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STATE OF THE ART FOR CONTROLLING NO_x EMISSIONS PART I. UTILITY BOILERS

Catalytic, Incorporated
Charlotte, North Carolina 28209

September 1972

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A report is presented with the objective of identifying the "State of the Art" of NO_x emission reduction from stationary sources through combustion modification. This first part of a two part report deals with the control of NO_x from utility boilers. The report presents information on: Sources of, and formation of nitrogen oxides. A total of five factors which effect utility boiler emissions are discussed in detail. A discussion of "Combustion Modification for NO_x Emission Control", includes the following topics: combustion operating modification, combustion equipment, design modifications, and flue gas treatment.

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"STATE OF THE ART" FOR CONTROLLING NO_X EMISSIONS

PART I. UTILITY BOILERS

by

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SUMMARY

Utility boilers fired by gas, oil or coal contribute 19.4 per cent of NO_x to the atmosphere. The NO_x is generated by thermal conversion of nitrogen contained in the atmosphere and by conversion of fuel nitrogen. The oxides of nitrogen can be controlled by combustion modification or flue gas treatment. Because of the ease and quickness of adaptability and lower cost, combustion modification is more viable and it has been performed with different degrees of success in controlling NO_x. The work in reducing NO_x from oil- and gas-fired boilers has been demonstrated extensively both experimentally and commercially. The NO_x control from coal-fired boilers is still in the experimental stage, and thus far data are scarce. The following controls of NO_x have been reported by combustion modifications:

A. Boiler load reduction reduces NO_x effectively in gas- and oil-fired boilers and has been demonstrated in some coal-fired boilers but this has the disadvantage of de-rating the boiler.

B. Low excess air firing reduces NO_x, along with improving boiler performance. The limit of low excess air is governed by the tolerability limits of CO and hydrocarbons in all boilers and slagging in coal-fired boilers.

C. The combination of low excess air at low load further reduces NO_x.

D. The off-stoichiometric firing and two-stage firing accomplished by firing some burners "fuel rich" and others on air

alone or "air rich" reduce NO_x up to 72 per cent in gas-fired boilers and 50 - 60 per cent in oil- and coal-fired boilers.

E. The combination of two-stage combustion, low excess air and load reduction has reduced the levels of NO_x up to 90 per cent and has in most gas-fired boilers reduced NO_x to EPA limits of 0.2 lb NO_x/million BTU.

F. Reducing the peak combustion temperature by reducing air preheat reduces NO_x emissions, but at the penalty of reducing combustion efficiency.

G. Recirculating a portion of flue gases through the burners, or wind box reduces peak flame temperature, oxygen availability, and hence NO_x. The degree of NO_x reduced is directly dependent on the amount of flue gas recirculated to about 30% recirculation.

H. Other techniques reported effective in NO_x reduction are: steam or water injection in boilers; fuel switching; burner design and configuration changes; and burner spacing, location, and tilt.

I. The cost of combustion modifications varies with the fuel burned. The two-stage firing effected by overfire ports costs between \$0.15 - \$0.25 for gas- and coal-fired boilers where as complete equipment design change costs up to \$3.30/KW. The cost of flue gas recirculation for a 600 MW oil-, gas-, and coal-fired plant is \$1.65, \$2.65 and \$3.50 per kilowatt respectively.

INTRODUCTION

The Clean Air Act of 1967 (Public Law 90-148 as amended) and the Clean Air Amendment of 1970 (Public Law 91-604) assigned to the Environmental Protection Agency (EPA) the responsibility of developing emission standards for existing sources that are to be enforced by the states, and setting performance standards for new sources to be enforced by the EPA.

Under the provisions of these laws, the EPA published the "National Primary and Secondary Ambient Air Quality Standards" on April 30, 1971, in Federal Register, Volume 36, No. 84.

The National Primary and Secondary Ambient Air Quality Standards for nitrogen oxides is 100 micrograms per cubic meter (0.055 parts per million), annual arithmetic mean measured as nitrogen dioxide.

The EPA also published guidelines to the states for preparation, adoption and submittal of implementation plans for enforcement of National Ambient Air Quality Standards (Federal Register, Volume 36, No. 158, August 14, 1971) and the Performance Standards for New Stationary Sources (Federal Register, Volume 36, No. 247, December 23, 1971).

The nitrogen oxides emissions from existing and new fuel burning sources based on EPA published standards are as follows:

	Fuel Burning Equipment (Pounds per Million BTU)		
	Gas	Oil	Coal
New Sources	0.2	0.3	0.7
Existing Sources	0.2	0.2	
(Recommended in Implementation Plans)	(175 ppm)	(230 ppm)	

Both stationary as well as mobile sources contribute to NO_x concentrations in the atmosphere. The objective of this report is to identify the "State of the Art" of NO_x emission reduction from stationary sources through combustion modification. The first of the two part report deals with the control of NO_x from utility boilers. The second segment of the report deals with the control of NO_x from industrial, commercial and residential boilers.

SOURCES OF NO_x

Source estimates for nitrogen oxides emissions for the U. S. were developed by the National Air Pollution Control Administration[1] (now the Environmental Protection Agency). Shown in Table 1, these estimates of pollutant emission rates are based on emission factors developed by past stack sampling data, material balances and engineering appraisals of other sources similar to the listed sources.

Table 1[1] [2]

ESTIMATES OF NITROGEN OXIDE EMISSIONS IN THE UNITED STATES, BY SOURCE 1968

Source	NOx Emissions, Tons/Yr.
Mobile fuel combustion	
Motor vehicles	
Gasoline	6,600,000
Diesel	600,000
Aircraft	40,000
Railroad	400,000
Vessels	300,000
Non-highway users	300,000
Stationary fuel combustion	
Coal	4,000,000
Fuel oil	1,110,000
Natural gas	4,640,000
Wood	230,000
Solid waste	
Open burning	450,000
Conical incinerators	18,000
Municipal incinerators	19,000
On-site incinerators	69,000
Coal waste banks	190,000
Forest burning	1,200,000
Agricultural burning	280,000
Structural fires	23,000
Industrial processes	200,000
Total	20,669,000

Another independent source analysis has shown that stationary sources contribute 9,790,000 tons/yr. of NO_x, as shown in Figure 1 and Table 2.(1)

Table 2

ESTIMATES OF TONS OF NO_x IN THE UNITED STATES BY INSTALLATION, 1968

Type of Installation	NO_x (as NO_2) Tons/Yr.(1)
Electric utility	4,000,000
Industrial combustion	2,485,000
Pipelines and gas plants	2,280,000
Domestic and commercial	825,000
Non-combustion	200,000
U. S. Total	9,740,000

Electric utilities represent 19.4 per cent of the total nitrogen oxide emissions from all sources. A comparison between coal, oil and gas for these utilities is given in Table 3, which lists average emission factors on a uniform BTU basis for ready comparison.

Table 3(3)

AVERAGE NO_x EMISSIONS FROM UTILITY BOILERS

Fuel	Lb. $NO_x/10^9$ BTU Calculated as NO_2
Natural gas	373
Fuel oil	693
Coal	842

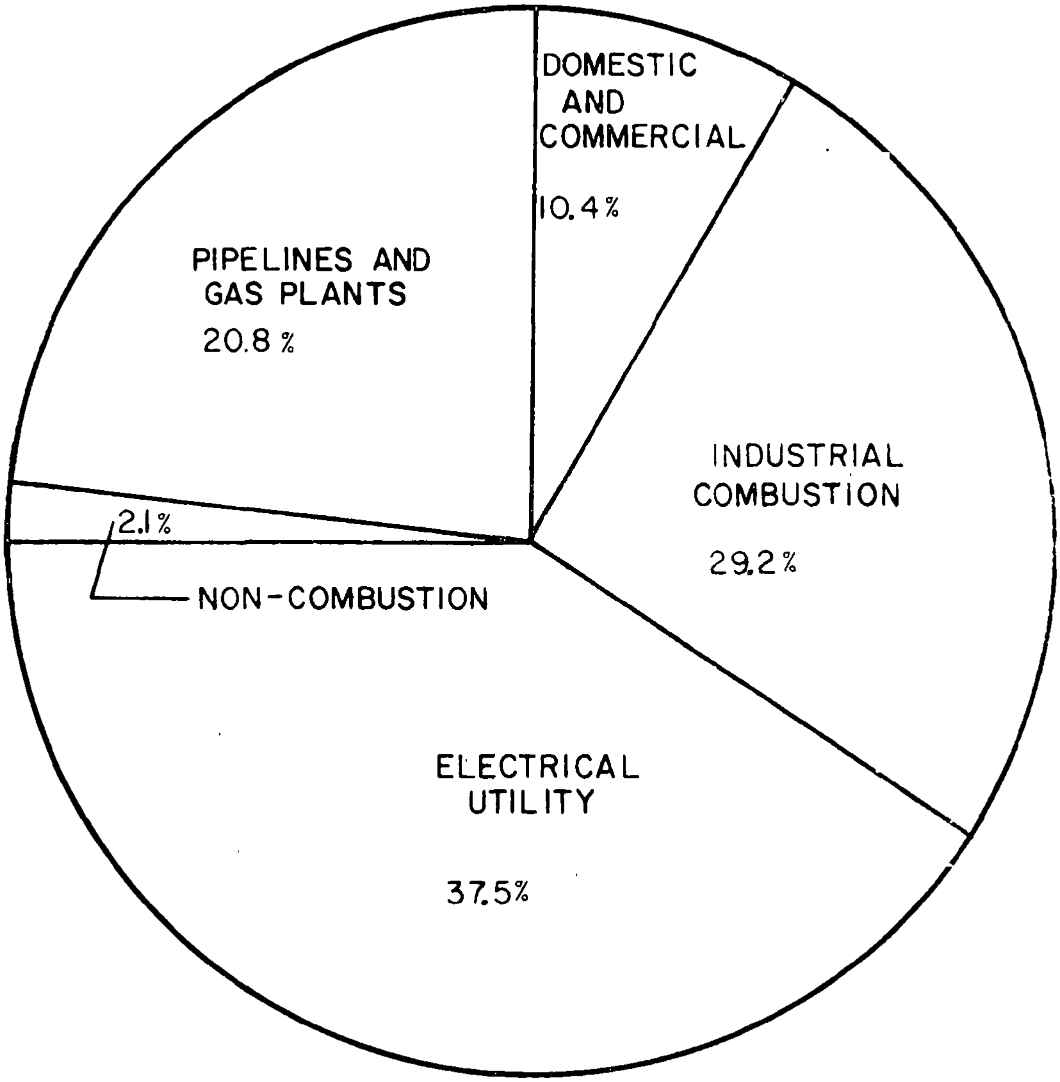


Figure 1. Total Estimated Oxides of Nitrogen Emitted From Stationary Installations in U. S. by Type of Use And Tonnage, 1968 (1)

Electric power generation by fuel for 1968 is shown in Table 4a:

Table 4a (4)

ELECTRIC POWER GENERATION BY FUEL - 1968

Fuel	Total KWH Produced, % *
Natural gas	27.8
Fuel oil	9.5
Coal	62.7
Total	100.0

* Nuclear power generation excluded.

Table 4b represents contributions of each type fuel to NO_x emissions, assuming a constant power generating efficiency (heat rate) in BTU/KWH.

Table 4b

CONTRIBUTIONS OF NO EMISSIONS BY

ELECTRIC UTILITIES FOR EACH FUEL

Fuel	Average NO_x Emissions Lb. $NO_x/10^9$ BTU Calculated as NO2	Portion of Total KWH Produced, %	Fraction of Electric Utility NO_x Emissions, %	Fraction of Total NO_x Emissions, %
Natural gas	373	27.8	17.5	3.6
Fuel oil	693	9.5	11.2	2.2
Coal	842	62.7	71.3	13.8
Total	-	100.0	100.0	19.6

In addition to man-made nitrogen oxides, there is a natural nitrogen cycle that generates 500,000,000 tons of NO_x per year. NO_x is removed from the atmosphere by hydrolysis to form nitric acid, which is then precipitated as nitrates in rainfall or dust. The residence time of NO_x in the atmosphere is only a few days.[(5)] NO_x is an essential part of the natural nitrogen cycle of organic growth, decomposition into the atmosphere and return to the soil as natural fertilizer.

The problem is one of local high concentrations since the urban areas of the U. S. average 40 to 50 parts per billion (ppb),[(6)] which is much greater than the natural background level of 1 ppb. This has led to approaches based on the total quantity of nitrogen oxides emitted by individual sources.

Los Angeles County, California, is an example. The electric power plants in Los Angeles County constitute the largest stationary source of nitrogen oxide emissions and are clustered in discrete "source areas" where high ambient levels of NO_x are recorded. The problem is approached on the basis of pounds per hour of nitrogen oxide emissions in order to lower the local concentrations. This results in increasingly stringent requirements on boilers as a direct function of size. The result is a much greater restriction for large boilers than small boilers.[(7)]

FORMATION OF NITROGEN OXIDES

A. Equilibrium and Kinetics

High temperature reaction of molecular nitrogen and oxygen present in the combustion air in accordance with the following chain-reaction mechanism forms most of the NO.

$$O_2 + O^{\cdot} + O.$$

$$O^{\cdot} + N_2 = NO + N^{\cdot}$$

$$N^{\cdot} + O_2 = NO + O.$$

In these high temperature processes the atmospheric nitrogen and oxygen perform the dominant role. The nitrogen in fuel has a secondary effect in NO_x formation.

NO is the major oxide of nitrogen formed in combustion processes. The other oxides of nitrogen, such as NO_2, N_2O_3, etc. are formed from the NO. Typically, from Figure 2 [8], the concentration of nitrogen oxides formed at 3,000°F with natural gas combustion at six per cent excess air is as follows:

NO:	1,000 ppm
NO_2:	1 ppm
N_2O_4:	1×10^{-13} ppm.

Spectroscopic studies of typical power plant gases also confirm that most of nitrogen oxides are in the form of NO.[9]

The formation of NO is temperature-time-concentration dependent. The reaction is controlled by a forward and reverse equilibrium constant, as follows:

$$N_2 + O_2 \rightleftharpoons 2NO$$

At the rate of reaction (r)

$$r_{net} = r_{forward} - r_{reverse}$$

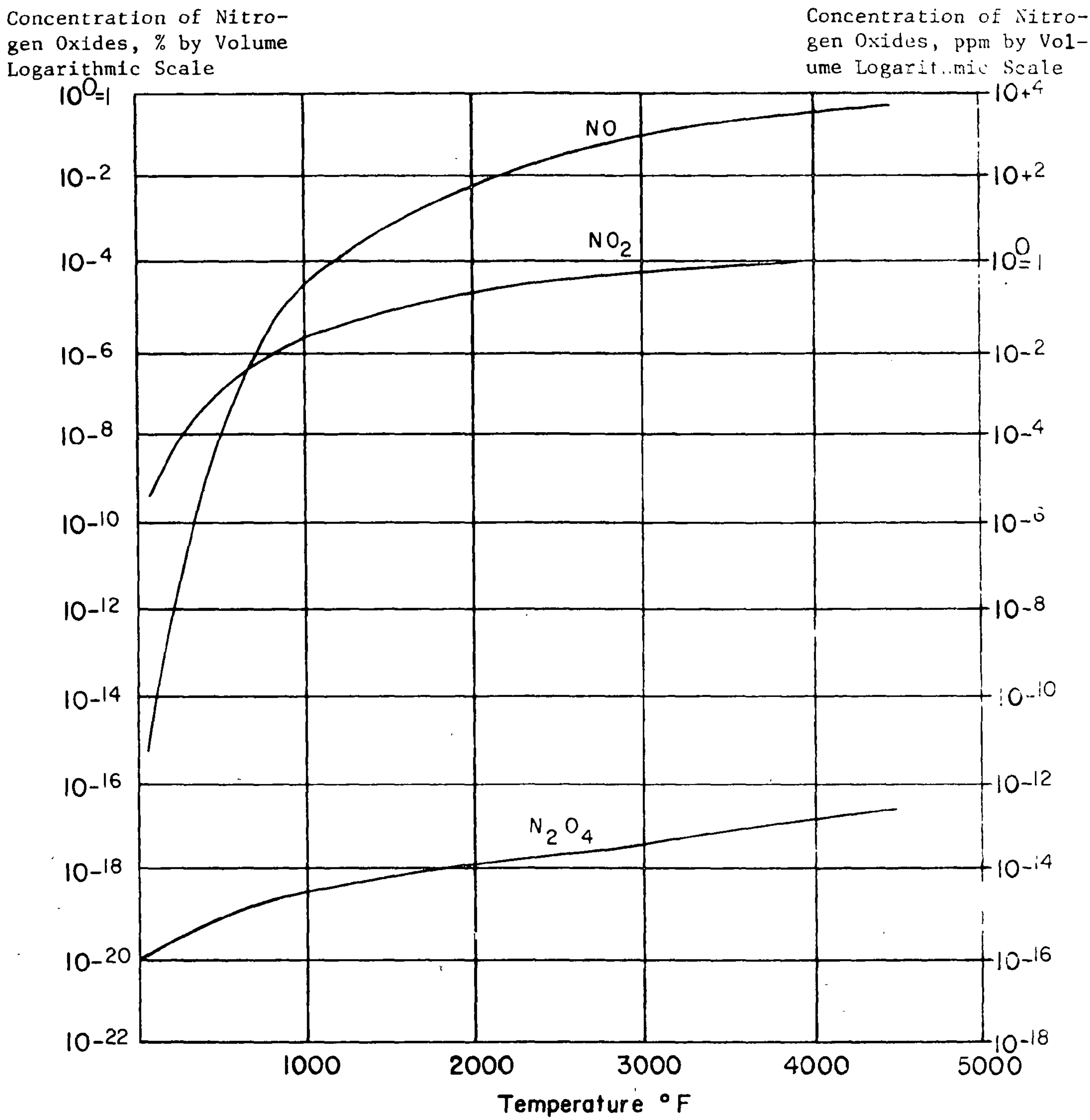


Figure 2. Nitrogen Oxide Equilibrium Concentrations. Natural Gas Burned with 6% Excess Air. (8)

The rate and extent of the reaction increases rapidly with increased temperature. The thermodynamic equilibrium constant of reaction is given by[3]

$$k = 21.9 \, e^{(-43,400/RT)}.$$

The equilibrium concentration of NO at flame temperature and stoichiometric mixture is 3,000 ppm.[10] The NO levels found in stacks are generally less than the equilibrium concentration corresponding to flame temperature, but higher than those corresponding to stack gas temperature. This results in the prediction that the NO concentration is determined by the time-temperature-composition history of gases as they move through the combustion system.

A typical expression of the NO formation for combustion of natural gas at stoichiometric mixture, showing time-temperature behavior, is shown in Figure 3.[11] Consequently, any technique that can lower the flame temperature or reduce the time the gases are at high temperatures will reduce the NO formation.

The concentration of various components influence equally NO equilibrium. The equilibrium concentration is expressed as

$$k = \frac{(NO)^2}{(N_2)\ (O_2)}$$

$$\text{and } r_{forward} = X_1\ (N_2)\ (O_2)^{1/2}$$

$$r_{reverse} = X_2\ (NO)^2\ (O_2)^{-1/2}$$

where (NO) (O_2) (N_2) are mole fractions of the respective components and X_1 and X_2 are temperature dependent constants.

This expression leads to the conclusion that lower oxygen and nitrogen concentration at high temperature will lead to lower NO

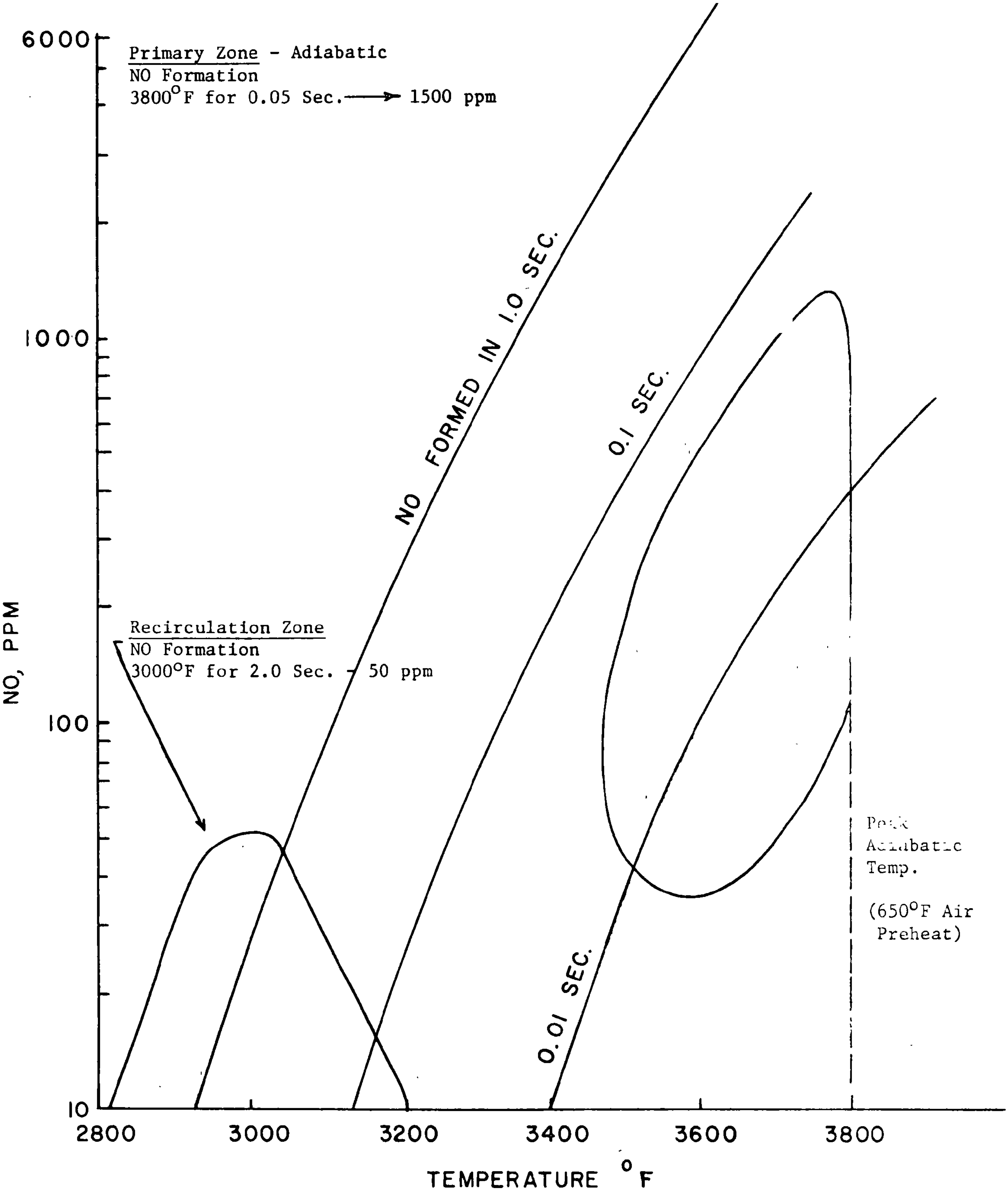


Figure 3. Kinetic (NO) Formation for Combustion of Natural Gas at Stoichiometric Mixture Ratio - Atmospheric Pressure.[11]

formation.

B. Factors Affecting Utility Boiler Emissions

The major factors affecting the formation of nitrogen oxides in combustion processes based on previous kinetic theory and in actual practice are, as follows:

1. Combustion temperature. NO formation equilibrium and kinetics are extremely dependent upon peak combustion temperatures, with higher peak temperatures favoring higher emissions.

2. Availability of combustion air. NO formation is dependent upon the availability of air for the "fixation" reaction.

3. Mixing of fuel, air and combustion products. Internal recirculation or "backmixing" of combustion products into the combustion zone dilutes the fuel and air, lowers the flame temperature and thereby reduces NO_x emissions. Distribution of the fuel and air so as to achieve most of the combustion under fuel-rich conditions also reduces NO_x emissions. Slow diffusion of the fuel and air streams can also accomplish this objective.

4. Heat release and removal. Low heat-release rates and high heat-removal rates reduce NO formation, because lower peak temperatures and shorter residence times at high temperatures are achieved.

5. Fuel type. On an equivalent heat-input basis, using modified combustion techniques, coal firing usually emits the most NO_x; oil emits less; and gas the least.

DISCUSSION

Combustion Modification for NO_x Emission Control

NO_x emissions from boilers can be reduced by two methods; combustion modification and flue gas treatment.

Combustion modification appears to be the quicker and possibly the more economical method to control NO_x emissions to desired levels. Combustion modification can be further divided into two major categories; combustion operating modification and combustion equipment design modification.

The major combustion operating modifications are:

1. Load reduction
2. Low excess air firing
3. Load reduction with low excess air
4. Two-stage combustion
5. Two-stage combustion with low excess air and/or load reduction.
6. Reduced preheat temperature
7. Flue gas recirculation
8. Water or steam injection
9. Fuel substitution

The major combustion equipment design modifications are:

1. Furnace design
2. Burner design/configuration
3. Burner tilt, location, spacing.

The details of the "State of the Art" of the above modifications and their effects are discussed individually for different fuels (coal, oil and gas) in the following section.

A. Combustion Operating Modification

1. Load Reduction

a. Effect of Boiler and Fuel Type

Operating most boilers at a reduced load lowers NO_x emissions. The reduction of the NO_x is dependent on the fuel being used in the boiler. Gas-fired boilers respond with greater NO_x reduction than oil- and coal-fired.[12]

Load reduction in various gas- and oil-fired units were tested by ESSO.[13] The results of NO_x reduction by load reduction for various types of boilers are summarized in Table 5. The same results are also shown in Figure 4 to illustrate the relative degree of NO_x control in oil- and gas-fired boilers.

Table 5

NO_x REDUCTION BY LOAD REDUCTION

Boiler Type and Size	Operating Load, MW	Load Reduction,%	NO_x Emission, ppm	NO_x Reduction,%	Reference
180 MW Front Wall,	180	0	390	0	(13)
Gas-Fired	120	33	230	41	(13)
	70	61	116	70	(13)
80 MW Front Wall,	82	0	497	0	(13)
Gas-Fired	50	39	240	52	(13)
	20	76	90	82	(13)
480 MW Horizontally	450	0	236	0	(13)
Opposed, Gas-Fired	220	51	166	30	(13)
600 MW Horizontally	560	0	560	0	(13)
Opposed, Gas-Fired	410	27	335	40	(13)
	335	42	253	55	(13)
220 MW All Wall,	220	0	675	0	(13)
Gas-Fired	190	14	550*	19	(13)
	125	43	313	54	(13)
180 MW Front Wall,	180	0	367	0	(13)
Oil-Fired	120	33	322	12	(13)
	80	56	266	28	(13)
80 MW Front Wall,	82	0	580	0	(13)
Oil-Fired	50	39	361	38	(13)
	21	74	258	54	(13)
350 MW Horizontally	350	0	457*	0	(13)
Opposed, Oil-Fired	154	56	264*	42	(13)
480 MW Horizontally	455	0	246	0	(13)
Opposed, Oil-Fired	365	20	219	11	(13)

* Estimated values reported by ESSO[13] for comparison.

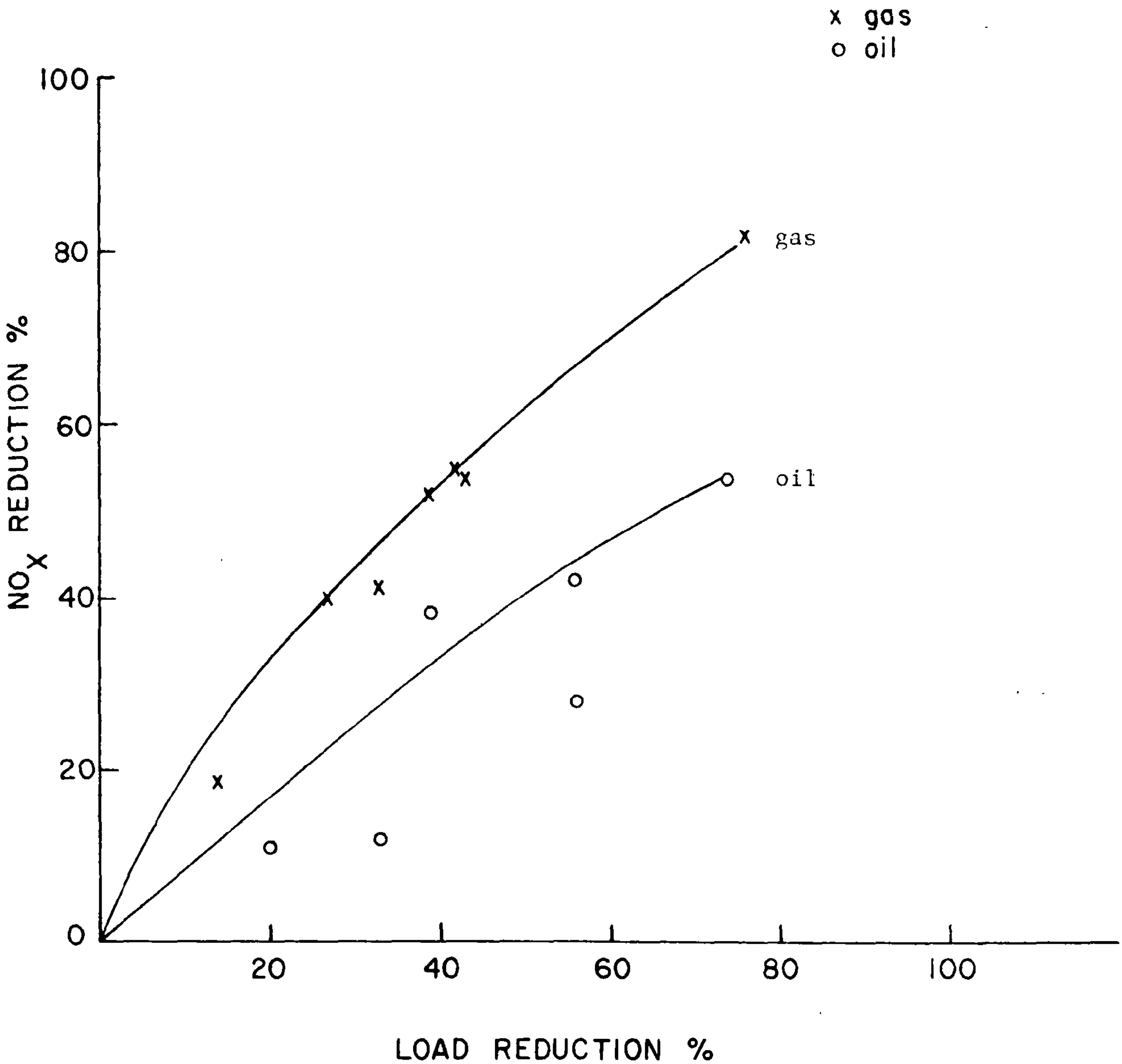


Figure 4. NO_x reduction at reduced loads - oil- and gas-fired boilers

In general, the load reduction in coal-fired boilers has shown a decrease in NO_x emissions. The Combustion Engineering work [(12)] reports 25 per cent decrease of NO emission with a 25 per cent load reduction. The results of Cuff and Gerstle (1967) work on coal-fired boilers as summarized in the literature [(14) (15)] is presented in Table 6.

Table 6

NITROGEN OXIDE EMISSIONS (ppm NO_x) FROM COAL-FIRED BOILERS [(14) (15)]

Type of Firing	Full Load, Mean of 3 or 4 Tests at Each Unit		Partial Load, Mean of 2 Tests at Each Unit	
	Before Fly-ash Collector	After Fly-ash Collector	Before Fly-ash Collector	After Fly-ash Collector
Vertical	221	310	161	171
Corner	526	413	393	325
Front Wall	416	606	500	453
Horizontally Opposed	393	350	395	328
Spreader Stoker	431	437	430	390
Cyclone	1,204	1,160	742	784

b. Load Reduction Effects and Cost

Boiler load reduction reduces fuel input and, hence, other pollutants, such as CO, SO_2 and hydrocarbons, are also reduced relative to fuel reduction.

There are no capital costs involved in load reduction; however, it is an undesirable option for utilities to reduce boiler capacity. The load reduction increases the boiler efficiency but decreases turbine efficiency with a net result in decrease in overall efficiency. The loss of capacity has to be compensated by starting other power generating equipment which may be idle, or by increasing the capacity by installation of additional equipment.

2. Low Excess Air (LEA) Firing

The amount of air relative to fuel fed to the combustion process had an effect on the level of nitrogen oxides emitted. The rate equation for NO_x formation is written as follows: (16)

$$NO_x \text{ Formation Rate} = K \, P_{O_2}{}^{1/2} \; P_{N_2}$$

Other factors being equal, an increase in oxygen concentration (excess O_2) will increase both the rate of formation and its equilibrium concentration.

The effects of low excess air firing on oil- and gas-fired boilers are well documented, but the effect on coal has been limited to laboratory scale and few full scale tests. "Low excess air firing" is a relative term, because of the boiler-to-boiler variation in the normal level of excess air, as established by boiler operators, depending on fuel type, boiler design and operating conditions.

The effects of low excess air by fuel types reported in the literature and practice are described in the following sections.

a. Low Excess Air Gas-Fired Boilers

Gaseous fuels are burned at a normal 10-15 per cent excess air and have a resultant NO_x emissions range from 200 to 1,500 ppm, depending on type and size of the boiler. The lower limit of excess air is determined by the need to limit the emissions of unburned combustibles (CO, hydrocarbons) to control operating problems. The ease of fuel and air mixing in gas-fired boilers facilitates lowering the excess air to very near the stoichiometric amounts with proper instrumentation.

The lower excess air conversion is achieved by practically no major modification to the boiler; however, an instrument control system to give a precise method for proportioning fuel and air is required to provide safe and efficient operation.

Effect of LEA on Gas-Fired Boilers

LEA in gas-fired boilers has shown to produce a 15-23 per cent decrease in NO_x in tests run by ESSO.[13]

In the Pacific Gas and Electric Moss Landing 750 MW boilers, the lowering of excess air from ten to five per cent reduced the NO_x from 1,475 ppm to 1,000 ppm, a reduction of 33 per cent.[17]

With proper technique and instrumentation, LEA does not result in any boiler problem or other pollutant increase, but improper control can result in higher CO emissions and possible boiler vibration. A detailed list of tests results is given in Table 7 to show the reduction in NO_x by low excess air firing in gas-fired boilers.

Table 7

NO_x REDUCTION BY LOW EXCESS AIR– GAS-FIRED BOILERS

Boiler Type and Size	NO_x Emission ppm Normal Excess Air (3% O_2 Dry Basis)	Excess Air % O_2	NO_x Emission ppm Low Excess Air (3% O_2 Dry Basis)	Excess Air % O_2	NO_x Reduction,%	Reference
180 MW, Front Wall	390	2.75	332	1.1	15	(13)
80 MW, Front Wall	497	4.18	421	2.59	15	(13)
350 MW, Horizontally Opposed	946	2.6	783	1.6	21	(13)
450 MW, Horizontally Opposed	236	4.0	198	3.0	16	(13)
600 MW, Horizontally Opposed	560	2.3	478	1.2	15	(13)
220 MW, All Wall	675	3.3	519	1.7	23	(13)
750 MW, Front Wall	1,475	-	1,000	-	23	(17)
250 MW, Tangential	375	3.9	250	.6	37	(18)

Cost and Cost Effectiveness of LEA on Gas-Fired Boilers

The costs for conversion to low excess air firing are estimated on the basis that instruments would be required for precise combustion control. It is assumed that 1,000 MW plants would require no capital charges, 10 per cent of 750 MW plants, 25 per cent of 500 MW plants, 50 per cent of 250 MW plants and 90 per cent of 120 MW plants will require capital investment for modification to improve fuel distribution and rest would be converted at no cost.[3]

It is also assumed that low excess air would result in a one per cent improvement in efficiency and, hence, reduce the annual operating and fuel cost of the boiler. A detailed breakdown of costs[3] is given in Table 8.

(3)

Table 8

COST OF LEA CONVERSION (GAS-FIRED BOILERS)

Plant Size	Capital Cost	Annual Capital Costs	Annual Maintenance Costs	Other Operating Costs*	Total Annual Costs*
1,000 MW	$120,000	$17,000	$21,000	($102,000)	($95,000)
750 MW	$119,000	$15,300	$18,900	($120,000)	($68,000)
500 MW	$106,000	$12,500	$15,400	($ 62,900)	($35,000)
250 MW	$ 82,000	$ 8,600	$10,800	($ 23,400)	($ 4,000)
120 MW	$ 63,000	$ 6,200	$ 7,600	($ 3,800)	$10,000

* Figures in parentheses indicate operating savings.

Where, annual capital cost is calculated as 14% of fixed cost. This covers depreciation interest and other fixed cost.

Annual maintenance cost is the total cost of maintenance supplies and overhead. The maintenance is estimated at 10% of fixed cost for instruments, 5% of fixed cost for modifications having moving parts and 1% of fixed cost for modifications having no moving parts. Supplies are at 15% of maintenance and overhead is 50% of maintenance plus supplies.

Other operating cost is the cost due to increase or decrease in the operating efficiency of the boiler.

Total annual costs are the additions of annual capital costs, annual maintenance cost and other operating costs.

b. Low Excess Air, Oil-Fired Boilers

Low excess air boiler operation in oil-fired units was developed in the United Kingdom in the 1950's to overcome undesirable operating conditions such as low temperature corrosion and air heater plugging. It is now standard practice in oil-fired boilers to operate at low excess air, generally below five per cent. Previously the normal excess air in oil-fired units was 13 to 20 per cent.[(19) (20)]

Low excess air in oil-fired units is achieved by re-adjusting the air flow to burners without major modification to the boiler itself. NO_x reduction of 36 per cent in a horizontal oil-fired boiler and 28 per cent in a tangential fired unit were obtained as flue gas oxygen (excess air) was reduced from 3.5 - 4 per cent to 2 per cent. A further reduction of excess air (0.4 - 0.6 per cent oxygen) reduced NO_x up to 67 per cent. The results of NO_x reduction[(21) (22)] are documented in Figures 5 and 6.

The results of NO_x control in oil-fired boilers is tabulated in Table 9.

Figure 5: Effect of Excess Air on NO_x Emission from Oil Fired Boilers (21)

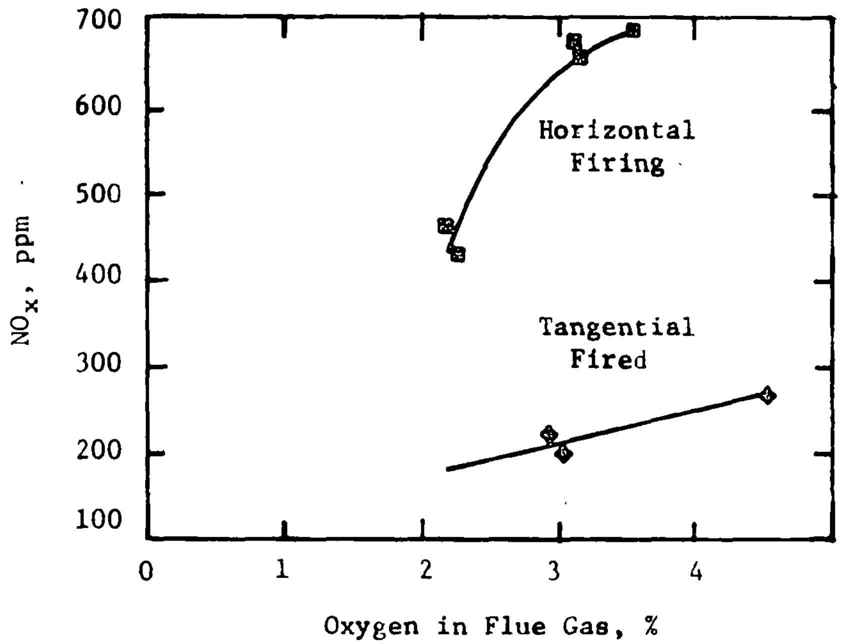


Figure 6: NO_x Emissions from Oil Fired Boilers at Low Excess Air (22)

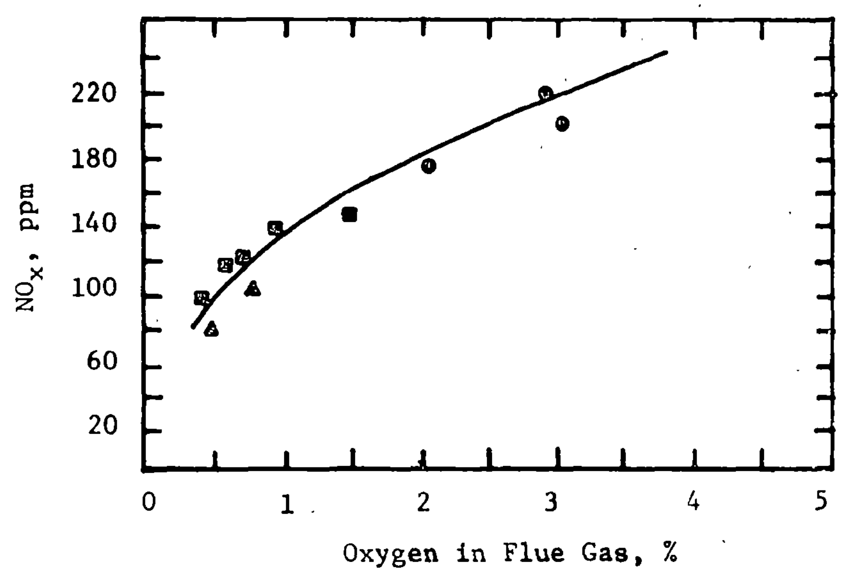


Table 9

NO_x CONTROL BY LOW EXCESS AIR-,OIL-FIRED BOILERS

Boiler Type and Size	NO_x ppm (Normal Air) (3% O_2 Dry Basis)	Excess Air O_2%	NO_x ppm (LEA) (3% O_2 Dry Basis)	Excess Air O_2%	NO_x Reduction,%	Reference
180 MW, Front Wall	367	3.9	238	1.7	35	(13)
80 MW, Front Wall	580	3.65	470	2.2	19	(13)
350 MW, Horizontally Opposed	457	*3.0	442	1.4	3	(13)
480 MW, Horizontally Opposed	246	4.7	223	3.6	9	(13)
220 MW, All Wall	291	3.9	235	2.6	23	(13)
180 MW, Front Wall	621	2.5	452	0.5	27	(19)

* Estimated

A study by Los Angeles Power and Light [19] shows that the average heat rate was reduced by 60 BTU/KWH. The control of low excess air in oil-fired units is achieved by instruments to detect unburned combustible material; however, visible smoke is a good indicator of the limit of low excess air.

Low excess air firing in oil-fired units has shown an increase in ash generation, but a decrease in corrosion due to a possible reduction in the formation of SO_3. [3]

<u>Cost and Cost Effectiveness of Low Excess Air in Oil-Fired Boilers</u>

Low excess air operation in oil-fired units, as in the gas-fired units, is achieved without incurring investment costs for alterations or redesign, especially in larger units. In preparation of cost estimates in Table 10, [3] it is assumed that 10 per cent of 750 MW, 25 per cent of 500 MW, 50 per cent of 250 MW and 90 per cent of 120 MW plants will require alteration in design to achieve low excess air operation, and the remainder could be converted at no cost. The required cost involves modifying the burner windbox by addition of division plates and isolating dampers to the air to each burner for individual control. Also, a sophisticated combustion control instrument system would be required to provide safe operation at low excess air.

As pointed out by Los Angeles Power and Light [19] and other sources, the low excess air provides a fuel saving and corrosion and maintenance reduction. A net two per cent increase in efficiency is assumed for cost estimates.

The fuel savings are calculated by net heat rate reduction in BTU/KWH. Los Angeles Power and Light showed a heat rate reduction by low excess air of 60 BTU/KWH in test data. [19] The fuel savings in Los Angeles Power and Light were calculated as:

Fuel dollars saved per year =

$$\frac{\text{Dollars}}{\text{Million BTU}} \times \begin{matrix}\text{Heat Rate Reduc-}\\ \text{tion BTU/KWH}\end{matrix} \times \begin{matrix}\text{Net Generator}\\ \text{Load, KW}\end{matrix} \times$$

$$(\text{Operating Hours}) \times \begin{pmatrix}\text{Plant}\\ \text{Load Factor}\end{pmatrix} \times \begin{pmatrix}\text{Oil Burning}\\ \text{Time Factor}\end{pmatrix}$$

where dollars per million BTU is the cost of fuel; heat rate reduction is calculated experimentally before and after low excess air; net generator load, operating hours and plant loading factors are regular plant operating parameters; and oil burning time factor is the fraction of time the boiler is on oil-firing if the boiler is designed for multi-fuel burning. These calculations produced a new fuel savings of $9,676 for a 173 MW plant burning 0.335 dollars per million BTU oil, 42 per cent of the 8,280 operating hours at 0.8 load factor for 60 BTU/KWH fuel rate savings.

More generalized savings from oil-fired boilers are given in Table 10, based on two per cent increase in the efficiency of the boiler. [3]

Table 10

LOW EXCESS AIR MODIFICATION COSTS: OIL-FIRED BOILERS [3]

Boiler Size	Capital Cost	Annual Capital Charges	Annual Maintenance Cost	Other Operation Costs *	Total Cost Per Year *
1,000	$120,000	$17,000	$21,000	($335,000)	($297,000)
750	$119,000	$15,300	$18,900	($260,000)	($226,000)
500	$106,000	$12,500	$15,500	($150,000)	($132,000)
250	$ 82,000	$ 8,700	$10,800	($ 52,500)	($ 33,000)

* Figure in paranthesis indicates operating savings.

c. Low Excess Air, Coal-Fired Boilers

Low excess air in coal-fired installations has not been commercially applied or the application has not been documented. Coal, of all the fuels, requires the highest excess air for good combustion generally, 20 to 50 per cent excess air. Tests on a laboratory unit with a single burner [23] have indicated that low excess air lowers NO_x in pulverized coal combustion the same as in oil and gas combustion. The laboratory study showed a 62 per cent NO_x reduction by lowering excess air from 22 to five per cent.

It appears that low excess air application in coal combustion would be more difficult than in oil- and gas-fired boilers. Furnace slagging is also increased with decrease in excess air, thus causing operating problems and increased maintenance. Regulation of uniform coal streams to burners from a single pulverizer is difficult.

Introducing low excess air to each burner and maintaining the same combustion conditions are even greater problems.

Laboratory scale experiments in coal combustion with lower excess air showing an NO_x decrease are documented in Figure 7.

The data obtained by Bienstock et al. [23] from a laboratory furnace show the following NO_x reduction by lower excess air.

Excess Air, %	NO_x, ppm	Carbon in Ash, %
0	105	42.3
5	210	13.8
22	550	2.0

The above data also indicate that, as the NO_x was lowered by reducing excess air, the combustion efficiency was adversely affected. The heat transfer in larger boilers will probably be similarly affected.

Further experiments with low excess air firing were performed on a four-burner 500 lb/hr. pulverized coal-fired boiler by Bienstock et al. [24] The results show a decrease of NO_x from 570-580 ppm at a 25 per cent excess air, a 70 per cent decrease. The combustion efficiency dropped from 99.5 per cent to 92.3 per cent under the same conditions. The sulfur oxides emission is lowered by low excess air, and the sulfur in ash increased correspondingly. Details of these

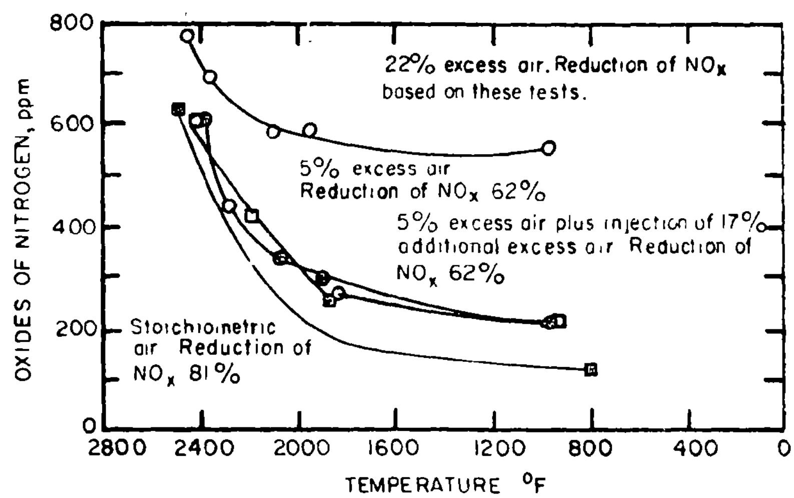


Figure 7: Effect of Lowering Excess Air and Two-Stage Combustion on NO_x Emission from Coal Combustion.(41)

results are outlined in Table 11. [24]

The short-term full-scale experiments by ESSO [13] with low excess air in a 175 MW front wall, coal-fired power plant reduced NO_x emissions by 14 per cent, and in a 300 MW tangential coal-fired plant by less than 10 per cent. In recent ESSO tests, NO reductions of up to 40 per cent have been achieved. However, the long-term effect on corrosion and tube corrosion under these test conditions is still being investigated.[39]

Table 11

500 LB/HR. PULVERIZED COAL-FIRED COMBUSTOR

Excess Air,%	NO_x, ppm	Carbon Efficiency, %	SO_2 Furnace Outlet, ppm	S in Ash % by Wgt.
25.7	571	99.5	-	-
25.0	583	99.5	-	-
23.5	-	99.3	-	-
21.4	567	98.2	1,415	7
20.7	-	98.4	1,449	6
20.1	527	98.4	1,459	3
19.4	570	99.2	-	-
16.2	481	98.4	-	-
10.8	412	96.6	1,520	5
9.1	376	96.3	-	-
8.5	383	96.7	-	-
6.9	338	96.7	-	-
5.4	382	95.7	1,651	1
4.8	329	95.7	1,657	4
4.3	-	96.7	-	-
3.8	303	96.2	1,785	4
2.4	-	92.3	-	-
1.4	174	92.3	-	-

Cost and Cost Effectiveness of LEA in Coal-Fired Boilers

The cost incurred in applying low excess air in coal-fired boilers will result from addition of division plates and isolation dampers to control air in each burner. In addition, some means of insuring uniform distribution of the coal to all burners served by the same pulverizer will be required. It is assumed that a 50 per cent increase in cost over the oil- and gas-fired units will cover the additional costs required by coal-fired units.[3] The savings in efficiency in the coal-fired units at low excess air are estimated at 1.5 per cent.[3] The results of cost and cost effectiveness for various size plants are estimated, as follows:[3]

Table 12

LEA MODIFICATION COSTS, COAL-FIRED BOILERS[3]

Boiler Size, MW	Total * Capital Cost	Annual Capital Cost	Annual Maintenance Cost	Other Annual Costs	Total Annual Costs
1,000	$480,000	$67,000	$52,000	($198,000)	($79,000)
750	$385,000	$54,000	$42,000	($155,000)	($59,000)
500	$275,000	$38,500	$30,000	($ 95,500)	($27,000)
250	$159,000	$17,500	$17,500	($ 39,500)	0
120	$ 88,000	$12,300	$10;000	($ 11,300)	$11,000

* Also assumed that all the coal-fired boilers require investment for modification.

3. Load Reduction with Low Excess Air

Load reduction in low excess air combinations tested in gas, oil and coal units resulted in lower NO_x emissions, than either alone. The techniques and costs involved with these systems are the net combined effects of the two modifications; individually, however, the results obtained in NO_x reductions are not additive. The results are summarized, as follows:

Table 13

NO_x REDUCTION THROUGH LOAD REDUCTION AND LOW EXCESS AIR (13)

Boiler Type and Size	Reduced Operating Load (MW)	NO_x Without Controls, ppm (3% O_2 Dry Basis)	NO_x @ Reduced Load & Low Excess Air, ppm (3% O_2 Dry Basis)	% of Reduction (Overall)
180 MW, Front Wall Gas-Fired	120	390	188	52
	70	390	108	72
80 MW, Front Wall Gas-Fired	50	497	170*	65*
480 MW, Horizontally Opposed	220	236	120	49
600 MW, Horizontally Opposed	410	560	271	51
	325	560	185	67
180 MW, Front Wall Oil-Fired	120	367	241	33
	80	367	190	48
80 MW, Front Wall Oil-Fired	50	580	318	45
	21	580	185	68
350 MW, Horizontally Opposed, Oil-Fired	150	457*	228	50
480 MW, Horizontally Opposed	365	246	183	25
	228	246	163	34

* Estimated Values.

4. Two-Stage Combustion

Two-stage combustion was developed by Southern California Edison and Babcock and Wilcox Company in a cooperative effort. The application of delayed mixing of air and fuel and operation of burners with less than the normal amount of combustion air led to a reduction in NO_x emissions. The application led to investigation of burners operating with about 95 per cent of the stoichiometric air admitted through the burner throat and the remainder of the air to complete combustion through ports (referred to as NO ports) located above the burners.

Additional work by Southern California Edison and KVB engineers[25] produced the technique referred to as "Off-Stoichiometric Firing." This technique involves firing some burners "fuel rich" and others "air rich" or in staggered configuration with some burners supplying air only.

The off-stoichiometric firing and NO ports for two-stage combustion have been proven commercially successful in oil- and gas-fired units and have been demonstrated in laboratory and full-scale in coal-fired units.

The effect of two-stage combustion on NO_x emissions may be explained by a combination of following factors:[3] (a) there is a lack of oxygen available for NO_x formation in the first-stage operated under sub-stoichiometric air conditions; (b) the flame temperature may be lower in the first-stage than in normal combustion; (c) to the degree that the heat is removed between stages, the maximum flame temperature in the second-stage is lower than for single-stage combustion; (d) the effective residence time available for NO_x formation at the peak temperature reached in the second-stage may be reduced.

a. Two-Stage Combustion: Gas-Fired Boilers

The reduction in NO_x in two-stage combustion is achieved by adding NO ports to admit secondary air or by operating the burners "air rich" and "fuel rich" in a staggered manner. The optimum arrangement is achieved by experimenting with each boiler. As a general rule, the boilers with more than four horizontal rows of burners are easy to control by air alone in top row or rows and fuel-air in other rows of burners. Several experiments were conducted by utilities and their consultants in reduction of NO_x by two-stage combustion. The stagger arrangements and results are listed under "Effects of Two-Stage Combustion: Gas-Fired Boilers" in the following section.

Effects of Two-Stage Combustion: Gas-Fired Boilers

To facilitate discussion of off-stoichiometric firing, a term, "Equivalence Ratio," defined as the ratio of stoichiometric air/fuel to actual air/fuel, is used. Operation of top row/rows of burners on air alone represents two-stage combustion, whereas zig-zag patterns of "air alone" burners or "air rich," "fuel rich" combination firing represents off-stoichiometric combustion. Sometimes the pattern has little effect on NO emission; however, in any given pattern, a boiler may be limited by high CO. The optimum operation of off-stoichiometric combustion is obtained by operating in a pattern which produces the least

NO at no significant increase in CO (generally below 50 ppm). The result of KVB-Southern California Edison and ESSO and other tests on gas-fired boilers are as follows:

(i) Huntington Beach Unit 2: In a 220 MW wall-fired unit with four horizontal rows of six burners each for a total of 24 burners, the first series of tests were run operating some top row burners on air alone and the rest "fuel rich" to simulate two-stage combustion. With four burners on air alone (17 per cent air by-pass), and the remaining burners operating at an Equivalence Ratio of 1.2, the NO concentration decreased from 470 ppm to 230 ppm. With six burners on air alone (25 per cent air by-pass), and "fuel rich" burners at an Equivalence Ratio of 1.33, the NO concentration decreased to 180 ppm.[11]

The same off-stoichiometric conditions have been successfully tried and incorporated at Mandalay units.[26]

The burner configurations in the Huntington Beach units are as follows:

0	A	0	A	0	A		
0	0	0	0	0	0	A:	Air only
A	0	A	0	A	0	0:	Fuel rich
0	0	0	0	0	0		

and in Mandalay units as follows:

0	A	0	A	0	A
A	0	A	0	A	0
0	0	0	0	0	0
0	0	0	0	0	0

(ii) In a second test on a boiler similar to the above, some burners were operated "air rich" and the remaining "fuel rich." The air and fuel "richness" were achieved by terminating fuel in every other spud on selected burners ("air rich") and increasing the fuel flow on the remaining burners ("fuel rich"). In the tests with six and twelve "air rich" burners respectively, the NO_x was reduced from the original 470 ppm to approximately 250 and 180 ppm, respectively. The CO and unburned hydrocrabons were lower than in test (i) because of the more uniform injection flow across the entire boiler face.[11] The results of tests (i) and (ii) are both plotted in Figure 8.

(iii) In tests on four 480 MW front wall fired units, "NO port" openings permitted reduction of NO_x from 700-750 to 390-400 ppm. Further reduction of NO_x to 200 ppm (reduction of 70 per cent) was obtained by applying off-stoichiometric firing techniques by operating "fuel" and "air rich" burners in conjunction with open "NO ports." In two of the four units

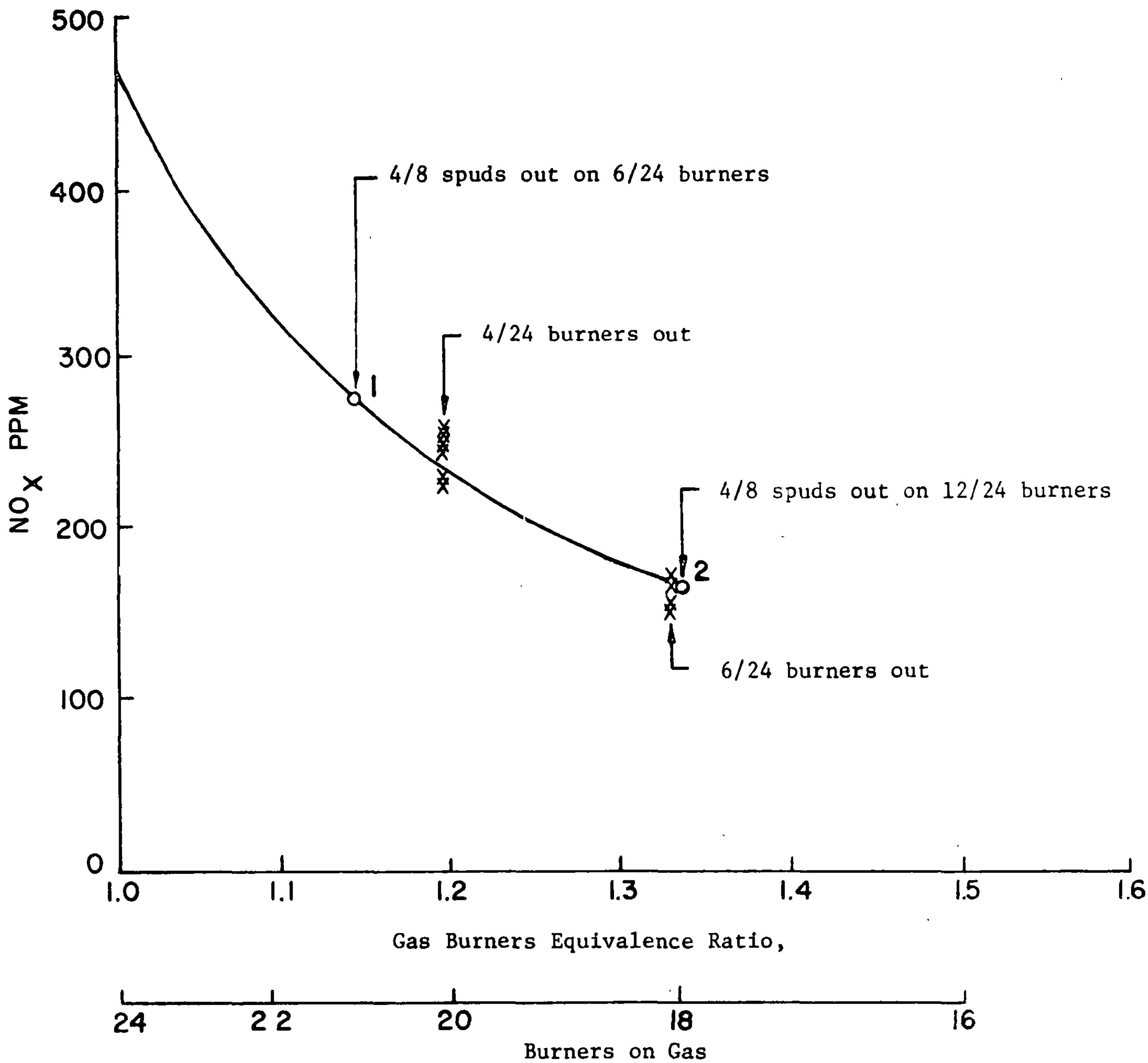


Figure 8. NO, Concentration Obtained for Off-Stoichiometric Burner Operation on a 220 MW Power Plant.[11]

tested, division wall failures due to over-heating were experienced. Although the contribution of off-stoichiometric firing to the failure was inconclusive, this method of firing was temporarily suspended.[26]

(iv) A 180 MW front wall fired boiler with four rows of four burners each was tested for NO_x reduction with staged firing. At normal load and excess air the emissions of NO_x were reduced from the original 390 ppm without staged firing to 190 ppm with staged firing.[13] The pattern of staged firing was as follows:

0	0	0	0		
A	0	0	A	A:	Air only
0	A	A	0	0:	Fuel rich
0	0	0	0		

Hydrocarbon content showed no increase, and CO measurements were inconclusive at full load operation.

(v) In an 80 MW front wall fired boiler with two rows of six burners each, the NO_x reduced from a normal 500 ppm to 376 ppm in staged firing.[13] The burner arrangement for "fuel rich" and air only was as follows:

0	A	0	0	A	0	A:	Air only
0	0	0	0	0	0	0:	Fuel rich

Other pollutants at staged firing conditions showed no significant increase.[13] The authors predicted that the following alternate burner patterns could further reduce NO :

0 A 0 0 A 0	or	0 A 0 A 0 A
0 0 A A 0 0		A 0 A 0 A 0

However, no data were obtained on these patterns.

(vi) A 350 MW horizontally opposed unit equipped with "NO ports" was tested under normal condition with "NO ports" closed, two-stage combustion with "NO ports" open and off-stoichiometric combustion with "NO ports" open.[13] During the series of tests, the NO_x emissions were reduced from 950 ppm at normal condition to 515 ppm with "NO ports" open and to 275 ppm with "NO ports" open in combination with off-stoichiometric firing.[13] The off-stoichiometric conditions were achieved by changing the burner firing configuration, as follows:

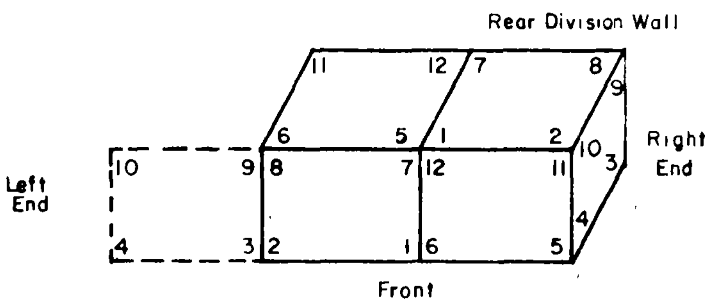
0	0	0		A	A	A
0	0	0		0	0	0
0	0	0	to	0	0	0
0	0	0		0	0	0
0	0	0		0	0	0
0	0	0		0	0	0

(vii) In a 480 MW horizontally opposed boiler, the boiler is permanently in the following staged configuration:[13]

A	A	A	A	(front and rear furnace faces)
0	0	0	0	
0	0	0	0	
0	0	0	0	

In addition, it also has eight "NO ports" for additional effect of two-stage combustion. The initial NO_x levels were not known. The NO_x emissions at off-stoichiometric conditions are 236 ppm with the "NO ports" open. The CO levels did not change appreciably under the changed conditions.

(viii) The 220 MW All wall boiler has the following con-[13] figuration of burners.



At full load and all burners under normal firing, the NO_x emissions were 675 ppm. With staged firing of 18 burners, "fuel rich," and six burners, air only (Nos. 9, 10, 10), NO_x emissions were reduced to 286 ppm. Converting the firing to opposed wall and providing air alone to eight burners (3, 4, 9, 10), NO_x emission were 359 ppm. The boiler was capable of generating a maximum load of 190 MW. CO measurements were always less than 100 ppm and hydrocarbons less than one ppm. In two further experiments to simulate boilers with corner firing, burners 1, 3, 5, 7, 9, 11 were operated with air only and with no air or fuel. In both cases, the maximum power output lowered to 125 MW. The NO_x emissions were 130 ppm in cases where burners were on air alone and 350 ppm when the corner burners had no air or fuel.

(ix) In 1959, two 175 MW front wall fired Southern California Edison units at El Segundo were converted to two-stage combustion by the addition of "NO ports." The boilers with 16 burners were supplemented with four auxiliary air ports ("NO ports"). The NO_x emissions were reduced from 520 ppm normal to 305 ppm in two-stage combustion. The units have since been operating also with off-stoichiometric firing. No results are available from this operation.[28]

(x) In the tests run by Combustion Engineering on a 250 MW tangentially fired unit, staged combustion by overfire simulation (operating three rows of burners "fuel rich" and top row on air alone) reduced the NO_x emissions from 330 ppm to 90 ppm at full load.[18]

Overall Summary of Two-Stage Combustion on Gas-Fired Boilers

Several tests reported in the preceding section and others reported in literature have resulted in a reduction of NO_x from gas-fired boilers. The reduction of NO_x from the base-line levels with no controls have ranged from 25 to 72 per cent reduction. The results in tests discussed above and others reported are summarized in the following table.

Table 14

TWO-STAGE COMBUSTION, GAS-FIRED BOILERS

Boiler Type and Size	NO_x Emissions (No Control) (3% O_2 Basis)	NO_x Emissions Two-Stage Combustion or "NO Ports" Alone (3% O_2 Basis)	NO_x Emissions Two-Stage Combustion and Off-Stoichiometric Firing (3% O_2 Basis)	Total NO_x Reduction %	References
220 MW Front Wall	470		230 (17% air by-pass)	51	(26)
			180 (25% air by-pass)	62	(26)
	470	-	250 (burners air-rich)	47	(26)
			180 (12 burners air-rich)	62	(26)
480 MW Front Wall Fired	700-750	390-400	200	72	(11)
180 MW Front Wall	390	-	190	51	(13)
80 MW Front Wall	500	-	376	25	(13)
300 MW Horizontally Opposed	950	515	275	71	(13)
480 MW Horizontally Opposed	-	236*	145	38	(13)
220 MW All Wall	675	-	286	58	(13)
175 MW Front Wall	520	-	305	31	(28)
250 MW Tangential	330	-	90	73	(18)
175 MW B&W	450	330	245	45	(26)
	450	330	300	33	(26)

Table 14

TWO-STAGE COMBUSTION, GAS-FIRED BOILERS

(Continued)

Boiler Type and Size	NO_x Emissions (No Control)	NO_x Emissions Two-Stage Combustion or "NO Ports" Alone	NO_x Emissions Two-Stage Combustion and Off-Stoichiometric Firing	Total NO_x Reduction %	References
78 MW Tangential	140	70	-	50	(12)
160 MW Tangential	280	120	-	57	(12)
230 MW Tangential	200	90	-	55	(12)
418 MW Tangential	250	140	-	44	(12)

* The 480 MW unit is permanently equipped with off-stoichiometric burning air ports and auxiliary "NO ports" that can be opened or closed.

b. Two-Stage Combustion: Oil-Fired Boilers

The two-stage combustion in oil-fired boilers is achieved the same as in gas-fired boilers by adding "NO ports" and/or by operating some burners "air rich" and the remaining "fuel rich". The control of off-stoichiometric combustion with oil-fired boilers is more difficult than with gas-fired boilers. Unbalanced two-stage combustion could produce smoke in oil-fired boilers and result in increased unburned hydrocarbon emissions. Some boilers are equipped with extra fuel guns, making it easier to offer "fuel rich", "air rich" operation.

Effects of Two-Stage Combustion on Oil-Fired Boilers

Several oil-fired boilers are being tested and operated on two-stage combustion and/or off-stoichiometric combustion. The test results are as follows:

(i) In a 180 MW front wall fired plant having 20 burners, but operating only 16 burners, the normal NO_x was 367 ppm. The same boiler at the two-stage combustion condition with the following burner arrangement of air alone and air-fuel produced 253 ppm NO_x, a 31 per cent reduction.(13)

Burner Patterns

0	0	0	0
A	0	0	A
0	A	A	0
0	0	0	0

(ii) In an 80 MW front wall fired unit, NO_x was reduced from 580 ppm at normal conditions to 404 ppm in staged firing. The burner patterns during normal firing and staged firing were as follows:(13)

Normal						Staged					
0	0	0	0	0	0	0	A	0	0	A	0
0	0	0	0	0	0	0	0	0	0	0	0

CO concentration did not increase appreciably.

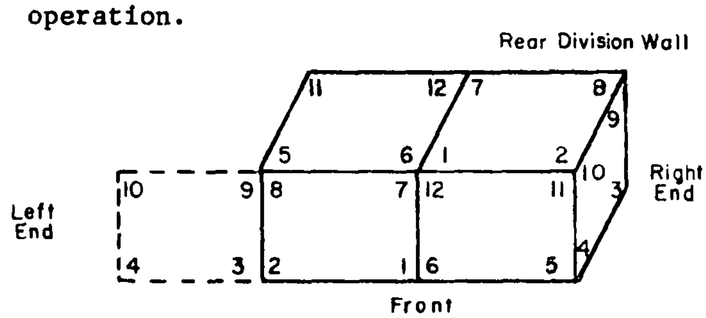
(iii) A 350 MW horizontally opposed Babcock and Wilcox boiler, equipped with "NO ports" for two-stage combustion, was tested under normal conditions with "NO ports" closed, two-stage combustion "NO ports" open and off-stoichiometric firing with "NO ports" open. Three successive analysis gave 457 ppm NO_x during normal firing, 308 ppm (33 per cent reduction) with "NO ports" open and 297 ppm (35 per cent reduction) during off-stoichiometric firing. The burner configuration for the latter condition was as follows:(13)

Front Face				Rear Face			
0	0	0	0	0	0	A	0
A	A	A	A	A	A	0	A
0	0	0	0	0	0	0	0

CO concentration in all three cases remained below 100 ppm.

(iv) A 480 MW horizontally opposed boiler in two-stage combustion tests reduced NO_x emissions from 246 ppm to 200 ppm (a reduction of 19 per cent) by operating with "NO ports" closed and open.[13]

(v) A 220 MW all wall Babcock and Wilcox boiler has the following burner configuration in normal operation.[13]



The boiler was not quite flexible enough for tests because of high water-tube-wall temperature developed during tests. A gradual approach of two-stage firing was successful, however, by first achieving three burners, then four burners (9 and 10 pairs) and ultimately six burners (9, 10 and 12 pairs) on air alone in three different tests. The NO_x in the above tests decreased from an original 267 to 234 ppm (3 burners on air only) to 199 ppm (4 burners on air only) and 183 ppm (6 burners on air only), respectively. CO concentration in all cases remained at 15 ppm and hydrocarbons less than one ppm.

(vi) In a 320 MW tangentially fired boiler, operating at 220 MW with all 24 burners operating in the normal case, the top 16 burners firing fuel/air and bottom rows on air alone for staged combustion, the NO_x was reduced according to Table 15 for different damper settings, burner tilt and flue gas recirculation.[13] (The boiler was equipped with primary secondary air dampers and flue gas recirculation). The average NO_x overall burner tilt settings and damper settings was reduced to 180 ppm at staged conditions from 219 ppm at normal conditions.[13]

(vii) In a 400 MW cyclone boiler with simulated staged combustion firing six of eight cyclones at reduced loads of 260 - 275 MW, the NO_x increased from 206 ppm to 310 ppm. This is assumed to be from higher intensity firing of the six furnaces.[13]

(viii) Test data reported in the literature[27] for operating with a Babcock Wilcox unit in El Segundo 90-95 per cent air through burners and 15 to 20 per cent through auxiliary "NO ports" showed NO_x was reduced from 685 to less than 350 ppm under the same fuel and load conditions. The boiler is a front wall fired unit with 175 MW capacity. A conversion cost of $45,000 was required to accomplish the two-stage combustion.[28] Modifications included replacement of tube sections to provide furnace wall openings, connections

(13)

Table 15

NO$_x$ EMISSIONS: 320 MW TANGENTIAL BOILERS

		NO$_x$ Emissions ppm			
		Normal Firing		Staged Firing	
		D1	D2	D1	D2
Normal Excess Air	T1	244	171	139	136
	T2	161	143	156	139

T1 - Burners tilted down.

T2 - Burners tilted up.

D1 - Primary air dampers at maximum open;
Secondary air dampers at minimum open.

D2 - Primary air dampers at minimum open;
Secondary air dampers at maximum open.

to air port dampers and damper control modification. The results of all the above tests and other reported with fewer details are summarized in Table 16.

Table 16

NO_x REDUCTION, OIL-FIRED BOILERS - TWO STAGE AND OFF-STOICHIOMETRIC COMBUSTION

Boiler Type and Size	NO_x ppm (3% O_2 Basis) Normal Firing	Two-Stage Firing	Off-Stoichiometric Firing	Net Reduction %	Reference
180 MW Front Wall	367	-	253	31	13
80 MW Front Wall	580	-	404	30	13
450 MW Horizontally Opposed	457	308	297	35	13
480 MW Horizontally Opposed	246	200	-	19	13
220 MW All Wall	267	-	183	31	13
320 Tangential (at 220 MW)	180	-	142	21	13
400 MW Cyclone (260 - 275 MW)	206	-	310	(-50)	13
175 MW Front Wall	685	350	-	49	27
78 MW Tangential	310	205	-	33	12
180 MW Tangential	290	130	-	55	12
378 MW Tangential	200	160	-	20	12
400 MW Tangential	175	110	-	37	12

c. Two-Stage Combustion: Coal-Fired Boilers

Two-stage combustion in coal-fired boilers has been demonstrated in laboratory scale tests [(24)] as well as a few large boiler tests and proven to be successful in reducing NO_x. In most instances the simulated two-stage combustion is achieved by removing the coal pulverizer supplying the upper level of burners from service.

Results of Two-Stage Combustion in Coal-Fired Boilers

The full scale tests in coal-fired boilers have reduced NO_x. In some cases, because of removing burners from service, the desired load was not achieved, and the boilers operated at reduced loads. The NO_x reduction did not indicate any effects on steam temperature characteristics, furnace slagging or unit efficiency. Solid combustibles and CO were virtually unaffected. The NO_x reductions are documented in the following Table 17 for different boilers.

Table 17

TWO-STAGE COMBUSTION COAL-FIRED BOILERS

Boiler Type and Size	NO_x PPM ($3\%\ O_2$ BASIS) Normal Firing	Top Row Not Firing No Overfire	Top Row Not Firing Overfire	Net Reduction %	Reference
100 MW Tangential (80 MW-Load Reduced)	400	220	160	60	12
170 MW Tangential (157 MW-Load Reduced)	550	440	270	51	12
215 MW Tangential (158 MW-Load Reduced)	450	480	230	49	12
250 MW Tangential	530	370	--	30	12
250 MW Tangential	400	200	--	50	12
265 MW Tangential	600	400	--	33	12
565 MW Tangential (395 MW-Load Reduced)	480	410	280	42	12
576 MW Tangential (80% Load Operation)	405	--	246	39	13

The Bureau of Mines coal-fired furnace (500 lb/hr.), designed to simulate a wall-fired dry bottom boiler, has been tested for two-stage combustion by supplying 95, 100 and 105 per cent stoichiometric air through the burners and the rest of the air to the secondary stage to give a total excess air of 10 - 20 per cent.[(24)]

The greatest reduction in NO_x was obtained by firing 95 per cent of stoichiometric air through burners and the rest of the total excess air (16 per cent) to the secondary stage.[(24)] The combustion efficiency of the coal remained above 98 per cent in all cases, and no increase in particulate loading or slagging was observed at different conditions. The detailed results of NO_x reduction are summarized in Table 18 and Figure 9.

Table 18

NO_x REDUCTION: TWO-STAGE FIRING - TEST - COAL-FIRED FURNACE [24]

Excess Air %	First Stage Air, % of Stoichiometric	NO_x Emission ppm	NO_x Emission Lb. $NO_2/10^6$ BTU	Combustion Efficiency Wt. %
21.4	105	257	0.64	99.2
20.1	105	448	.62	99.2
20.1	105	444	.62	99.2
16.8	105	447	.60	99.1
15.5	105	437	.58	99.0
15.5	105	428	.57	99.0
9.1	105	397	.49	98.9
8.0	105	307	.45	98.7
21.4	100	358	.50	99.0
19.4	100	372	.50	99.0
19.4	100	355	.49	99.0
17.4	100	354	.48	98.9
16.2	100	348	.46	98.3
16.2	100	342	.45	98.3
10.3	100	308	.39	98.4
8.0	100	301	.37	98.2
8.0	100	294	.37	98.2
21.4	95	333	.46	99.0
18.7	95	315	.43	98.9
15.5	95	290	.38	98.3
15.5	95	287	.38	98.3
12.6	95	266	.34	98.2
11.3	95	260	.33	98.2

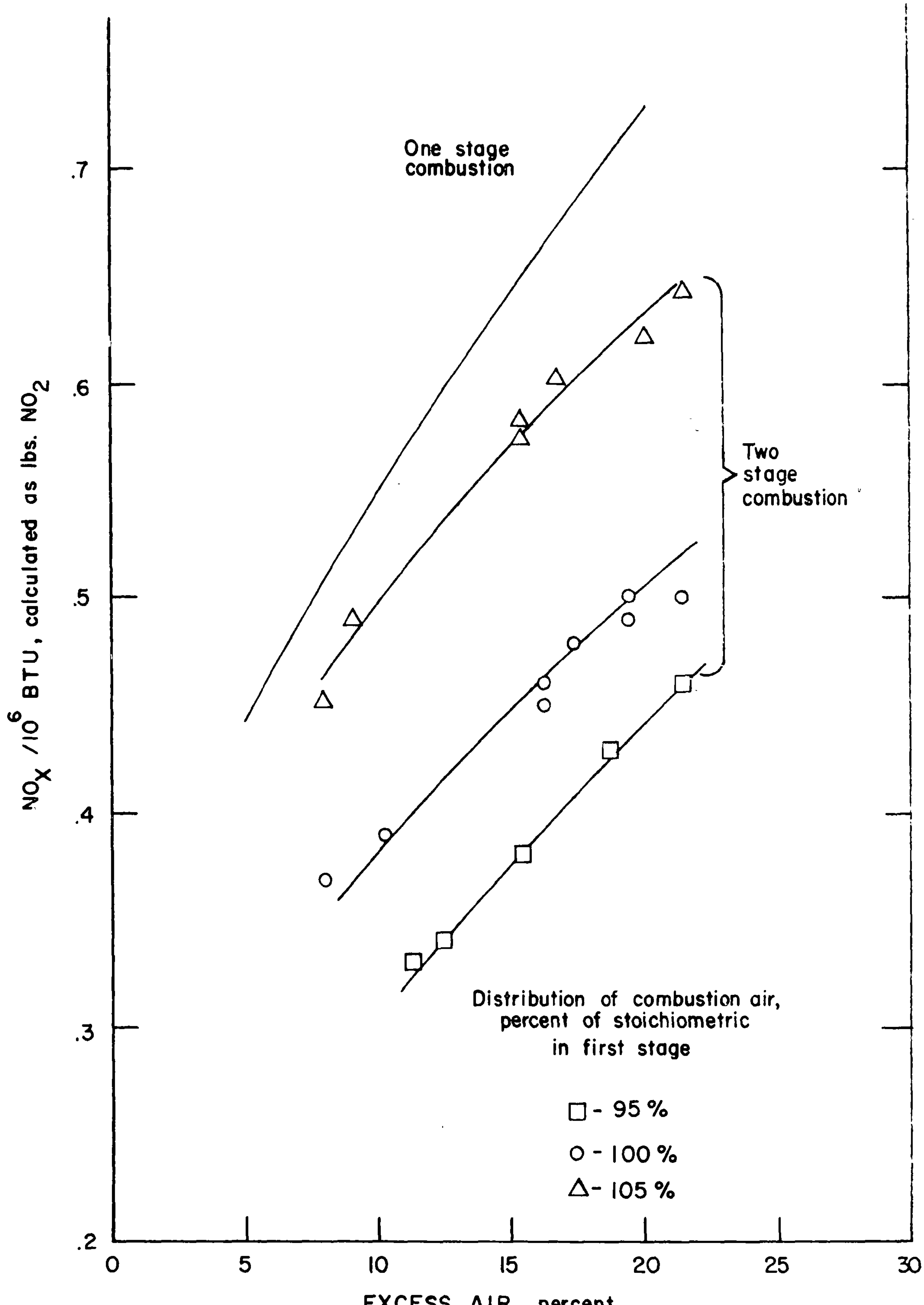


Fig. 9 Two Stage Combustion - Coal Fired Boilers (24)

d. Cost and Cost Effectiveness: Two Stage Combustion

The cost of two-stage combustion is based on two different cases. In the first case, as experience of Pacific Gas and Electric [30] and others has shown [3], simulated two-stage combustion by introducing air alone in upper burners and air-fuel in other burners does not involve any capital cost. In the second case, where simulation is not possible due to burner configuration or other operational reasons, capital cost is required to increase the size of windbox, to install separate auxiliary air ports ("NO ports") above the top row of burners and to connect ducts from the windbox to each port with a separate control damper in each duct. A typical cost to install overfire "NO ports" in the El Segundo 175 MW unit was $45,000. [27] In another source [3] the costs of conversion to two-stage firing for a 100 MW and a 750 MW unit are estimated at $3.30/KW and $2.08/KW, respectively.

The cost investment analysis as estimated by Combustion Engineering [40] for two-stage combustion based on simulated operation at no cost for alteration or redesign of equipment except addition of overfire ports is: $0.25/KW for coal-fired boilers; $0.20/KW for oil-fired boilers and $0.15/KW for gas-fired boilers. These costs are based on new 600 MW boiler.

The retrofit operation is estimated to cost 50 per cent more.

The cost investment analysis performed by ESSO in 1969 [3][30] is given in Table 19. It is based on the assumption that larger units would be suitable for two-stage combustion or would be able to simulate two-stage combustion more readily than smaller units. The costs in Table 19 are also based on estimates of capital expenditures required to alter or redesign equipment as discussed above.

Table 19

TWO-STAGE COMBUSTION COST [3]

Plant Size Fuel	Investment Cost	Annual Cost
1,000 MW		
Gas	0	0
Oil	0	0
Coal	1,900,000	299,000
750 MW		
Gas	153,000	24,000
Oil	153,000	24,000
Coal	1,530,000	240,000
500 MW		
Gas	280,000	44,000
Oil	280,000	44,000
Coal	1,120,000	176,000
250 MW		
Gas	330,000	52,000
Oil	330,000	52,000
Coal	660,000	103,000
120 MW		
Gas	342,000	54,000
Oil	342,000	54,000
Coal	380,000	60,000

5. <u>Two-Stage Combustion with Low Excess Air and/or Reduced Load</u>

It is demonstrated by data in previous sections that two-stage combustion, low excess air and load reduction are effective in reducing NO_2 by varying degrees. If higher NO_x reduction is required by any of the above individual controls, a combination of two-stage combustion with low excess air and/or reduced load was tested as a possible choice. The combination of two-stage combustion with low excess air is achieved by either using "NO ports" or some burners on air alone, the rest as fuel-burners but at a constant total excess air. Load reduction along with two-stage combustion and low excess air, is achieved by sealing off completely some of the burners.

Two-stage combustion with low excess air and reduced load has been demonstrated in tests summarized in Table 20.

Two-Stage Combustion with Low Excess Air and/or Reduced Load

Table 20

Boiler Type and Size	Operating Load MW	NO_x Emissions ppm (3% O_2, Dry Basis) Normal at Full Load	Two-Stage at Operating Load	Two Stage and LEA Full Load	Two Stage and LEA Operating Load	Maximum NO_x Reduction %	Reference
180 MW Frontwall	120	390	133	156	88	78	13
Gas-Fired	70	390	81	156	66	83	13
80 MW Frontwall	50	497	200	311	-	60	13
Gas-Fired	20	497	-	311	65	87	13
480 MW Horizontally Opposed Gas-Fired	220	236	95	140	70	70	13
600 MW Horizontally Opposed Gas-Fired	325	560	120	-	77	86	13
220 MW All Wall	190	675	359	270	284	58	13
Gas-Fired	125	675	313	270	107	84	13
750 MW Frontwall Gas-Fired	750	1,475		140		90	17
180 MW Frontwall Oil-Fired	120	367	241	201	185	50	13
80 MW Frontwall	50	580	290	314	252	56	13
Oil-Fired	21	580	207	314	203	65	13

Two-Stage Combustion with Low Excess Air and/or Reduced Load

Table 20 (Continued)

Boiler Type and Size	Operating Load MW	NO_x Emissions ppm (3% O_2, Dry Basis) Normal at Full Load	Two-Stage at Operating Load	Two-Stage and LEA Full Load	Two-Stage and LEA Operating Load	Maximum NO_x Reduction %	Reference
350 MW Horizontally Opposed Oil-Fired	150	457	139	294	118	74	13
480 MW Horizontally Opposed Oil-Fired	365	246	164	-	163	34	13
	228	246	155	-	-	37	13
575 MW Tangential Coal-Fired (80% Load Operating)	460	405 (at 460 MW)	-	204		50	13
175 MW Frontwall Coal-Fired	140	660 (at 140 MW Load)	-	-	260	60	13
315 MW Frontwall Coal-Fired (Full Load 275)	190	1,480	1,280	-	1,190	20	13
315 MW Frontwall Coal/Gas Fired (Full Load 280 MW)	194	-	830	-	630	-	13

6. Reduced Preheat Temperature

NO_x emissions are influenced extremely by the effective peak temperature of the combustion process. Any modification that lowers these temperatures is expected to lower NO_x emissions. One alternate to achieve lower temperature has been predicted to be air preheat temperature reduction.

The approach is not very practical because the air preheat in existing boilers can only be varied in a narrow range without upsetting the thermal balance. It has only been demonstrated in gas-fired plants. In view of plant efficiency problems and other disadvantages, it is preferable to apply other methods for NO_x control. (13)

In oil- and coal-fired boilers, nitrogen emitted by the fuel has a major influence on NO_x formation. Lower air preheat would not affect the NO_x from fuel nitrogen. Also, it would increase particulate emissions in oil- and coal-fired boilers. (12)

Preheated air is required for the pulverizer operation on the coal-fired boilers. Higher exit temperatures resulting from elimination of preheat would require additional water spray if a scrubber system is incorporated in the design. Electrostatic précipitation and induced draft fans, if required, would become larger and more expensive. (12)

The test results reported on effects of air preheat reduction on NO_x emission are as follows:

(i) In a test and kinetic analysis prediction, reported by KVB-SCE [25], 200°F reduction in air preheat reduced NO_x by 50 per cent. [25] The results of tests and predictions are shown in Figure 10. The authors reported the thermal efficiency reduced with the changes, and concluded this method of reducing NO_x to be undesirable from an operational standpoint.

(ii) In tests reported by Combustion Engineering [18] with the Ljungstrom air heater rotor stopped, air preheat temperature was reduced from 522°F and 466°F (at 75 per cent and 50 per cent loads respectively) to 80°F. NO_x levels were reduced from 200 ppm to 100 ppm at comparable operating excess air. A load reduction to 75 per cent was required to protect air heater exit ducts and stack from excessive temperature. At 75 per cent load, exit temperature increased from a normal value of 220°F with the air preheater running to a value of 540°F with the air preheater rotor stopped.

7. Flue Gas Recirculation

Flue gas recirculation is a technique for recycling a portion of flue gases produced back to the combustion chamber, using either forced or natural draft. In addition to recycling flue gases for steam temperature control, the recirculation is used to control NO_x emission from utility boilers.

The control of NO_x by flue gas recirculation results

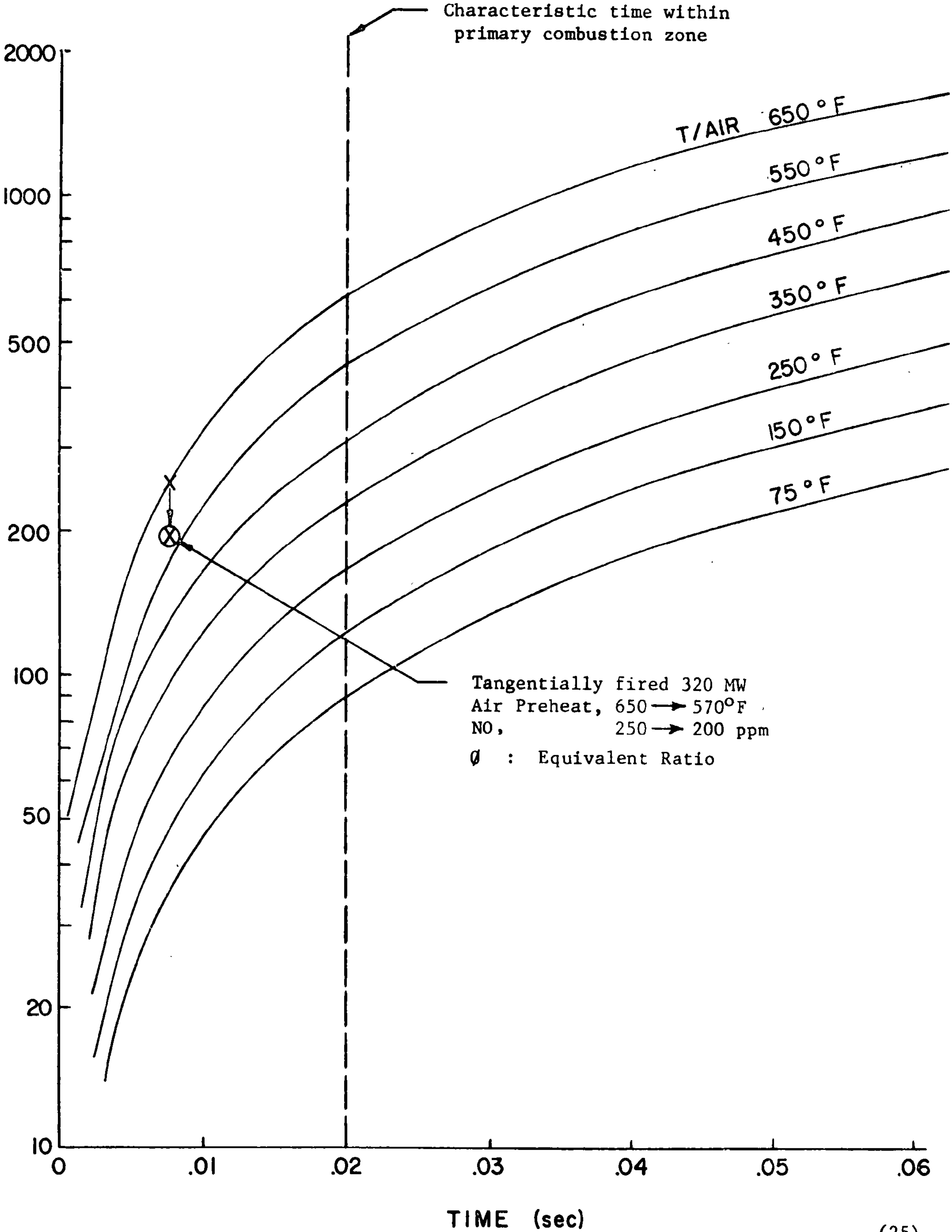


Figure 10. – Effect of Combustion Air Preheat on NO Formation. Ø = 0.95 [25]

from two factors: the temperature of the flame zone is reduced by circulating cool flue gases; the concentration of oxygen available for NO formation is reduced.[13] Of these two, the thermal effect is generally accepted to be more important.[3]

Flue gas recirculation into the bottom of the furnace is standard design in some utility boilers to control steam temperature. Normally, as boiler load decreases, steam temperature tends to decrease unless some method of control is employed. By recirculating an increasing portion of the flue gas as the boiler load decreases, it is possible to maintain steam temperature at a constant level over a wider load range. Where this type of control is used, the flue gases are injected to reduce the effectiveness of the furnace heat absorption surface without interfering with the combustion process. Tests made during the California joint between B and W and SCE project NO_x investigation in 1960-62 concluded that recirculation for steam control was relatively ineffective in suppressing NO_x. Recent data, however, indicated that recirculation of 20 per cent of the gases into combustion zone in a gas-fired boiler equipped with recirculation steam temperature control reduced emissions by 20 per cent.[3]

The flue gas recycled for NO_x control requires recycle into the primary combustion zone. The effect of gas recirculation on NO_x control is shown in Figure 11 [11] [25] which is based on kinetic analysis predictions of the reduction in

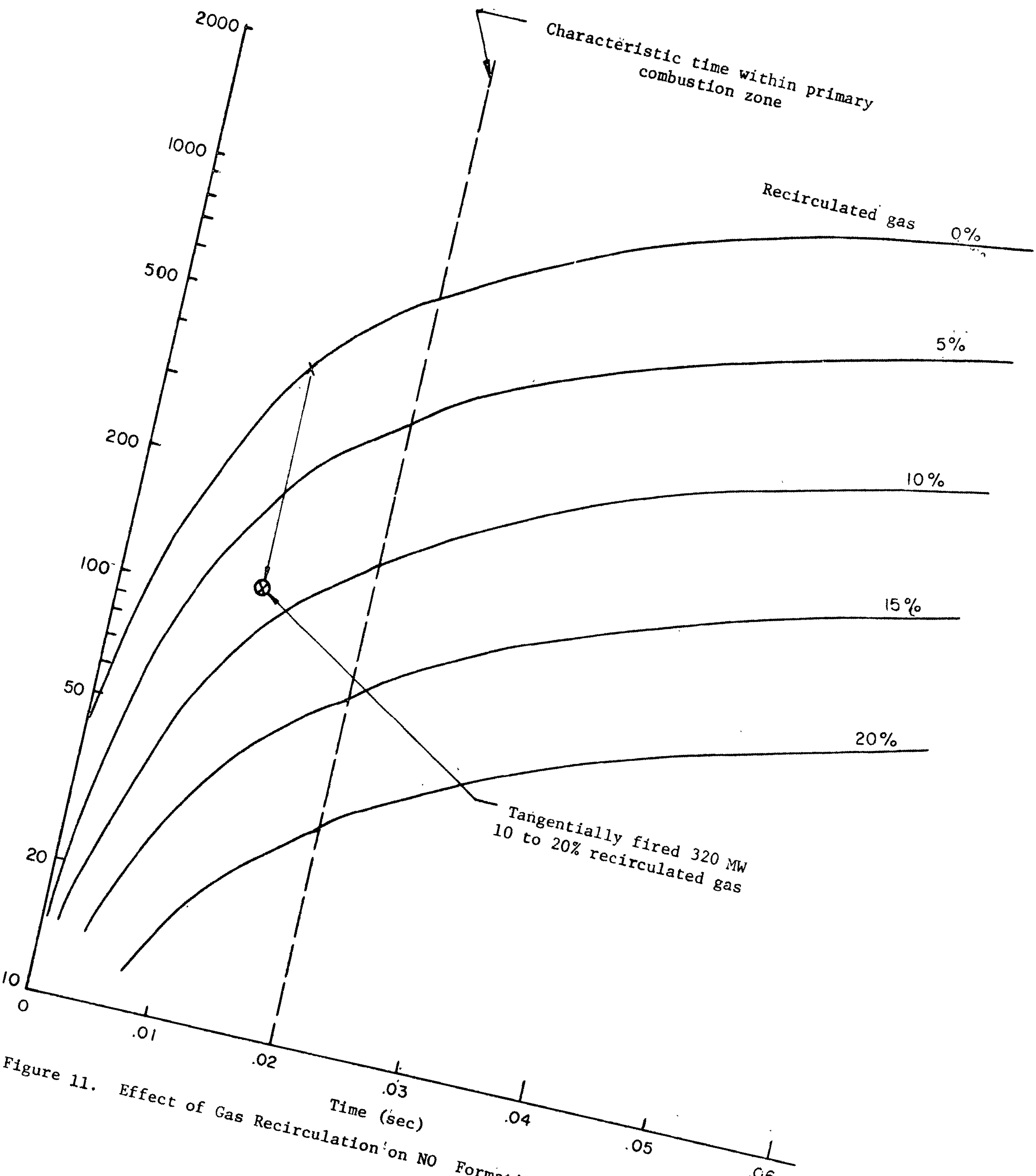


Figure 11. Effect of Gas Recirculation on NO Formation. Ø = 0.95 (11) (25)

NO formation for various flue gas recirculation rates.

Flue gas recirculation has shown a reduction in CO concentration from normal operation because of increased mixing and decreased CO_2 dissociation accompanying the decreased temperature.(11) Gas recirculation does not significantly reduce plant thermal efficiency, but it can influence boiler operation. Radiation heat transfer is reduced in the furnace because of lower gas temperatures. Convective heat transfer is increased in the convective sections because of the greater gas flow.(11)

The extent of applicability of this modification remains to be investigated. The quantity of recirculated gas necessary to achieve the desired effect in different installations is important and can influence the feasibility of applications. For instance, recycling large quantities of flue gas in utility boilers poses gas handling problems in addition to increased investment and operating costs.

a. Flue Gas Recirculation: Gas-Fired Boilers

Flue gas recirculation tests in gas-fired tangential utility boilers were run by Southern California Edison (25) and Combustion Engineering Company.(12)

(i) The Southern California tangential fired boilers are equipped with flue gas recirculation into combustion air. Tests of these 320 MW units showed a substantial NO_x reduction as the rate of gas recirculation increased. The test results of the units at full load are shown in Figure 12.(25)

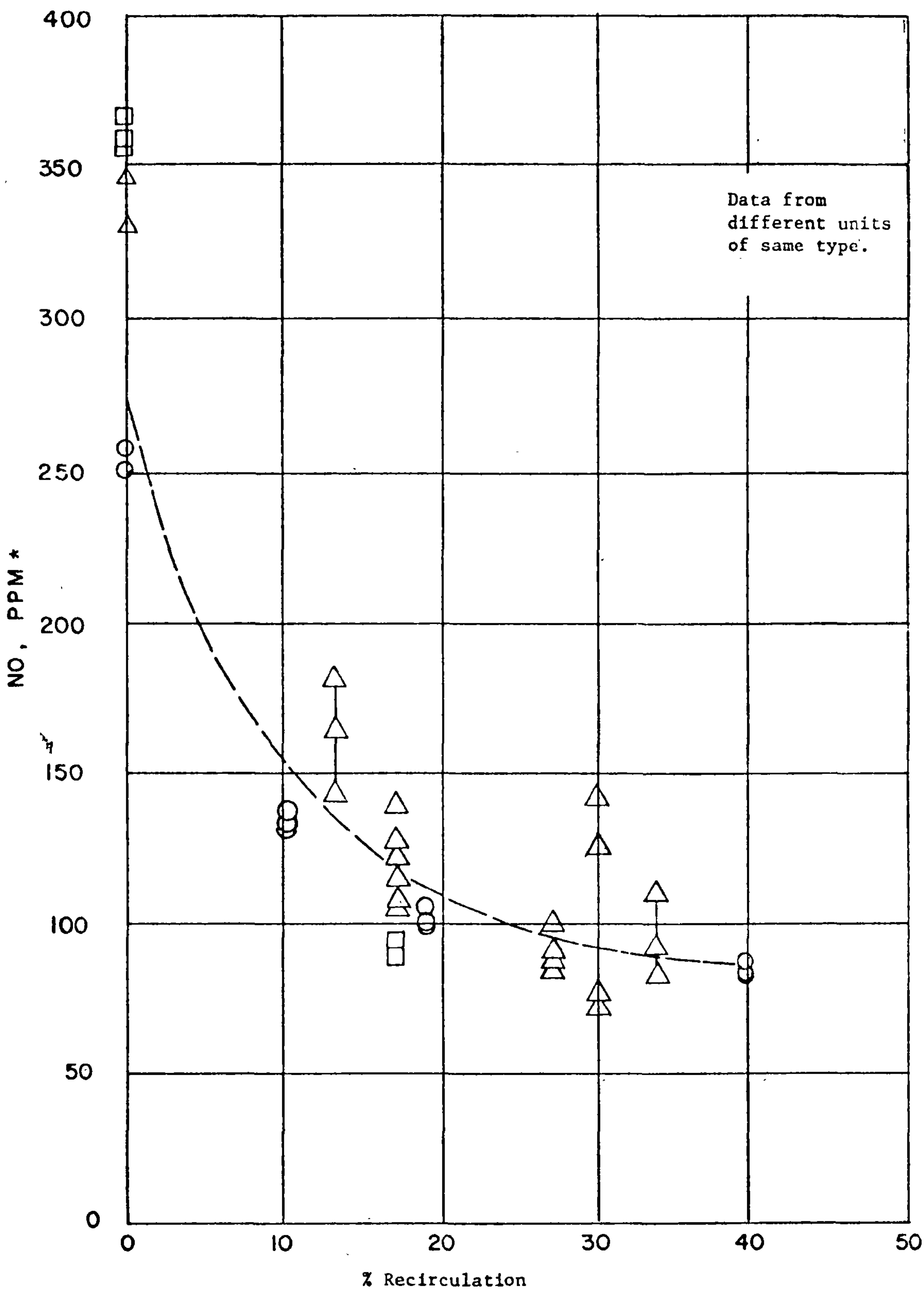


Figure 12. Gas Recirculation with Natural Gas Firing: 320 MW Corner Fired Unit.[25]

* Dry Basis 3% Excess O_2

(ii) In a test on a 320 MW tangential fired boiler, ESSO reports [13] that flue gas recirculation at low excess air levels provides a practical and effective means of reducing NO_x emissions from this boiler. The use of flue gas recirculation at adjusted burner tilt and with air dampers to avoid higher water tube metal temperature reduced NO_x from 340 ppm to 110 ppm at full load and to 65-85 ppm at lower loads. The levels of low excess air used were limited by the CO emission. Complete analysis of the data is presented in Table 21 and Figure 13.

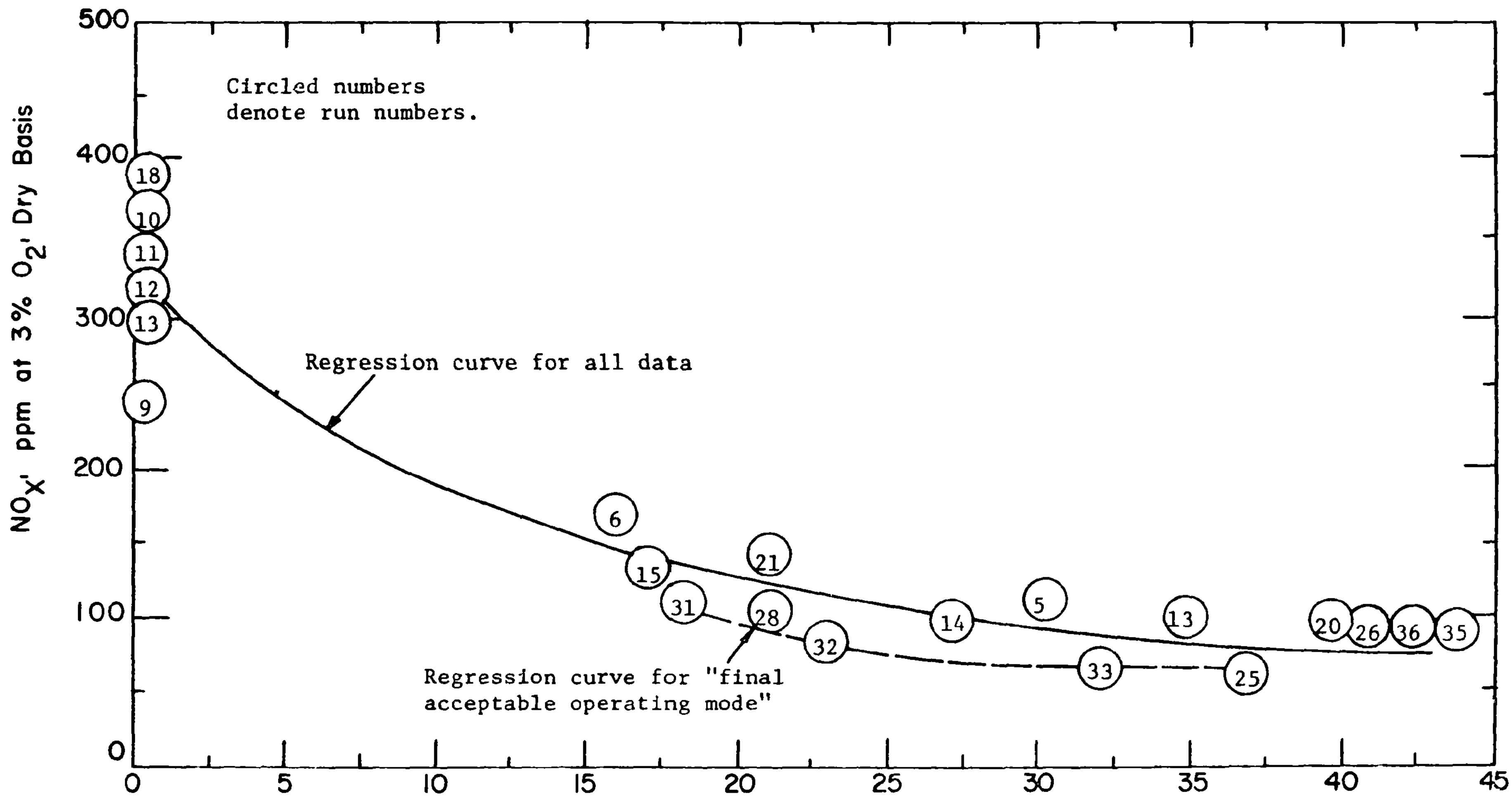
Table 21

SUMMARY OF EMISSION DATA FROM 320 MW,[13]

TANGENTIAL, GAS FIRED

Run No.	Boiler Load MW	Staging	% Flue Gas Recirculation	Burner Tilt	Primary/Secondary Air Dampers	$\%O_2$ Dry Basis	ppm 3% O_2, Dry Basis NO_x	ppm 3% O_2, Dry Basis CO
1	320	No	0	Normal	Normal	3.3	340	175
3	320	No	0	+Max. (up)	Normal	2.7	335	50
5	320	No	30	Normal	Normal	2.2	105	50
6	320	No	16	Normal	Normal	2.7	165	80
9	320	No	0	Normal	32%100%	2.7	245	100
10	315	Yes	0	Normal	Closed	5.5	375	200
11	280	Yes	0	Normal	Closed	5.6	320	80
13	280	No	35	Normal	Open	2.5	95	50
14	320	No	27	Normal	Open	2.9	90	50
15	320	No	17	Normal	Open	2.4	130	60
16	240	No	0	Normal	Normal	5.0	230	2100
17	240	No	0	Normal	Normal	7.5	435	50
18	240	No	0	+Max. (up)	Normal	6.0	390	50
20	240	No	39	Normal	Normal	2.9	95	50
21	240	No	21	Normal	Normal	4.1	135	100
24	240	Yes	0	Normal	Open	6.2	345	50
25	240	Yes	0	Normal	Open	5.7	315	160
26	240	No	41	Normal	Normal	2.7	90	100
28	320	Yes	21	Normal	Open	2.2	105	150
31	320	No	18	Normal	Normal	2.0	110	50
32	240	No	23	Normal	Normal	2.2	80	600
33	160	No	32	Normal	Normal	2.9	65	50
34	120	No	37	Normal	Normal	5.5	65	50
35	80	No	43	Normal	Normal	8.9	85	50
36	60	No	43	Normal	Normal	11.0	85	50

Figure 13. NO_x Emissions fro.. 320 MW, Tangential, Gas Fired.[13]



* Emission date supplied by boiler operator.

(iii) Combustion Engineering reports a 60 per cent NO_x reduction with 30 percent flue gas recirculation on a 320 MW tangential fired boiler.(12)

(iv) Pacific Gas and Electric reports installing a flue gas recirculation system on a 750 MW front wall-fired Babcock and Wilcox unit at a cost of $850,000. The unit, equipped with off-stoichiometric firing and operating at low excess air after addition of 15 per cent flue gas recirculation, is reported to have reduced NO_x from 1,350-1,450 ppm uncontrolled to 100 ppm under controlled conditions. The unit has reported problems with heat transfer due to increase in mass flow.(30)

b. <u>Flue Gas Recirculation: Oil-Fired Boilers</u>

Flue gas recirculation in the windbox or in the combustion air in oil-fired utility boilers reduces the NO_x. However, since the NO_x in oil-fired boilers is both from fuel and thermal nitrogen, the reduction of thermal NO_x is much greater than reduction of fuel NO_x.

Flue gas recirculation in oil-fired boilers has been tested both on front wall-fired and tangentially fired boilers. Typical gas recirculation system in oil- or gas-fired tangential boilers is shown in Figure 14.(12) The recirculated gas is mixed with air in the two outer channels of the duct from the air preheater to the windbox. The center channel contains air only, which flows

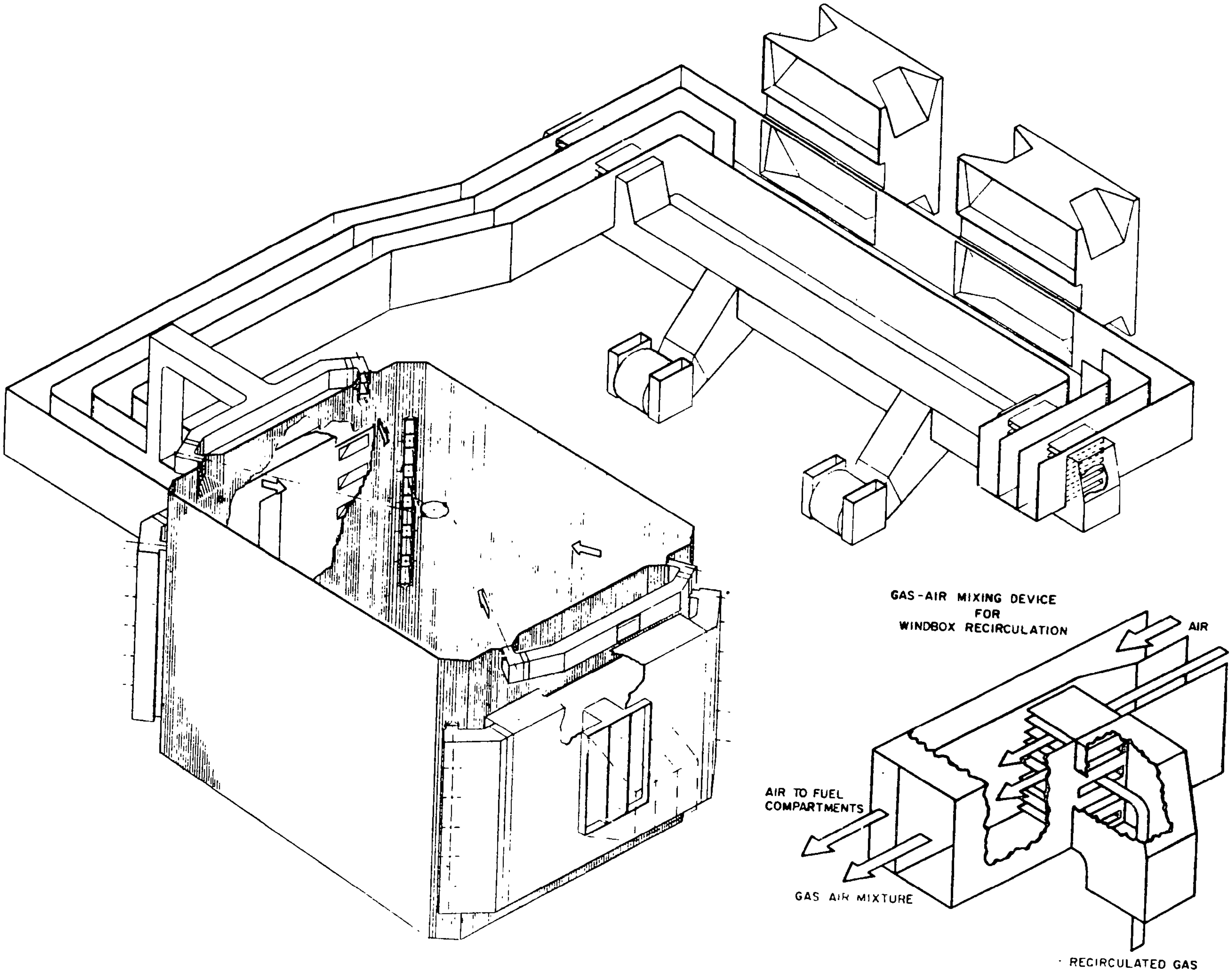


Fig. 14: Recirculated gas and air duct system for oil or gas fired units (12)

to the fuel and overfire air compartments. Figure 14 also shows a device installed in the duct work to insure thorough mixing of the recirculated gas and air to prevent stratification.[12]

The reported test results on all types of oil fired boilers are, as follows:

(i) In a 250 MW twin furnace, front wall boiler, flue gas recirculation, along with staged firing and low excess air, reduced NO_x by more than 50 per cent at full load (from about 340 ppm to less than 150 ppm) and about 50 per cent at two-thirds load (from 300 ppm to 155 ppm).[13]

(ii) In a 320 MW tangential oil-fired boiler, equipped with flue gas recirculation, the NO_x was reduced from 180 ppm to 158 ppm by switching from minimum gas recirculation to maximum gas recirculation at normal firing and normal excess air.[12]

(iii) In a Combustion Engineering test[12] on a 320 MW tangentially fired twin furnace boiler, tested on both sides (160 MW each), NO_x was reduced from 500 ppm to 300 ppm in one and from 330 ppm to 215 ppm in the other compartment (a reduction of about 40 per cent in both cases).

c. Flue Gas Recirculation: Coal-Fired Boilers

There is presently no commercial coal-fired unit equipped with flue gas recycle into the windbox to test.[13]

Flue gas recycle is, however, predicted as a favorable means of future control of thermal NO_x from coal-fired boilers.[(33)(34)] It is predicted that increasing the mass flow through the boiler system, along with properly designed superheat recovery systems, may help maintain boiler tubes cleaner and reduce slagging. These effects require exploration in pilot and simulated studies. A study also is needed to indicate the effect of flue gas recycle on particulate emissions.

The costs incurred with flue gas recirculation are in the addition of duct work and recycle fans, enlarging the windbox for additional combustion air, addition of dampers, and proper instrumentation to vary flue gas recirculation as required for operating conditions and loads.

d. Cost and Cost Effectiveness of Flue Gas Recirculation

The costs incurred with flue gas recirculation are: addition of duct work and recycle fans, enlarging the windbox for additional combustion air, and addition of dampers and proper instrumentation to vary flue gas recirculation as required for operating conditions and loads.

In an actual case, a 750 MW front wall boiler was equipped with flue gas recirculation for $850,000. This cost does not include any steam temperature adjustment alterations.

The cost of flue gas recirculation on a per unit power output capacity basis has been quoted by Esso in 1969 as \$0.656/KW for a 750 MW unit to \$1.033/KW for a 100 MW unit. Based on these factors, the cost of equipping and operating flue gas recirculation for different sized gas, oil and coal-fired boilers is, as follows:

Table 22

COST OF FLUE GAS RECIRCULATION (29)

Size of Boiler MW	Capital Cost of FGR Installation	Annual Cost Capital + Operating
1,000	\$600,000	\$202,000
750	\$490,000	\$160,000
500	\$360,000	\$109,000
250	\$210,000	\$ 58,000
120	\$120,000	\$ 30,000

In a more recent publication, the flue gas recirculation costs are estimated at \$2.65/KW for large gas-fired boilers. (10)

The cost of flue gas recirculation estimated by Combustion Engineering (40) recently is: \$3.50/KW for coal fired boilers, \$1.50 for oil fired boilers and \$2.65/KW for gas fired boilers, based on a 600 MW new boiler. The costs for existing boiler conversions are estimated to be 50 per cent higher.

Because of the lack of actual thermal efficiency data, no cost effects on boiler operation could be developed.

8. Steam and Water Injection

Flame temperature, as discussed earlier, is one of the important parameters affecting the production of NO_x. One of the several ways to control NO_x by lower flame temperature is to inject steam or water into boilers. Water injection was found to be preferred over steam in many cases, due not only to its availability and lower cost, but also to its potentially greater thermal effect. In gas- and coal-fired units equipped for standby oil firing with steam atomization, the atomizer offers a simple means for injection. Other installations require special rigging, and a systematic study to determine the degree of atomization and mixing required with the flame, the optimum point of injection and the quantities of water or steam necessary to achieve the desired effect.

The use of water or steam injection may entail some undesirable operating conditions, such as decreased efficiency, increased corrosion, etc. These factors require evaluation before selection of this control technique for NO_x control can logically be made.

Use of the water or steam injection technique is limited to gas units for practical reasons. It does not reduce fuel nitrogen conversion, and even in gas boilers, it is uneconomic to use water or steam injection over the amount that will reduce the boiler efficiency by more than one per cent. The NO_x reduction at that injection rate is about

10 per cent. Based on this concept, the water injection is only used to trim peak NO_x emissions.

The following test result has been reported on NO_x control by water or steam injection.

> On a 250 MW gas-fired unit water injection tests, using existing oil guns as atomizers, reduced the NO_x emission level from 330 ppm to 110 ppm at full load. Boiler efficiency decreased five per cent at the maximum water injection rate of 45 lb/10^6BTU fired. (18)

a. Cost of Steam and Water Injection

The use of water in water injection requires an injection pump and attendant piping. Cost estimates of water injection systems based on installing an atomizer in each burner together with required piping are estimated as \$0.0238/KW for a 750 MW unit and \$0.0363/KW for a 100 MW unit. (3) The costs based on one per cent operating efficiency losses and annual expenses are, as follows:

Table 23

COSTS OF WATER INJECTION (3)

Boiler Size	Capital Cost	Annual Cost by Fuel (Operating and Efficiency Loss and Capital) Gas	Oil	Coal
1,000 MW	\$23,000	\$144,000	\$179,000	\$143,000
750 MW	\$19,000	\$114,000	\$141,000	\$113,000
500 MW	\$14,000	\$ 71,000	\$ 87,000	\$ 70,000
250 MW	\$ 8,000	\$ 29,000	\$ 36,000	\$ 21,000
120 MW	\$ 5,000	\$ 9,000	\$ 11,000	\$ 9,000

9. Fuel Substitution

Fuel type affects NO_x formation both through the theoretical flame temperature attainable (coal > oil > gas) and rate of radiative heat transfer (coal > oil > gas). In general, the NO_x by fuel type can be ranked as coal > oil > gas, but in limited cases in large boilers this order is reversed, presumably due to the shift in heat release/heat removal ratios.

Oil and coal contain fuel nitrogen which is converted to NO_x by fuel combustion. The average fuel nitrogen reported in coal is 1.1 to 2.1 per cent.[36] Nitrogen contained in crude oil ranges by states averages from 0.056 per cent to 0.49 per cent and ranges by field averages from 0.01 per cent to 0.94 per cent. The data on conversion of fuel nitrogen to NO_x are limited. The reported conversion varies between 20-70 per cent.[36] The conversion of fuel nitrogen to NO_x is influenced by other combustion modifications such as flue gas recirculation.

It is desirable to switch to low nitrogen fuels, along with implementing other combustion modifications reported earlier to reduce the NO_x from utility boilers.

The fuel switching from coal to oil or gas involves combustion equipment design changes; however, if the boiler is equipped with a multi-fuel firing system, the costs involved are simply costs of fuel.

The coal-fired to oil-fired conversion involves addition of oil tanks, oil heaters and modification to boilers. The cost of these conversions is estimated as \$2-3/KW. The conversion of oil-fired or coal-fired to gas fired does not involve any storage cost; however, cost of pipeline gas and change in burners is estimated to be \$.50/KW. The fuel costs for various fuels by regions are reported in Table 24.

Table 24

FUEL PRICES BY REGIONS, 1970

Regions	Fuel Cost ¢/million BTU Coal	Oil	Gas
NEW ENGLAND Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticutt	34.9	35.6	31.2
MID-ATLANTIC New York, New Jersey, Pennsylvania	36.9	42.6	39.4
EAST NORTH CENTRAL Ohio, Indiana, Illinois, Michigan, Wisconsin	30.4	63.7	36.9
WEST NORTH CENTRAL Minnesota, Iowa, Missouri, North Dakota, South Dakota, Nebraska, Kansas	29.5	65.1	25.6
SOUTH ATLANTIC Delaware, Maryland, D. C., Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida	36.0	34.8	35.5
EAST SOUTH CENTRAL Kentucky, Tennessee, Alabama Mississippi	23.5	50.5	25.2
WEST SOUTH CENTRAL Arkansas, Louisiana, Texas Oklahoma	38.9	44.9	20.9
MOUNTAIN STATES Montana, Wyoming, Colorado, Utah, New Mexico, Arizona, Nevada	19.1	28.5	29.5
PACIFIC STATES Washington, Oregon, California	15.1	39.0	32.6
ALASKA	67.7	146.6	-
HAWAII	-	39.2	-

B. Combustion Equipment Design Modifications

1. Equipment Design

Boilers are referred to by their firing type e.g., front wall-fired, horizontally opposed, all wall, cyclone tangential. The boilers generate different amounts of NO_x per their type of firing. An analysis of uncontrolled NO_x by types of boilers is given in Figures 15, 16 and 17.

Tangential firing units usually generate the least NO_x. The fuel is admitted at the corners of the combustion chamber through alternate compartments. Distribution dampers proportion the air to the individual fuel and air compartments. Thus, it is possible to vary the distribution of the air over the height of the windbox, vary the velocity of the air stream and change the rate of mixing of the fuel and air. Fuel and air nozzles tilt in unison to raise or lower the flame in the furnace to control furnace heat absorption in the superheater and reheater sections. The fuel and air streams from each corner of the furnace are aimed tangent to the circumference of a circle in the center of the furnace. In operation, a large swirl is created in the furnace.

The impingement of each stream on the adjacent stream provides a source of ignition energy and promotes bulk gas mixing. Since the entire furnace acts as a burner, precise proportioning of fuel and air at each of the individual fuel admission points is not required. Locally "fuel rich" or "air rich" streams are blended in passing through the furnace

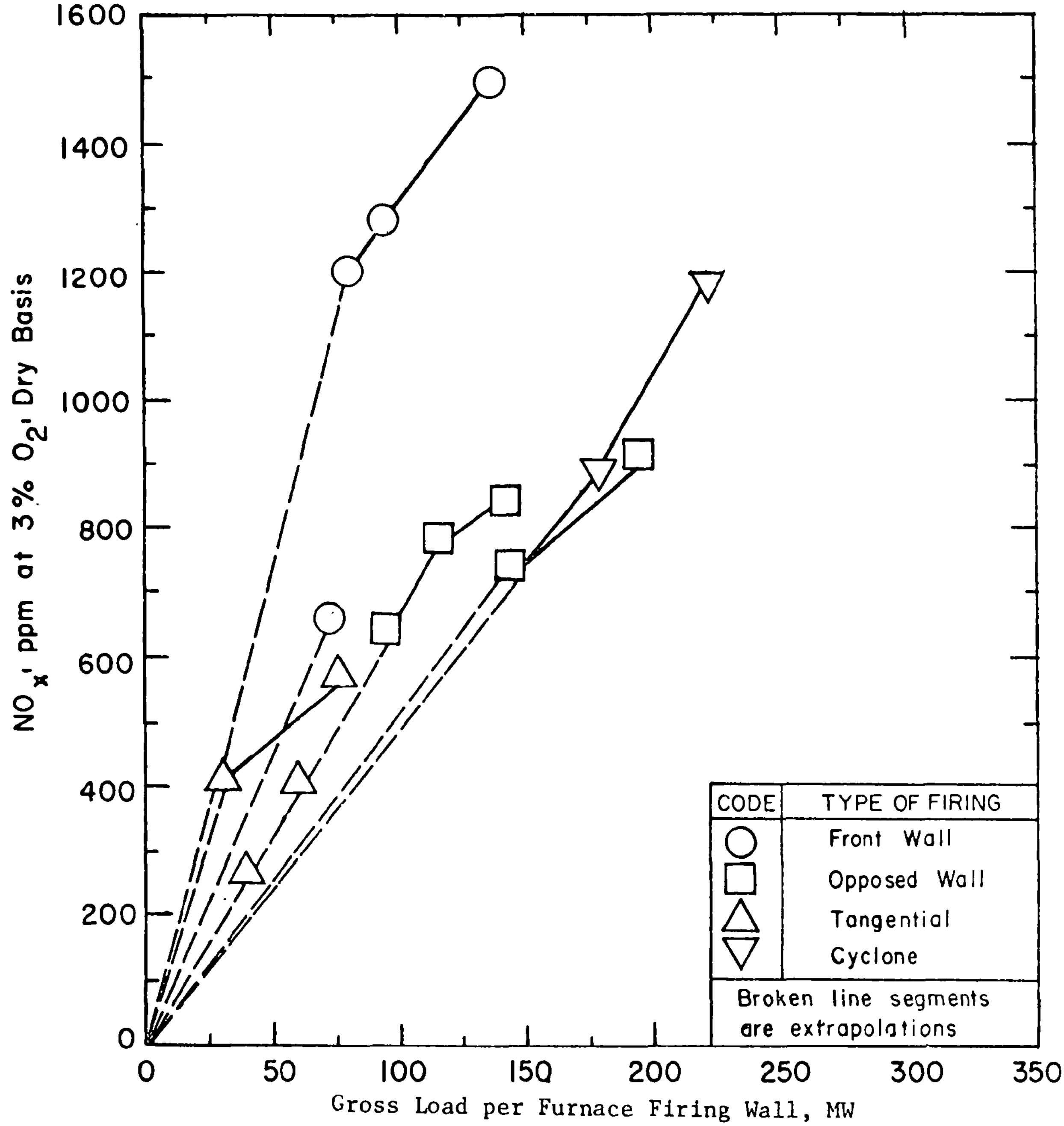


Figure 17. Coal Fired Boilers. Uncontrolled NO_x Emissions vs. Gross Load per Furnace Firing Wall. (13)

resulting in complete combustion of the fuel. A large amount of internal recirculation of bulk gas, coupled with slower mixing of fuel and air, provides a combustion system which is inherently low in NO_x production for all fuel types.

2. Burner Design and Configuration

The specific design and configuration of a burner has an important bearing on the amount of NO_x formed. Certain types of burner designs have been found to give greater emissions than others. Among the three types of gas burners, spud, radial spud and ring, the ring type generates minimum and spud type maximum NO_x.

The spray angle in oil atomizers effects NO_x concentration. Narrower spray angle, producing proper atomization, has been reported to provide lower NO_x emissions[3] as opposed to the results of Barnhart and Diehl tests.[35]

The cyclone and vortex type burners operate under highly turbulent, high intensity conditions. In field adjustment of these burners to decrease turbulence to a minimum, NO_x was reduced 40 per cent but this resulted in an unsatisfactory flame conditon. Throttling the burner registers to increase windbox pressure and turbulence increased NO_x by more than 15 per cent. Foster Wheeler reports[33] that burner turbulence is produced by swirling combustion air. When firing natural gas, the flame color is an index of flame turbulence. Bright blue flames with good definition are considered highly turbulent flames. Yellow, lazy flames have low turbulence. Figure 18 vividly demonstrates the NO_x formation as a function of turbulence alone.

Removal of approach cone vanes resulted in NO_x level reduction from 300 ppm to 285 ppm in a test.[35] The throat diameter of the burners has no effect on NO_x formation.[35]

In the late 50's, a two-stage burner was developed in California. In this burner, about 85 - 95 per cent of the stoichiometric air needed for combustion is admitted to the flame through the burner throat. The remainder of the air required for complete combustion is injected through ports above the burner to complete the burn-out of the initial combustion phase. With 95 per cent of stoichiometric air passing through the burner throat, NO_x reduction of 30 per cent was observed. With 90 per cent stoichiometric air supplied into the primary zone, the NO_x content was reduced by 47 per cent. This technique is successfully used in oil- and gas-fired boilers.

A further modification of an off-stoichiometric firing burner is used by Pacific Gas and Electric. In the boiler with a matrix of three rows vertically, each boiler tube is divided by a triangular cut to supply air and fuel air mixture in the following arrangement

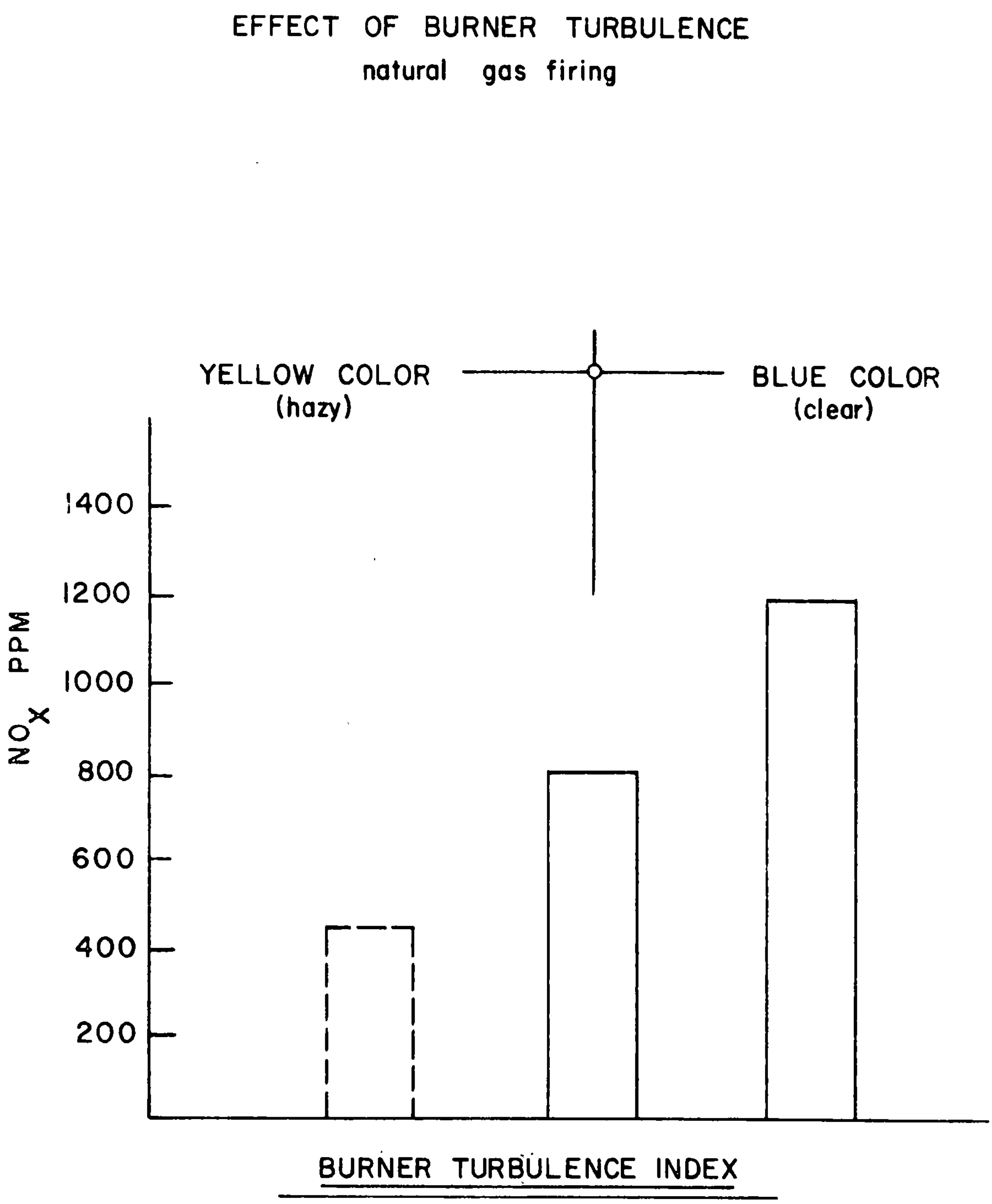
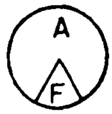
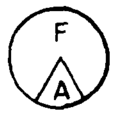


Figure 18. Effect of Burner Turbulence. Natural Gas Firing.[33]

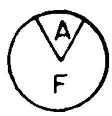
and ratios:



A: Air Alone



F: Fuel/Air Mixture



$$\frac{\text{(Fuel/Air)}}{\text{(Fuel/Stoichiometric Air)}} = 1.51$$

The NO_x reduced from 450 - 500 ppm to 140 ppm.

3. <u>Burner Location, Spacing and Tilt</u>

Although data are scarce regarding the effect of burner spacing and location on NO_x concentrations, potentially these items are important variables. The interaction between closely spaced burners, especially in the center of a multiple burner installation, could be expected to increase flame temperature at these locations. The tighter the spacing and the lower the ability to radiate to cooling surfaces, the greater the tendency towards increased NO_x emissions. This effect is illustrated by higher NO_x emissions from larger boilers with greater multiples of burners and tighter spacing. In the course of the California investigations in the early 1960's, tests were conducted on large boiler units where the number and spacing of burners in use were varied. It was reported that, when the burners in operation were closely grouped or when more burners were in use, more NO_x was produced than when the same amount of fuel was burned using fewer burners with wider spacing. These results were attributed to the relative amount of cold waterwall surface "seen" by each burner. Less NO_x is formed when more cooling surface is available to absorb radiant heat from each individual burner flame.[3]

Tilting burners is a design feature used in tangentially fired boilers for superheat temperature control. This additional flexibility in combustion operations was exploited, where possible, in planning and conducting tests in the ESSO[3] Boiler Test Program.

Varying burner tilt away from the horizontal position can to some extent "enlarge" or "constrict" the effective furnace combustion zone. Thus, depending on flame patterns and transport effects, a longer effective residence time may be available for NO_x formation, or conversely, a lower combustion intensity may prevail in the enlarged combustion zone, leading to lower NO_x emissions. The first one of these two alternatives was expected to be more likely because of the diffuse, swirling fireball pattern prevailing in tangentially fired boilers.[13]

Tangential boilers capable of $\pm 30^{\circ}$ tilt from horizontal position generally produce the least NO_x at horizontal positions.[12]

C. Flue Gas Treatment

Flue gas treatment is an alternate method for control of NO_x. This method of control is applied after the NO_x has formed and can be used either by itself or following combustion modification.

To-date no NO_x flue gas treatment has been demonstrated commercially on a power plant, however, aqueous scrubbing, catalytic reduction, adsorption by solids and catalytic re-composition se a to be candidates for development. Flue gas treatment methods are discussed briefly as follows:

1. Absorption of Nitrogen Oxides

Nitrogen oxides can be absorbed by various liquids within specific limits and conditions. Aqueous alkali seems to be the most promising method of NO_x absorption. The method would be most successful on an equimolecular mixture of NO and NO_2,[42] however this mixture is not found in combustion stacks.

Combustion Engineering[43] and UOP[44] report 20% NO_x removal by caustic scrubbing in their SO_2 removal experimentation.

Among other aqueous absorption liquids proved experimentally are: (a) molten alkali metal carbonates[45] (less than 15% removal efficiency in presence of CO_2), (b) sulfuric acid[3] (very uneconomical because of high fuel use for regeneration), (c) solutions of complex forming salts[3] and (d) organic solutions.

2. Adsorption of NO_x by Solids

Common adsorbents such as silica gel, alumina, char, molecular sieves and metal oxides and hydroxides are used to separate NO_x by adsorption from gas streams. Adsorption processes at low concentrations of NO_x in combustion sources have shown very limited success.

3. Catalytic Decomposition

NO_x can be decomposed to N_2 and O_2 by decomposition in the presence of catalysts, however, a very high temperature is required to achieve decomposition. There is no experimental data available to show catalytic decomposition at the NO_x concentrations that are found in power plant stacks.

4. Catalytic Reduction

Catalytic reduction of NO_x to N_2 by a reducing agent such as ammonia requires a sulfur resistent catalyst if coal or oil are used as the fuel source. Space velocity and catalyst life also limit this method at present. Available information is insufficient to assess the potential of this method for control of NO_x.

5. Other Methods

NO_x removal from flue gas based on differences in physical factors such as molecular size, condensation temperature and magnetic susceptibility of components appears very improbable.(3)

APPENDICES

Appendix A: Scattergood Unit 3: Los Angeles Power and Light (38)

Scattergood No. 3 unit rated at 460 MW is scheduled to go into operation in 1974. It is a tangentialy fired Combustion Engineering unit. The boiler is equipped with flue gas recirculation, provisions for over fire operation and for operation with selected burners out of service for off-stoichiometric combustion.

The unit as designed can operate with an NO_x emission of 30 ppm based on Los Angeles County Air Pollution Regulation Rule 67.

A use of 30 per cent gas recirculation combined with upper four burners out of service (33 per cent off-stoichiometric) combustion would lower the NO_x to about 70 ppm.

A combined chart of NO_x reduction by various operations of the burners and allowable NO_x emission at various loads is plotted in Figure 19.(38) The Figure shows that this unit can be operated in compliance with Los Angeles NO_x regulations at 315 MW emitting 42 ppm when operating with 33 per cent off-stoichiometric combustion and 30 per cent gas recirculation. The power company management has received Los Angeles County permit to operate the boiler at these conditions.

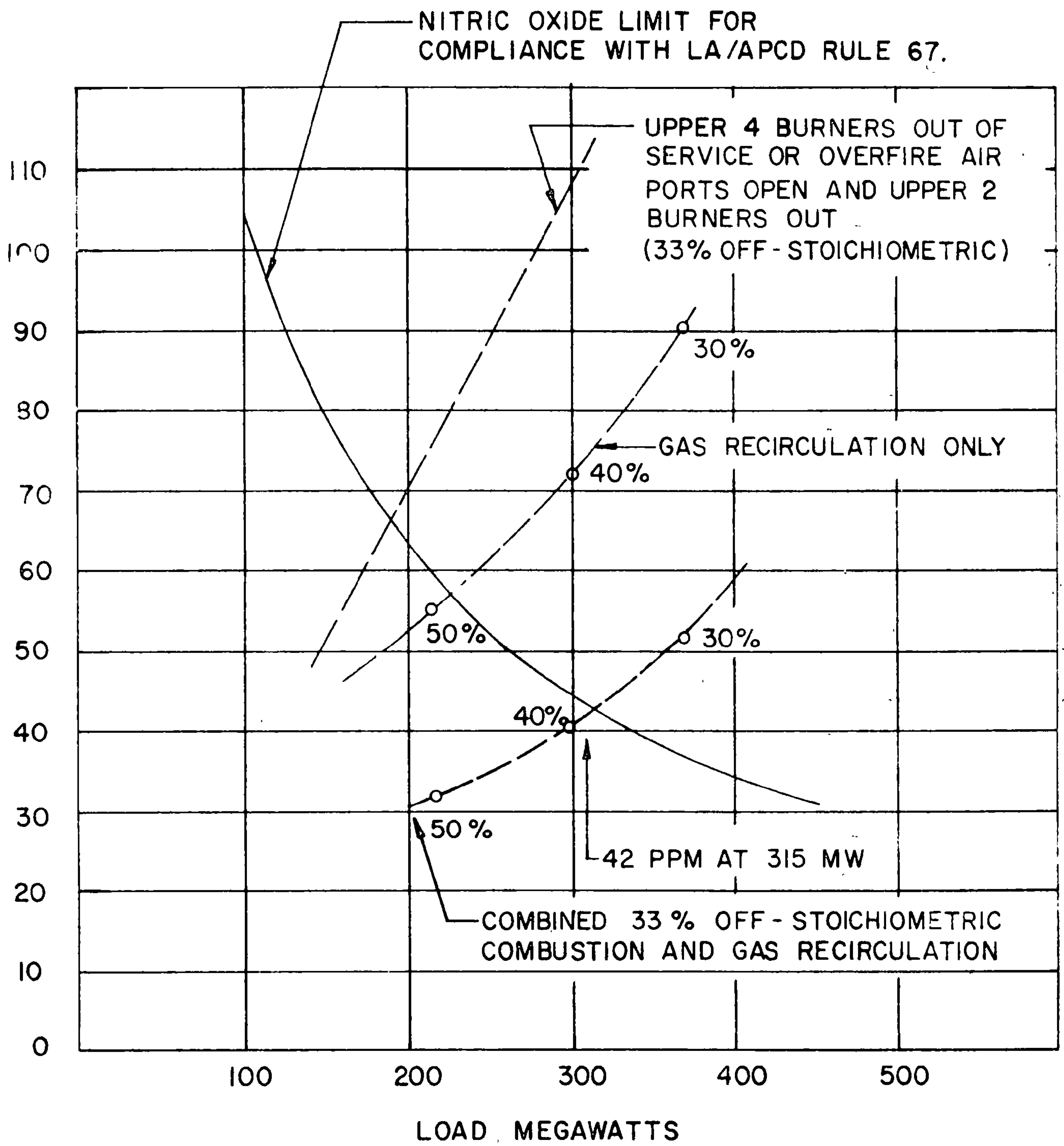


Figure 19. Predicted NO_x Emissions vs. Mode of Operation as Compared to Rule 67. (38)

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