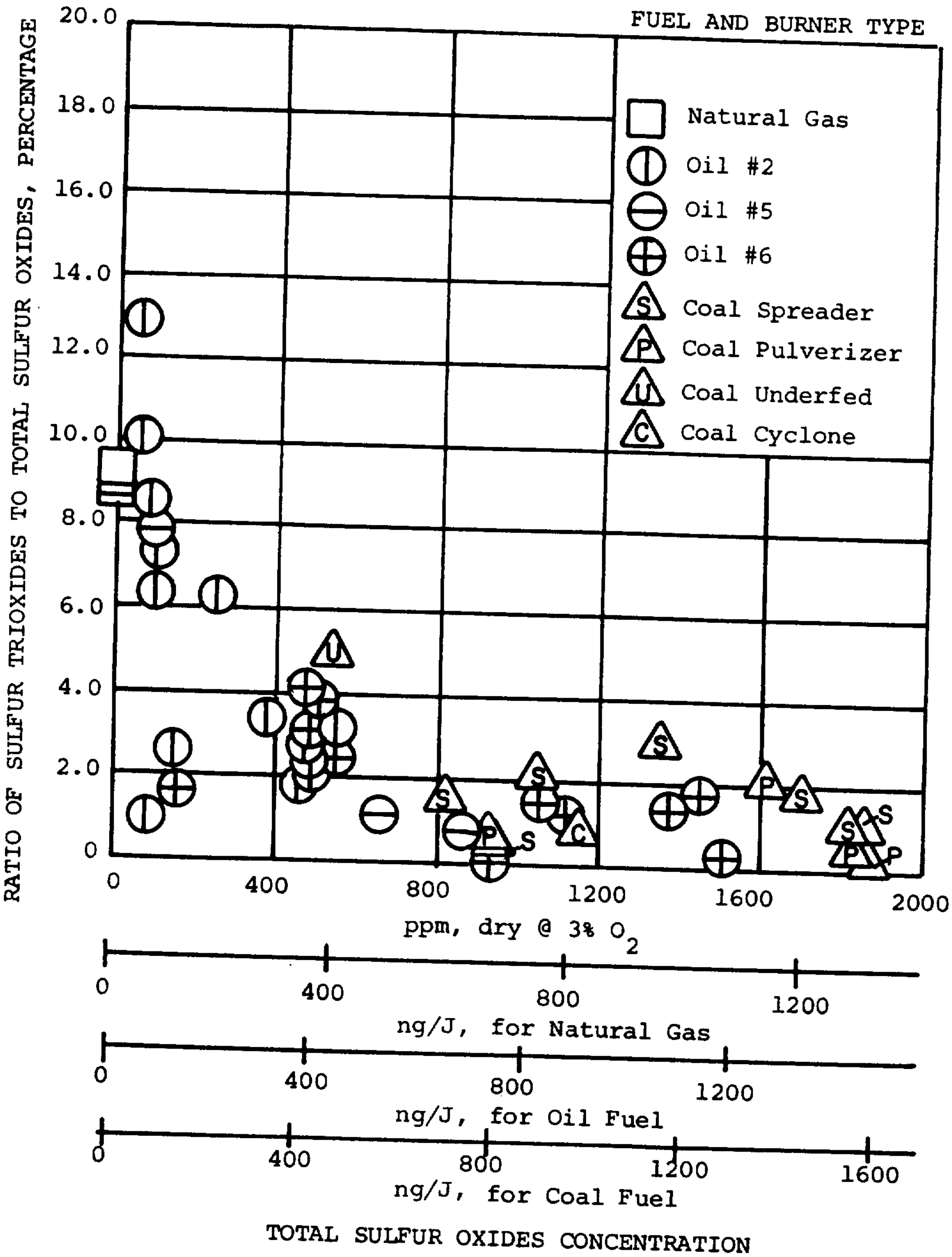

Figure 6-2. Ratio of sulfur trioxides to total sulfur oxides at baseload as a function of total sulfur oxides measured.

There appears to be no strong effect of fuel type other than its sulfur content. For example, No. 6 oil data are shown between 400 and 1200 ng/J (500 and 1500 ppm) and the SO_3/SO_x decreases with total sulfur oxides just as with the other fuels. For coal the type of coal burner has no significant effect on the SO_3/SO_x ratio in the exhaust gas.

6.4 FUEL ASH CONTENT

A coal and oil fuel property that correlates reasonably well to solid particulate emissions is the fuel ash content. Figure 6-3 illustrates baseline solid particulates as a function of fuel ash content for coal and Nos. 2, 5, and 6 fuel oil testing from Phase I and II. Particulates were the lowest for the relatively ash-free No. 2 oils, then increased as the oils became heavier and higher in ash content, as with the No. 5 and 6 oils. Particulates were the highest with coal.

Figure 6-3 also shows a line of equality corresponding to the mass of solid particulate matter contained in the combustion produce gases being equal to the mass of fuel ash input. The data do not lie on this line. For oil fuels more solid particulate matter was emitted than ash input. For coal the particulates were less than the ash input. The coal data are easily explained; a significant amount of the fuel ash drops out in the furnace bottom as dry ash or slag and does not appear as part of the particulate measurement. For oils the answer is slightly more complex. When the ash content of a fuel is determined by an ultimate analysis all combustible materials including sulfur are eliminated from the fuel sample prior to the determination of ash content. However, the combustion process occurring in the boiler is incomplete, resulting in carbon particles being present in the combustion gases. In addition, a very small amount of sulfur may combine with other materials to form solid sulfate compounds. The

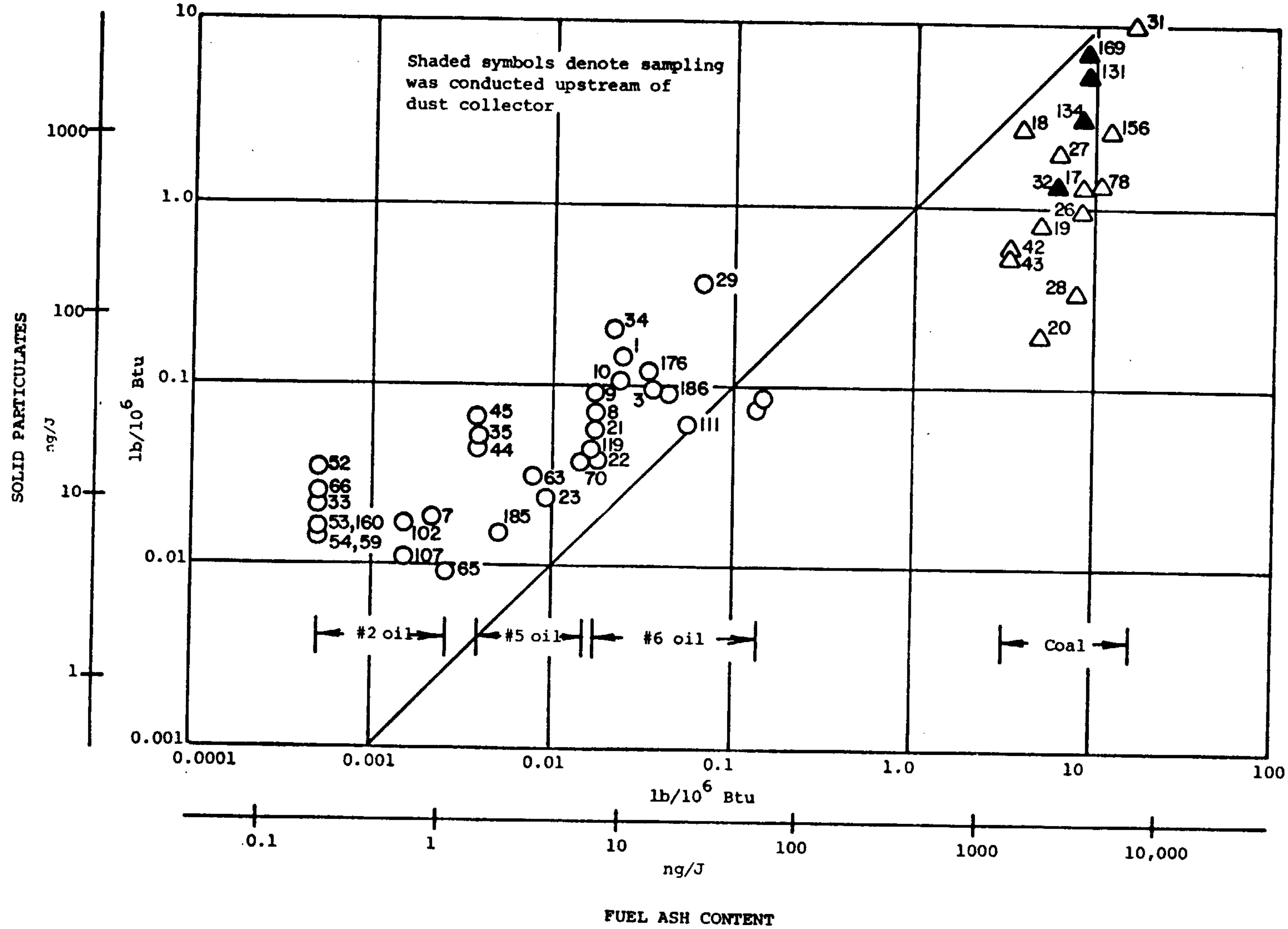

Figure 6-3. Effect of fuel ash content on baseline solid particulate emissions for coal and oil fuels.

6001-43

carbon and sulfate particles are combined with the fuel ash and the sum can be larger than the amount of ash in the original oil.

A limited number of particulate tests were conducted on natural gas fired boilers in Phase I. The particulate levels were very low, nevertheless, they were significant. This suggests that airborne dust particles may contribute to particulate emissions since natural gas contains no ash.

The amount of volatile substances, such as unburned sulfur or carbon, contained in the fly ash from six coal fuels and one No. 6 oil fuel burned at baseline conditions was determined during Phase I and Phase II. A quantity of fly ash was placed in a crucible, weighed, baked in a furnace and then reweighed. The results are tabulated below:

Test No.	Loc. No.	Burner Type	Test Load GJ/hr	Fuel Content Carbon %	Fuel Content Sulfur %	Fuel Content Ash %	Ash Volatile Content %
19-6	21	SpStk	42	76	0.76	6.8	74
20-6	21	SpStk	66	76	1.6	6.9	29
32-4	20	Cyclone	338	77	2.9	7.8	12
134-2	30	SpStk	87	68	1.2	9.7	20
156-2	13	Pulv.	422	70	1.4	14	89
165-1	35	ChGrt	110	63	3.0	14	73
Ref. 17	38	Steam Atom.	47	85	2.0	0.05	2

The ash from the cyclone burner was the lowest in volatile content of the coal fuel tests. This low residual volatile content is not surprising, because the combustion zone temperature of a cyclone burner is very high and nearly all of the volatile substances in the coal should be driven off.

The fly ash that had the highest volatile content was from a pulverizer. This was expected, since other information had indicated that the carbon content of the particulate from spreader stokers should have been the highest.[8] However, the sulfur content of the coal was 1.4%, and the presence of sulfur and sulfates in the fly ash could account for the high volatile content. An analysis of No. 6 oil fuel fly ash that is reported in Reference 17 found that 71% of the fly ash was sulfur and sulfates and only 8% was carbon.

The volatile content of the fly ash from a spreader stoker found in Test 19-6 was relatively high, but the contents from Tests 20-6 and 134-2 using spreader stokers were not. The volatile content of the chain grate fly ash was high, which is consistent with the contention that the larger the size of the coal as fired, the larger is the carbon content of the fly ash. It is likely that sulfates also are a significant factor, since the sulfur content of the coal was a high 3.0%. The grouping of variations in volatile content is deemed to be due to the characteristics of the combustion process as well as the coal feeding method, because there appears to be no fuel property, such as sulfur content, that would cause certain test results to belong to one group or another. This contention can be verified by referring to Table 6-1 of this report for the properties of the coal burned during Phase II and to Table 6-1 of Reference 1 for the Phase I coal properties. Phase I tests were numbers 19-6, 20-6, and 32-4.

6.5 API GRAVITY

An oil fuel property which correlates with nitrogen oxide and particulate emissions is the API gravity measured at 20°C. This is not a unique correlation, since fuel nitrogen and ash contents decrease in going from heavy to light oils or as the gravity increases.

The nitrogen oxides and solid particulates are shown as a function of API gravity in Figure 6-4. The measured NO fell into two groups: (1) where the fuel oil gravity matched the API gravity

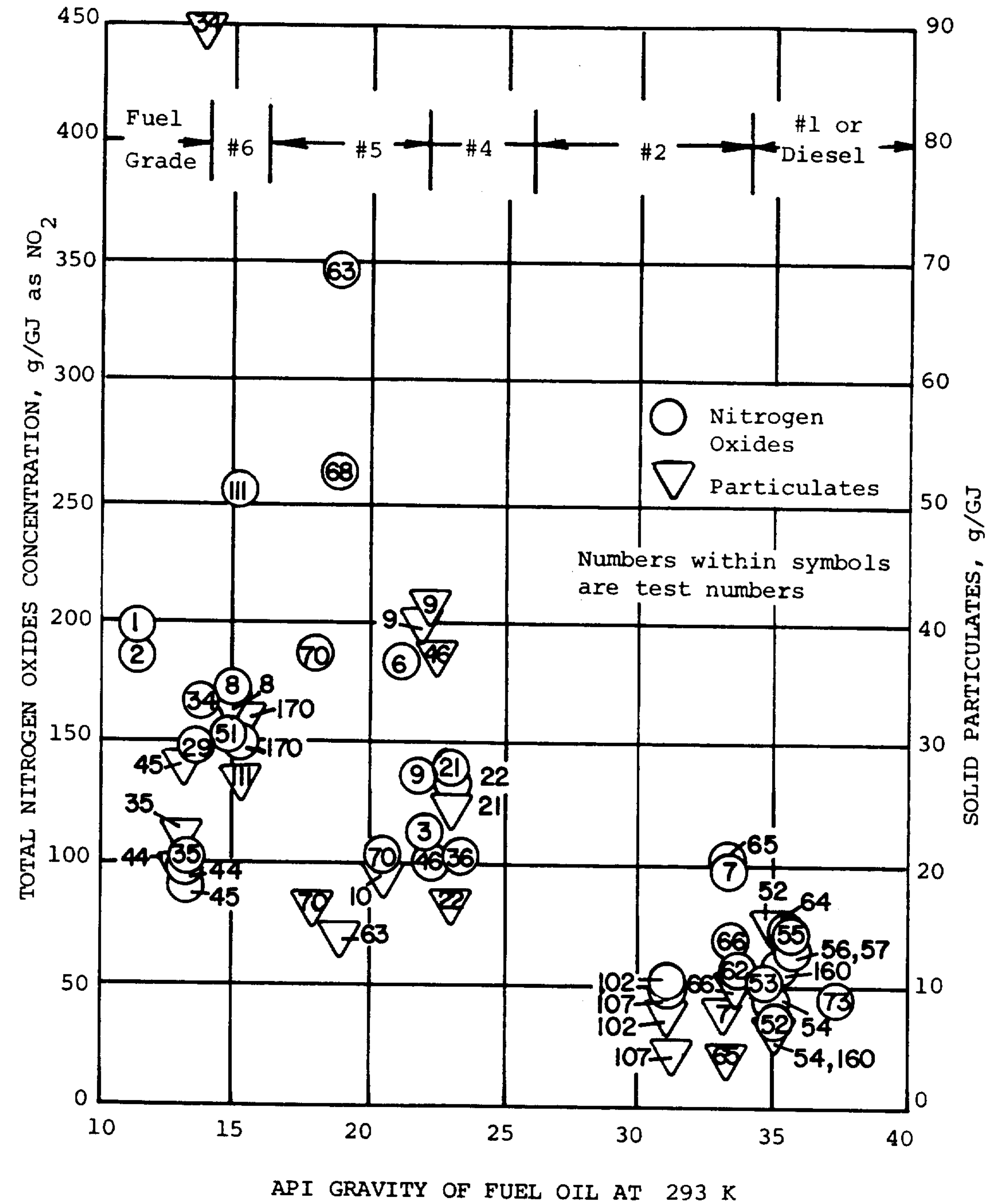

Figure 6-4. Effect of API gravity on baseload nitrogen oxides and particulates emissions.

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specification for diesel or No. 2 oil the nitrogen oxides was between 56 and 110 ng/J (100 and 200 ppm), and (2) where the fuel oil gravity matched No. 5 or 6 oil and the nitrogen oxides was between 95 and 350 ng/J (170 and 620 ppm). The fuel burned for Tests 63, 68, and 70 was designated as PS 300 which when analyzed was found to have properties much like No. 5 oil.

It should be noted that the data might be correlated as well by fuel grade number, as indicated at the top of the figure. While fuel grade number could in no way be considered a natural property, it does reflect a grouping of properties and reflects the similarity between different oils as previously discussed.

SECTION 7.0

BOILER DESIGN CHARACTERISTICS

7.1 FURNACE AND BURNER CHARACTERISTICS

Although the design of existing boilers cannot be adjusted day to day, the influence of boiler and burner design on emissions is of interest in terms of new unit design and potential modification of existing units. The major influences are expected to be in burner design (degree of mixing, ingestion of recirculated gases, atomization, etc.) and the rate of heat loss from the flame (burner face cooling, burner spacing, furnace area, furnace volume, etc.). The specifications of the boilers tested in Phase II are listed in Table 7-1.

7.2 COST OF MODIFICATION

Four methods of combustion modification that required modification of the boiler were investigated during Phase II. These were:

Staged combustion air

Variable combustion air temperature

Flue gas recirculation

An 18.5 GJ/hr (17.5×10^3 lb/hr) D-type boiler at Location 19 was modified to add a staged air and flue gas recirculation capability. The installation is discussed and pictured in Subsection 5.2.2. The cost of modifying this boiler was estimated at about $5,000. The current cost of a new boiler of this type is about $60,000.

The cost of a similar modification on other modern D-type boilers could run as high as $7,500 if the existing burner registers could not be used. At Location 19 the windbox depth was increased and a second set of registers to control the flue gas being recirculated was installed within the extension.

Table 7-1. TEST BOILER DESIGN CHARACTERISTICS

Test No. From-Thru	Loc. No.	BOILER No.	BOILER Mfg.	BOILER Date	BOILER Cap GJ/hr (10^3 lb/hr)	FURNACE Type	FURNACE Wall Const	FURNACE Size L-W-H Meter (feet)	FURNACE Area m^2 (ft^2)	FURNACE Vol. m^3 (ft^3)	HEAT ABSORPTION Area $\frac{GJ/hr}{m^2}$ ($\frac{MBH}{ft^2}$)	HEAT ABSORPTION Vol. $\frac{GJ/hr}{m^3}$ ($\frac{MBH}{ft^3}$)	BURNER Test Fuel	BURNER Type	BURNER Mfg.	BURNER No. of	BURNER SPACING Horiz. Dist. cm (in.)	BURNER SPACING Vert. Dist. cm (in.)	Brn. Load GJ/hr Brn. MBH/Brn.	Fuel Temp. @ Brn. °C (°F)	Prim Air Temp. °C (°F)	Stack Temp. °C (°F)
101 only	1	2	B&W	1964	31 (29)	WT	RT	4.0-1.8-2.1 (13-6-7)	49.7 (535)	21.4 (755)	.631 (.0556)	1.62 (.0435)	NG	Ring	B&W	1	-	-	30.6 (29.0)	- -	Amb Amb	268 (515)
102-103	1	2	B&W	1964	31 (29)	WT	RT	4.0-1.8-2.1 (13-6-7)	49.7 (535)	21.4 (755)	.631 (.0556)	1.62 (.0435)	#2	Steam	B&W	1	-	-	30.6 (29.0)	Amb Amb	Amb Amb	288 (550)
104-106	1	1	B&W	1964	31 (29)	WT	RT	4.0-1.8-2.1 (13-6-7)	49.7 (535)	21.4 (755)	.631 (.0556)	1.62 (.0435)	NG	Ring	B&W	1	-	-	30.6 (29.0)	- -	Amb Amb	293 (560)
107-108	1	1	B&W	1964	31 (29)	WT	RT	4.0-1.8-2.1 (13-6-7)	49.7 (535)	21.4 (755)	.631 (.0556)	1.62 (.0435)	#2	Steam	B&W	1	-	-	30.6 (29.0)	Amb Amb	Amb Amb	243 (470)
109-110	27	1	B&W	1967	106 (100)	WT	WF	6.4-1.8-2.7 (21-6-9)	68.6 (738)	32.1 (1134)	1.53 (.135)	3.30 (.0885)	NG	Ring	Coen	1	-	-	106 (100)	- -	Amb Amb	171 (340)
111-112	27	1	B&W	1967	106 (100)	WT	WF	6.4-1.8-2.7 (21-6-9)	68.6 (738)	32.1 (1134)	1.53 (.135)	3.30 (.0885)	PS 300	Steam	Coen	1	-	-	106 (100)	71.1 (160)	Amb Amb	168 (334)
113-115	29	5	Riley	1972	158 (150)	WT	TT	8.5-3.4-5.8 (28-11-19)	167 (1795)	154 (5450)	.946 (.0833)	1.02 (.0275)	NG	Ring	Coen	2	-	168 (66)	79.1 (75.0)	- -	193 (380)	143 (290)
116-121	29	5	Riley	1972	158 (150)	WT	TT	8.5-3.4-5.8 (28-11-19)	167 (1795)	154 (5450)	.946 (.0833)	1.02 (.0275)	#6	Steam	Coen	2	-	168 (66)	79.1 (75.0)	118 (245)	202 (395)	154 (310)
122-125	28	1	Erie	1957	74 (70)	WT	RT	2.7-4.3-6.1 (9-14-20)	104 (1115)	76.5 (2700)	.693 (.0610)	.965 (.0259)	NG	Ring	Todd	3	91.4 (36)	-	24.6 (23.3)	- -	168 (335)	127 (260)
126-130	28	1	Erie	1957	74 (70)	WT	RT	2.7-4.3-6.1 (9-14-20)	104 (1115)	76.5 (2700)	.693 (.0610)	.965 (.0259)	#6	Steam	Todd	3	91.4 (36)	-	24.6 (23.3)	93.9 (201)	171 (340)	135 (275)
131-133	31	7	Erie	1963	274 (260)	WT	TT	6.4-6.4-12 (21-21-39)	460 (4950)	552 (19500)	.847 (.0746)	.708 (.0190)	Coal	Pulv.	CE	4	198 (78)	193 (76)	98.1 (93.0)	- -	260 (500)	166 (330)
134-139	30	8	Erie	1963	132 (125)	WT	RT	5.2-4.3-10 (17-14-33)	193 (2080)	190 (6700)	.931 (.0820)	.946 (.0254)	Coal	SpStk	Det Stk	4	150 59	-	44.3 (42.0)	- -	93.3 (200)	160 (320)
140-142	32	4	ClBrk	1969	137 (130)	WT	TT	10.4-2.1-5.5 (34-7-18)	181 (1949)	123 (4340)	1.05 (.0926)	1.55 (.0415)	NG	Ring	Pea-body	1	- -	- -	190 (180)	- -	199 (390)	149 (300)
143-148	32	1	Erie	1963	127 (120)	WT	TT	5.2-4.0-8.8 (17-13-29)	200 (2150)	177 (6250)	.902 (.0794)	1.01 (.0272)	NG	Ring	Erie	4	183 (72)	122 (48)	45 (43.0)	- -	* *	160 (320)
149-152	33	32	B&W (Com Cyc)	1965	580 (550)	WT	TT	11-10-8 (35-32-27)	488 (5250)	856 (30240)	1.19 (.105)	.678 (.0182)	Ref Gas	Spud	B&W	1	- -	- -	101 (96.0)	Amb Amb	443 (830)	171 (340)
153-155	34	2	CE	1972	264 (250)	WT	TT	14-3.7-2.4 (46-12-8)	158 (1700)	123 (4355)	1.67 (.147)	2.14 (.0575)	NG	Spud	CE	1	- -	- -	264 (250)	- -	110 (230)	377 (710)
156-159	13	2	B&W	1967	528 (500)	WT	TT	26-6.1-6.1 (86-20-20)	684 (7360)	988 (34900)	.772 (.0680)	.533 (.0143)	Coal Oil	Pulv. Steam	B&W Pea-body	6 3	183 (72)	168 (66)	87.9 (83.3)	65.6 150	216 (420)	216 (420)
160-164	36	6	B&W	1971	211 (200)	WT	TT	11-2.1-3.0 (35-7-10)	117 (1260)	69.4 (2450)	2.15 (.189)	3.65 (.0980)	#2	Steam	B&W	1	- -	- -	253 (240)	- -	Amb Amb	199 (390)
165-168	35	6	Erie	1960	227 (215)	WT	TT	4.3-8.2-13 (14-27-43)	398 (4282)	460 (16250)	.568 (.0500)	.496 (.0133)	Coal	ChGrt	CE	4	- -	- -	56 (54)	Amb Amb	107 (225)	143 (290)
169 only	31	6	Erie	1963	274 (260)	WT	TT	6.4-6.4-12 (21-21-39)	460 (4950)	552 (19500)	.847 (.0746)	.708 (.0190)	Coal	Pulv.	CE	4	198 (78)	193 (76)	98.1 (93.0)	- -	260 (500)	166 (330)

*Unit has air preheat, but it was not possible to measure combustion air temperature.

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Table 7-1. Continued

Test No. From-Thru	Loc. No.	BOILER No.	BOILER Mfg.	BOILER Date	BOILER Cap GJ/hr (10^3 lb/hr)	FURNACE Type	FURNACE Wall Const.	FURNACE Size L-W-H Meter (feet)	FURNACE Area m^2 (ft^2)	FURNACE Vol. m^3 (ft^3)	HEAT ABSORPTION Area $\frac{GJ/hr}{m^2}$ $\left(\frac{MBH}{ft^2}\right)$	HEAT ABSORPTION Vol. $\frac{GJ/hr}{m^3}$ $\left(\frac{MBH}{ft^3}\right)$	BURNER Test Fuel	BURNER Type	BURNER Mfg.	BURNER No. of	BURNER SPACING Horiz. Dist. cm (in.)	BURNER SPACING Vert. Dist. cm (in.)	Brn. Load GJ/hr Brn. MBH/Brn.	Fuel Temp. @ Brn. °C (°F)	Prim Air Temp °C (°F)	Stack Temp °C (°F)
170-175	20	4	CE	1966	84 (80)	WT	TT	7.3-2.1-3.0 (24-7-10)	67.8 (730)	41.6 (1470)	1.81 (.159)	2.91 (.0781)	#6	Steam	Coen	1	- -	- -	121 (115)	65.6 (150)	Amb Amb	332 (630)
176-179	37	2	Wicken	1955	42 (40)	WT	RT	3.0-3.7-3.7 (10-12-12)	46.2 (497)	40.8 (1440)	.915 (.0806)	1.04 (.0278)	#6	Steam	Pea-body	2	112 (44)	- -	21.1 (20.0)	90.0 (194)	141 (285)	218 (425)
180-185	38	2	CE	1951	47 (45)	WT	RT	3.4-3.7-4.6 (11-12-15)	66.9 (720)	56.1 (1980)	.710 (.0625)	.846 (.0227)	NG	Ring	Pea-body	1	- -	- -	47.5 (45.0)	- -	177 (350)	227 (440)
186-189	38	2	CE	1951	47 (45)	WT	RT	3.4-3.7-4.6 (11-12-15)	-6.9 (66.9)	56.1 (1980)	.710 (.0625)	.846 (.0227)	#6	Steam	Pea-body	1	- -	- -	47.5 (45.0)	113 (235)	160 (320)	204 (400)
190-194	19	1	Keeler	1970	18.5 (17.5)	WT	TT	2.7-1.8-2.4 (9-6-8)	30.4 (327)	11.1 (392)	.6075 (.0535)	1.66 (.0446)	NG	Ring	Faber	1	- -	- -	18.5 (17.5)	- -	Amb Amb	254 (490)
195-199	19	1	Keeler	1970	18.5 (17.5)	WT	TT	2.7-1.8-2.4 (9-6-8)	30.4 (327)	11.1 (392)	.6075 (.0535)	1.66 (.0446)	#6	Steam	Faber	1	- -	- -	18.5 (17.5)	93 (200)	Amb Amb	254 (490)
200-203	19	1	Keeler	1970	18.5 (17.5)	WT	TT	2.7-1.8-2.4 (9-6-8)	30.4 (327)	11.1 (392)	.6075 (.0535)	1.66 (.0446)	#6	Air	Faber	1	- -	- -	18.5 (17.5)	93 (200)	Amb Amb	254 (490)
207-212	39	B108	B&W	1974	211 (200)	WT	TT	12-2.1-3.0 (35-7-10)	801.6 (8629)	72.0 (2542)	.263 (.0232)	2.93 (.0787)	Ref. Gas	Spud	B&W	1	- -	- -	211 (200)	- -	Amb Amb	166 (330)

*Unit has air preheat, but it was not possible to measure combustion air temperature.

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During discussions with a manufacturer of boilers in the 320 GJ/hr (300×10^3 lb/hr) and one million dollar size and cost range it was estimated that a staged air installation in general would add two to four percent to the cost of the boiler. For A-type boilers the additional cost would be about two percent and for D-type boilers about three percent. If another booster air fan were required the cost would be increased by about an additional one percent.

SECTION 8.0

FUTURE RESEARCH

Staged combustion air, variable combustion air temperature and flue gas recirculation were very effective in reducing the emissions of nitrogen oxides. But before the advantages of incorporating these forms of combustion modification into current boiler designs can be determined, a large body of parametric data is needed.

In the past it was not practicable to gather good design data on these combustion modification methods. Laboratory research suffered from scaling inconsistencies. Research with full-size boilers in the field was limited, because it was difficult to reproduce prior conditions exactly, and process needs frequently interrupted testing. But most serious was the complete lack of flexibility. For example, industrial boilers with staged combustion air ports are in service, but the port location is fixed and the effect of port number and location cannot be investigated.

Two boilers now exist at Locations 19 and 38, where controlled research over a wide range of combustion parameters can be done readily. It is recommended that a field research program be initiated to investigate one or all of the staged combustion air, variable combustion air temperature and flue gas recirculation combustion modification methods.

The measurement of emissions and the effect on emissions of combustion modifications should be extended to industrial combustion equipment. Industrial combustion equipment includes waste-product-fueled boilers, kilns, glass melting furnaces, steel furnaces, incinerators, etc.

Industrial combustion devices contribute a large fraction of the total air pollution from stationary sources. Recent studies have shown as much as 40% of the stationary source nitrogen oxides emissions originate from industrial devices. A similar figure was obtained for oxides of sulfur, while particulate emissions from stationary industrial sources account for more than 80% of the total.[1,2,3] Combustion modifications for industrial boilers have been demonstrated in this report which can reduce emissions of nitrogen oxides, carbon monoxide, and hydrocarbons while improving boiler efficiency. Application of these modifications to industrial combustion devices, if successful, could have a profound impact on air quality and energy conservation. In order to apply these modifications, baseline emissions and efficiency from industrial combustion devices must be determined. Then, application of combustion modification techniques under controlled conditions can be performed to determine efficiency and emission trends.

SECTION 9.0

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SECTION 10.0

GLOSSARY OF TERMS

ABIS	All burners in service
Air	Usually referring to air atomized fuel oil burner
Air Reg	Air Registers
Amb	Ambient temperature
API	American Petroleum Institute
Atm	Atomization
Atom Press	Burner atomizing pressure adjustment
Base	Baseline
BOOS	Burner(s) out of service
B# X OOS	Burner number X out of service
Brn	Burner
BrTune	Boiler tune-up
Btu	British Thermal Unit
Burnh	Burnham/Golden Scotch
B&W	The Babcock and Wilcox Company
c	Coal
c	centi; one-hundredth
C_2	Multiple carbon atom hydrocarbons
CE	Combustion Engineering, Incorporated
CH_4	Methane
C_2H_6	Ethane
ChGrt	Chain Grate
CI	Cast iron furnace walls
CL	Unheated sample line (cold line)
Cl Brk	Cleaver-Brooks Division
CO	Carbon monoxide
CO_2	Carbon dioxide
Coen	The Coen Company
Comb Cyc	Combined cycle
Con Part	Condensible particulates
Coppus	Coppus Engineering Corporation
cor.	Data corrected to standard conditions
Cup	Rotary cup fuel oil atomizer
cyclone or cyc	Cyclone furnace coal combustor
D	Diameter
Damper	As test type: air damper adjustment
°C	Degrees Centigrade or Celsius
°F	Degrees Fahrenheit
Det Stk	Detroit Stoker Company
EPA	Environmental Protection Agency
Equivalence Ratio, ϕ	The actual fuel to air ratio divided by the stoichiometric fuel to air ratio. $\phi > 1$: Fuel rich $\phi < 1$: Air rich
Faber	Faber Engineering Company Incorporated
FD	Forced draft
FGR	Flue gas recirculation
ft	foot
FT	Firetube furnace
FW	Foster Wheeler Corporation
g	Grams
G	Giga, one billion
H	Height
HC	Unburned hydrocarbons measured as methane
High Air	High excess air
Hi Load	High load
HL	Heated sample line (hot line)
hr(s)	Hour(s)
Hz	Hertz; cycles per second
IBW	International Boiler Works Company
ID	Inside diameter
in	Inches
in. Hg	Pressure in inches of mercury, usually gage
Ind. Comb.	Industrial Combustion Incorporated
IR	Infrared
iwg	Pressure in inches of water column gage
J	Joule
K	Kelvin temperature scale
k	Kilo; one thousand
Keeler	E. Keeler Company
Kewan	Kewanee Boiler Corporation
L	Length
Low Air	Low excess air
lbs or #	Pounds
M	Mega; one million
m	As prefix: milli; one-thousandth
m	Meter
MB or MBtu	One million British thermal units
MBH or MBtu/hr	One million British thermal units per hour
Mcal	One million calories
MCH or Mcal/hr	One million calories per hour
Mfg	Manufacturer
min	Minutes
MR	Mixture ratio in terms of the air flow rate divided by the fuel flow rate
μ	Micro; one-millionth
μm or μ	Micrometer or "micron" (10^{-6} meter)

N	Molecular nitrogen content of fuel, percent by weight
N_2	Nitrogen gas
Nebr	Nebraska Boiler Company
NG or G	Natural Gas Fuel
NO	Nitric oxide
No.	Number
NO_2	Nitrogen dioxide
No. Am.	North American Company, Cleveland, Ohio
NOx	Total nitrogen oxides ($NO + NO_2$)
Nrml Air	Normal excess air
NSF-Oil	Navy standard fuel-oil (similar to No. 5 oil)
O_2	Oxygen gas
OD	Outside diameter
OFA	Overfire air
O/S	Off-stoichiometric
P	Preheated combustion air
Pa	Pascals, newtons per square meter
Peabody	Peabody Engineering Company
ϕ	See Equivalence Ratio
ppm	Parts of constituent per million parts of total volume
PS 300	Pacific standard fuel-oil No. 300 (similar to No. 5 oil)
psi	Pressure in pounds per square inch
psia	Pressure absolute in pounds per square inch
psig	Pressure gauge in pounds per square inch
Pulv.	Pulverized coal burning equipment
R	Refractory
Ray	Ray Burner Company
Ref Gas or RG	Refinery gas
Riley	Riley Stoker Corporation
Ring	Natural gas ring
rms	Root mean square
RT	Water wall tubes spaced such that refractory tile is exposed to flame
SCA	Staged combustion air
S	Sulfur content of fuel, percent by weight
s	Seconds
Sec	Seconds
Sld. Part.	Solid Particulates
Sngl Cyc	Single cycle
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SOx	Total sulfur oxides ($SO_2 + SO_3$)
Sprd. or SpStk	Spreader stoker coal burning equipment
Spud	Natural gas gun
Steam	As Burner Type: steam atomized oil burners
Steam Injec.	Steam injection
Supr.	Superior Combustion Industries
t	Metric ton (10^3 kilograms)
Temp.	Temperature
TIW	Titusville Iron Works
Todd	Todd-CEA Incorporated
TP	Toxic Particulate
Trane	The Trane Company
TT	Furnace walls where the watertubes are tangent
U or UFS	Underfed stoker coal burning equipment
uncor.	Data presented as measured and not corrected to a standard condition
Union	Union Iron Works
V	Voltage in volts
viscosity	As test type: fuel oil viscosity variation via temperature change
Vol	Volume
VPH	Variable combustion air preheat
W	As unit of power: Watt
W	As a dimension: Width
Wall Const.	Furnace wall construction
WF	Furnace wall constructed with welded fin design
Winkler	Winkler burner manufacturer
WT	Watertube furnace
Wtgh	Westinghouse

SECTION 11.0

CONVERSION FACTORS

SI Units to Metric or English Units

To Obtain	From	Multiply By
g/Mcal	ng/J	0.004186
10^6 Btu	GJ	0.948
MBH/ft^2	$GJ \cdot hr^{-1} \cdot m^{-2}$	0.08806
MBH/ft^3	$GJ \cdot hr^{-1} \cdot m^{-3}$	0.02684
Btu	gm cal	3.9685×10^{-3}
10^3 lb/hr* or MBH	GJ/hr	0.948
lb/MBtu	ng/J	0.00233
ft	m	3.281
in	cm	0.3937
ft^2	m^2	10.764
ft^3	m^3	35.314
lb	Kg	2.205
Fahrenheit	Celsius	$t_F = 9/5(t_c)+32$
	Kelvin	$t_F = 1.8K - 460$
psig	Pa	$P_{psig} = (P_{pa})(1.450X10^{-4})-14.7$
psia	Pa	$P_{psia} = (P_{pa})(1.450X10^{-4})$
iwg (39.2°F)	Pa	$P_{iwg} = (P_{pa})(4.014X10^{-3})$

*lb/hr of equivalent saturated steam

To Obtain ppm at 3% O_2 of	Multiply Concentration in ng/J by
Natural Gas Fuel	
CO	3.23
HC	5.65
NO or NOx	1.96
SO_2 or SOx	1.41
Oil Fuel	
CO	2.93
HC	5.13
NO or NOx	1.78
SO_2 or SOx	1.28
Coal Fuel	
CO	2.69
HC	4.69
NO or NOx	1.64
SO_2 or SOx	1.18
Refinery Gas Fuel (Location 33)	
CO	3.27
HC	5.71
NO or NOx	1.99
SO_2 or SOx	1.43
Refinery Gas Fuel (Location 39)	
CO	3.25
HC	5.68
NO or NOx	1.98
SO_2 or SOx	1.42

English and Metric Units to SI Units

To Obtain	From	Multiply By
ng/J	lb/MBtu	430
ng/J	g/Mcal	239
$GJ \cdot hr^{-1} \cdot m^{-2}$	MBH/ft^2	11.356
$GJ \cdot hr^{-1} \cdot m^{-3}$	MBH/ft^3	37.257
GJ/hr	10^3 lb/hr* or 10^6 Btu/hr	1.055
m	ft	0.3048
cm	in	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
Kg	lb	0.4536
Celsius	Fahrenheit	$t_C = 5/9\ (t_F-32)$
Kelvin		$t_K = 5/9\ (t_F-32) + 273$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895X10^3)$
Pa	psia	$P_{pa} = (P_{psia})(6.895X10^3)$
Pa	iwg (39.2°F)	$P_{pa} = (P_{iwg})(249.1)$

*lb/hr of equivalent saturated steam

To Obtain ng/J of	Multiply Concentration in ppm at 3% O_2 by
Natural Gas Fuel	
CO	0.310
HC	0.177
NO or NOx (as equivalent NO_2)	0.510
SO_2 or SOx	0.709
Oil Fuel	
CO	0.341
HC	0.195
NO or NOx (as equivalent NO_2)	0.561
SO_2 or SOx	0.780
Coal Fuel	
CO	0.372
HC	0.213
NO or NOx (as equivalent NO_2)	0.611
SO_2 or SOx	0.850
Refinery Gas Fuel (Location 33)	
CO	0.306
HC	0.175
NO or NOx (as equivalent NO_2)	0.503
SO_2 or SOx	0.700
Refinery Gas Fuel (Location 39)	
CO	0.308
HC	0.176
NO or NOx (as equivalent NO_2)	0.506
SO_2 or SOx	0.703

APPENDIX A

BOILER EMISSION MEASUREMENTS OF PHASE I

All of the measurements made during Phase I on the test boilers when operated at normal settings and at low total nitrogen oxides emissions settings are summarized in the following table.[4] The data are tabulated in order of Test Run Numbers. The Test Run Number consists of two parts: the basic test designation which corresponds to a particular boiler-fuel combination to the left of the dash and the run number within the given test to the right of the dash. A typical test consisted of six to ten individual measurement runs made with different settings of the boiler controls.

The Location Number in the second column positions the test site geographically on Figure 2-1. The columns from Boiler Number through Capacity indicate where the particular test falls among the principal test variables.

The columns to the right of the one labeled "Test Load" are data taken during the corresponding Test Run.

For almost all boilers four basic types of measurements were made:

1. Baseline: ~80% of rated capacity and normal control settings.
2. High Load: Highest load obtainable at the time on the unit under test.
3. Low Load: Minimum load at which unit normally is operated.
4. Low Air: Minimum excess air level at baseline load at which the boiler could be operated without smoke, excessive carbon monoxide, or hydrocarbon emissions.

When a boiler had two or more burners, often a test was run with the fuel to one of the burners turned off and only air passing through the burner and into the furnace. The air-only burner then was acting like an overfire air port. This type of test was designated by "BOOS" for burners-out-of-service. The test type designation "Register" indicates a test that investigated the effect on the emissions of increasing or decreasing the air swirl by changing the register setting.

The column titled Test Fuel indicates the fuel being fired at the time of the test run. When more than one fuel type was being burned, e.g., Test run 23, the entry so indicates.

Table A-1. FIELD TEST MEASUREMENTS

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
1-12	19	2	5/14	1	1	WT	Steam	#6 Oil	Baseline	7.95 (17.5)	6.36 (14)	3.6	.806 (350)	.797 (346)	.834 (262)	13.4	0 (0)	.026 (32)	4.64 (1448)	4.56 (1424)	-	-	65	-
1-8	19	2	5/13	1	1	WT	Steam	#6 Oil	Low Load	7.95 (17.5)	2.72 (6)	11.0	.986 (423)	.901 (417)	.933 (405)	8.2	0 (0)	-	-	-	-	-	-	-
1-11	19	2	5/14	1	1	WT	Steam	#6 Oil	Low Air	7.95 (17.5)	6.36 (14)	2.3	.763 (331)	.737 (320)	.758 (329)	14.8	.062 (45)	.022 (28)	-	-	.2743 (.1524)	.2005 (.1447)	86	-
2-5	19	2	5/14	1	1	WT	Air	#6 Oil	Baseline	7.95 (17.5)	6.81 (15)	4.4	.770 (334)	.760 (330)	.774 (336)	12.9	0 (0)	-	4.42 (1378)	4.36 (1359)	-	-	85	-
2-4	19	2	5/14	1	1	WT	Air	#6 Oil	Low Air	7.95 (17.5)	6.36 (14)	2.8	.638 (277)	.611 (265)	.601 (261)		0 (0)	-	-	-	-	-	85	-
2-6	19	2	5/15	1	1	WT	Air	#6 Oil	LoAtm Press.	7.95 (17.5)	6.36 (14)	4.7	.687 (298)	.675 (293)	.664 (283)	12.6	0 (0)	.053 (60)	-	-	.5238 (.2910)	.5072 (.2818)	-	-
3-5	15	4	4/9	123-1	1	WT	Cup	#5 Oil	Baseline	8.63 (19)	5.45 (12)	7.6	.461 (200)	.449 (195)	.461 (200)	10.4	0 (0)	-	2.78 (868)	2.76 (861)	.2020 (.1122)	.1728 (.0960)	74	-
3-2	15	4	4/9	123-1	1	WT	Cup	#5 Oil	Hi Load	8.63 (19)	6.36 (14)	5.3	.320 (139)	.290 (126)	.304 (132)	11.8	.382 (234)	-	-	-	-	-	78	-
3-6	15	4	4/9	123-1	1	WT	Cup	#5 Oil	Low Load	8.63 (19)	3.63 (8)	14.4	.627 (272)	.618 (268)	.604 (262)	5.8	0 (0)	-	-	-	-	-	74	-
4-1	5	9	12/13	716-3	1	WT	Ring	NG	Baseline	11.4 (25)	9.08 (20)	2.9	.157 (72)	.148 (68)	.140 (64)	9.6	.228 (170)	.023 (39)	-	-	.0090 (.0050)	.0023 (.0013)	78	-
4-2	5	9	12/13	716-3	1	WT	Ring	NG	Hi Load	11.4 (25)	10.4 (23)	2.15	.142 (65)	.135 (62)	.135 (62)	10.1	>2.57 (>2000)	.030 (41)	-	-	-	-	79	-
4-5	5	9	12/13	716-3	1	WT	Ring	NG	Low Load	11.4 (25)	3.36 (7.4)	12.5	.175 (80)	.170 (78)	.190 (87)	4.0	0 (0)	.045 (28)	-	-	-	-	70	-
5-1	1	9	11/9	2	2	WT	Ring	NG	Baseline	13.2 (29)	9.99 (22)	3.4	.153 (70)	-	.146 (67)	9.6	.219 (159)	-	-	-	-	-	80	-
5-2	1	9	11/9	2	2	WT	Ring	NG	Hi Load	13.2 (29)	9.99 (22)	4.0	.164 (75)	-	.157 (72)	9.2	.080 (56)	-	-	-	-	-	77	-
5-3	1	9	11/9	2	2	WT	Ring	NG	Low Air	13.2 (29)	9.99 (22)	2.7	.162 (74)	-	.153 (70)	10.0	.331 (250)	-	-	-	-	-	77	-
6-6	7	9	1/7	3	2	WT	Steam	#5 Oil	Baseline	38.6 (85)	26.8 (59)	7.6	.758 (329)	.802 (348)	.804 (349)	10.2	.119 (10)	.103 (12)	-	-	-	-	86	-
6-2	7	9	1/7	3	2	WT	Steam	#5 Oil	Hi Load	38.6 (85)	38.6 (85)	4.7	.742 (322)	.797 (346)	.788 (342)	12.2	.044 (28)	.103 (15)	-	-	-	-	83	-
6-5	7	9	1/7	3	2	WT	Steam	#5 Oil	Low Load	38.6 (85)	9.99 (22)	14.5	.862 (374)	.917 (398)	.894 (388)	6.2	.114 (29)	.022 (10)	-	-	-	-	77	-
6-17	7	9	1/7	3	2	WT	Steam	#5 Oil	Low Air	38.6 (85)	25.4 (56)	4.5	.560 (243)	.595 (254)	.571 (248)	12.0	.012 (8)	.014 (16)	-	-	-	-	84	-
6-26	7	9	1/7	3	2	WT	Steam	#5 Oil	B#3 OCS	38.6 (85)	22.7 (50)	8.0	.567 (246)	.555 (241)	.560 (243)	9.5	.039 (20)	.016 (14)	-	-	-	-	81	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
7-10	17	2	4/29	T-8	2	WT	Steam	#2 Oil	Base-line	49.9 (110)	40 (88)	5.7	.408 (177)	.401 (174)	.406 (176)	11.6	0 (0)	- -	.35 (108)	.32 (100)	.0353 (.0196)	.0329 (.0183)	87	-
7-5	17	2	4/29	T-8	2	WT	Steam	#2 Oil	Hi Load	49.9 (110)	49.9 (110)	5.8	.541 (235)	.532 (231)	.541 (235)	11.4	0 (0)	- -	- -	- -	- -	- -	--	-
7/9	17	2	4/29	T-8	2	WT	Steam	#2 Oil	Low Load	49.9 (110)	14.5 (32)	8.2	.364 (158)	.359 (156)	.357 (155)	9.8	0 (0)	- -	- -	- -	- -	- -	--	-
7-4	17	2	4/29	T-8	2	WT	Steam	#2 Oil	Low Air	49.9 (110	40.4 (89)	3.8	- -	- -	.373 (162)	13.0	0 (0)	- -	- -	- -	- -	- -	--	-
7-13	17	2	4/30	T-8	2	WT	Steam	#2 Oil	Air Regi.	49.9 (110)	37.2 (82)	6.6	.415 (180)	.396 (172)	.408 (177)	11.2	0 (0)	- -	- -	- -	- -	- -	--	-
7-15	17	2	4/30	T-8	2	WT	Steam	#2 Oil	Air Reg. & Top BOOS	49.9 (110)	25 (55)	12.0	.502 (218)	.498 (216)	.456 (198)	7.6	0 (0)	- -	- -	- -	- -	- -	--	-
8-5	20	2	5/20	4	2	WT	Steam	#6 Oil	Base-line 63%Max	36.3 (80)	23.2 (51)	5.7	.703 (305)	.687 (298)	.689 (299)	11.4	0 (0)	- -	1.54 (480)	1.5 (468)	.1562 (.0868)	.1267 (.0704)	80	-
8-2	20	2	5/20	4	2	WT	Steam	#6 Oil	Hi Load 75%Max	36.3 (80)	27.2 (60)	5.2	.742 (322)	.724 (314)	.730 (317)	11.6	0 (0)	- -	- -	- -	- -	- -	80	-
8-4	20	2	5/20	4	2	WT	Steam	#6 Oil	Low Load	36.3 (80)	15 (33)	6.5	.634 (275)	.624 (271)	.643 (279)	10.7	0 (0)	- -	- -	- -	- -	- -	82	-
6-6	20	2	5/21	4	2	WT	Steam	#6 Oil	Low Air	36.3 (80)	23.2 (51)	4.7	.618 (268)	.604 (262)	.618 (268)	12.0	0 (0)	- -	- -	- -	- -	- -	83	-
9-1	18	2	5/8	2	2	WT	Steam	#6 Oil	Base-line	40.9 (90)	32.2 (71)	7.4	.567 (246)	.560 (243)	.553 (240)	10.7	0 (0)	- -	1.55 (485)	1.49 (465)	.1964 (.1091)	.1642 (.0912)	82	-
9-4	18	2	5/8	2	2	WT	Steam	#6 Oil	Hi Load	40.9 (90)	35.9 (79)	6.8	.553 (240)	.546 (237)	.535 (232)	10.8	.180 (100)	- -	- -	- -	- -	- -	83	-
9-3	18	2	5/8	2	2	WT	Steam	#6 Oil	Low Load	40.9 (90)	18.6 (41)	8.6	.445 (193)	.438 (190)	.435 (189)	9.7	0 (0)	- -	- -	- -	- -	- -	83	-
9-6	18	2	5/9	2	2	WT	Steam	#6 Oil	Low Air	40.9 (90)	32.7 (72)	7.0	.493 (214)	.484 (210)	.477 (207)	10.7	.016 (9)	- -	- -	- -	- -	- -	83	-
9-10	18	2	5/9	2	2	WT	Steam	#6 Oil	B#1 COS	40.9 (90)	27.2 (60)	8.2	.403 (175)	.403 (175)	.406 (176)	10.2	0 (0)	- -	- -	- -	- -	- -	82	-
10-2	16	2	4/22	2	2	WT	Steam	#6 Oil	Base-line Hi Load	29.5 (65)	24.5 (54)	4.7	.429 (186)	.417 (181)	.412 (179)	12.4	0 (0)	- -	1.56 (488)	1.52 (473)	.2032 (.1129)	.1881 (.1045)	85	-
10-7	16	2	4/23	2	2	WT	Steam	#6 Oil	Low Load	29.5 (65)	11.4 (25)	13.3	.634 (275)	.615 (267)	.622 (270)	6.6	0 (0)	- -	- -	- -	- -	- -	82	-
10-4	16	2	4/22	2	2	WT	Steam	#6 Oil	Low Air	29.5 (65)	24.1 (53)	[illegible].6	.424 (184)	.422 (183)	.392 (170)	13.0	0 (0)	- -	- -	- -	- -	- -	88	-
10-12	16	2	4/23	2	2	WT	Steam	#6 Oil	Air Regi.	29.5 (65)	22.0 (48.5)	3.9	.401 (174)	.399 (173)	.410 (178)	12.8	0 (0)	- -	- -	- -	- -	- -	85	-
12-20	1	9	12/4	1	2	WT	Ring	NG	Base-Line	13.2 (29)	10.9 (24)	2.9	.212 (97)	- -	.201 (92)	10.0	.194 (145)	.032 (42)	.014 (4.72)	.013 (4.30)	.0045 (.0026)	.0027 (.0015)	77	-

Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
12-28	1	9	12/4	1	2	WT	Ring	NG	Hi Load	13.2 (29)	10.9 (24)	3.6	.1[illegible]2 (66)	.157 (72)	.166 (76)	9.6	.237 (170)	.019 (24)	-	-	-	-	77	-
12-22	1	9	12/4	1	2	WT	Ring	NG	Low Load	13.2 (29)	6.36 (14)	8.8	.148 (68)	-	.142 (65)	6.6	.324 (163)	.050 (45)	-	-	-	-	73	-
12-29	1	9	12/4	1	2	WT	Ring	NG	Low Air	13.2 (29)	10.9 (24)	0.5	.155 (71)	.135 (62)	.146 (67)	11.0	2.37 (>2000)	.023 (34)	.017 (5.5)	.015 (5.0)	.0189 (.0105)	.0009 (.0005)	79	-
13-4	2	9	11/28	2	2	WT	Ring	NG	Base-line	26.8 (59)	21.8 (48)	3.0	.253 (116)	.223 (102)	.205 (94)	9.9	1.37 (1015)	.021 (27)	-	-	-	-	77	-
13-3	2	9	11/28	2	2	WT	Ring	NG	Hi Load	26.8 (59)	21.8 (48)	3.95	.266 (122)	.229 (105)	.227 (104)	9.2	.178 (125)	.022 (28)	-	-	-	-	76	-
13-10	2	9	11/28	2	2	WT	Ring	NG	Low Load	26.8 (59)	11.4 (25)	11.0	.308 (141)	.336 (154)	.290 (133)	5.4	.133 (55)	.037 (27)	-	-	-	-	72	-
13-1	2	9	11/28	2	2	WT	Ring	NG	Low Air	26.8 (59)	21.8 (48)	2.2	.282 (129)	.247 (113)	.227 (104)	10.2	.858 (665)	.020 (28)	-	-	-	-	78	-
14-1	10	6	2/26	4	2	WT	Ring	NG	Base-line	27.2 (60)	21.8 (48)	5.2	.227 (104)	-	.214 (98)	9.3	0 (0)	-	-	-	.0080 (.0045)	.0047 (.0026)	80	-
14-6	10	6	2/26	4	2	WT	Ring	NG	Hi Load	27.2 (60)	27.7 (61)	3.7	.251 (115)	-	.240 (110)	9.6	0 (0)	-	-	-	-	-	78	-
14-9	10	6	2/26	4	2	WT	Ring	NG	Low Load	27.2 (60)	9.08 (20)	9.6	.188 (86)	-	.179 (82)	6.8	0 (0)	-	-	-	-	-	77	-
14-4	10	6	2/26	4	2	WT	Ring	NG	Low Air	27.2 (60)	22.2 (49)	2.4	.240 (110)	-	.227 (104)	10.4	.378 (290)	-	-	-	-	-	79	-
15-1	9	6	2/22	BC-1	2	WT	Ring	NG	Base-line	27.2 (60)	20.9 (46)	2.6	.528 (242)	-	.502 (230)	10.6	.013 (10)	-	-	-	.0083 (.0046)	.0045 (.0025)	79	-
15-6	9	6	2/22	BC-1	2	WT	Ring	NG	Hi Load	27.2 (60)	26.8 (59)	1.95	.535 (245)	-	.509 (233)	10.7	.051 (40)	-	-	-	-	-	75	-
15-8	9	6	2/22	BC-1	2	WT	Ring	NG	Low Load	27.2 (60)	15.4 (34)	1.8	.301 (13[illegible])	-	.286 (131)	9.8	>2.53 (>2000)	-	-	-	-	-	76	-
15-3	9	6	2/22	BC-1	2	WT	Ring	NG	Low Air	27.2 (60)	20.4 (45)	1.4	.345 (158)	-	.328 (150)	10.2	>2.48 (>2000)	-	-	-	-	-	77	-
15-12	9	6	2/22	BC-1	2	WT	Ring	NG	B#4 COS	27.2 (60)	18.6 (41)	4.4	.498 (228)	-	.474 (217)	9.5	.015 10	-	-	-	-	-	77	-
16-12	15	4	4/3	32-10	2	WT	Under Fed Stoker	Coal	Base-line	27.2 (60)	21.8 (48)	6.6	.670 (266)	.652 (259)	.645 (256)	12.7	0 (0)	-	1.88 (540)	1.79 (513)	-	-	76	-
16-8	15	4	4/3	32-10	2	WT	Under Fed Stoker	Coal	Hi Load	27.2 (60)	27.2 (60)	6.1	.793 (317)	.736 (292)	.791 (314)	12.8	0 (0)	-	-	-	-	-	74	-
16-16	15	4	4/3	32-10	2	WT	Under Fed Stoker	Coal	Low Load	27.2 (60)	9.53 (21)	12.3	.612 (243)	.597 (237)	.635 (252)	8.0	0 (0)	-	-	-	-	-	74	-
16-10	15	4	4/3	32-10	2	WT	Under Fed Stoker	Coal	Low Air	27.2 (60)	20.4 (45)	4.9	.474 (188)	.474 (188)	.463 (184)	14.0	0 (0)	-	-	-	-	-	77	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
17-6	15	4	4/8	32-13	2	WT	Under Fed Stoker	Coal	Base-line	27.2 (60)	20.9 (46)	9.8	.564 (224)	.549 (218)	.577 (229)	10.4	0 (0)	-	-	-	2.383 (1.324)	2.367 (1.315)	72	-
17-8	15	4	4/8	32-13	2	WT	Under Fed Stoker	Coal	Hi Load	27.2 (60)	27.2 (60)	7.1	.627 (249)	.610 (242)	.634 (252)	12.3	0 (0)	-	-	-	-	-	74	-
17-10	15	4	4/8	32-13	2	WT	Under Fed Stoker	Coal	Low Load	27.2 (60)	14.5 (32)	10.5	.499 (198)	.489 (194)	.516 (205)	8.2	0 (0)	-	-	-	-	-	68	-
17-15	15	4	4/8	32-13	2	WT	Under Fed Stoker	Coal	Low Air	27.2 (60)	20.9 (46)	7.0	.506 (201)	.491 (195)	.605 (240)	12.0	.640 (320)	-	-	-	-	-	75	-
18-3	11	4	3/5	1	2	WT	Spread	Coal	Base-line	61.3 (135)	49.9 (110)	7.0	.932 (370)	.914 (363)		12.0	.056 (28)	.024 (21)	6.46 (1848)	6.4 (1830)	5.166 (2.87)	5.094 (2,83)	82	-
18-13	11	4	3/5	1	2	WT	Spread	Coal	Low Load	61.3 (135)	22.7 (50)	11.6	1.207 (479)	1.556 (450)		9.0	0 (0)	-	-	-	-	-	81	-
18-6	11	4	3/6	1	2	WT	Spread	Coal	Low Air	61.3 (135)	51.76 (114)	4.9	.844 (335)	.811 (322)		13.5	.219 (126)	.007 (7)	-	-	-	-	82	-
18-20	11	4	3/6	1	2	WT	Spread	Coal	Hi Load	61.3 (135)	59.0 (130)	7.2	1.071 (425)	1.035 (411)		12.2	.057 (281)	-	-	-	-	-	80	-
19-6	21	2	5/30	2	2	WT	Spread	Coal	Base-line	22.7 (50)	18.2 (40)	8.0	1.171 (465)	1.154 (458)	1.118 (444)	10.6	.054 (25)	.013 (11)	6.54 (1817)	6.29 (1799)	1.505 (.8369)	1.444 (.8020)	81	-
19-5	21	2	5/30	2	2	WT	Spread	Coal	Hi Load	22.7 (50)	23.2 (51)	7.4	1.189 (472)	1.174 (466)	1.134 (450)	11.4	.092 (40)	.005 (4)	-	-	-	-	79	-
19-7	21	2	5/30	2	2	WT	Spread	Coal	Low Load	22.7 (50)	14.5 (32)	9.0	1.171 (465)	1.151 (457)	1.078 (428)	9.8	.058 (25)	.012 (9)	-	-	-	-	79	-
19-9	21	2	5/30	2	2	WT	Spread	Coal	Low Air	22.7 (50)	18.6 (41)	5.8	.831 (330)	.814 (323)	.806 (320)	12.6	.037 (20)	.021 (20)	-	-	.9864 (.548)	.9028 (.546)	82	-
20-6	21	2	5/29	3	2	WT	Spread	Coal	Base-line	34.1 (75)	28.6 (63)	7.8	1.171 (465)	1.154 (458)	1.116 (443)	10.7	.191 (90)	.013 (11)	5.94 (1698)	5.82 (1665)	.4289 (.239)	.3447 (.1915)	76	-
20-7	21	2	5/29	3	2	WT	Spread	Coal	Hi Load	34.1 (75)	34.5 (76)	5.9	1.028 (412)	1.023 (406)	.957 (380)	12.6	.204 (110)	.014 (13)	-	-	-	-	77	-
20-9	21	2	5/29	3	2	WT	Spread	Coal	Low Load	34.1 (75)	20.0 (44)	9.9	1.242 (493)	1.199 (476)	1.141 (453)	8.9	.154 (61)	.023 (16)	-	-	-	-	75	-
20-10	21	2	5/29	3	2	WT	Spread	Coal	Low Air	34.1 (75)	28.6 (63)	5.9	.975 (387)	.947 (376)	.902 (358)	12.6	.111 (60)	.019 (18)	-	-	.430 (.239)	.368 (.204)	79	-
21-6	18	2	5/2	3	3	WT	Steam	#6 Oil	Base-line	47.7 (105)	36.3 (80)	6.3	.578 (251)	.571 (248)	.571 (248)	11.2	0 (0)	-	1.62 (505)	1.55 (485)	.1154 (.0641)	.1040 (.0581)	63	-
21-5	18	2	5/2	3	3	WT	Steam	#6 Oil	Hi Load	47.7 (105)	45 (99)	5.0	.618 (268)	.569 (247)	.571 (248)	12.0	.208 (130)	-	-	-	-	-	84	-
21-4	18	2	5/2	3	3	WT	Steam	#6 Oil	Low Load	47.7 (105)	16.8 (37)	8.7	.530 (230)	.521 (226)	.523 (227)	9.7	0 (0)	-	-	-	-	-	85	-
21-8	18	2	5/2	3	3	WT	Steam	#6 Oil	Low Air	47.7 (105)	36.2 (80)	6.1	.512 (222)	.512 (222)	.539 (234)	11.3	0 (0)	-	-	-	-	-	85	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
21-20	18	2	5/3	3	3	WT	Steam	#6 Oil	B#4 OOS	47.7 (105)	34.5 (76)	6.6	.512 (222)	.505 (219)	.502 (218)	11.0	0 (0)	-	-	-	.1906 (.106)	.1622 (.0901)	84	-
22-1	18	2	5/6	4	3	WT	Steam	#6 Oil	Baseline	72.6 (160)	59.02 (130)	6.8	.553 (240)	.537 (233)	.541 (235)	11.0	0 (0)	-	1.74 (543)	1.7 (529)	.0830 (.0461)	.0693 (.0385)	86	-
22-4	18	2	5/6	4	3	WT	Steam	#6 Oil	Low Load	72.6 (160)	32.7 (72)	8.2	.737 (320)	.733 (318)	.705 (306)	9.6	0 (0)	-	-	-	-	-	86	-
22-9	18	2	5/6	4	3	WT	Steam	#6 Oil	Low Air	72.6 (160)	54.5 (120)	6.0	.532 (231)	.518 (225)	.521 (226)	11.5	.116 (68)	-	-	-	-	-	86	-
22-16	18	2	5/8	4	3	WT	Steam	#6 Oil	B#2 OOS	72.6 (160)	47.7 (105)	10.5	.463 (201)	.452 (196)	.510 (221)	9.0	0 (0)	-	-	-	.1744 (.0969)	.0873 (.0485)	83	-
23-1	8	9	1/14	10	3	WT	Steam	#5Oil & RG	Baseline	49.9 (110)	40 (88)	8.0	.396 (172)	.387 (168)	.376 (163)	9.3	.022 (11)	.029 (26)	.33 (102)	.3 (94)	.0724 (.0402)	.0437 (.0243)	77	-
23-2	8	9	1/14	10	3	WT	Steam	#5Oil & RG	Hi Load	49.9 (110)	41.3 (91)	7.3	.382 (166)	.382 (166)	.364 (158)	9.7	.019 (10)	.023 (22)	-	-	-	-	76	-
23-6	8	9	1/14	10	3	WT	Steam	#5Oil & RG	Low Load	49.9 (110)	12.3 (27)	1.35	.447 (194)	.417 (131)	.401 (174)	5.0	.046 (35)	.008 (11)	-	-	-	-	83	-
23-10	8	9	1/14	10	3	WT	Steam	#5Oil & RG	Low Air	49.9 (110)	41.3 (91)	4.7	.412 (179)	.412 (179)	.396 (172)	11.2	.016 (10)	.019 (21)	-	-	-	-	78	-
24-3	9	6	2/20	BC-6	3	WT	Ring	NG	Baseline	72.6 (160)	61.7 (136)	3.8	.817 (374)	-	.777 (356)	9.8	.071 (50)	-	-	-	.0117 (.0065)	.0058 (.0032)	76	-
24-2	9	6	2/20	BC-6	3	WT	Ring	NG	Hi Load	72.6 (160)	68.1 (150)	3.45	.882 (404)	-	.841 (385)	10.0	.117 (85)	-	-	-	-	-	83	-
24-4	9	6	2/20	BC-6	3	WT	Ring	NG	Low Load	72.6 (160)	57.7 (127)	4.0	.775 (355)	-	.738 (338)	9.8	.043 (30)	-	-	-	-	-	83	-
24-7	9	6	2/21	BC-6	3	WT	Ring	NG	Low Air	72.6 (160)	61.3 (135)	2.6	.808 (370)	-	.769 (352)	10.6	.170 (129)	-	-	-	-	-	83	-
25-3	6	9	12/20	3	3	WT	Ring	NG	Baseline	71.7 (158)	56.8 (125)	12.0	.629 (288)	.629 (288)	.526 (241)	4.6	0 (0)	.026 (17)	-	-	.0023 (.0013)	.0014 (.0008)	79	-
25-4	6	9	12/20	3	3	WT	Ring	NG	Hi Load	71.7 (158)	68.1 (150)	11.5	.799 (366)	.775 (355)	.600 (275)	4.8	0 (0)	.032 (22)	-	-	-	-	80	-
25-6	6	9	12/20	3	3	WT	Ring	NG	Low Load	71.7 (158)	28.2 (62)	14.0	.240 (110)	.240 (110)	.170 (78)	-.8	.055 (16)	.035 (18)	-	-	-	-	81	-
25-9	6	9	12/20	3	3	WT	Ring	NG	Low Air	71.7 (158)	54.5 (120)	11.0	.563 (258)	.563 (258)	.463 (212)	5.2	.036 (15)	.018 (13)	-	-	-	-	82	-
26-1	12	4	3/19	24	3	WT	Pulverizer	Coal	Baseline	102 (225)	82.2 (181)	5.3	.952 (378)	.907 (360)	---	13.6	0 (0)	.016 (16)	6.507 (1861)	6.486 (1655)	1.865 (1.036)	1.788 (.9931)	86	-
26-7	12	4	3/19	24	3	WT	Pulverizer	Coal	Hi Load	102 (225)	108 (238)	5.3	1.108 (440)	1.078 (428)	---	13.6	-	.008 (8)	-	-	-	-	85	-
26-9	12	4	3/19	24	3	WT	Pulverizer	Coal	Low Load	102 (225)	72.6 (160)	5.8	1.015 (403)	.997 (396)	---	13.2	-	.008 (8)	-	-	-	-	86	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
26-2	12	4	3/19	24	3	WT	Pulverizer	Coal	Low Air	102 (225)	83.1 (183)	4.5	.907 (360)	.864 (343)	--- ---	14.4	--- ---	.005 (5)	--- ---	--- ---	--- ---	--- ---	86	-
26-14	12	4	3/19	24	3	WT	Pulverizer	Coal	Register	102 (225)	81.7 (180)	5.1	.927 (368)	.912 (362)	--- ---	13.4	--- ---	.006 (6)	--- ---	--- ---	--- ---	--- ---	85	-
27-1	14	4	4/15	1	3	WT	Spread	Coal	Baseline	68.1 (150)	54.5 (120)	10.2	1.393 (553)	1.393 (553)	1.350 (536)	9.8	0 (0)	--- ---	4.699 (1344)	4.552 (1302)	4.167 (2.315)	3.629 (2.016)	81	-
27-10	14	4	4/15	1	3	WT	Spread	Coal	Hi Load	68.1 (150)	68.1 (150)	9.0	1.429 (567)	1.368 (543)	1.330 (528)	10.8	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	80	-
27-8	14	4	4/15	1	3	WT	Spread	Coal	Low Load	68.1 (150)	22.7 (50)	15.8	1.602 (636)	1.537 (610)	1.526 (606)	5.6	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	76	-
27-4	14	4	4/15	1	3	WT	Spread	Coal	Low Air	68.1 (150)	55.8 (123)	8.9	1.136 (471)	1.126 (447)	1.151 (457)	11.2	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	82	-
28-2	14	4	4/17	4	3	WT	Spread	Coal	Baseline	104 (230)	73.5 (162)	10.8	1.378 (547)	1.277 (507)	1.282 (509)	9.6	- (0)	--- ---	3.273 (936)	3.255 (931)	.8566 (.4759)	.6102 (.3390)	80	-
28-11	14	4	4/17	4	3	WT	Spread	Coal	Hi Load	104 (230)	90.8 (200)	10.8	1.524 (605)	1.431 (568)	1.504 (579)	9.8	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	82	-
28-7	14	4	4/17	4	3	WT	Spread	Coal	Low Load	104 (230)	34.1 (75)	15.5	1.554 (617)	1.471 (584)	1.458 (579)	6.0	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	76	-
28-6	14	4	4/17	4	3	WT	Spread	Coal	Low Air	104 (230)	68.1 (150)	8.9	.907 (360)	.861 (342)	.849 (335)	11.3	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	83	-
28-15	14	4	4/17	4	3	WT	Spread	Coal	Low NOx	104 (230)	65.8 (145)	12.6	.992 (394)	.907 (360)	.917 (364)	8.3	0 (0)	--- ---	2.857 (817)	2.804 (802)	.6201 (.3445)	.5958 (.3310)	80	-
29-5	13	4	3/25	2	4	WT	Steam	#6	Baseline	227 (500)	182 (400)	9.5	.615 (267)	.604 (262)	--- ---	9.2	--- ---	.005 (4)	4.814 (1502)	4.801 (1498)	.6748 (.3749)	.6473 (.3596)	78	-
29-4	13	4	3/25	2	4	WT	Steam	#6	Hi Load	227 (500)	236 (520)	6.2	.415 (180)	.401 (174)	--- ---	11.2	000 ---	.004 (4)	--- ---	--- ---	--- ---	--- ---	79	-
29-5	13	4	3/25	2	4	WT	Steam	#6	Low Load	227 (500)	132 (400)	9.5	.615 (267)	.604 (262)	--- ---	9.2	--- ---	.005 (4)	--- ---	--- ---	--- ---	--- ---	78	-
29-8	13	4	3/25	2	4	WT	Steam	#6	Low Air	227 (500)	182 (400)	7.6	.434 (210)	.470 (204)	--- ---	10.6	--- ---	.007 (7)	--- ---	--- ---	--- ---	--- ---	80	-
29-1	13	4	3/25	2	4	WT	Steam	#6	Fuel	227 (500)	193 (425)	9.0	.622 (270)	.585 (254)	--- ---	10.0	- (0)	.016 (13)	--- ---	--- ---	--- ---	--- ---	--	-
30-14	9	6	2/19	VA-1	4	WT	Ring	NG	Baseline	136 (300)	118 (259)	3.1	.434 (199)	.417 (191)	.413 (189)	10.4	0 (0)	.002 (3)	--- ---	--- ---	.0149 (.0083)	.0049 (.0027)	84	-
30-11	9	6	2/19	VA-1	4	WT	Ring	NG	Hi Load	136 (300)	127 (280)	4.0	.450 (206)	--- ---	.428 (196)	9.8	0 (0)	0 (0)	--- ---	--- ---	--- ---	--- ---	83	-
30-13	9	6	2/19	VA-1	4	WT	Ring	NG	Low Load	136 (300)	64.9 (143)	2.6	.378 (173)	.378 (173)	.358 (164)	10.4	0 (0)	.001 (2)	--- ---	--- ---	--- ---	--- ---	85	-
30-15	9	6	2/19	VA-1	4	WT	Ring	NG	Low Air	136 (300)	118 (259)	2.3	.413 (189)	.428 (196)	.393 (180)	10.8	.036 (28)	.001 (1)	--- ---	--- ---	--- ---	--- ---	84	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
30-30	9	6	2/19	VA-1	4	WT	Ring	NG	Registers	136 (300)	118 (259)	3.1	.445 (204)	---	.424 (134)	10.0	.011 (8)	.001 (1)	---	---	---	---	84	-
30-28	9	6	2/19	VA-1	4	WT	Ring	NG	B#3 OOS	136 (300)	91.7 (202)	5.0	.369 (169)	---	.352 (161)	9.6	.136 (90)	---	---	---	---	---	84	-
31-1	13	4	3/28	2	4	WT	Pulverizer	Coal	Base-line	227 (500)	182 (400)	9.8	1.461 (580)	1.375 (540)	---	10.0	- (0)	.006 (4)	5.605 (1603)	5.486 (1569)	18.49 (10.27)	18.41 (10.23)	81	-
32-4	20	2	5/22	42	4	WT	Cyclone	Coal	Base-line	182 (400)	143 (320)	3.4	2.015 (800)	2.003 (795)	1.965 (788)	15.0	0 (0)	---	3.969 (1135)	3.923 (1122)	2.207 (1.226)	2.147 (1.193)	88	-
32-2	20	2	5/22	42	4	WT	Cyclone	Coal	Hi Load	182 (400)	183 (402)	3.2	1.990 (790)	1.975 (784)	1.935 (768)	14.8	0 (0)	---	---	---	---	---	87	--
32-3	20	2	5/22	42	4	WT	Cyclone	Coal	Low Load	182 (400)	109 (240)	3.2	1.869 (742)	1.848 (732)	1.756 (697)	14.6	0 (0)	---	---	---	---	---	88	-
32-5	20	2	5/22	42	4	WT	Cyclone	Coal	Low Air	182 (400)	146 (321)	3.1	1.902 (755)	1.851 (735)	1.661 (739)	14.8	0 (0)	---	---	---	---	---	68	--
33-3	3	9	12/6	2	5	FT	Air	#2	Base-line & Hi Load	4.54 (10)	3.18 (7)	7.2	.389 (169)	.346 (150)	.270 (117)	9.5	---	.078 (75)	.285 (89)	.282 (88)	.0736 (.0409)	.0369 (.0205)	64	--
33-6	3	9	12/6	2	5	FT	Air	#2	Low Load	4.54 (10)	1.36 (3)	7.0	.350 (152)	.327 (142)	---	10.0	0 (0)	.031 (30)	---	---	---	---	84	-
33-10	3	9	12/6	2	5	FT	Air	#2	Low Air	4.54 (10)	2.27 (5)	3.6	.343 (149)	---	.306 (133)	12.3	0 (0)	.022 (26)	---	---	---	---	86	-
34-11	23	3	6/11	1	5	FT	Air	#6	Base-line & Hi Load	3.18 (7)	3.04 (6.7)	5.4	.687 (298)	.675 (293)	.620 (269)	11.8	.030 (18)	.006 (7)	3.615 (1128)	3.577 (1116)	.680 (.489)	.373 (.207)	88	2.3
34-8	23	3	6/7	1	5	FT	Air	#6	Low Load	3.18 (7)	1.14 (2.5)	10.3	.781 (339)	.781 (339)	.763 (331)	8.0	.024 (10)	.022 (16)	---	---	---	---	--	1.0
34-4	23	3	6/7	1	5	FT	Air	#6	Low Air	3.18 (7)	3.04 (6.7)	3.9	.574 (249)	.569 (247)	.562 (244)	13.0	.037 (25)	.009 (11)	---	---	---	---	--	4.0
34-10	23	3		1	5	FT	Air	#6	Low Fuel Temp.	3.18 (7)	3.04 (6.7)	5.6	.726 (316)	.714 (310)	.680 (295)	11.8	.030 (18)	.007 (7)	---	---	---	---	--	1.0
35-1	26	5	6/26	2	5	FT	Air	#5	Base-line & Hi Load	4.99 (11)	5.40 (11.9)	4.1	.422 (183)	.410 (178)	.369 (160)	12.8	0 (0)	---	2.638 (823)	2.609 (814)	.1141 (.0634)	.0922 (.0512)	87	-
35-3	26	5	6/26	2	5	FT	Air	#5	Low Load	4.99 (11)	1.91 (4.2)	7.7	.373 (162)	.369 (160)	.336 (146)	10.2	0 (0)	---	---	---	---	---	87	-
35-4	26	5	6/26	2	5	FT	Air	#5	Low Air	4.99 (11)	5.40 (11.9)	3.7	.424 (184)	.412 (179)	.373 (162)	13.6	.044 (30)	---	---	---	---	---	87	-
36-2	15	4	4/10	2-1	5	FT	Cup	NSF	Base-line	7.72 (17)	6.81 (15)	6.7	.424 (184)	.412 (179)	.406 (176)	10.8	.161 (90)	---	---	---	---	---	72	-
36-4	15	4	4/10	2-1	5	FT	Cup	NSF	Hi Load	7.72 (17)	9.99 (22)	7.6	.493 (214)	.486 (211)	.495 (215)	10.4	.038 (20)	---	---	---	---	---	75	-
36-1	15	4	4/10	2-1	5	FT	Cup	NSF	Low Load	7.72 (17)	5.45 (12)	9.0	.512 (222)	.495 (215)	.500 (217)	9.4	0 (0)	---	---	---	---	---	--	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
37-8	5	9	12/17	248-3	5	FT	Ring	NG	Base-line	4.54 (10)	3.63 (8)	5.1	.120 (55)	.114 (52)	--- ---	3.4	0 (0)	.010 (12)	--- ---	--- ---	.0113 (.0063)	.0061 (.0034)	--	-
37-4	5	9	12/17	248-3	5	FT	Ring	NG	Hi Load	4.54 (10)	4.54 (10)	3.7	.117 (53)	.109 (50)	.103 (47)	9.1	0 (0)	.013 (17)	--- ---	--- ---	---	---	--	-
37-2	5	9	12/17	248-3	5	FT	Ring	NG	Low Load	4.54 (10)	1.36 (3)	11.6	.177 (81)	.168 (77)	.145 (67)	4.8	0 (0)	.023 (26)	--- ---	--- ---	--- ---	--- ---	--	-
37-6	5	9	12/17	248-3	5	FT	Ring	NG	Low Air	4.54 (10)	3.63 (8)	1.9	.083 (38)	.068 (31)	.066 (30)	10.2	>2.54 (>2000)	.286 (400)	--- ---	--- ---	--- ---	--- ---	--	-
38-2	4	9	12/7	4	6	FT	Ring	NG	Base-Line	9.08 (20)	6.36 (14)	6.8	.234 (107)	.203 (93)	.177 (81)	7.6	0 (0)	.046 (48)	--- ---	--- ---	.0347 (.0193)	.0214 (.0119)	90	-
38-1	4	9	12/7	4	6	FT	Ring	NG	Hi Load	9.08 (20)	8.17 (18)	6.9	.216 (99)	.190 (87)	.181 (83)	7.7	--- ---	.050 (52)	--- ---	--- ---	--- ---	--- ---	--	-
38-4	4	9	12/7	4	6	FT	Ring	NG	Low Load	9.08 (20)	2.27 (5)	11.8	.216 (99)	.197 (90)	.192 (88)	4.8	0 (0)	.071 (48)	--- ---	--- ---	--- ---	--- ---	--	-
38-8	4	9	12/7	4	6	FT	Ring	NG	Low Air	9.08 (20)	6.36 (14)	0.7	.164 (75)	.146 (67)	.144 (66)	10.9	.837 (700)	.036 (54)	--- ---	--- ---	--- ---	--- ---	--	-
39-1	26	5	6/24	2	5	FT	Ring	NG	Base-line & Hi Load	4.99 (11)	4.72 (10.4)	3.6	.199 (87)	.190 (84)	.164 (75)	10.1	.203 (150)	--- ---	--- ---	--- ---	--- ---	--- ---	83	-
39-3	26	5	6/24	2	5	FT	Ring	NG	Low Load	4.99 (11)	.127 (2.8)	8.8	.190 (83)	.183 (81)	.162 (74)	7.1	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	83	-
39-4	26	5	6/24	2	5	FT	Ring	NG	Low Air	4.99 (11)	4.72 (10.4)	2.9	.201 (88)	.197 (86)	.172 (79)	10.6	.563 (420)	--- ---	--- ---	--- ---	--- ---	--- ---	83	-
40-1	23	3	6/10	1	5	FT	Ring	NG	Base-Line & Hi Load	3.18 (7)	2.77 (6.1)	5.0	.162 (71)	.157 (69)	.142 (65)	8.6	.273 (180)	.043 (50)	--- ---	--- ---	--- ---	--- ---	--	0.0
40-6	23	3	6/10	1	5	FT	Ring	NG	Low Load	3.18 (7)	.91 (2.0)	12.5	.170 (74)	.168 (73)	.127 (58)	5.0	.742 (260)	.121 (75)	--- ---	--- ---	--- ---	--- ---	--	0.0
40-2	23	3	6/10	1	5	FT	Ring	NG	Hi Air	3.18 (7)	2.77 (6.1)	7.2	.153 (67)	.151 (66)	.142 (65)	7.8	.070 (40)	.015 (15)	--- ---	--- ---	--- ---	--- ---	--	0.0
41-6	3	9	12/5	2	5	FT	Ring	NG	Base-Line	4.54 (10	3.18 (7)	8.0	.199 (91)	.183 (84)	.183 (84)	7.4	.230 (123)	.210 (200)	--- ---	--- ---	--- ---	--- ---	82	-
41-1	3	9	12/5	2	5	FT	Ring	NG	Hi Load	4.54 (10)	4.54 (10)	7.0	.197 (90)	.181 (83)	.183 (84)	7.6	.090 (52)	.195 (200)	--- ---	--- ---	--- ---	--- ---	81	-
41-5	3	9	12/5	2	5	FT	Ring	NG	Low Load	4.54 (10)	1.36 (3)	11.0	.260 (119)	.247 (113)	.223 (102)	5.2	0 (0)	.109 (80)	--- ---	--- ---	--- ---	--- ---	78	-
41-10	3	9	12/5	2	5	FT	Ring	NG	Low Air	4.54 (10)	2.27 (5)	3.6	.183 (84)	--- ---	.172 (79)	9.6	0 (0)	.126 (160)	--- ---	--- ---	--- ---	--- ---	84	-
42-1	22	3	6/3	1	5	FT	UFS	Coal	Base-line	4.54 (10)	3.63 (8)	14.9	.688 (273)	.688 (273)	.670 (266)	4.8	.505 (110)	--- ---	--- ---	--- ---	1.102 (.6122)	1.062 (.5899)	--	-
43-1	22	3	6/4	2	5	FT	UFS	Coal	Base-line	4.54 (10)	3.63 (8)	18.0	.872 (346)	.793 (315)	.756 (300)	2.0	1.68 (180)	--- ---	--- ---	--- ---	2.219 (1.232)	1.052 (.5844)	--	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
44-4	26	5	6/24	1	6	FT	Air	#5	Baseline	8.17 (18)	7.99 (17.6)	7.3	.408 (177)	.403 (175)	.371 (161)	10.4	0 (0)	---	2.513 (784)	2.487 (776)	.1175 (.0653)	.0806 (.0448)	86	-
44-1	26	5	6/24	1	6	FT	Air	#5	Hi Load	8.17 (18)	9.99 (22)	5.0	.433 (188)	.426 (165)	.387 (168)	12.4	0 (0)	---	---	---	---	---	88	0.0
44-3	26	5	6/24	1	6	FT	Air	#5	Low Load	8.17 (18)	3.41 (7.5)	7.2	.355 (154)	.350 (152)	.323 (140)	10.2	0 (0)	---	---	---	---	---	88	-
44-6	26	5	6/24	1	6	FT	Air	#5	Low Air	8.17 (18)	7.99 (17.6)	3.6	.422 (183)	.419 (182)	.378 (164)	13.6	0 (0)	---	---	---	---	---	82	-
45-7	26	5	6/24	1	6	FT	Steam	#5	Baseline	8.17 (18)	7.65 (17.3)	6.7	.371 (161)	.371 (161)	.357 (155)	10.9	.018 (10)	---	2.590 (808)	2.567 (801)	.1402 (.0779)	.1128 (.0660)	86	1.0
45-1	26	5	6/24	1	6	FT	Steam	#5	Hi Load	8.17 (18)	9.99 (22.0)	4.7	.394 (171)	.385 (167)	.369 (160)	12.6	.031 (20)	---	---	---	---	---	87	-
45-3	26	5	6/24	1	6	FT	Steam	#5	Low Load	8.17 (18)	3.22 (7.1)	6.7	.355 (154)	.346 (150)	.327 (142)	10.8	0 (0)	---	---	---	---	---	88	-
45-5	26	5	6/24	1	6	FT	Steam	#5	Low Air	8.17 (18)	7.72 (17.0)	3.8	.350 (152)	.348 (151)	.320 (139)	13.2	.030 (20)	---	---	---	---	---	87	-
46-7	24	3	6/14	TV	6	FT	Air	#5	Baseline	5.90 (13)	4.95 (10.9)	3.2	.417 (181)	.412 (179)	.392 (170)	13.2	0 (0)	.004 (5)	2.558 (798)	(790)	.1544 (.0858)	.1537 (.0854)	85	0.0
46-3	24	3	6/14	TV	6	FT	Air	#5	Low Load	5.90 (13)	1.04 (2.3)	7.3	.507 (220)	.505 (219)	.479 (206)	10.0	0 (0)	.003 (3)	---	---	---	---	--	0.0
46-5	24	3	6/14	TV	6	FT	Air	#5	Low Air	5.90 (13)	4.95 (10.9)	1.9	.394 (171)	.394 (171)	.355 (154)	14.0	.161 (120)	---	---	---	---	---	--	8.5
47-1	24	3	6/13	TV	6	FT	Ring	NG	Baseline & Hi Load	5.90 (13)	5.63 (12.4)	4.1	.131 (57)	.131 (57)	.116 (53)	9.6	0 (0)	.019 (23)	---	---	---	---	--	0.0
47-5	24	3	6/13	TV	6	FT	Ring	NG	Low Load	5.90 (13)	.953 (2.1)	7.8	.181 (79)	.179 (78)	.153 (70)	7.0	0 (0)	.005 (5)	---	---	---	---	--	0.0
47-7	24	3	6/13	TV	6	FT	Ring	NG	Low Air	5.90 (13)	5.63 (12.4)	3.1	.133 (58)	.133 (58)	.116 (53)	9.8	.027 (20)	.004 (5)	---	---	---	---	--	0.0
48-4	26	5	6/24	1	6	FT	Ring	NG	Baseline	8.17 (18)	7.81 (17.2)	7.2	.129 (56)	.122 (54)	.103 (47)	7.7	.018 (10)	.020 (20)	---	---	---	---	82	0.0
48-1	26	5	6/24	1	6	FT	Ring	NG	Hi Load	8.17 (18)	9.90 (21.8)	4.3	.155 (68)	.151 (66)	.129 (59)	9.6	.029 (20)	.029 (35)	---	---	---	---	82	0.0
48-3	26	5	6/24	1	6	FT	Ring	NG	Low Load	8.17 (18)	3.50 (7.7)	8.6	.120 (53)	.120 (53)	.105 (48)	7.1	.020 (10)	.039 (35)	---	---	---	---	83	0.0
48-6	26	5	6/24	1	6	FT	Ring	NG	Low Air	8.17 (18)	7.81 (17.2)	2.7	.162 (70)	.157 (69)	.144 (66)	10.4	.080 (60)	.015 (20)	---	---	---	---	84	0.0
49-1	25	5	6/20	1	6	FT	Ring	NG	Baseline & Hi Load	9.08 (20)	5.68 (12.5)	2.8	.181 (79)	.181 (79)	.155 (71)	10.0	.187 (140)	.432 (575)	---	---	---	---	83	-
49-3	25	5	6/20	1	6	FT	Ring	NG	Low Load	9.08 (20)	1.91 (4.2)	3.3	.153 (67)	.148 (65)	.133 (61)	9.7	.014 (10)	.251 (325)	---	---	---	---	85	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
49-6	25	5	6/20	1	6	FT	Ring	NG	Hi Air	9.08 (20)	5.68 (12.5)	4.2	.183 (80)	.177 (77)	.162 (74)	9.2	.036 (25)	.468 (575)	---	---	---	---	81	-
51-1	23	3	6/10	1	5	FT	Air	#5	Baseline & Hi Load	3.18 (7)	3.04 (6.7)	6.3	.634 (275)	.622 (270)	.599 (260)	11.2	0 (0)	---	---	---	---	---	--	2.0
52-5	19	2	5/16	1	1	WT	Steam	#2	Baseline	7.95 (17.5)	6.36 (14)	3.6	.150 (65)	.147 (64)	.147 (64)	12.6	.069 (47)	---	.199 (62)	.173 (54)	.0680 (.0378)	.0610 (.0339)	85	-
52-2	19	2	5/16	1	1	WT	Steam	#2	Low Air	7.95 (175)	6.36 (14)	2.6	.145 (63)	.143 (62)	.145 (63)	13.1	.675 (485)	---	---	---	---	---	85	-
53-1	19	2	5/15	1	1	WT	Air	#2	Baseline	7.95 (17.5)	6.36 (14)	3.0	.224 (97)	.224 (97)	.212 (92)	13.1	0 (0)	.002 (3)	---	---	---	---	85	-
53-6	19	2	5/15	1	1	WT	Air	#2	Hi Air	7.95 (17.5)	6.36 (14)	4.3	.235 (102)	.230 (100)	---	12.5	0 (0)	.010 (12)	.221 (69)	.199 (62)	.0295 (.0164)	.0293 (.0163)	84	-
53-2	19	2	5/15	1	1	WT	Air	#2	Low Air	7.95 (175)	6.36 (14)	1.6	.198 (86)	.196 (85)	.194 (84)	14.2	.272 206	.007 (9)	---	---	---	---	86	-
54-5	19	2	5/17	1	1	WT	Mech	#2	Baseline	7.95 (175)	5.45 (12)	4.3	.184 (80)	.184 (80)	.184 (80)	12.0	0 (0)	---	---	---	.0349 (.0194)	.0272 (.0151)	85	-
54-2	19	2	5/17	1	1	WT	Mech	#2	Low Air	7.95 (17.5)	5.45 (12)	3.7	.184 (80)	.180 (78)	.182 (79)	12.6	0 (0)	---	---	---	---	---	86	-
55-1	26	5	6/26	2	5	FT	Air	#2	Baseline & Hi Load	4.99 (11)	5.13 (11.3)	4.7	.295 (128)	.290 (126)	.272 (118)	11.8	0 (0)	---	---	---	---	---	88	-
56-1	26	5	6/25	1	6	FT	Air	#2	Baseline	8.17 (18)	7.22 (15.9)	8.0	.267 (116)	.263 (114)	.240 (104)	9.4	0 (0)	---	---	---	---	---	85	0.0
57-1	26	5	6/25	1	6	FT	Steam	#2	Baseline	8.17 (18)	7.13 (15.7)	8.0	.272 (118)	.270 (117)	.242 (105)	9.6	0 (0)	---	---	---	---	---	86	1.5
58-2	5	9	12/17	248-1	5	FT	Ring	NG	Baseline	3.63 (8)	2.91 (6.4)	11.0	.153 (70)	.148 (68)	.122 (56)	4.8	0 (0)	.025 (18)	---	---	.0079 (.0044)	.0043 (.0024)	--	-
58-1	5	9	12/17	248-1	5	FT	Ring	NG	Hi Load	3.63 (8)	3.63 (8)	10.2	.172 (79)	.170 (78)	---	5.4	.009 (4)	.020 (16)	---	---	---	---	--	-
58-5	5	9	12/17	248-1	5	FT	Ring	NG	Low Load	3.63 (8)	.726 (1.6)	15.0	.120 (55)	.046 (21)	---	2.3	0 (0)	.387 (170)	---	---	---	---	--	-
58-8	5	9	12/17	248-1	5	FT	Ring	NG	Low Air	3.63 (8)	2.91 (6.4)	3.2	.098 (45)	.081 (37)	(35)	9.4	>2.88 (>2000)	.184 (240)	---	---	---	---	--	-
59-6	4	9	12/10	4	6	FT	Air	#2	Baseline	9.08 (20)	7.26 (16)	5.8	.445 (193)	.415 (180)	.403 (175)	10.2	0 (0)	.022 (23)	.487 (152)	.474 (148)	.0506 (.0281)	.0261 (.0145)	85	-
59-5	4	9	12/10	4	6	FT	Air	#2	Hi Load	9.08 (20)	8.17 (18)	6.2	.429 (186)	.403 (175)	.408 (177)	10.4	---	.019 (20)	---	---	---	---	--	-
59-8	4	9	12/10	4	6	FT	Air	#2	Low Load	9.08 (20)	2.04 (4.5)	6.3	.382 (166)	.364 (158)	.373 (162)	10.2	0 (0)	.024 (24)	---	---	---	---	--	-
59-4	4	9	12/10	4	6	FT	Air	#2	Low Air	9.08 (20)	6.36 (14)	2.7	.325 (141)	.304 (132)	.309 (134)	13.2	0 (0)	.071 (90)	---	---	---	---	--	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (K#/hr)	Test Load t/hr (K#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
60-1	4	9	12/12	3	6	FT	Ring	NG	50% Max	9.08 (20)	4.54 (10)	1.5	.221 (101)	.207 (95)	.212 (97)	10.6	2.63 (>2000)	.020 (28)	---	---	---	---	--	-
62-1	1	9	11/1	1	2	WT	Steam	#2	Low Load	13.2 (29)	4.54 (10)	9.0	.237 (103)	---	.226 (98)	8.3	.111 (52)	---	---	---	---	---	77	-
63-6	2	9	11/26	2	2	WT	Steam	PS 300	Base-line	26.8 (59)	20.9 (46)	2.9	1.426 (619)	---	1.256 (545)	13.0	.050 (35)	.056 (70)	1.782 (556)	1.728 (539)	.0711 (.0395)	.0552 (.0310)	82	-
63-11	2	9	11/26	2	2	WT	Steam	PS 300	Hi Load	26.8 (59)	24.1 (53)	4.9	1.491 (647)	---	1.256 (545)	12.0	0 (0)	.054 (60)	---	---	---	---	79	-
63-15	2	9	11/26	2	2	WT	Steam	PS 300	Low Load	26.8 (59)	12.7 (28)	10.8	1.424 (616)	---	1.173 (509)	7.4	.070 (28)	.052 (37)	---	---	---	---	75	-
63-9	2	9	11/26	2	2	WT	Steam	PS 300	Low Air	26.8 (59)	21.3 (47)	2.3	1.194 (518)	---	.995 (432)	13.6	.323 (236)	.064 (83)	---	---	---	---	78	-
63-20	2	9	11/26	2	2	WT	Steam	PS 300	B#3 COS	26.8 (59)	21.3 (47)	5.5	1.189 (516)	---	1.101 (478)	11.0	0 (0)	.046 (50)	1.526 (476)	1.484 (463)	.1213 (.0674)	.1062 (.0590)	79	-
64-1	23	3	6/10	1	5	FT	Air	#2	Base-line & HiLoad	3.18 (7)	3.04 (6.7)	6.8	.293 (127)	.288 (125)	.276 (120)	10.5	0 (0)	---	---	---	---	---	--	1.0
65-1	6	9	1/3	3	3	WT	Steam	#2	Base-line	71.7 (158)	52.5 (115)	5.2	.417 (181)	.454 (197)	.447 (194)	7.7	0 (0)	.008 (9)	.301 (94)	.276 (86)	.0522 (.0290)	.0157 (.0087)	84	-
65-2	6	9	1/3	3	3	WT	Steam	#2	Hi Load	71.7 (158)	63.6 (140)	4.8	.608 (264)	.634 (275)	.620 (269)	8.6	0 (0)	.048 (54)	---	---	---	---	85	-
65-4	6	9	1/3	3	3	WT	Steam	#2	Low Load	71.7 (158)	36.3 (80)	6.4	.276 (120)	.286 (124)	.279 (121)	6.4	0 (9)	.047 (48)	---	---	---	---	84	-
66-1	1	9	11/1	3	2	WT	Steam	#2	Base-line	15.0 (33)	10.4 (23)	5.9	.233 (123)	---	.270 (117)	10.8	0 (0)	---	.356 (111)	.333 (104)	.0704 (.0391)	.0443 (.0246)	81	-
66-4	1	9	11/1	3	2	WT	Steam	#2	Hi Load	15.0 (38)	10.9 (24)	4.8	.274 (119)	---	.260 (113)	11.4	0 (0)	---	---	---	---	---	81	-
66-5	1	9	11/1	3	2	WT	Steam	#2	Low Air	15.0 (33)	10.9 (24)	2.8	.240 (104)	---	.228 (99)	13.6	.024 (17)	---	---	---	---	---	83	-
67-6	1	9	11/7	3	2	WT	Ring	NG	Base-line	15.0 (33)	10.9 (24)	4.5	.197 (90)	---	.188 (86)	9.2	0 (0)	---	.013 (4.4)	.012 (4.0)	.0101 (.0056)	---	78	-
67-2	1	9	11/7	3	2	WT	Ring	NG	Hi Load	15.0 (33)	13.6 (30)	3.8	.181 (83)	---	.172 (79)	9.8	0 (0)	---	---	---	---	---	78	-
67-7	1	9	11/7	3	2	WT	Ring	NG	Low Air	15.0 (33)	10.9 (24)	2.7	.177 (81)	---	.168 (77)	10.3	0 (0)	---	---	---	---	---	79	-
68-2	2	9	11/20	4	2	WT	Steam	PS 300	Base-line	29.5 (65)	22.7 (50)	5.8	1.074 (466)	---	.963 (418)	10.8	- (0)	---	1.554 (485)	1.522 (475)	---	---	78	-
68-3	2	9	11/20	4	2	WT	Steam	PS 300	Hi Load	29.5 (65)	24.5 (54)	3.8	1.044 (453)	---	.896 (389)	12.0	0 (0)	---	---	---	---	---	80	-
68-5	2	9	11/20	4	2	WT	Steam	PS 300	Low Load	29.5 (65)	15.4 (34)	11.2	1.242 (539)	---	.915 (397)	6.8	- (0)	---	---	---	---	---	74	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
68-9	2	9	11/20	4	2	WT	Steam	PS 300	Low Air	29.5 (65)	23.6 (52)	3.4	.993 (431)	---	.843 (368)	12.9	0 (0)	---	---	---	---	---	61	-
68-14	2	9	11/20	4	2	WT	Steam	PS 300	B#4 OOS	29.5 (65)	23.6 (52)	5.0	1.007 (437)	---	.892 (387)	11.4	.013 (6)	---	---	---	---	---	80	-
68-21	2	9	11/20	4	2	WT	Steam	PS 300	B#4 OOS Registers	29.5 (65)	23.2 (51)	5.6	1.005 (436)	---	.931 (404)	11.2	0 (0)	.065 (70)	---	---	---	---	73	-
69-1	2	9	11/27	4	2	WT	Ring	NG	Base-line	29.5 (65)	24.1 (53)	3.8	.214 (98)	---	.207 (95)	9.4	.131 (89)	---	---	---	---	---	--	-
69-3	2	9	11/27	4	2	WT	Ring	NG	Low Air	29.5 (65)	24.1 (53)	3.0	.188 (86)	---	(82)	9.4	.960 (675)	---	---	---	---	---	--	-
70-2	2	9	11/15	6	3	WT	Steam	PS 300	Base-line	56.8 (125)	45.4 (100)	6.4	.776 (337)	---	.740 (321)	10.4	---	---	1.513 (472)	1.484 (463)	.0776 (.0431)	.0673 (.0374)	77	-
70-3	2	9	11/15	6	3	WT	Steam	PS 300	Hi Load	56.8 (125)	45.4 (100)	5.1	.753 (327)	---	.717 (311)	11.6	---	---	---	---	---	---		-
70-6	2	9	11/15	6	3	WT	Steam	PS 300	Low Load	56.8 (125)	17.3 (38)	7.2	.809 (351)	---	.770 (334)	10.0	---	---	---	---	---	---	82	-
70-8	2	9	11/15	6	3	WT	Steam	PS 300	Low Air	56.8 (125)	45.9 (101)	4.6	.742 (322)	---	.707 (307)	11.8	---	---	---	---	---	---	78	-
70-10	2	9	11/15	6	3	WT	Steam	PS 300	Regis-ter	56.8 (125)	45.4 (100)	6.6	.933 (405)	---	.889 (386)	10.4	---	---	---	---	---	---	75	-
71-3	20	2	5/23	42	4	WT	Cyc-lone	50%C 50%O	Base-line	182 (400)	145 (320)	3.5	1.721 (716)	1.678 (698)	1.553 (646)	14.1	0 (0)	---	---	---	---	---	--	-
71-1	20	2	5/23	42	4	WT	Cyc-lone	50%C 50%O	Hi Load	182 (400)	182 (400)	3.7	1.916 (797)	1.892 (787)	1.800 (749)	14.0	0 (0)	---	---	---	---	---	--	-
72-4	20	2	5/23	42	4	WT	Cyc-lone	30%C 70%C	Base-line	182 (400)	145 (320)	3.4	1.707 (710)	1.675 (697)	1.625 (676)	14.4	0 (0)	---	---	---	.8170 (.4539)	.7720 (.4289)	--	-
72-3	20	2	5/23	42	4	WT	Cyc-lone	30%O 70%C	Hi Load	182 (400)	185 (408)	3.6	2.067 (860)	2.014 (838)	1.930 (803)	14.4	0 (0)	---	---	---	---	---	--	-
73-1	24	3	6/14	TV	6	FT	Air	#2	Base-line	5.90 (13)	4.99 (11)	3.1	.194 (84)	.189 (82)	.177 (77)	12.7	0 (0)	---	---	---	---	---	--	-
74-1	8	9	1/15	10	3	WT	Steam	#5& RG	Base-line & HiLoad	49.9 (110)	40.9 (90)	6.5	.495 (215)	.507 (220)	.509 (221)	9.2	0 (0)	.012 (12)	---	---	---	---	75	-
74-4	8	9	1/15	10	3	WT	Steam	#5& RG	Low Load	49.9 (110)	19.5 (43)	11.3	.486 (211)	.486 (211)	.590 (256)	6.6	0 (0)	0 (0)	---	---	---	---	72	-
75-7	12	4	3/15	24	3	WT	Nozzle	NG	Base-line	102 (225)	81.7 (180)	6.0	.463 (212)	.439 (201)	---	9.0	---	.006 (7)	---	---	.0103 (.0057)	.0083 (.0046)	84	-
75-5	12	4	3/15	24	3	WT	Nozzle	NG	Hi Load	102 (225)	102 (225)	5.3	.469 (215)	.445 (204)	---	9.4	---	.008 (9)	---	---	---	---	84	-
75-2	12	4	3/15	24	3	WT	Nozzle	NG	Low Load	102 (225)	59.0 (130)	5.8	.408 (187)	.393 (180)	---	9.9	---	.004 (5)	---	---	---	---	85	-

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Table A-1. Continued

Test Run No.	Location	Region No.	Date 73/74	Boiler No.	Test Category	Furnace Type	Burner Type	Test Fuel	Test Type	Capacity t/hr (k#/hr)	Test Load t/hr (k#/hr)	Excess O_2 (% dry)	NOx Hot Line g/Mcal (ppm)	NO Hot Line g/Mcal (ppm)	NO Cold Line g/Mcal (ppm)	CO_2 % dry	CO g/Mcal (ppm)	HC g/Mcal (ppm)	SOx g/Mcal (ppm)	SO_2 g/Mcal (ppm)	Total Partic. g/Mcal (#/MBtu)	Solid Partic. g/Mcal (#/MBtu)	Boiler Efficiency %	Bacharach Smoke Spot No.
75-8	12	4	3/15	24	3	WT	Nozzle	NG	Low Air	102 (225)	84.0 (185)	4.4	.321 (147)	.310 (142)	--- ---	10.0	--- ---	.007 (8)	--- ---	--- ---	--- ---	--- ---	55	-
75-16	12	4	3/15	24	3	WT	Nozzle	NG	Register	102 (225)	84.0 (185)	6.10	.367 (168)	.358 (164)	--- ---	8.8	--- ---	.012 (14)	--- ---	--- ---	--- ---	--- ---	84	-
77-11	12	4	3/12	20	4	WT	Nozzle	NG	Baseline	145 (320	118 (260)	4.5	.699 (320)	.657 (301)	--- ---	9.3	0 (0)	.004 (5)	--- ---	--- ---	.0191 (.0106)	--- ---	85	-
77-10	12	4	3/12	20	4	WT	Nozzle	NG	Hi Load	145 (320)	136 (300)	3.9	.727 (333)	.690 (316)	--- ---	9.6	0 (0)	.002 (3)	--- ---	--- ---	--- ---	--- ---	84	-
77-5	12	4	3/12	20	4	WT	Nozzle	NG	Low Load	145 (320)	90.8 (200)	4.9	.502 (230)	.474 (217)	--- ---	9.2	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	85	-
77-13	12	4	3/12	20	4	WT	Nozzle	NG	Low Air	145 (320)	118 (260)	3.5	.607 (278)	.563 (258)	--- ---	10.0	0 (0)	.005 (6)	--- ---	--- ---	--- ---	--- ---	85	-
78-1	12	4	3/13	20	4	WT	Pulverizer	Coal	Baseline	145 (320)	118 (260)	5.8	1.219 (484)	1.189 (472)	--- ---	13.2	0 (0)	.008 (8)	6.378 (1824)	6.343 (1814)	2.948 (1.638)	2.369 (1.316)	86	-
78-9	12	4	3/13	20	4	WT	Pulverizer	Coal	Hi Load	145 (320)	123 (270)	5.6	1.244 (494)	1.237 (491)	--- ---	13.4	--- ---	.007 (7)	--- ---	--- ---	--- ---	--- ---	65	-
78-4	12	4	3/13	20	4	WT	Pulverizer	Coal	Low Load	145 (320)	86.3 (190)	7.4	1.491 (592)	1.476 (586)	--- ---	11.8	0 (0)	.003 (3)	--- ---	--- ---	--- ---	--- ---		-
78-7	12	4	3/13	20	4	WT	Pulverizer	Coal	Low Air	145 (320)	118 (261)	4.8	1.244 (494)	1.219 (484)	--- ---	14.0	0 (0)	.006 (6)	--- ---	--- ---	--- ---	--- ---	86	-
80-11	10	6	2/26	5	2	WT	Ring	NG	Baseline	49.9 (110)	38.6 (85)	8.1	.205 (94)	--- ---	.197 (90)	7.8	0 (0)	--- ---	--- ---	--- ---	.0104 (.0058)	.0081 (.0045)	70	-
80-13	10	6	2/26	5	2	WT	Ring	NG	Hi Load	49.9 (110)	49.0 (108)	6.9	.271 (124)	--- ---	.258 (118)	8.4	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	75	-
80-9	10	6	2/26	5	2	WT	Ring	NG	Low Load	49.9 (110)	13.6 (30)	7.1	.234 (107)	--- ---	.223 (102)	8.2	0 (0)	--- ---	--- ---	--- ---	--- ---	--- ---	78	-
80-19	10	6	2/26	5	2	WT	Ring	NG	Low Air	49.9 (110)	40.4 (89)	2.0	.354 (162)	--- ---	.336 (154)	11.0	.147 (109)	--- ---	--- ---	--- ---	--- ---	--- ---	76	-

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(Please read Instructions on the reverse before completing)

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16. ABSTRACT The report gives results of testing 19 coal, oil, and gas-fired industrial boilers to determine their normal emissions and the effectiveness of combustion modifications in reducing NOx emissions without increasing the emission of particulates and other pollutants. Combustion modifications investigated were: reducing excess air, recirculating flue gas, staging combustion air, adjusting burner swirl registers, reducing combustion air temperature, tuning the burner, changing atomization pressure, and changing oil temperature. Emissions were found to be not significantly dependent on boiler size, but very dependent on the fuel. Generally, the normal NOx emissions were below EPA Standards for New Stationary Sources. Particulate emissions from oil and gas were below 43 ng/J (0.1 lb/million Btu); from coal, they are above by a factor of 5. NOx reductions of as much as 50% were obtained with several combustion modifications. In most instances the boiler heat-loss efficiency was not degraded. Although particulate emissions usually increased, the increase could be limited by fine-tuning the boiler. There was no significant effect on any other pollutant emission.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution; Combustion; Boilers Burners; Nitrogen Oxides; Smoke Fossil Fuels; Particle Size; Flue Gases Circulation; Atomizing Coal; Fuel Oil; Natural Gas	Air Pollution Control Stationary Sources Combustion Modification Industrial Boilers Particulate; Excess Air Staged Combustion Burner Tune-Up	13B 21B 13A 07B 21D 14B 13H, 07A

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