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Project Summary

Industrial Boiler Combustion Modification NO_x Controls

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Volume I of the report gives results of an environmental assessment of combustion modification NO_x control techniques for coal-, oil-, and gas-fired industrial boilers, with focus on NO_x control effectiveness, operational impacts, thermal efficiency impacts, capital and annualized operating costs, and effects on emissions of pollutants other than NO_x. Major industrial boiler design types are characterized and equipment trends are reviewed. Currently available control techniques can achieve 10 - 25 percent NO_x reductions for coal- and residual-oil-fired boilers and 40 - 70 percent reductions for distillate-oil- and gas-fired units with minimal adverse operating impacts. Controls should increase steam costs by only 1 - 2 percent, but the initial investment required could be significant; up to 20 percent of the boiler cost on a new boiler and up to 40 percent of the boiler cost for a retrofit. Volumes II and III of the report give results of detailed Level 1 tests on two stoker-coal-fired boilers, indicating that combustion modification reduces the source potential environmental hazard by lowering NO_x emissions, leaving the emissions of other pollutants largely unaffected.

This Project Summary was developed by EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

With the increasing extent of NO_x control application in the field, and expanded NO_x control development anticipated for the future, there is currently a need to: (1) ensure that the current and emerging control techniques are technically and environmentally sound and compatible with efficient and economical operations of systems to which they are applied, and (2) ensure that the scope and timing of new control development programs are adequate to allow stationary sources of NO_x to comply with potential air quality standards. With these needs as background, EPA's IERL-RTP initiated an "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies Program" (NO_x EA) in 1976. This program has two main objectives: (1) to identify the multimedia environmental impact of stationary combustion sources and NO_x combustion modification controls applied to these sources, and (2) to identify the most cost-effective, environmentally sound NO_x combustion modification controls for attaining and maintaining current and projected NO_2 air quality standards to the year 2000.

The NO_x EA's assessment activities have placed primary emphasis on major *stationary fuel combustion NO_x sources* - utility boilers, industrial boilers, gas turbines, internal combustion engines, and commercial and residential warm air furnaces; conventional gaseous, liquid, and solid fuels burned in these sources; and combustion modification controls applicable to these sources with potential for implementation to the year 2000.

Volume I of the report summarizes the EA of combustion modification controls for industrial boilers. It outlines the environmental, economic, and operational impacts of applying combustion modification controls to this source category. Volumes II and III summarize results of two field test programs aimed at providing data to support the environmental and operational impact evaluation.

Conclusions

Source Characterization

Industrial boilers are defined here as coal-, oil-, or natural-gas-fired steam generators with heat input capacities of 2.9 - 73 MW (10 - 250 $\times 10^6$ Btu/hr). The boilers provide electrical or mechanical power, process heat, or a combination of these in a wide variety of industries. This capacity range does not encompass all steam and hot water generators used in industry. In fact boilers in this size category represent about 60 percent of the installed capacity used in the industrial sector. In addition, industrial boilers fire fuel other than coal, oil, or natural gas.

However, industrial boilers larger than 73 MW (250 $\times 10^6$ Btu/hr) heat input are generally similar in design and controllability to utility boilers. Boilers smaller than 2.9 MW (10 $\times 10^6$ Btu/hr), generally used for hot water and space heating, can be grouped with commercial heating units. Both utility boilers and commercial heating units are treated in other NO_x EA reports. [1-6]

The industrial boiler category as defined here represented the third largest contributor to stationary source NO_x emissions in the U.S. in 1977, contributing about 14 percent, as shown in Figure 1. This share is expected to remain high, given incentives to switch to coal firing in the future. Thus, this same category represents a priority category for control evaluation in the NO_x EA.

Coal-fired industrial boilers are generally of the watertube design. Two major design categories are: pulverized-coal-fired units and stokers. Pulverized-coal-fired units accounted for only about 8 percent of the installed coal-fired population. But since these units are almost entirely greater than 29 MW (100 $\times 10^6$ Btu/hr) capacity, they account for almost 20 percent of the coal-fired capacity. Characteristic designs are similar to those in the utility

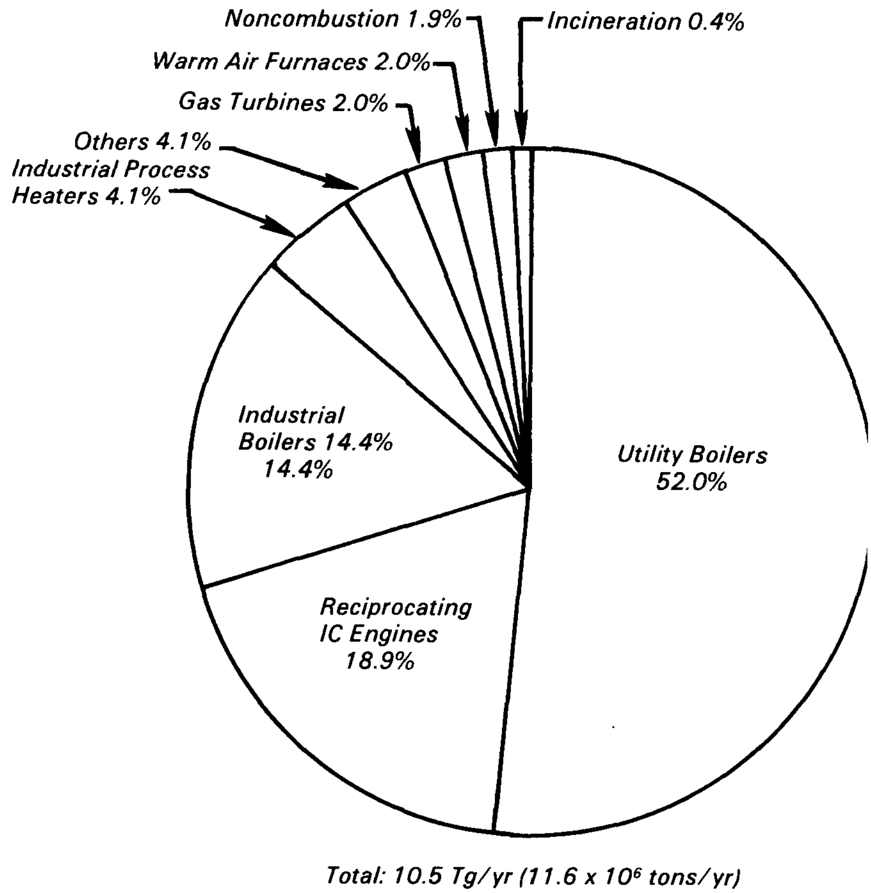

Figure 1. *Distribution of stationary anthropogenic NO_x emissions for the year 1977 (controlled NO_x levels).*

sector; tangential and single- and opposed-wall designs predominate.

Stoker-fired boilers account for nearly all the remaining coal-fired installations. These boilers are classified by the method of introducing fuel to the furnace: spreader, underfeed, and overfeed. Spreader stokers are most popular in newer installations.

Oil- and gas-fired boilers can be classified as either watertube or firetube. Both shop-assembled, or packaged, and field-erected watertube boilers exist; however virtually all firetube boilers are packaged units since firetube boilers are generally limited in size to about 8.7 MW (30 $\times 10^6$ Btu/hr).

There are two major types of packaged watertube boilers: horizontal straight-tube and bent-tube. Newer boilers are exclusively bent-tube, further classified by tube configuration. A-, D-, and O-tube configurations are most common.

Industrial firetube boilers can be classified as horizontal return tube (HRT), scotch, or firebox. The HRT is a two-pass boiler and was the most popular into the 1960s. Scotch boilers, in two, three, or four passes, have since become the most popular. Firebox boilers are short and compact, employing three passes at most, finding use in installations where floor space is limited.

Control Alternatives

NO_x is the primary flue gas pollutant from industrial boilers amenable to control by combustion modification. The major combustion modification techniques which have been shown to be effective in reducing NO_x emissions from industrial boilers are: low excess air firing, staged combustion using overfire air ports or burners-out-of service, low NO_x burner designs, flue gas recirculation, reduced air preheat load reduction or reduced combustion intensity, and homogeneous reduction of NO_x using ammonia injection.

Typical baseline (uncontrolled) NO emission factors for industrial boilers are given in Table 1. Note that these are average values; NO_x emissions from individual units can vary significantly within a design/fuel category. Similarly, the effectiveness of the above NO_x control techniques varies with boiler design and fuel fired, as well as within a given design/fuel category. Thus, the following discussion is organized by design and fuel.

Pulverized Coal-Fired Boilers

Combustion modification NO_x controls have been successfully applied to only a limited number of coal-fired industrial boilers. Those considered most promising on pulverized coal-fired units are low excess air, staged combustion, low NO_x burners, and ammonia injection.

Low excess air (LEA) operation is relatively simple to implement. It applies to all boilers and requires only reducing airflow to the burner windbox. However, in a multiburner unit, the windbox may have to be modified to improve air distribution to individual burners during LEA operation. Lowering excess air can reduce the safety margin for complete combustion. Hence, an oxygen trim system may have to be added, in addition to the normal airflow controllers. Nevertheless, boiler efficiency gains with LEA should offset any additional hardware costs, making LEA the most attractive NO_x control technique for first implementation (5 - 25 percent NO_x reduction). Figure 2 shows results of LEA tests on representative coal-fired industrial boilers. The slopes of the data bands indicate the relative effectiveness of LEA on each equipment category. LEA is about equally effective for each.

Staged combustion with overfire air (OFA) and LEA is the best demonstrated, available control option for pulverized coal-fired industrial boilers, potentially reducing NO_x emissions by up to 30 percent. The LEA and OFA control system has an advantage over other control systems because of its commercial availability and effectiveness. The cost of the system is not prohibitive when OFA ports are designed as part of new boilers. In addition, careful operation of staged air injection is not expected to affect emissions of other criteria pollutants seriously. Burner stoichiometries of 100 - 110 percent would achieve a 20-percent NO_x reduction. At these stoichiometry levels, oxidizing atmospheres would prevail in the furnace, thus minimizing concern over possible furnace slagging and boiler tube wastage. However, achieving more stringent NO_x control with combined LEA and OFA may require burner stoichiometries below 100 percent in some cases. This low burner stoichiometry level would cause reducing atmospheres in parts of the furnace, creating the potential for corrosion of water tubes, especially when firing high-sulfur coal. Generally, boiler manufacturers do not recommend burner operation with stoichiometry below 100 percent, primarily because of increased corrosion potential. Another potential adverse impact is that additional excess air may be required to ensure complete combustion, resulting in a decrease in boiler efficiency. However, experience with utility boilers indicates that these potential problems can be overcome with proper design and implementation. Indeed, 30-day, continuous monitoring tests of staged combustion with LEA, at varying reduced boiler loads, demonstrated a 30-percent NO_x reduction with no adverse operational impacts.

Burners-out-of-service (BOOS), the other technique that can be used for staged combustion, is primarily considered for retrofits. However, it is not favored for several reasons:

- Extensive engineering and testing on an individual boiler basis is required to determine the optimal BOOS pattern.
- An effective BOOS pattern is sometimes not possible because pulver-

Table 1. Representative Industrial Boilers and Typical Baseline NO_x Emission Levels

Fuel	*Boiler Type*	*Typical Size (Heat Input Capacity) MW*	*(10^6 Btu/hr)*	*Average NO_x Baseline Emission Level ng NO_2/J*	*(lb/10^6 Btu)*
Pulverized Coal	*Single Wall and Tangential*	*59*	*(200)*	*285*	*(0.663)*
Stoker Coal	*Spreader*	*44*	*(150)*	*265*	*(0.616)*
	Underfeed	*9*	*(30)*	*150*	*(0.349)*
	Chain Grate	*22*	*(74)*	*140*	*(0.0326)*
Residual Oil[a]	*Firetube*	*4.4*	*(15)*	*115*	*(0.267)*
	Watertube	*44*	*(150)*	*160*	*(0.372)*
Distillate Oil	*Firetube*	*4.4*	*(15)*	*70*	*(0.163)*
	Watertube				
	Without air preheater	*29*	*(100)*	*55*	*(0.128)*
	With air preheater			*90*	*(0.208)*
Natural Gas	*Firetube*	*4.4*	*(15)*	*40*	*(0.093)*
	Watertube				
	Without air preheater	*29*	*(100)*	*45*	*(0.105)*
	With air preheater			*110*	*(0.255)*

[a]Includes No. 5 and No. 6 fuel oils.

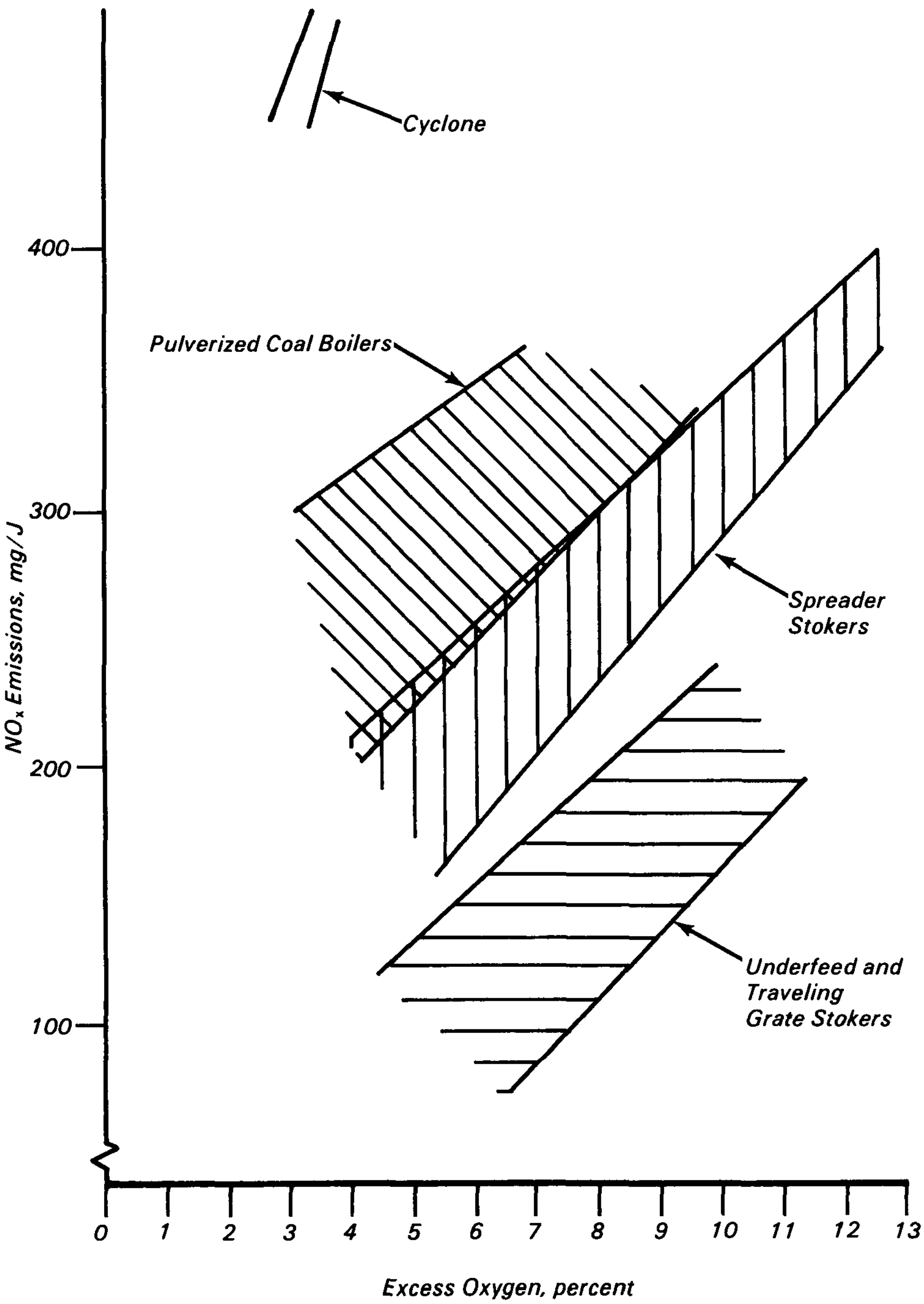

Figure 2. *Effect of excess oxygen on NO_x emissions from coal-fired boilers.*

izers may serve burners on two levels. The most effective BOOS pattern often involves the top level of burners on air only.

- Burners/pulverizers that operate during BOOS often cannot handle increased coal flow, necessitating a significant reduction in the boiler steam rating (e.g., 20-percent).
- Potential increased slagging and corrosion.

Several low NO_x burner (LNB) designs are under development by commercial firms, with 40 - 60 percent NO_x control projected. In addition, an advanced design under study by EPA is the distributed fuel/air mixing concept. Field testing and application is scheduled for late 1982, with a target NO_x level of 86 ng/J (0.2 lb/10^6 Btu).

In some applications, LNBs may have several advantages over other combustion modifications such as OFA and BOOS. For example, one utility boiler manufacturer claims that LNBs will maintain the furnace in an oxidizing environment, minimizing slagging and reducing the potential for furnace corrosion when firing high-sulfur coal. Also, more complete carbon utilization may be achieved due to better coal/air mixing in the furnace. Finally, lower oxygen levels may be obtained with all the combustion air admitted through the burners.

Since the burners generally alter the flame configuration, care must be taken when applying the burners to existing boilers. For instance, some LNBs have longer flames. Such burners can be installed only in boilers large enough to avoid cold-wall impingement. Once developed, however, low NO_x, coal-fired burners for industrial boilers could become the best control system because of the expected lower cost, higher NO_x reduction capability, and other operational advantages.

If additional control, over and above boiler/burner modifications, is needed (e.g., to meet stringent local regulations), ammonia injection is offered commercially. The technique has yet to be demonstrated on coal-fired boilers and is several times more costly than conventional combustion modifications. In addition, as a developing technology, several potential implementation and operational problems need to be resolved:

- Optimal effectiveness for noncatalytic reduction of NO by NH_3 occurs over a very narrow temperature range; hence, the precise location of NH_3 injection ports.
- Since the temperature profile in a boiler changes with load, NO_x control with NH_3 may restrict load.
- Emissions of NH_3 and by-products.
- Possible boiler equipment fouling by ammonium sulfates.

However, the major strengths of ammonia injection are its potential for moderate NO_x removal (40 - 60 percent), and its applicability as an additional control that can be combined with conventional combustion techniques for increased NO_x reductions.

Stoker-Coal-Fired Boilers

NO_x emissions from stokers are generally lower than those from pulverized coal. These lower emissions can be attributed to the lower combustion intensity and to the partial staged combustion that naturally occurs during combustion on fuel beds.

As shown in Figure 2, NO_x emissions from spreader stokers tend to be higher than those from other stokers. The coal in a spreader stoker boiler burns partly in a suspended state and partly on a moving or vibrating grate. The combustion of coal in the suspended state apparently causes generally higher NO_x emissions than for other stokers that feed and combust coal directly on a moving grate. In addition, the higher heat release rates of spreader stokers probably contribute to high NO_x emissions.

Four methods have been used to modify stoker coal combustion to reduce NO_x emissions: reduced undergrate air or LEA, OFA, reduced heat input, and reduced air preheat (RAP). Of these methods, only LEA firing has been demonstrated to be widely effective.

EPA field tests of 17 stokers indicate that the excess oxygen levels at baseline operating conditions averaged about 9 percent. During LEA tests, the average excess oxygen level was reduced to 6.4 percent by reducing the undergrate airflow while maintaining the OFA flow close to normal operation. Such reduction lowered NO_x emission levels approximately 10 percent for each 1 percent reduction in excess oxygen. Additional data from an EPA-DOE-ABMA field test program, involving 11 relatively new design stokers operating near the lower excess air level, support this conclusion.

The minimum achievable excess air is limited by several factors. Except for the water-cooled vibrating grate, the grate is cooled only by airflow. If this air is cut back too much, the grate can overheat. There is also the danger of creating local reducing zones and of forming harmful corrosion products as the air is cut back. Another problem during field tests was the formation of clinkers and increased CO emissions as the excess oxygen was reduced. However, test results indicate that, if excess oxygen levels are maintained above 5 percent, CO emissions will stay below 150 ppm.

Fuel combustion with lowest possible levels of excess air ensures maximum boiler efficiency unless the air is decreased to the point where unburned carbon losses are greatly increased. Limited available data indicate that, if airflow is maintained for an excess oxygen level above about 6 percent, no serious operational or emission problems should result. NO_x emission reductions of about 5 - 25 percent and increases in boiler efficiency of 1 percent can be expected with LEA. if fuel burnout does not change during the process.

Residual-Oil-Fired Boilers

As with coal-fired boilers, combustion modification NO_x controls have been applied only to a limited number of oil-fired boilers.

This experience indicates that low excess air firing is the only demonstrated universally applicable control technique for all oil-fired boilers. Figure 3 shows excess air test results.

Baseline NO_x emissions from residual-oil-fired firetube boilers are relatively low, averaging 115 ng/J, as noted in Table 1. Low excess air operation should lower emissions by about 20 percent and also increase boiler efficiency. The same possibility of increased

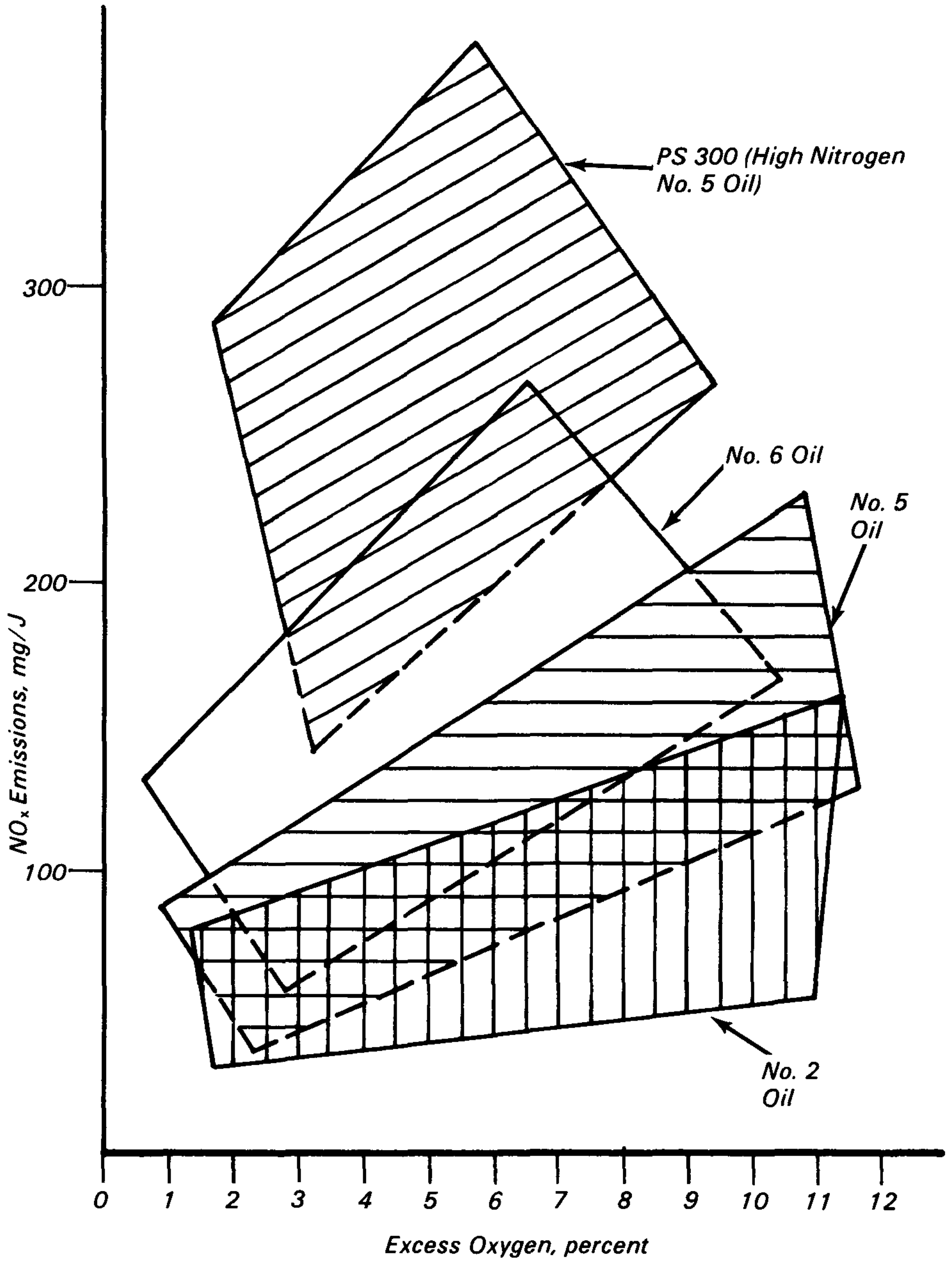

Figure 3. *Effect of excess oxygen NO_x emissions from distillate and residual oil-fired boilers.*

CO and hydrocarbon emissions discussed for coal firing under low excess air applies here also. Low NO_x burners and staged combustion are the preferred alternatives for additional control. However, neither has been demonstrated for firetube boilers. Developing low NO_x burners may become the first control choice after LEA because of their potential for high NO_x reduction with the lowest boiler operational impact.

The generally larger watertube boilers with higher NO_x emissions (160 ng/J average) can also benefit from the same controls: low excess air, low NO_x burners, and staged combustion. Staged combustion has been demonstrated for large multiburner watertube boilers. However, if developing low NO_x burners are successful and achieve 40 - 60 percent reduction, down to 86 ng/J (0.2 lb/10^6 Btu), they should prove more cost effective. The only other alternative for stringent control is ammonia injection. Although demonstrated and in limited commercial operation for oil and gas firing in Japan, this system is a severalfold more costly alternative for NO_x reduction than the other two. In addition, operational problems and potential emissions of NH_3 and byproducts are of environmental concern.

Distillate-Oil- and Gas-Fired Boilers

NO_x emissions from distillate oil and natural gas combustion are primarily from thermal NO_x formation. The relatively low uncontrolled baseline NO_x emissions of these boilers (see Table 1) should permit very low controlled NO_x levels. These control levels can be met in most cases with commercially available combustion modification techniques. The preferred control systems are low excess air, reduced air preheat, flue gas recirculation, and low NO_x burners (under development), in that order, lowering NO_x down to about 65 ng/J (0.15 lb/10^6 Btu). Distillate oil- and natural-gas-fired boilers not equipped with air preheaters (all firetubes, some watertubes) generally exhibit significantly lower average NO_x emissions than those with air preheaters, regardless of boiler heat input capacity, as shown in Figure 4. Figure 4 shows that bypassing an existing preheater substantially reduces NO_x (shown for natural gas, though similar behavior is expected for distillate oil). Those boilers without air preheat should be able to

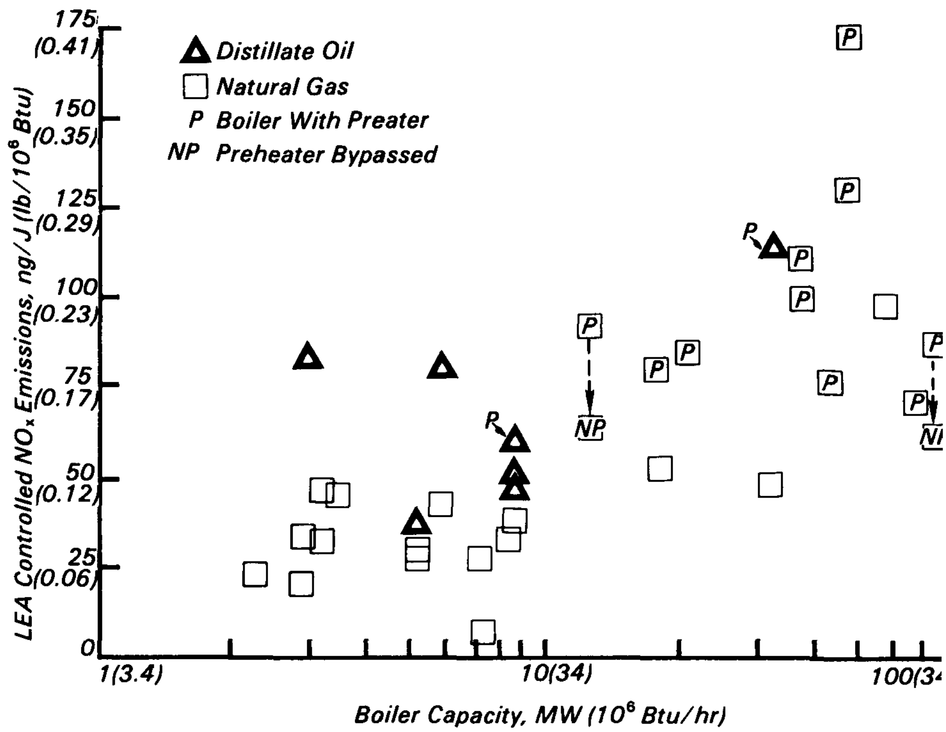

Figure 4. *Effect of combustion air preheat and boiler capacity of NO_x emissions from distillate-oil- and gas-fired industrial boilers.*

reach 43 ng/J (0.1 lb/10^6 Btu) with just flue gas recirculation; air-preheater-equipped boilers may require combined reduced air preheat and flue gas recirculation. Figure 5 shows the high effectiveness (40 - 75 percent NO_x reduction) of flue gas recirculation for distillate oil and natural gas firing.

Cost of Controls

The primary contributions of combustion modification controls to steam cost changes are the equipment modification costs and changes in thermal efficiency and fan power demand. In general, combustion modification controls should be cost-effective for industrial boilers, raising steam costs only 1 - 2 percent in most cases. However, the initial investment, especially for smaller boilers, may be a large fraction of the cost of the boiler itself, up to 25 percent when controls are installed on a new boiler. Retrofit control costs, highly site specific, could be two to three times higher.

Table 2 summarizes costs and cost effectiveness of controls to attain various control levels for the various boiler design and fuel categories. Costs in Table 2 reflect annualizing capital costs and adding these to annual operating costs.

LEA, in many cases, will actually lowe steam costs due to the increase in ther mal efficiency. In general, LEA is recom mended with other control technique to lessen their cost impact and to give higher NO_x reductions. Staged combus tion causes an estimated small increase in steam cost; but, with careful desigr and operation, this estimated cost car probably be reduced. Flue gas recircula tion, although costly, is the most effec tive technique for the clean fuels distillate oil and natural gas. Again optimal design and operation will proba bly lower the cost. Low NO_x burner promise to be the most cost-effective However, they are still under develop ment.

Post-combustion control, because o higher capital equipment, raw material and energy requirements, is signifi cantly more costly. Ammonia injectio is several times more costly than con ventional combustion modifications Flue gas treatment costs are about a order of magnitude higher than com bustion modifications.

Incremental Emissions Due to Controls

Combustion modifications, used t control NO_x emissions from industri

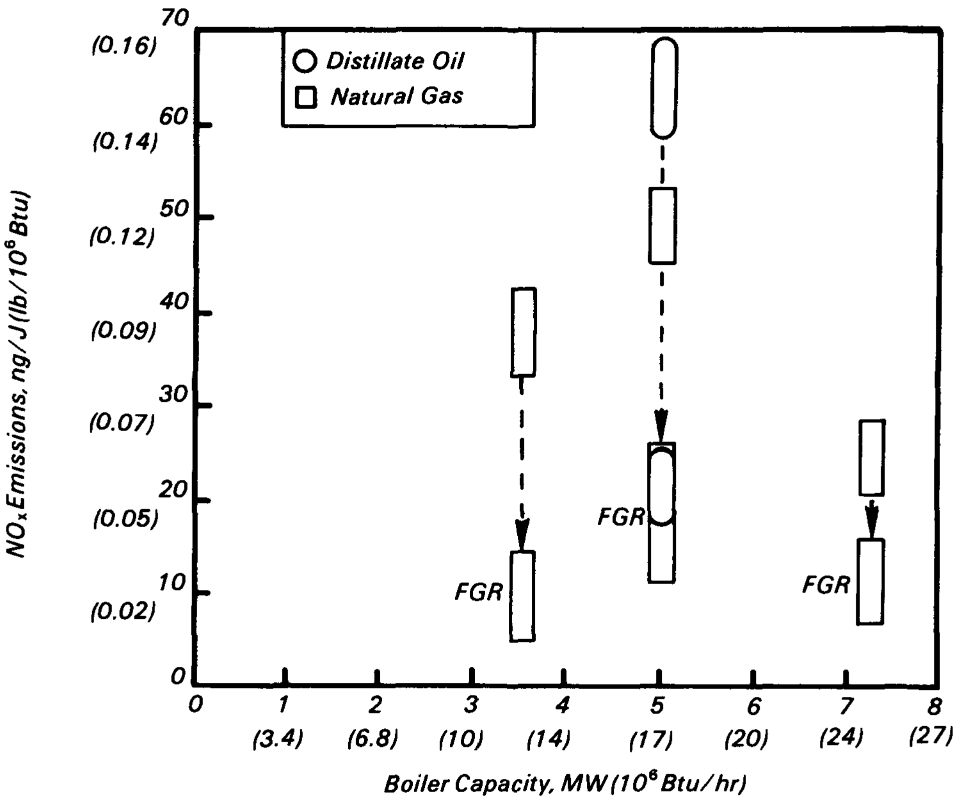

Figure 5. *Effect of flue gas recirculationon NO_x emissions from distillate-oil- and gas-fired industrial boilers.*

Table 2. *Cost-Effectiveness of NO_x Controls*

Boiler Type	Control Level ng/J	(lb/10⁶ Btu)	Control Technique	Control Cost mills/ 10^3 kg Steam	Cost Effectiveness \$/kg NO_x Reduced
Pulverized Coal	285	(0.66)	Baseline	--	--
	258	(0.6)	LEA	0	0
	215	(0.5	OFA	70	0.3
	172	(0.4)	OFA + LNB	~140	~0.4
	129	(0.3)	OFA + NH_3 injection	~275	~0.5
Spreader Stoker	265	(0.62)	Baseline	--	--
	215	(0.5)	OFA	20	0.1
	129	(0.3)	NH_3 injection	~220	0.5
Residual Oil Watertube	160	(0.37)	Baseline	--	--
	129	(0.3)	LEA	-60	-0.6
	86	(0.2)	LNB	~170	~0.7
Distillate Oil Firetube	70	(0.16)	Baseline	--	--
	65	(0.15)	LEA	65	0.2
	43	(0.1)	FGR	367	1.2
Natural Gas Firetube	40	(0.093)	Baseline	--	--
	24	(0.06)	FGR	350	2.0

boilers, might also be expected to affect the level of emissions of other pollutant species discharged. If other pollutant emissions increase significantly, the net environmental effect of controlling NO_x through combustion modification may be detrimental. For stationary combustion sources, the pollutants of concern are the criteria pollutants — CO, unburned hydrocarbon (UHC), and particulate (both mass emission rates and emitted size distribution) — along with sulfates, organic compounds, and trace metals, in both the flue gas and discharged ash streams.

To assess the effects of combustion modifications on incremental emissions from industrial boilers, two field tests (see report Vols. II and III) were conducted. In each, slightly modified EA Level 1 sampling and chemical analysis procedures were followed.[7] Level 1 bioassay tests also were performed on some of the samples collected. Results of the field tests are summarized below.

Site A

The unit tested at Site A was a Foster Wheeler Ltd. boiler combined with a Detroit Stoker traveling-grate spreader stoker, with a total effective grate area of about 48 m^2 (515 ft^2). Coal is supplied through seven feeders in the front wall of the furnace. Overfire air (OFA) is injected into the furnace through two rows of ports located on the back and front walls of the furnace. The OFA is delivered by a fan that is independent of the forced draft system used for supplying undergrate air. Therefore, the flowrates of undergrate and overfire air can be set independently. A tubular air preheater heats the undergrate air to about 175°C (350°F). The overfire air is not preheated. The Foster Wheeler steam generator was designed to produce 38 kg/s (300,000 lb/hr) of saturated steam at a pressure of 2.3 MPa (320 psig).

The gases and particulate exiting the boiler pass through the boiler-bank collector, air heater, mechanical ash collector, ESP, economizer, and wet SO_2 scrubber before entering the stack. The design efficiency of the mechanical collector is 70 percent. The design efficiency of the ESP is 97.83 percent with one of the ESP's fields out of service.

Particulate material collected in the boiler-bank collector, air heater collector, and mechanical collector may be continuously reinjected. Reinjection rates are controlled by the boiler operator. The flyash reinjection ports are on the rear wall of the furnace, under the

OFA ports. The reinjection air is supplied by the OFA fan.

During this program, two furnace operating conditions were tested: (1) under normal operating conditions, and (2) with increased OFA (at constant overall excess air) to determine the effect on NO_x as well as particulate and trace element emissions.

Increased OFA caused apparent operating efficiency to increase from 77.8 to 80.8 percent. The largest contributing factor to this increase was a decrease in the combustible content of the flyash.

Table 3 summarizes flue gas emissions at the ESP outlet for all components analyzed. The table shows that NO_x emissions were reduced 18 percent under OFA firing; however, emission levels of CO, SO_2, and SO_3 increased. The increases in sulfur species emissions were probably due to measurement difficulties or nonhomogeneities in coal composition, rather than changes in firing mode. Particulate load increased at the ESP outlet, as did flue gas organic species ($>C_7$) emissions under low NO_x firing. Infrared analyses of flue gas sample extracts indicated the presence of carboxylic acids and some aromatics in the baseline extract, and aromatics and possibly an amide in the low NO_x extract. Emission levels of the trace element species remained unchanged, within analytical accuracy, with firing mode.

The bottom ash, mechanical hopper ash, and ESP hopper ash were also analyzed for trace elements, ionic species, and Level 1 organic content.

Results indicated that concentrations of the trace elements and most ionic species were unchanged with firing mode. Interestingly, however, bottom ash nitrate content (oxidized nitrogen) apparently decreased while ammonium content (reduced nitrogen) apparently increased for the low NO_x test. For the organic species, levels were higher in the low NO_x bottom ash than in the baseline bottom ash, although the baseline mechanical hopper ash had higher organic content than the low NO_x mechanical hopper ash.

Infrared spectrometry analyses of ash sample extracts showed that carboxylic acids, esters, and ethers were present in both bottom ash samples, and that only aliphatic hydrocarbons were present in ESP hopper ash samples.

Table 3. *Flue Gas Composition at the ESP Outlet (µg/dscm): Site A*

	Baseline	*Low NO_x*
NO_x	6.3×10^5	5.2×10^5
SO_2	8.2×10^5	1.1×10^6
SO_3	5.8×10^3	3.5×10^4
CO	2.5×10^5	4.8×10^5
Particulate	4.0×10^4	6.3×10^4
Antimony	<19	<3.2
Arsenic	3.2	<7.0
Barium	420	70
Beryllium	3.8	<0.097
Bismuth	<24	<6.7
Boron	910	350
Cadmium	6.1	<17
Chromium	17	150
Cobalt	9.2	<48
Copper	29	<98
Iron	1.1×10^3	1.9×10^3
Lead	<57	<180
Manganese	32	<77
Mercury	<0.037	<0.016
Molybdenum	10	<8.0
Nickel	34	<140
Selenium	32	45
Tellurium	1.1	<5.5
Thallium	<34	<37
Tin	8.4	<220
Titanium	1.2	580
Vanadium	8.7	<17
Zinc	63	35
Organics ($>C_7$)	1.0×10^3	1.8×10^3
Methane	4.9×10^4	

Site B

The unit tested at Site B was a Riley single-pass boiler with a Riley spreader stoker. The unit had a continuous rating of 25 kg/s steam (200,000 lb/hr) with a 2 hour maximum capacity of 28 kg/s. The steam is produced at a pressure of 1.38 MPa (185 psig) and temperature of 260°C (500°F). This boiler also had a flyash reinjection system. All the ash from the boiler hopper is reinjected and part of the ash from the mechanical collector is also reinjected. An ESP is used for final flyash control. The boiler was also equipped with an economizer.

The NO_x EA field tests at Site B consisted of a baseline (normal operation) test and a test with low excess air. Low NO_x operation reduced NO_x by 37 percent at the economizer outlet.

Table 4 summarizes the flue gas emissions at the economizer outlet for all species analyzed in the test. As shown, CO levels remained relatively unchanged while particulate emissions increased slightly under low NO_x firing. Results of sulfur species analyses were inconclusive; errors are suspected in the values obtained by the Shell-Emeryville method used. Flue gas organic emissions increased with low NO_x firing. Infrared spectrometry indicated the presence of aliphatic hydrocarbons, ethers, esters, and carboxylic acids in the extracts from both tests. Trace element emissions were not affected by firing mode, within analytical accuracy. The bottom ash, mechanical hopper ash, and ESP hopper ash were analyzed for trace elements, ionic species, and Level 1 organic content.

Concentrations of these did not vary significantly with firing mode. Infrared

Table 4. Flue Gas Composition at ESP Outlet (μg/dscm): Site B

	Baseline	*Low NO_x*
NO_x	4.7×10^5	3.4×10^5
SO_2	5.2×10^5	3.3×10^5
SO_3	2.4×10^3	2.2×10^3
CO	5.4×10^4	3.5×10^4
CO_2	2.1×10^8	2.4×10^8
Particulate	1.9×10^4	2.9×10^4
Antimony	3.5	3.5
Arsenic	35	39
Barium	170	2.7
Beryllium	1.2	0.25
Bismuth	2.6	3.2
Boron	$<6.8 \times 10^3$	7.8×10^3
Cadmium	<1.2	5.2
Chromium	61	20
Cobalt	23	5.8
Copper	64	0.050
Iron	280	<71.2
Lead	<1.2	<0.50
Manganese	12	11
Mercury	2.4	1.3
Molybdenum	320	210
Nickel	2.6×10^3	2.4×10^3
Selenium	13	13
Tellurium	2.2	<3.0
Thallium	2.0	<2.2
Tin	9.5	<8.8
Titanium	<55	<49
Vanadium	130	18
Zinc	9.7	<0.058
Organics ($>C_7$)	920	1.37×10^3
Methane	1.27×10^4	5.72×10^4

spectrometry of ash sample extracts indicated the presence of aliphatic and aromatic hydrocarbons, esters, and carboxylic acids in bottom ash samples; aliphatic hydrocarbons in mechanical hopper ash samples; and possibly an ester or carboxylic acid in ESP hopper ash samples.

Environmental Impact Evaluation

The data obtained in the field test program discussed above were evaluated by a Source Analysis Model (SAM), specifically SAM/IA,[8] to give quantified measures of the potential hazard posed by emissions from stoker-fired industrial boilers and to evaluate how low NO_x firing affects the potential hazard. SAM/IA was developed by IERL-RTP for use in EA projects to estimate the potential hazards of source discharge streams.

The SAM/IA model defines two indices of potential hazard: Discharge Severity (DS) and Weighted Discharge Severity (WDS). DS is the ratio of the pollutant discharge concentration to its Discharge Multimedia Environmental Goal (DMEG). (DMEGs, within IERL-RTP's EA program for a large number of species, represent maximum pollutant concentrations desirable in discharge streams to preclude adverse effects on human health or ecological systems.) A DS exceeding unity flags the existence of a potential hazard. A stream's Total Discharge Severity (TDS) is the sum of the DSs calculated for the discharge stream.

WDS is the product of DS times the discharge stream mass flowrate. Total Weighted Discharge Severity (TWDS) is the sum of WDSs calculated for the discharge stream. Thus WDS and TWDS indicate the magnitude of a potential hazard and can be used to rank the relative hazard posed by different discharge streams.

Table 5 gives results of the SAM/IA evaluation of the flue gas composition data from Site A, for uncontrolled (baseline) and controlled operation (low NO_x). The table shows MEG category DS for each firing condition for components with DS greater than 1 in either test. DS values shown were calculated from air/health-based DMEGs. Table 5 shows that NO_x and SO_2 are potentially the most hazardous flue species. The sum of the DS values for these two species comprises over 70 percent of the stream TDS. The DS for SO_2 fluctuates with day-to-day fuel sulfur content, masking the effects of the reduction of the NO_x DS with the application of NO_x control, so that stream TDS remains relatively constant with NO_x control application. Other species of potential concern include CO, SO_3 (vapor), and several trace elements. In this test the SO_3 increased sixfold with NO_x control. However, this increase may be within the accuracy of the analytical technique used to measure SO_3. Carboxylic acids are flagged here also.

Table 6 shows stream TWDS for each stream under each firing mode tested. The table shows that the flue gas stream dominates the potential hazard of the source, with a WDS over two orders of magnitude larger than any other stream. In addition, the TWDSs for the ash streams remain relatively constant with firing mode. Thus, changes in flue gas TWDS will elicit corresponding changes in total source TWDS. It is concluded that the NO_x control tested does not, of itself, increase total source potential hazard.

Table 7 gives results of the SAM/IA evaluation of the flue gas from the Site B unit, for the two modes of operation (baseline and low NO_x). MEG category DS values for compounds with DS greater than 1 in either test are given. Again, these values were calculated with air/health DMEGs.

Conclusions from Table 7 are analogous to those discussed for Table 5. NO_x and SO_2 remain the potentially most hazardous species, accounting for over half the flue gas stream TDS. Here, though, the DS for SO_2 (which varies exclusively with fuel sulfur content) drops in the low NO_x mode, so that

Table 5. *Flue Gas Discharge Severity: Site A*

Component	MEG Category	Discharge Severity Baseline	Low NO_x
NO_x	47	70	58
SO_2	53	63	85
CO	42	6.3	12
SO_3 (vapor)	53	5.8	35
Beryllium	32	1.9	0.049
Arsenic	49	1.6	3.5
Iron	72	1.1	1.9
Carboxylic acids	8	1.0	1.8
Titanium	41	0.34	3.7
Cadmium	82	0.61	1.7
Lead	46	0.38	1.2
Total Stream		154	206

Table 6. *Total Weighted Discharge Severity: Site B*

Stream	Total Weighted Discharge Severity (kg/s) Baseline	Low NO_x
Flue gas	6,600	7,900
Bottom ash	15	16
Mechanical collector hopper ash	1.7	1.8
ESP hopper ash	5.3	2.6

Table 7. *Flue Gas Discharge Severity: Site B*

Component	MEG Category	Discharge Severity Baseline	Low NO_x
NO_x	47	68	38
SO_2	53	39	23
CO_2	42	35	27
Arsenic	49	18	20
Boron	68	2.2	2.5
SO_3 (vapor)	53	2.4	1.6
CO	42	1.4	0.88
Total stream		168	114

stream TDS decreases with NO_x control application.

Other flue gas species with DS greater than 1 include CO_2, CO, SO_3 (vapor), and the trace elements arsenic and boron. The DS for SO_3 shows essentially no change with firing mode. In addition, no organic category had a DS value greater than 1.

Table 8 shows stream TWDS values for each stream at Site B, under both firing modes tested. The Site A conclusions hold here as well. Specifically, the flue gas stream dominates the potential source hazard, and NO_x control reduces total source potential hazard in the absence of SO_2 considerations which depend on the fuel sulfur content and not on the NO_x control.

Bioassays of the bottom ash and ESP hopper ash from the Site B low NO_x test indicated negative mutagenicity and nondetectable toxicity. Only the ESP hopper ash elicited a positive response, giving a low toxicity result in the RAM cytotoxicity assay.

Recommendations

NO_x controls have been applied to industrial boilers only to a limited extent. An exception is low excess air, which is often used to increase boiler efficiency. Thus, there is a general need for data on the effectiveness, costs, and operational impacts of NO_x combustion modification control applied to industrial steam raising equipment. The general trends highlighted in this report are meant to be only guidelines; there will certainly be exceptions, and much research and development work remains to be done before NO_x control technology is well characterized for the wide diversity of industrial boiler design and equipment types.

However, it can be generally concluded that currently available combustion modification technology is capable of moderate reductions (10 - 25 percent) for coal- and residual-oil-fired boilers, while major reductions (40 - 70 percent) are possible for distillate-oil- and gas-fired units with minimal adverse operational or environmental impacts. Advanced techniques under development, such as low NO_x burners and ammonia injection, are potentially capable of more efficient operation and/or additional reductions, and the development of these techniques should continue.

EPA is currently sponsoring several field test programs demonstrating combustion modification NO_x controls for industrial boilers. Results from these studies should help fill some of the data gaps identified in this study. In addition, several other field tests of these and other combustion controls are underway, including 30-day continuous monitoring programs. The results of these and other test programs should be monitored and incorporated in future updates of the assessment of combustion modification NO_x controls.

Table 8. *Total Weighted Discharge Severity: Site B*

Stream	Total Weighted Discharge Severity (kg/s) Baseline	Low NO_x
Flue gas	7,160	3,640
Bottom ash	--[a]	7.7
Mechanical collector hopper ash	50	5.5
ESP hopper ash	1.9	3.7

[a]Bottom ash sample not taken.

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