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Alternative Control Techniques Document -- NOx Emissions from Utility Boilers

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Alternative Control Techniques Document--
NO_x Emissions from Utility Boilers

Emission Standards Division

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

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ALTERNATIVE CONTROL TECHNIQUES DOCUMENTS

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TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

Page

LIST OF TABLES (Continued)

LIST OF FIGURES

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

Page

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

Page

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

Page

LIST OF FIGURES (Continued)

1.0 INTRODUCTION

The 1990 Amendments (1990 Amendments) to the Clean Air Act amended title I of the Clean Air Act (ACT) by adding a new subpart 2 to part D of section 103. The new subpart 2 addresses ozone nonattainment areas. Section 183 (c) of the new subpart 2 provides that:

> [w]ithin 3 years after the date of the enactment of the [CAAA], the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of...oxides of nitrogen which emit, or have the potential to emit 25 tons per year or more of such pollutant.

These documents are to be subsequently revised and updated as the Administrator deems necessary.

Fossil fuel-fired utility boilers have been identified as a category of stationary sources that emit more than 25 tons of nitrogen oxides (NO_x) per year. This alternative control techniques (ACT) document provides technical information for State and local agencies to use in developing and implementing regulatory programs to control NO_x emissions from fossil fuel-fired utility boilers. Additional ACT documents are being or have been developed for other stationary source categories.

The information provided in this ACT document has been compiled from previous EPA documents, literature searches, and contacts with utility boiler manufacturers, individual utility companies, engineering and construction firms, control equipment vendors, and Federal, State, and local regulatory agencies. A summary of the findings from this study is presented in chapter 2.0. Descriptions of fossil fuel-fired utility boilers are given in chapter 3.0. A discussion of uncontrolled and baseline NO_x emissions from utility boilers is presented in chapter 4.0. Alternative NO_x control techniques and expected levels of performance are discussed in chapter 5.0. Chapter 6.0 discusses costs and cost effectiveness of each NO_x control technique. Chapter 7.0 discusses the environmental and energy impacts associated with NO_x control techniques. Information used to derive the costs of each NO_x control technology is contained in appendix A.

2.0 SUMMARY

The purpose of this document is to provide technical information that State and local agencies can use to develop strategies for reducing nitrogen oxides (NO_x) emissions from fossil fuel-fired utility boilers. This chapter presents a summary of the information contained in this document, including uncontrolled and controlled NO_x emissions data, alternative control techniques (ACT's), capital and annual costs, cost effectiveness, and secondary environmental and energy impacts associated with the various NO_x control techniques. Section 2.1 presents a summary of fuel use in utility boilers, section 2.2 presents an overview of NO_x formation, and section 2.3 describes utility boiler types and uncontrolled NO_x emission levels. Section 2.4 gives an overview of ACT's. The performance and costs of NO_x controls for coal-fired boilers is presented in section 2.5. The performance and costs of NO_x controls for natural gas- and oil-fired boilers is given in section 2.6. Secondary environmental impacts of NO_x controls are summarized in section 2.7.

2.1 SUMMARY OF FUEL USE IN UTILITY BOILERS

As of year-end 1990, the operable capacity of U. S. electric power plants totaled approximately 690,000 megawatts (MW). Of this, coal-fired generating capacity accounted for approximately 43 percent, or 300,000 MW. Coal that is fired in utility boilers can be classified by different ranks, i.e., anthracite, bituminous, subbituminous, and lignite. Each rank of coal has specific characteristics which can influence NO_x

emissions. These characteristics include heating value, volatile matter, and nitrogen content.

As of year-end 1990, natural gas- and oil-fired boilers accounted for approximately 28 percent of the total U. S. generating capacity. Of this, natural gas-fired generating capacity accounted for about 17 percent (120,000 MW) and oil-fired units, the remaining 11 percent (77,000 MW). The term "fuel oil" covers a broad range of petroleum products--from a light petroleum fraction (similar to kerosene) to a heavy residue. However, utility boilers typically fire No. 6 oil (residual oil).

2.2 OVERVIEW OF NO_x FORMATION

The formation of NO_x from a specific combustion device is determined by the interaction of chemical and physical processes occurring within the furnace. The three principal NO_x forms are "thermal" NO_x, "prompt" NO_x, and "fuel" NO_x. Thermal and fuel NO_x account for the majority of the NO_x formed in coal- and oil-fired utility boilers; however, the relative contribution of each of the total NO_x formed depends on the combustion process and fuel characteristics. Natural gas contains virtually no fuel nitrogen; therefore, the majority of the NO_x in these boilers is thermal NO_x.

Thermal NO_x results from the oxidation of atmospheric nitrogen in the high-temperature, post-flame region of a combustion system. The major factors that influence thermal NO_x formation are temperature, concentrations of oxygen and nitrogen, and residence time. If the temperature or the concentration of oxygen or nitrogen can be reduced quickly after combustion, thermal NO_x formation can be suppressed or quenched.

Prompt NO_x is formed in the combustion system through the reaction of hydrocarbon fragments and atmospheric nitrogen. As opposed to the slower formation of thermal NO_x, prompt NO_x is formed rapidly and occurs on a time scale comparable to the energy release reactions (i.e., within the flame). Thus, it is not possible to quench prompt NO_x formation as it is for thermal NO_x formation. However, the contribution of prompt NO_x to the total NO_x emissions of a system is rarely large.

The oxidation of fuel-bound nitrogen (fuel NO_x) is the principal source of NO_x emissions from combustion of coal and some oils. All indications are that the oxidation of fuel-bound nitrogen compounds to NO_x is rapid and occurs on a time scale comparable to the energy release reactions during combustion. The primary technique for controlling the formation of fuel NO_x is delayed mixing of fuel and air so as to promote conversion of fuel-bound nitrogen to N_2 rather than NO_x. As with prompt NO_x, fuel NO_x formation cannot be quenched as can thermal NO_x.

The formation of thermal, prompt, and fuel NO_x in combustion systems is controlled by modifying the combustion gas temperature, residence time, and turbulence (sometimes referred to as the "three T's"). Of primary importance are the localized conditions within and immediately following the flame zone where most combustion reactions occur. In utility boilers, the "three T's" are determined by factors associated with boiler and burner design, fuel characteristics, and boiler operating conditions.

2.3 DESCRIPTION OF BOILER TYPES AND UNCONTROLLED NO_x EMISSIONS

The various types of fossil fuel-fired utility boilers include tangentially-fired, single and opposed wall-fired, cell burner, cyclone, stoker, and fluidized bed combustion (FBC). Each type of furnace has specific design characteristics which can influence NO_x emissions levels. These include heat release rate, combustion temperatures, residence times, combustion turbulence, and oxygen levels.

As mentioned, NO_x emission rates are a function of various design and operating factors. Pre-new source performance standards (NSPS) boilers were not designed to minimize NO_x emission rates; therefore, their NO_x emissions are indicative of uncontrolled emission levels. Boilers subject to the subpart D or Da NSPS have some type of NO_x control and their

NO_x emissions are considered to be baseline emissions. To define uncontrolled NO_x emissions for the pre-NSPS boilers, emissions data from various databases and utility retrofit applications were examined. To define baseline NO_x emissions for the subpart D and Da boilers, the NSPS limits as well as emissions data from various databases were examined.

Table 2-1 summarizes the uncontrolled and baseline NO_x emission levels from conventional utility boilers. The NO_x levels are presented as a range and a typical level. The typical level reflects the mode, or most common value, of the NO_x emissions data in the various databases for the different types of boilers.

The range reflects the NO_x emissions expected on a short-term basis for most boilers of a given fuel and boiler type. However, the actual NO_x emissions from a specific boiler may be outside this range due to unit-specific design and operating conditions. Additionally, averaging time has an important impact on defining NO_x levels. The achievable emission limit for a boiler increases as the averaging time decreases. For example, a boiler that can achieve a particular NO_x limit on a 30-day basis may not be able to achieve that same limit on a 24-hour basis.

The tangential boilers are designed with vertically stacked nozzles in the furnace corners that inject stratified layers of fuel and air into relatively low-turbulence areas. This creates fuel-rich regions in an overall fuel-lean environment. The fuel ignites in the fuel-rich region before the layers are mixed in the highly turbulent center fireball. Local peak temperatures and thermal NO_x are lowered by the off-stoichiometric combustion conditions. Fuel NO_x formation is suppressed by the delayed mixing of fuel and air, which allows fuel-nitrogen compounds a greater residence time in a fuel-rich environment.

Tangential boilers typically have the lowest NO_x emissions of all conventional utility boiler types. As shown in table 2-1, the coal-fired, pre-NSPS tangential boilers have

TABLE 2-1. UNCONTROLLED/BASELINE NO_x EMISSION LEVELS FROM CONVENTIONAL FOSSIL FUEL-FIRED UTILITY BOILERS

Fuel type	Boiler type	NO_x emissions[a] (lb/MMBtu)		
		Pre-NSPS[b]	Subpart D[c]	Subpart Da[c]
Coal	Tangential	0.4-1.0 (0.7)	0.3-0.7 (0.6)	0.3-0.5 (0.5)
	Wall, dry	0.6-1.2 (0.9)	0.3-0.7 (0.6)	0.3-0.6 (0.5)
	Wall, wet	0.8-1.6 (1.2)	NA[d]	NA
	Cell	0.8-1.8 (1.0)	NA	NA
	Vertical, dry	0.6-1.2 (0.9)	NA	NA
	Cyclone	0.8-2.0 (1.5)	NA	NA
	Stoker	ND[e]	ND	0.3-0.6 (0.5)
Oil	Tangential	0.2-0.4 (0.3)	0.2-0.3 (0.25)	0.2-0.3 (0.25)
	Wall	0.2-0.8 (0.5)	0.2-0.3 (0.25)	0.2-0.3 (0.25)
	Vertical	0.5-1.0 (0.75)	NA	NA
Natural gas	Tangential	0.1-0.9 (0.3)	0.1-0.2 (0.2)	0.1-0.2 (0.2)
	Wall, single	0.1-1.0 (0.5)	0.1-0.2 (0.2)	0.1-0.2 (0.2)
	Wall, opposed	0.4-1.8 (0.9)	0.1-0.2 (0.2)	0.1-0.2 (0.2)

[a]NO_x emission levels shown are the expected range from tables 4-2, 4-3, and 4-4. The typical NO_x level is shown in parentheses.

[b]Pre-NSPS levels are uncontrolled NO_x emissions.

[c]Subpart D and subpart Da levels are baseline emissions (i.e., boilers have some types of NO_x controls). The typical NO_x level is shown in parentheses.

[d]NA = Not applicable since there are no boilers in this category.

[e]Data not available.

NO_x emissions in the range of 0.4 to 1.0 pound per million British thermal unit (lb/MMBtu), with typical NO_x emissions of 0.7 lb/MMBtu. For the tangential boilers subject to subpart D standards, the NO_x emissions are in the range of 0.3 to 0.7 lb/MMBtu with typical NO_x emissions of 0.6 lb/MMBtu. The NO_x emissions for the subpart Da boilers are in the range of 0.3 to 0.5 lb/MMBtu, with typical NO_x emissions of 0.5 lb/MMBtu.

The oil-fired, pre-NSPS tangential boilers have NO_x emissions in the range of 0.2 to 0.4 lb/MMBtu (0.3 lb/MMBtu typical). For the boilers subject to subpart D and Da standards, the NO_x emissions are in the range of 0.2 to 0.3 lb/MMBtu with typical emissions of 0.25 lb/MMBtu. The NO_x emissions from the natural gas-fired, pre-NSPS tangential boilers range from 0.1 to 0.9 lb/MMBtu (0.3 lb/MMBtu typical). For the boilers subject to subpart D and Da standards, the NO_x emissions are in the range of 0.1 to 0.2 lb/MMBtu with typical emissions of 0.2 lb/MMBtu.

The various types of wall-fired boilers include single, opposed, and cell burner. Single wall-fired boilers have several rows of burners mounted on one wall of the boiler, while opposed wall-fired boilers have multiple rows of burners mounted on the two opposing walls. Cell-burner units have two or three vertically-aligned, closely-spaced burners, mounted on opposing walls of the furnace. Single, opposed, and cell burners boilers all have burners that inject a fuel-rich mixture of fuel and air into the furnace through a central nozzle. Additional air is supplied to the burner through surrounding air registers. Of these types of wall-fired boilers, the cell burner is the most turbulent and has the highest NO_x emissions.

Table 2-1 presents the ranges and typical NO_x emissions for wall-fired boilers. For the pre-NSPS, dry-bottom, wall-fired boilers firing coal, the NO_x emissions are in the range of 0.6 to 1.2 lb/MMBtu with typical NO_x emissions of 0.9 lb/MMBtu. The range of NO_x emissions for these boilers subject to subpart D and subpart Da are in the range of 0.3 to 0.7 lb/MMBtu and 0.3 to 0.6 lb/MMBtu, respectively. The typical NO_x emissions for the subpart D, wall-fired boilers are 0.6 lb/MMBtu, while 0.5 lb/MMBtu is typical for the subpart Da boilers.

The pre-NSPS, wet-bottom, wall-fired boilers firing coal have NO_x emissions in the range of 0.8 to 1.6 lb/MMBtu with typical NO_x emissions of 1.2 lb/MMBtu. The pre-NSPS cell-type boiler has NO_x emissions in the range of 0.8 to 1.8 lb/MMBtu with typical NO_x emissions of 1.0 lb/MMBtu.

The NO_x emissions for the oil-fired pre-NSPS wall boilers are in the range of 0.2 to 0.8 lb/MMBtu with typical NO_x emissions of 0.5 lb/MMBtu. The natural gas-fired pre-NSPS single wall-fired boilers have NO_x emissions in the range of 0.1 to 1.0 lb/MMBtu with typical NO_x levels of 0.5 lb/MMBtu. The opposed wall, pre-NSPS boilers firing natural gas ranged from 0.4 to 1.8 lb/MMBtu with typical NO_x of 0.9 lb/MMBtu.

Vertical-fired boilers have burners that are oriented downward from the top, or roof, of the furnace. They are usually designed to burn solid fuels that are difficult to ignite. The NO_x emissions from these boilers are shown on table 2-1 and range from 0.6 to 1.2 lb/MMBtu. The typical NO_x emissions from these boilers are 0.9 lb/MMBtu. The vertical oil-fired boilers have NO_x emissions in the range of 0.5 to 1.0 lb/MMBtu with typical NO_x level of 0.75 lb/MMBtu.

Another type of utility boiler is the cyclone furnace. Cyclone furnaces are wet-bottom and fire the fuel in a highly turbulent combustion cylinder. Table 2-1 shows the range (0.8 to 2.0 lb/MMBtu) and typical NO_x level (1.5 lb/MMBtu) for these boilers. There have not been any wet-bottom wall-fired, cell, cyclone, or vertical boilers built since the subpart D or subpart Da standards were established.

Stoker boilers are designed to feed solid fuel on a grate within the furnace and remove the ash residual. The NO_x emissions from these boilers are in the range of 0.3 to 0.6 lb/MMBtu with typical NO_x levels of 0.5 lb/MMBtu.

Fluidized bed combustion is an integrated technology for reducing both sulfur dioxide (SO_2) and NO_x during the combustion of coal. These furnaces operate at much lower temperatures and have lower NO_x emissions than conventional types of utility boilers. While larger FBC units may be feasible, at this time the largest operating unit is 203 MW. Table 2-2 gives the NO_x emissions for the FBC using combustion controls to limit NO_x formation, and also when using selective noncatalytic reduction (SNCR). The NO_x emissions from FBC without SNCR are in the range of 0.1 to 0.3 lb/MMBtu with typical NO_x levels of 0.2 lb/MMBtu. The NO_x emissions from FBC with SNCR are in the range of 0.03 to 0.1 lb/MMBtu with typical NO_x levels of 0.07 lb/MMBtu.

2.4 OVERVIEW OF ALTERNATIVE CONTROL TECHNIQUES

Alternative control techniques for reducing NO_x emissions from new or existing fossil fuel-fired utility boilers can be grouped into one of two fundamentally different methods--combustion controls and post-combustion controls (flue gas treatment). Combustion controls reduce NO_x formation during the combustion process and include methods such as operational modifications, flue gas recirculation (FGR), overfire air (OFA), low NO_x burners (LNB), and reburn. The retrofit feasibility, NO_x reduction potential, and costs of combustion controls are largely influenced by boiler design and operating characteristics such as firing configuration, furnace size, heat release rate, fuel type, capacity factor, and the condition of existing equipment. Flue gas treatment controls reduce NO_x emissions after its formation and include SNCR and selective catalytic reduction (SCR).

Operational modifications involve changing certain boiler operational parameters to create conditions in the furnace that will lower NO_x emissions. Burners-out-of-service (BOOS) consists of removing individual burners from service by stopping the fuel flow. The air flow is maintained through the idle burners to create a staged-combustion atmosphere within the furnace. Low excess air (LEA) involves operating

TABLE 2-2. NO_x EMISSION LEVELS FROM FLUIDIZED BED COMBUSTION BOILERS

Classification	NO_x emissions[a] (lb/MMBtu)
Combustion controls only	0.1-0.3 (0.2)
With SNCR[b]	0.03-0.1 (0.07)

[a] NO_x emissions shown are the expected ranges from table 4-5. The typical NO_x level is shown in parentheses.

[b] Fluidized bed boilers with SNCR reduction for NO_x control as original equipment.

the boiler at the lowest level of excess air possible without jeopardizing good combustion. And, biased firing (BF) involves injecting more fuel to some burners and reducing the amount of fuel to other burners to create a staged-combustion environment. To implement these operational modifications, the boiler must have the flexibility to change combustion conditions and have excess pulverizer capacity (for coal firing). Due to their original design type or fuel characteristics, some boilers may not be amenable to the distortion of the fuel/air mixing pattern imposed by BOOS and BF. Also, some boilers may already be operating at the lowest excess air level.

Flue gas recirculation is a flame-quenching strategy in which the recirculated flue gas acts as a diluent to reduce combustion temperatures and oxygen concentrations in the combustion zone. This method is effective for reducing thermal NO_x and is used on natural gas- and oil-fired boilers. Flue gas recirculation can also be combined with operational modifications or other types of combustion controls on natural gas- and oil-fired boilers to further reduce NO_x emissions. Flue gas recirculation is used on coal-fired boilers for steam temperature control but is not effective for NO_x control on these boilers.

Overfire air is another technique for staging the combustion process to reduce the formation of NO_x. Overfire air ports are installed above the top row of burners on wall and tangential boilers. The two types of OFA for tangential boilers are close-coupled overfire air (CCOFA) and separated overfire air (SOFA). The CCOFA ports are incorporated into the main windbox whereas the SOFA ports are installed above the main windbox using separate ducting. The two types of OFA for wall-fired boilers are analogous to the tangential units. Conventional OFA has ports above the burners and utilizes the air from the main windbox. Advanced OFA has separate ductwork above the main windbox and, in some cases, separate fans to provide more penetration of OFA into the furnace.

Low NO_x burners are designed to delay and control the mixing of fuel and air in the main combustion zone. Lower combustion temperatures and reducing zones are created by the LNB which lower thermal and fuel NO_x. Low NO_x burners can sometimes be fitted directly into the existing burner opening; however, there may be instances where changes to the high-pressure waterwall components may be required. Low NO_x burners have been applied to both tangentially- and wall-fired boilers in new and retrofit applications. While tangential boilers have "coal and air nozzles" rather than "burners" as in wall-fired boilers, the term "LNB" is used in this document for both tangential and wall applications.

Retrofit applications must have compatible and adequate ancillary equipment, such as pulverizers and combustion control systems, to minimize carbon monoxide and unburned carbon emissions and to optimize the performance of the LNB. The NSPS subpart D and subpart Da standards have been met with LNB on new boilers; however, they tend to have larger furnace volumes than pre-NSPS boilers which results in lower NO_x emissions.

Low NO_x burners and OFA can be combined in some retrofit applications provided there is sufficient height above the top row of burners. However, there is limited retrofit experience with combining LNB and OFA in wall-fired boilers in the United States. There is more experience in retrofitting LNB and OFA in tangential boilers since most LNB for these boilers use some type of OFA (either CCOFA or SOFA). Some new boilers subject to subpart Da standards have used a combination of LNB and OFA to meet the NO_x limits. Low NO_x burners can also be combined with operational modifications and flue gas treatment controls to further reduce NO_x emissions.

Reburn is a NO_x control technology that involves diverting a portion of the fuel from the burners to a second combustion area (reburn zone) above the main combustion zone. Completion air (or OFA) is then added above the reburn zone to complete fuel burnout. The reburn fuel can be either natural gas, oil, or pulverized coal; however, most of the experience is with natural gas reburning. There are many technical issues in applying reburn, such as maintaining acceptable boiler performance when a large amount of heat input is moved from the main combustion zone to a different area of the furnace. Utilizing all the carbon in the fuel is also an issue when pulverized coal is the reburn fuel.

Reburn can be applied to most boiler types and is the only known combustion NO_x control technique for cyclone boilers although flue gas treatment controls may be effective on these boilers. There are only four full-scale demonstrations of reburn retrofit on coal-fired boilers in the United States, two of which have been on cyclone boilers, one on a tangentially-fired boiler, and one on a wall-fired boiler. All of these installations are on boilers smaller than 200 MW. There is one full-scale reburn + LNB project on a 150 MW wall-fired boiler. To date, there have not been any reburn installations on new boilers.

A similar technology is natural gas co-firing which consists of injecting and combusting natural gas near or concurrently with the main fuel (coal, oil, or natural gas). There is one full-scale application of natural gas co-firing on a 400 MW tangential, coal-fired boiler reported in this document.

Two commercially available flue gas treatment technologies for reducing NO_x emissions from existing fossil fuel utility boilers are SNCR and SCR. Selective noncatalytic reduction involves injecting ammonia (NH_3) or urea into the flue gas to yield elemental nitrogen and water. By-product emissions of SNCR are N_2O and NH_3 slip. The NH_3 or urea must be injected into specific high-temperature zones in the upper furnace or convective pass for this method to be effective. If the flue gas temperature at the point of NH_3 or urea injection is above the SNCR operating range, the injected reagent will oxidize to form NO_x. If the flue gas temperature is below the SNCR operating range, the reagent does not react with NO_x and is emitted to the atmosphere as NH_3. Ammonia emissions must be minimized because NH_3 is a pollutant and can also react with sulfur oxides in the flue gas to form ammonium salts, which can deposit on downstream equipment such as air heaters.

The other flue gas treatment method, SCR, involves injecting NH_3 into the flue gas in the presence of a catalyst. Selective catalytic reduction promotes the reactions by which NO_x is converted to elemental nitrogen and water at lower temperatures than required for SNCR. The SCR reactor can be placed before the air preheater (hot-side SCR) or after the air preheater (cold-side SCR). The catalyst may be made of precious metals (platinum or palladium), base metal oxides (vanadium/titanium are most common), or zeolites (crystalline aluminosilicate compounds). The performance of the SCR system is influenced by the flue gas temperature and moisture, fuel sulfur and ash content, NH_3/NO_x ratio, NO_x concentration at the SCR inlet, oxygen level, flue gas flow rate, space velocity, and catalyst condition. While SCR has been applied to some natural gas- and oil-fired boilers in the United States (primarily California), its use in the United States on coal has been limited to slip-stream applications. Several full-scale utility coal-fired SCR systems are currently under construction on new boilers.

Flue gas treatment controls can be combined with combustion controls to achieve additional NO_x reduction. Conceivably, either SNCR or SCR could be used with LNB; however, there is only one application of SNCR + LNB in the United States on a coal-fired boiler and it is in the early stages of demonstration. When combining LNB with SCR or SNCR, the design of the system is critical if the two NO_x control technologies are to achieve maximum reduction. In some cases, LNB can be designed to achieve the majority of the NO_x reduction, with SNCR or SCR used to "trim" the NO_x to the desired level.

2.5 SUMMARY OF PERFORMANCE AND COSTS OF NO_x CONTROLS FOR COAL-FIRED UTILITY BOILERS

2.5.1 Performance of NO_x Controls

A summary of NO_x emissions from coal-fired boilers with combustion NO_x controls is given in table 2-3. The table includes the NO_x reduction potential, typical uncontrolled NO_x levels, expected controlled NO_x levels for pre-NSPS boilers, and typical baseline NO_x levels for NSPS boilers. The typical uncontrolled NO_x levels for the pre-NSPS boilers are based on actual retrofit applications, published information, the National Utility Reference File (NURF), the EPA's AP-42 emission factors, and utility-supplied data. For the NSPS boilers, the typical baseline levels were derived from NO_x emission data from boilers with NO_x controls as original equipment. The typical uncontrolled NO_x level for a specific boiler may differ from those shown in table 2-3. Therefore, the expected controlled NO_x emission level should be adjusted accordingly. The expected controlled NO_x levels were determined by applying the range of NO_x reduction potential (percent) to the typical uncontrolled NO_x level.

Operational modifications have been shown to reduce NO_x emissions by 10-20 percent from pre-NSPS tangential boilers from uncontrolled NO_x levels of 0.7 lb/MMBtu to approximately 0.55 to 0.65 lb/MMBtu. Pre-NSPS wall-fired boilers with uncontrolled NO_x emissions of 0.9 lb/MMBtu may be reduced to 0.7 to 0.8 lb/MMBtu with operational modifications. Post-NSPS boilers may be originally designed to operate with LEA as part of the overall NO_x control strategy; therefore, additional reductions with operational modifications may only reduce NO_x marginally. There were no data available concerning the effectiveness of operational controls on these boilers.

Emissions data from two pre-NSPS boilers indicate that retrofit of OFA can reduce NO_x emissions from such boilers by 20 to 30 percent. Based on these data, pre-NSPS tangential boilers with retrofit OFA are expected to have controlled NO_x emissions of 0.50 to 0.55 lb/MMBtu. Corresponding wall-fired

TABLE 2-3. EXPECTED NO_x EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION CONTROLS

Control technology	NO_x reduction potential (%)[a]	Pre-NSPS boilers NO_x level (lb/MMBtu)		NSPS boilers NO_x levels (lb/MMBtu)	Applicable boiler designs
		Typical uncontrolled level[b]	Expected controlled level[c]	Typical baseline level[c]	
Operational Modifications (BOOS, LEA, BF)	10-20	T=0.70 W=0.90	T=0.55-0.65 W=0.70-0.80	--	Some wall and tangential boilers that have operational flexibility.
OFA	20-30	T=0.70 W=0.90	T=0.50-0.55 W=0.60-0.70	--	Some wall and tangential boilers with sufficient furnace height above top row of burners.
LNB[d]	T=35-45 W=40-50 Ce=50-55	T=0.70 W=0.90 Ce=1.0	T=0.40-0.45 W=0.45-0.55 Ce=0.45-0.50	T=0.35-0.50[e] W=0.25-0.50[e]	Most wall and tangential boilers, except slagging units.
LNB + AOFA[f]	T=40-50 W=50-60 Ce=50-60	T=0.70 W=0.90 Ce=1.0	T=0.35-0.40 W=0.35-0.45 Ce=0.40-0.50	T=0.35-0.50[e] W=0.40-0.55[e]	Some wall and tangential boilers with sufficient furnace height above top row of burners.
Reburn	50-60	T=0.70 W=0.90 Cy = 1.5	T=0.30-0.35 W=0.35-0.45 Cy=0.60-0.75	--	Most boiler types with sufficient furnace height above top row of burners.

[a] NO_x reduction potential based on data presented in Chapter 5.0.

[b] Typical levels based on data presented in Chapter 4.0. T = tangential, W = wall, Ce = cell, and Cy = cyclone.

[c] Controlled NO_x level based on typical NO_x level and data presented in Chapter 5.0. The expected NO_x emissions should be adjusted according to the actual uncontrolled NO_x level for a specific boiler by the NO_x reduction potential.

[d] Tangential low NO_x burners incorporate close-coupled overfire air.

[e] Post-NSPS boilers with NO_x controls as original or retrofit equipment.

[f] Tangential low NO_x burners incorporate separated overfire air.

-- = Not applicable.

boilers with uncontrolled NO_x levels of 0.9 lb/MMBtu are expected to have controlled NO_x emissions of 0.60 to 0.70 lb/MMBtu with OFA. However, not all pre-NSPS boilers have enough furnace height above the top row of burners to accommodate OFA ports.

Some NSPS boilers have OFA as part of the original NO_x control equipment. One application of OFA on a subpart Da boiler was shown to reduce NO_x by approximately 25 percent; however, OFA and the original LNB did not reduce NO_x to the NSPS limit and the LNB had to be replaced. Another application of OFA on a subpart D boiler reduced NO_x by approximately 20 percent to the NSPS limit. There are no data available concerning the effectiveness of retrofitting OFA on a NSPS boiler.

With retrofit LNB (including CCOFA) on pre-NSPS tangential boilers, the controlled NO_x emissions are expected to be reduced by 35 to 45 percent to 0.40 to 0.45 lb/MMBtu from an uncontrolled level of 0.7 lb/MMBtu. With LNB on wall-fired boilers, the NO_x emissions are expected to be reduced by 40 to 50 percent to 0.45 to 0.55 lb/MMBtu from an uncontrolled level of 0.9 lb/MMBtu. The cell boilers are also expected to average 0.45 to 0.50 lb/MMBtu with LNB (50 to 55 percent reduction) from an uncontrolled level of 1.0 lb/MMBtu. Results from 18 retrofit applications were used to estimate the effectiveness of LNB.

Some post-NSPS boilers were designed with LNB to meet the subpart D and subpart Da standards and the NO_x emissions are in the range of 0.35 to 0.50 lb/MMBtu for tangential boilers and 0.25 to 0.50 lb/MMBtu for wall boilers. Results from 22 new applications were used to estimate the effectiveness of LNB.

For the pre-NSPS tangential boilers with retrofit LNB + OFA, the controlled NO_x emissions are expected to be reduced by 40 to 50 percent to 0.35 to 0.40 lb/MMBtu from an uncontrolled level of 0.7 lb/MMBtu. Wall-fired boilers with uncontrolled NO_x of 0.9 lb/MMBtu are expected to be reduced to 0.35 to

0.45 lb/MMBtu (50 to 60 percent reduction) with LNB + AOFA. Cell-fired boilers are expected to average 0.40 to 0.50 lb/MMBtu (50 to 60 percent reduction) from an uncontrolled level of 1.0 lb/MMBtu. The effectiveness of LNB + OFA is based on 11 retrofit applications.

Some post-NSPS boilers were designed with LNB + AOFA to meet the subpart D and subpart Da standards and the NO_X emissions range from 0.25 to 0.50 lb/MMBtu for tangential and 0.40 to 0.55 lb/MMBtu for wall boilers. As a retrofit control, the combination of LNB + AOFA may be applicable to only the boilers with sufficient furnace height and volume to accommodate the additional air ports. The effectiveness of LNB + AOFA on new boilers is based on results from two applications.

With reburn retrofit on pre-NSPS tangential boilers, the NO_X emissions are expected to be 0.30 to 0.35 lb/MMBtu. For the wall-fired boilers, the NO_X emissions are expected to be 0.35 to 0.45 lb/MMBtu, whereas the NO_X emissions are is expected to be 0.6 to 0.75 lb/MMBtu for cyclone boilers. These emission rates are based on limited data from four reburn retrofit projects on pre-NSPS boilers less than 200 MW in size. Based on these data, 50 to 60 percent reduction is estimated for all boiler types. One natural gas co-firing application on a 450 mw coal-fired boiler yielded only 20 to 30 percent NO_X reduction. There are no NSPS boilers in operation with reburn as original or retrofit equipment. However, it is estimated that these boilers can achieve approximately the same reduction (50 to 60 percent) as pre-NSPS boilers since they may have large furnace volumes and should be able to accommodate the reburn and completion air ports above the top row of burners.

As shown in table 2-4, applying SNCR to pre-NSPS tangential boilers is expected to reduce NO_X emissions by 30 to 60 percent to 0.30 to 0.50 lb/MMBtu. For wall-fired boilers, the NO_X emissions are expected to average 0.35 to 0.65 lb/MMBtu with SNCR. It is estimated that the range of

TABLE 2-4. EXPECTED NO_x EMISSIONS FROM COAL-FIRED UTILITY BOILERS WITH FLUE GAS TREATMENT CONTROLS

Control technology	NO_x reduction potential[a] (%)	Pre-NSPS boilers NO_x level (lb/MMBtu)		NSPS boilers NO_x levels (lb/MMBtu)	Applicable boiler designs
		Typical uncontrolled level[b]	Expected controlled level[c]	Expected controlled level[d]	
SNCR	30-60	T=0.70 W=0.90 Ce=1.0 Cy=1.5	T=0.30-0.50 W=0.35-0.65 Ce=0.40-0.70 Cy=0.6-1.10	T=0.20-0.35 W=0.25-0.40 FBC=0.03-0.10	Applicable to most boiler designs. Must have sufficient residence time at correct temperature (870-1,040 °C).
SCR	75-85[f]	T=0.70 W=0.90 Ce=1.0 Cy=1.5	T=0.10-0.20 W=0.15-0.25 Ce=0.15-0.25 Cy=0.25-0.40	T=0.10-0.15 W=0.10-0.15	Applicable to most boiler designs. Hot-side SCR best used on low sulfur fuel and low fly ash applications. Cold-side SCR can be used on high sulfur, high ash applications if equipped with upstream FGD.
LNB + SNCR	50-80[f]	T=0.70 W=0.90 Ce=1.0	T=0.15-0.35 W=0.20-0.45 Ce=0.20-0.50	T=0.20-0.35 W=0.25-0.40	Same as SNCR and LNB alone
LNB + AOFA + SCR	85-95[f]	T=0.70 W=0.90 Ce=1.0	T=0.05-0.10 W=0.05-0.10 Ce=0.05-0.15	T=0.10-0.15 W=0.10-0.15	Same as SCR and LNB + AOFA alone

[a]NO_x reduction based on data presented in Chapter 5.0.

[b]Typical uncontrolled levels based upon data presented in Chapter 4.0. T = tangential, W = wall, Ce = cell, Cy = cyclone, and FBC = fluidized bed combustion.

[c]Controlled NO_x level based on the typical NO_x level and data presented in Chapter 5.0. The expected NO_x emissions should be adjusted according to the actual uncontrolled NO_x level for a specific boiler by the NO_x reduction potential.

[d]Controlled levels for flue gas treatment as original or retrofit equipment.

controlled NO_x emissions from the cell and cyclone boilers retrofit with SNCR would be 0.40 to 0.70 lb/MMBtu and 0.60 to 1.10 lb/MMBtu, respectively. However, SNCR has not been applied to any cell and cyclone boilers at this time. The predicted effectiveness of SNCR for pre-NSPS boilers is based on three full-scale applications on coal-fired boilers (two wall-fired and one vertical-fired). There are no data available from any conventional NSPS utility boilers with SNCR as original or retrofit equipment. However, the same NO_x reduction (30 to 60 percent) is expected on these boilers as on pre-NSPS boilers.

The FBC boilers designed with SNCR as original equipment have NO_x emissions 50 to 80 percent lower than FBC boilers without SNCR and have emissions in the range of 0.03 to 0.10 lb/MMBtu. This is based on results from seven original applications of SNCR on FBC boilers.

The remaining flue gas treatment control, SCR, has had very limited application on coal firing in the United States. However, SCR is being used in Japan and Germany on a number of coal-fired utility boilers. Primary concerns associated with transfer of foreign SCR performance data to the U.S. are the higher sulfur and alkali contents in many U.S. coals, both of which may act as catalyst poisons and thereby reduce catalyst activity and lifetime. The predicted effectiveness of SCR is 75 to 85 percent, which is based on data from three pilot-scale applications in the U.S. By retrofitting SCR on pre-NSPS boilers, the estimated NO_x emissions from tangential and wall boilers would be 0.10 to 0.20 lb/MMBtu and 0.15 to 0.25 lb/MMBtu, respectively. Predicted emissions from cell and cyclone boilers would be 0.15 to 0.25 lb/MMBtu and 0.25 to 0.40 lb/MMBtu, respectively. Since there are no full-scale applications on coal in the United States, the expected ranges of NO_x reduction and NO_x emissions are estimated.

The combination of LNB + SNCR is estimated to reduce NO_x emissions by 50 to 80 percent; however, this combination of controls has only been applied to one coal-fired boiler and the results indicate approximately 70 percent reduction. For the pre-NSPS tangential boilers, the NO_x emissions are expected to be in the range of 0.15 to 0.35 lb/MMBtu. The NO_x emissions from the pre-NSPS wall boilers are expected to be in the range of 0.20 to 0.45 lb/MMBtu. For the cell boilers, the NO_x emissions are expected to be in the range of 0.20 to 0.50 lb/MMBtu. For the NSPS boilers, the NO_x reduction from LNB + SNCR is expected to be the same as SNCR alone (30 to 60 percent from the NSPS levels) since these boilers already have LNB as original equipment. However, there are no applications of LNB + SNCR as original equipment on new boilers yet.

By combining LNB + AOFA + SCR, it is estimated that 85 to 95 percent NO_x reduction can be achieved on pre-NSPS boilers. For these boilers, the NO_x emissions are expected to be in the range of 0.05 to 0.15 lb/MMBtu, depending on boiler type. For the NSPS boilers, the NO_x reduction are expected to be the same as for SCR alone (75 to 85 percent from NSPS levels), since these boilers may already have LNB + AOFA as original equipment. However, there are no applications of LNB + AOFA + SCR as original equipment in operation on new boilers at this time. This combination of controls has not been applied to existing pre-NSPS boilers either; therefore, these reductions and controlled levels are estimates only and have not been demonstrated.

2.5.2 <u>Costs of NO_x Controls</u>

The estimated costs for controlling NO_x emissions are based on data from utilities, technology vendors, and published literature. The actual costs for both new and retrofit cases depend on a number of boiler-specific factors, and a particular NO_x control technology may not be applicable to some individual boilers. The costs presented here are meant to provide general guidance for determining costs for similar situations. The costs are presented in 1991 dollars. However, cost indices for 1992 dollars are only 0.85 percent lower than 1991 dollars; therefore, the values in this section are indicative of the 1991-1992 timeframe.

Table 2-5 presents a summary of the cost effectiveness of various NO_x controls applied to coal-fired utility boilers. The costs presented are for LNB, LNB + AOFA, reburn, SNCR, SCR, LNB + SNCR, and LNB + AOFA + SCR applied to both tangential and wall boilers. Costs for reburn, SNCR, and SCR are given for cyclone boilers, and costs for SNCR are given for FBC boilers. The costs are based on various factors as described in chapter 6. The cost estimates for SNCR are for a low-energy, urea-based SNCR system as they were found to be comparable in cost to a high-energy NH_3-based SNCR system.

For tangential boilers, the cost effectiveness ranges from a low of $100 per ton for LNB (a new 600 MW baseload boiler) to a high of $12,400 per ton for LNB + AOFA + SCR (a 100 MW peaking boiler and a 2-year catalyst life). The retrofit of LNB or LNB + AOFA is estimated to result in the least cost per ton of NO_x removed for the tangential boilers. The cost effectiveness for LNB ranges from $100 to $1,800 per ton. The cost effectiveness for LNB + AOFA ranges from $170 to $3,300 per ton. The primary cause of the higher cost effectiveness values is boiler duty cycle (i.e., capacity factor). The retrofit of SCR or LNB + AOFA + SCR is estimated to be the highest cost per ton of NO_x removed. The cost effectiveness for SCR ranges from $1,580 to $12,200 per ton. The cost effectiveness for LNB + AOFA + SCR ranges from $1,500 to $12,400 per ton.

Figure 2-1 shows the NO_x control cost effectiveness for a 300 MW baseload tangential boiler. As shown, LNB and LNB + AOFA have the lowest cost effectiveness for controlled NO_x levels of 0.35 to 0.45 lb/MMBtu. The large variation in reburn cost effectiveness (on this and other figures in the section) is driven primarily by the fuel price differential between natural gas and coal ($0.50 to $2.50/MMBtu). The cost effectiveness of individual control techniques increases as the controlled NO_x emissions decrease.

TABLE 2-5. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS FOR COAL-FIRED UTILITY BOILERS (1991 DOLLARS)

Boiler firing type	NO_x control technology	Cost Effectiveness ($/ton)[a]				
		100 MW (peaking)[b]	100 MW (baseload)[c]	300 MW (cycling)[d]	300 MW (baseload)	600 MW (baseload)
Tangential	LNB[e]	1,120-1,800	220-350	280-440	140-220	100-170
	LNB + AOFA	2,060-3,300	400-630	460-730	230-370	170-260
	Reburn	3,870-5,930	970-3,030	1,150-3,220	720-2,790	620-2,680
	SNCR	2,600-2,960	860-1,160	900-1,210	670-970	600-910
	SCR	9,470-12,200	1,970-2,490	3,140-4,160	1,690-2,210	1,580-2,100
	LNB + SNCR	2,420-2,530	590-700	660-770	410-520	340-450
	LNB + AOFA + SCR	9,990-12,400	2,020-2,490	3,120-4,040	1,650-2,110	1,500-1,970
Wall	LNB	2,000-3,200	380-620	470-750	240-380	180-280
	LNB + AOFA	3,420-5,470	660-1,050	750-1,200	380-610	270-430
	Reburn	3,010-4,600	750-2,360	900-2,500	560-2,170	480-2,080
	SNCR	2,160-2,470	760-1,070	800-1,100	620-920	560-870
	SCR	7,540-9,650	1,580-1,990	2,500-3,300	1,360-1,760	1,270-1,670
	LNB + SNCR	2,750-2,860	650-760	740-850	450-560	370-480
	LNB + AOFA + SCR	9,250-11,100	1,870-2,230	2,760-3,480	1,460-1,820	1,300-1,600
Cyclone	Reburn	1,810-2,770	460-1,420	540-1,510	340-1,300	290-1,250
	SNCR	1,460-1,780	620-940	650-960	540-850	510-820
	SCR	4,670-5,940	1,010-1,260	1,560-2,040	870-1,110	810-1,050

[a]Cost effectiveness based on data presented in Chapter 6.0.
[b]Peaking = 10% capacity factor.
[c]Baseload = 65% capacity factor.
[d]Cycling = 30% capacity factor.
[e]Incorporates close-coupled overfire air.

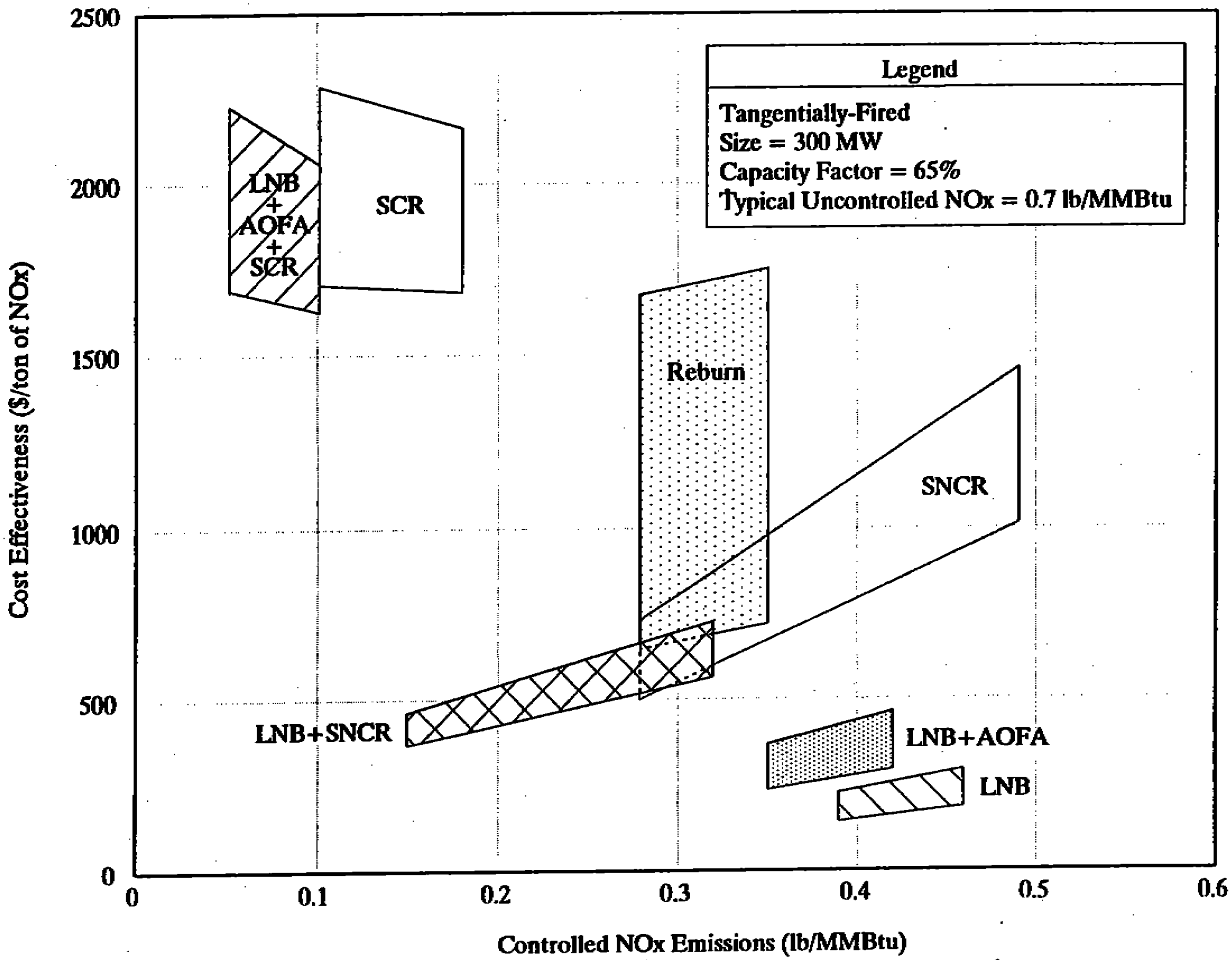


Figure 2-1. NO_x control cost effectiveness for coal-fired tangential boilers.

For wall boilers, the cost effectiveness ranges from a low of \$180 per ton for LNB (a new 600 MW baseload boiler) to a high of \$11,100 for LNB + AOFA + SCR (a 100 MW peaking boiler and a 2-year catalyst life). Typically, the retrofit of LNB or LNB + AOFA is estimated to result in the lowest cost per ton of NO_x removed for the wall boilers. The cost effectiveness for LNB ranges from \$180 to \$3,200 per ton. The cost effectiveness for LNB + AOFA ranges from \$270 to \$5,470 per ton. The retrofit of SCR or LNB + AOFA + SCR is estimated to have the highest cost per ton of NO_x removed. The cost effectiveness of SCR ranges from \$1,290 to \$9,650 per ton. The cost effectiveness of LNB + AOFA + SCR ranges from \$1,300 to \$11,100 per ton.

Figure 2-2 shows the NO_x control cost effectiveness for a 300 MW baseload wall boiler. As shown, LNB and LNB + AOFA have the lowest cost effectiveness for controlled NO_x levels of 0.35 to 0.55 lb/MMBtu. Reburn is also cost effective if the price of the reburn fuel is economical.

Estimated cost effectiveness for reburn, SNCR, and SCR for cyclone boilers are also shown in table 2-5. The retrofit of reburn and SNCR has the lowest estimated cost per ton of NO_x removed whereas retrofitting SCR has the highest. The cost effectiveness of reburn ranges from \$290 to \$2,770 per ton and the cost effectiveness of SNCR ranges from \$510 to \$1,780 per ton. The cost effectiveness of SCR ranges from \$810 to \$5,940 per ton. Figure 2-3 shows the NO_x control cost effectiveness for a 300 MW baseload cyclone boiler. The large variation in SNCR cost effectiveness is driven primarily by the variability in chemical costs and NO_x reductions among individual boilers.

The cost effectiveness for SNCR applied to FBC boilers is given in table 2-6 and ranges from a low of \$1,500 per ton (200 MW baseload) to a high of \$5,400 per ton (50 MW cycling).

In all cases, the factor having the greatest potential impact on the cost effectiveness of NO_x controls is boiler capacity factor. Depending on the control technology, the cost effectiveness associated with reducing NO_x emission from

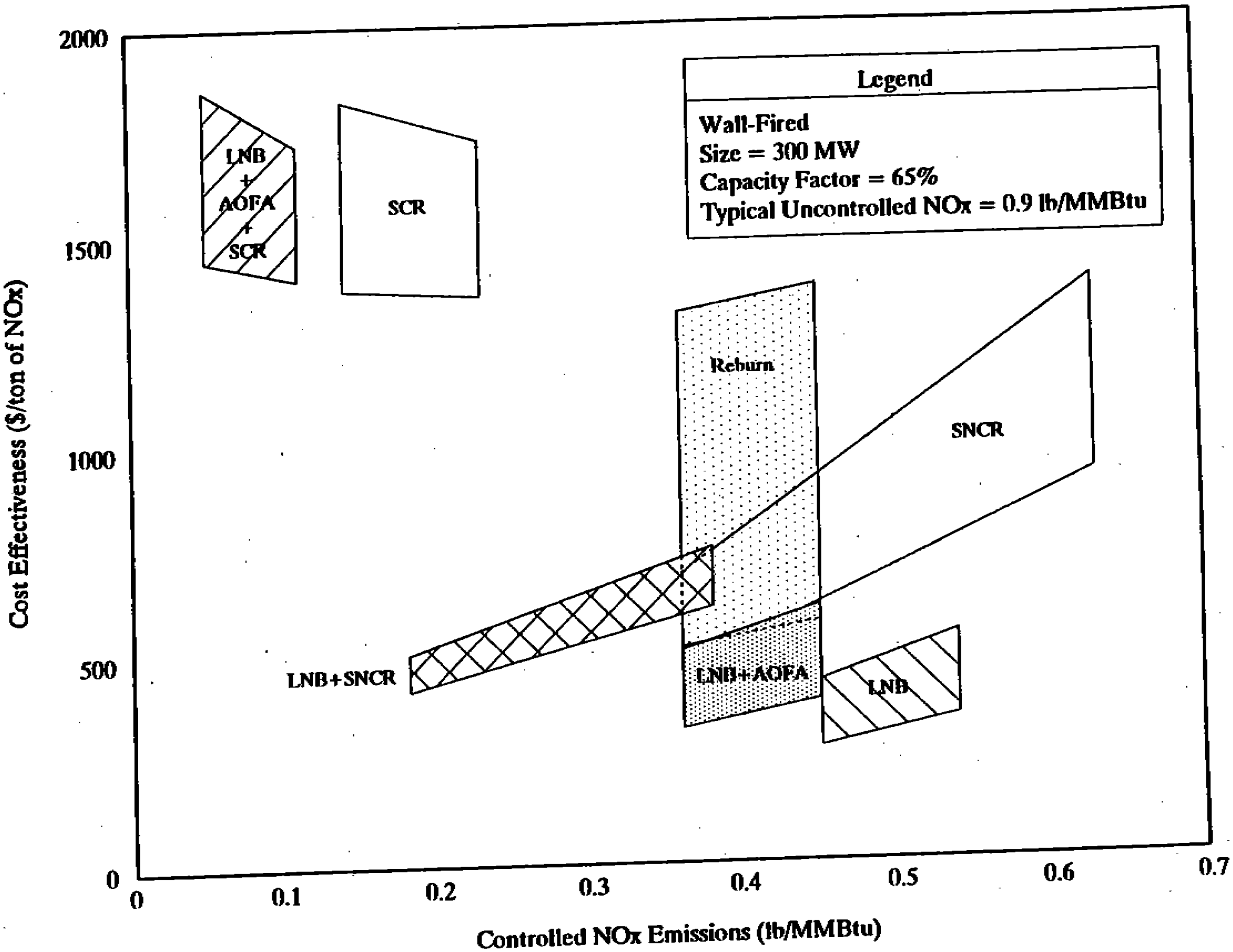


Figure 2-2. NO_x control cost effectiveness for coal-fired wall boilers

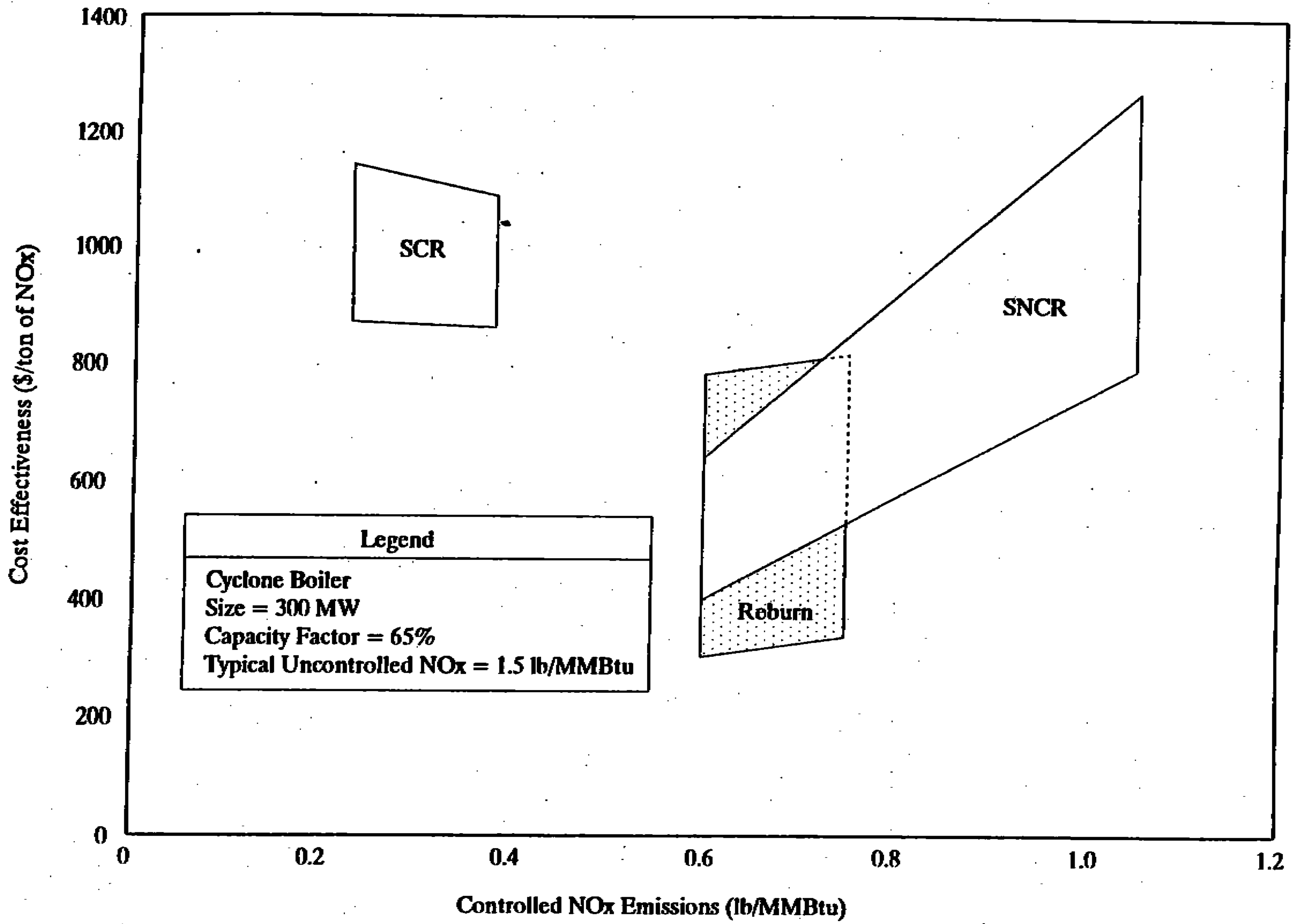


Figure 2-3. NO_x control cost effectiveness for coal-fired cyclone boilers.

TABLE 2-6. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS FOR FBC BOILERS (1991 DOLLARS)

Boiler firing type	NO_x control technology	Cost Effectiveness ($/ton)[a]				
		50 MW (cycling)[b]	50 MW (baseload)[c]	100 MW (cycling)	100 MW (baseload)	200 MW (baseload)
FBC	SNCR	5,100-5,400	2,800-3,100	3,550-3,850	2,000-2,300	1,500-1,800

[a]Cost effectiveness based on data presented in Chapter 6.0.

[b]Cycling = 30% capacity factor.

[c]Baseload = 65% capacity factor.

a peaking-duty boiler (10 percent capacity factor) is 2 to 5 times higher than for a baseload boiler (65 percent capacity factor). Other significant factors influencing control technology cost effectiveness are the economic life of the control system, the boiler size, and the uncontrolled NO_x level.

2.6 SUMMARY OF PERFORMANCE AND COSTS OF NO_x CONTROLS FOR NATURAL GAS- AND OIL-FIRED UTILITY BOILERS

2.6.1 Performance of NO_x Controls

A summary of NO_x emissions from natural gas- and oil-fired boilers with retrofit combustion controls is given in table 2-7. The table includes the NO_x reduction potential for each technology, typical uncontrolled NO_x levels, and expected controlled NO_x levels. These data are based on actual retrofit applications, published literature, NURF, the EPA's AP-42 emission factors, and information obtained from utilities. The typical uncontrolled NO_x level for a specific boiler may differ from those shown in table 2-7. Therefore, the expected controlled NO_x emission level should be adjusted accordingly. The expected controlled NO_x levels were determined by applying the range of NO_x reduction potential (percent) to the typical uncontrolled NO_x level.

For pre-NSPS tangential boilers, the uncontrolled NO_x level of 0.30 lb/MMBtu is expected to be reduced to 0.15 to 0.20 lb/MMBtu (30 to 50 percent reduction) with operational modifications such as BOOS + LEA. Corresponding pre-NSPS wall-fired boilers with uncontrolled NO_x emissions of 0.50 lb/MMBtu are expected to be reduced to 0.25 to 0.35 lb/MMBtu with operational modifications. Data was not available for operational controls on boilers subject to subpart D and subpart Da standards; however, it is estimated that these boilers may achieve approximately the same reduction (30 to 50 percent) as the pre-NSPS boilers. The effectiveness of operational controls are based on eight retrofit applications.

TABLE 2-7. EXPECTED NO_x EMISSIONS FROM NATURAL GAS- AND OIL-FIRED UTILITY BOILERS WITH COMBUSTION CONTROLS

Control technology[a]	NO_x reduction potential[b] (%)	Pre-NSPS Boilers NO_x level (lb/MMBtu)		NSPS Boilers NO_x level (lb/MMBtu)	Applicable boiler designs
		Typical uncontrolled level[c]	Expected controlled level[d]	Typical baseline level[e]	
Operational Modifications (LEA + BOOS)	30-50	Gas and oil: T=0.3 W=0.5	Gas and Oil: T=0.15-0.20 W=0.25-0.35	Oil: T,W=0.15-0.25 Gas: T,W=0.10-0.20	Most boilers that have operational flexibility.
FGR	45-55	Gas and Oil: T=0.3 W=0.5	Gas and Oil: T=0.15-0.20 W=0.25-0.30	Oil: T,W=0.10-0.25 Gas: T,W=0.10-0.20	Most wall and tangential boilers.
OFA	20-45	Gas and Oil: T=0.3 W=0.5	Gas and Oil: T=0.20-0.30 W=0.30-0.45	Oil: T,W=0.15-0.25 Gas: T,W=0.10-0.20	Most wall and tangential boilers.
LNB	30-50	Gas and Oil: T=0.3 W=0.5	Gas and Oil: T=0.15-0.20 W=0.25-0.35	Oil: T,W=0.10-0.25 Gas: T,W=0.10-0.20	Most wall and tangential boilers.
LNB + OFA (or BOOS)	40-50	Gas and Oil: T=0.3 W=0.5	Gas and Oil T=0.15-0.20 W=0.25-0.30	Oil: T,W=0.10-0.25 Gas: T,W=0.10-0.20	Most wall and tangential boilers with sufficient furnace height.
Combination Controls[f]	60-90	Gas and Oil: T=0.3 W=0.5	Gas and Oil: T=0.05-0.15 W=0.05-0.20	Oil: T,W=0.05-0.25 Gas: T,W=0.05-0.20	Most wall and tangential boilers.
Reburn[g]	50-60	Oil: T=0.3 W=0.5	Oil: T=0.10-0.20 W=0.20-0.25	Oil: T=0.10-0.25 W=0.10-0.25	Some boiler designs with large furnace volumes and sufficient furnace height.

[a]BOOS = burners-out-of-service, LEA = low excess air, FGR = flue gas recirculation, OFA = overfire air, LNB = low NO_x burners.
[b]NO_x reduction based on data presented in chapter 5.
[c]Typical uncontrolled levels based on data presented in chapter 4. T = tangential and W = wall.
[d]Controlled NO_x level based on typical NO_x level and data presented in chapter 5. The expected NO_x emissions should be adjusted according to the actual uncontrolled NO_x level for a specific boiler.
[e]Post-NSPS boilers with NO_x controls as original or retrofit equipment.
[f]Combination of FGR + BOOS or OFA; LNB + FGR + BOOS (or OFA).
[g]Limited experience abroad on gas/oil and nonexistent experience in U. S. Percent reduction based on coal-fired experience.

The pre-NSPS tangential boilers are expected to reduce NO_x from an uncontrolled level of 0.30 lb/MMBtu to a controlled NO_x level of 0.15 to 0.20 lb/MMBtu with FGR (45 to 55 percent reduction). Corresponding wall-fired boilers are expected to have controlled NO_x emissions of 0.25 to 0.30 lb/MMBtu with FGR. The post-NSPS boilers are expected to achieve the same percent reduction as the pre-NSPS boilers (45 to 55 percent). The effectiveness of FGR is based on two retrofit applications.

With retrofit OFA on pre-NSPS tangential boilers, the controlled NO_x emissions are expected to be 0.15 to 0.30 lb/MMBtu and the wall-fired boilers are expected to be 0.30 to 0.45 lb/MMBtu. Some post-NSPS boilers may be designed or retrofitted with OFA to meet the subpart D and subpart Da standards and are expected to be in the range of 0.10 to 0.25 lb/MMBtu depending on fuel. However, OFA is typically combined with other combustion modifications such as LEA rather than used alone. The estimated percent reduction is based on four applications of OFA + LEA on pre-NSPS boilers.

With retrofit LNB on pre-NSPS tangential boilers, the controlled NO_x emissions are expected to be 0.15 to 0.20 lb/MMBtu and the wall-fired boilers are expected to be 0.25 to 0.35 lb/MMBtu (30 to 50 percent reduction). Some post-NSPS wall and tangential boilers may be designed with LNB to meet the subpart D and subpart Da standards and are in the range of 0.10 to 0.25 lb/MMBtu depending on fuel. Results from six pre-NSPS retrofit applications were used to estimate the effectiveness of LNB.

By combining FGR + BOOS (or OFA) + LNB on pre-NSPS tangential and wall boilers, the controlled NO_x emissions are expected to be 0.05 to 0.20 lb/MMBtu. Some post-NSPS boilers may be designed with FGR + BOOS + LNB that meet the subpart D and subpart Da standards and are in the range of 0.05 to 0.25 lb/MMBtu. These results are based on two pre-NSPS boilers.

With reburn on pre-NSPS tangential and wall boilers firing oil, the NO_x emissions are estimated to be 0.10 to 0.20 lb/MMBtu and 0.20 to 0.25 lb/MMBtu, respectively. However, reburn experience on oil-fired boilers is very limited and the expected controlled emissions are estimated. There are no post-NSPS oil-fired boilers with reburn as original equipment. The effectiveness of reburn on oil-fired boilers is based on the coal-fired experience and is estimated to be 50 to 60 percent reduction.

Table 2-8 presents a summary of expected NO_x emissions from natural gas- and oil-fired boilers with flue gas treatment alone and combined with combustion controls. For pre-NSPS tangential boilers with SNCR, the expected controlled NO_x level is expected to be 0.20 to 0.25 lb/MMBtu, whereas the range for wall-fired boilers is 0.30 to 0.40 lb/MMBtu (25 to 40 percent). These results are based on two SNCR application on oil boilers and ten SNCR applications on natural gas boilers. For post-NSPS boilers with SNCR, the expected controlled NO_x level is 0.10 to 0.25 lb/MMBtu retrofit depending on boiler type. However, there are no data from post-NSPS boilers with SNCR, nor are there data from post-NSPS boilers designed with SNCR as original equipment. Therefore, these reductions and controlled levels are estimated.

For pre-NSPS tangential boilers, the expected controlled NO_x is 0.03 to 0.10 lb/MMBtu with retrofit SCR. The expected controlled NO_x for wall-fired boilers is 0.05 to 0.10 lb/MMBtu. For post-NSPS boilers, the expected controlled NO_x levels is 0.05 to 0.25 lb/MMBtu depending on boiler type. These results are based on one pilot-scale and one full-scale application. There are no data from post-NSPS boilers with retrofit SCR, nor are there data from post-NSPS boilers designed with SCR as original equipment. Therefore, these reductions and controlled levels are estimates only.

The combination of LNB + SNCR is estimated to reduce NO_x emissions by 70 to 80 percent and data from one application of LNB + OFA + SNCR on a coal-fired boiler shows 70-85 percent

TABLE 2-8. EXPECTED NO_x EMISSIONS FROM NATURAL GAS- AND OIL-FIRED UTILITY BOILERS WITH FLUE GAS TREATMENT CONTROLS

Control technology[a]	NO_x reduction potential[b] (%)	Pre-NSPS boilers NO_x level (lb/MMBtu)		NSPS boilers NO_x level (lb/MMBtu)	Applicable boiler designs
		Typical uncontrolled level[c]	Expected controlled level[d]	Expected controlled level[e]	
SNCR[f]	25-40	Gas and Oil: T=0.30 W=0.50	Gas and Oil: T=0.20-0.25 W=0.30-0.40	Oil: T,W=0.15-0.25 Gas: T,W=0.10-0.20	Applicable to most boiler designs; however, must have sufficient residence time in convective pass at correct temperature.
SCR[g]	80-90	Gas and Oil: T=0.30 W=0.50	Gas and Oil: T=0.03-0.10 W=0.05-0.10	Oil: T,W=0.05-0.25 Gas: T,W=0.03-0.20	Applicable to most boiler designs. Hot-side SCR best used on low sulfur fuel and low fly ash applications. Cold-side SCR can be used on high sulfur, high ash applications, if equipped with upstream FGD.
LNB + SNCR[g]	70-80	Gas and Oil: T=0.30 W=0.50	Gas and Oil: T=0.05-0.10 W=0.10-0.15	Oil: T,W=0.10-0.25 Gas: T,W=0.05-0.20	Same as SNCR and LNB's alone.
LNB + AOFA + SCR[g]	85-95	Gas and Oil: T=0.30 W=0.50	Gas and Oil: T=0.02-0.10 W=0.03-0.10	Oil: T,W=0.05-0.25 Gas: T,W=0.05-0.20	Same as SCR and LNB + AOFA alone.

[a] SNCR = Selective noncatalytic reduction, SCR = Selective catalytic reduction, LNB = Low NO_x burners, and AOFA = Advanced overfire air.
[b] NO_x reduction based upon data presented in chapter 5.0.
[c] Typical uncontrolled levels based on data presented in chapter 4.0. T = tangential, W = wall.
[d] Controlled NO_x level based on typical NO_x level and data presented in chapter 5.0. The expected NO_x emissions should be adjusted according to the actual uncontrolled NO_x level for a specific boiler by the NO_x reduction potential.
[e] Controlled levels for flue gas treatment controls as original or retrofit equipment.
[f] No SNCR applications on boilers above 200 MW.
[g] Limited or no full-scale installations in U. S.; therefore, these are estimated reduction levels.

reduction across the load range. For pre-NSPS tangential boilers, the NO_X emissions are expected to be in the range of 0.05 to 0.10 lb/MMBtu. For pre-NSPS wall-fired boilers, the NO_X emissions are expected to be 0.01 to 0.15 lb/MMBtu. There are no data from post-NSPS boilers with LNB + SNCR as original or retrofit equipment; therefore, these reductions and are estimated controlled levels.

By combining LNB + AOFA + SCR, it is estimated that 85 to 95 percent NO_X reduction can be achieved. The NO_X emissions are expected to be in the range of 0.02 to 0.1 lb/MMBtu and the post-NSPS boilers are expected to be in the range of 0.05 to 0.25 lb/MMBtu. This control technology combination has not yet been applied to existing or new boilers; therefore, these reductions and controlled levels are estimates.

2.6.2 Costs of NO_X Controls

Table 2-9 presents a summary of the cost effectiveness of various NO_X controls applied to natural gas- and oil-fired utility boilers. The costs presented are for LEA + BOOS, LNB, LNB + AOFA, reburn, SNCR, SCR, LNB + SNCR, and LNB + AOFA + SCR applied to both tangential and wall boilers. The costs are based on the various factors described in chapter 6.

For tangential boilers, the cost effectiveness ranges from a low of \$70 per ton for LEA + BOOS (a new 600 MW baseload boiler) to a high of \$16,900 per ton for LNB + AOFA + SCR (100 MW oil-fired peaking boiler and a 3-year catalyst life). The retrofit of LEA + BOOS or LNB is estimated to have the lowest cost per ton of NO_X removed for the tangential boilers. The cost effectiveness value of LEA + BOOS ranges from \$70 to \$500 per ton. The cost effectiveness value for LNB ranges from \$250 to \$4,200 per ton. The retrofit of SCR or LNB + AOFA + SCR is estimated to have the highest cost per ton of NO_X removed. The cost effectiveness value of SCR ranges from \$1,530 to \$11,700 per ton for natural gas-fired units and from \$1,800 to \$14,700 per ton for oil-fired units. The cost effectiveness of LNB + AOFA + SCR ranges from \$1,650 to

TABLE 2-9. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS FOR NATURAL GAS- AND OIL-FIRED UTILITY BOILERS (1991 DOLLARS)

Boiler firing type	NO_x control technology	Cost effectiveness ($/ton)[a]				
		100 MW (peaking)[b]	100 MW (baseload)[c]	300 MW (cycling)[d]	300 MW (baseload)	600 MW (baseload)
Tangential	LEA+BOOS	230-500	100-360	90-350	80-340	70-340
	LNB	2,620-4,190	500-810	640-1,020	330-520	250-400
	LNB+AOFA	4,810-7,690	930-1,480	1,060-1,700	540-860	380-620
	Reburn[e]	8,480-12,800	2,320-6,690	2,720-7,080	1,800-6,170	1,580-5,940
	SNCR	7,090-7,450	1,820-2,180	1,940-2,300	1,260-1,620	1,070-1,430
	SCR (natural gas)	10,800-11,700	2,310-2,470	3,150-3,470	1,740-1,900	1,530-1,690
	SCR (oil)	12,200-14,700	2,580-3,040	3,690-4,600	2,010-2,480	1,800-2,260
	LNB+SNCR	5,830-5,990	1,260-1,370	1,430-1,540	810-920	640-750
	LNB+AOFA+SCR (natural gas)	13,400-14,200	2,750-2,900	3,640-3,930	1,960-2,100	1,650-1,800
	LNB+AOFA+SCR (Oil)	14,700-16,900	3,010-3,400	4,130-4,970	2,210-2,690	1,900-2,330

TABLE 2-9. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS FOR NATURAL GAS- AND OIL-FIRED UTILITY BOILERS (1991 DOLLARS) (CONCLUDED)

Boiler firing type	NO_x control technology	Cost effectiveness ($/ton)[a] 100 MW (peaking)[b]	100 MW (baseload)[c]	300 MW (cycling)[d]	300 MW (baseload)	600 MW (baseload)
Wall Firing	LEA+BOOS	140-300	60-220	50-210	50-200	40-200
	LNB	3,600-5,750	690-1,110	840-1,340	430-680	310-500
	LNB+AOFA	6,160-9,850	1,180-1,900	1,350-2,160	680-1,090	480-770
	Reburn[e]	5,080-7,690	1,390-4,010	1,630-4,250	1,080-3,700	946-3,560
	SNCR	4,470-4,850	1,310-1,690	1,380-1,760	980-1,350	860-1,240
	SCR (natural gas)	6,700-7,200	1,460-1,550	1,960-2,150	1,100-1,200	970-1,070
	SCR (oil)	7,550-8,940	1,620-1,900	2,280-2,830	1,270-1,540	1,130-1,410
	LNB+SNCR	5,200-5,310	1,130-1,250	1,290-1,400	740-850	590-700
	LNB+AOFA+SCR (natural gas)	10,500-11,000	2,150-2,240	2,740-2,910	1,470-1,560	1,200-1,290
	LNB+AOFA+SCR (oil)	11,300-12,700	2,300-2,560	3,030-3,540	1,620-1,870	1,350-1,610

[a]Cost effectiveness based on percent reductions given in chapter 6.0.

[b]Peaking = 10% capacity factor.

[c]Baseload = 65% capacity factor.

[d]Cycling = 30% capacity factor.

[e]Oil-fired boilers only.

$14,200 per ton for natural gas-fired units and from $1,900 to $16,900 per ton for oil-fired units. Figure 2-4 shows the NO_x control cost effectiveness for a 300 MW baseload tangential boiler. As shown, LEA + BOOS and LNB have the lowest cost effectiveness value for controlled NO_x emissions of 0.1 to 0.2 lb/MMBtu. For controlled NO_x emissions of less than 0.1 lb/MMBtu the cost effectiveness increases.

For the wall boilers, the cost effectiveness ranges from a low of $40 per ton for LEA + BOOS (a new 600 MW baseload boiler) to a high of $12,700 per ton for LNB + AOFA + SCR (100 MW oil-fired peaking boiler and a 3-year catalyst life). The retrofit of LEA + BOOS or LNB is estimated to have the lowest cost per ton of NO_x removed for the wall boilers. The cost effectiveness of LEA + BOOS ranges from $40 to $300 per ton. The cost effectiveness of LNB ranges from $300 to $5,800 per ton. The retrofit of SCR or SCR + LNB + AOFA is estimated to be the highest cost per ton of NO_x removed. The cost effectiveness of SCR ranges from $970 to $7,200 per ton for natural gas-fired units and from $1,130 to $8,940 per ton for oil-fired units. Figure 2-5 shows the NO_x control cost effectiveness for a 300 MW baseload wall boiler. As shown, LEA + BOOS and LNB have the lowest cost effectiveness for controlled NO_x emissions of 0.25 to 0.35 lb/MMBtu. For controlled NO_x emissions of less than 0.25 lb/MMBtu, the cost effectiveness increases.

The effects of various plant parameters (e.g., capacity factor, economic life, boiler size, uncontrolled NO_x levels) on the cost effectiveness of individual NO_x controls are similar to those for coal-fired boilers. Due to lower uncontrolled NO_x levels, the cost effectiveness of applying controls to oil- and natural gas-fired boilers is higher than for coal-fired boilers.

2.7 SUMMARY OF IMPACTS OF NO_x CONTROLS

2.7.1 Impacts from Combustion NO_x Controls

Combustion NO_x controls suppress both thermal and fuel NO_x formation by reducing the peak flame temperature and by

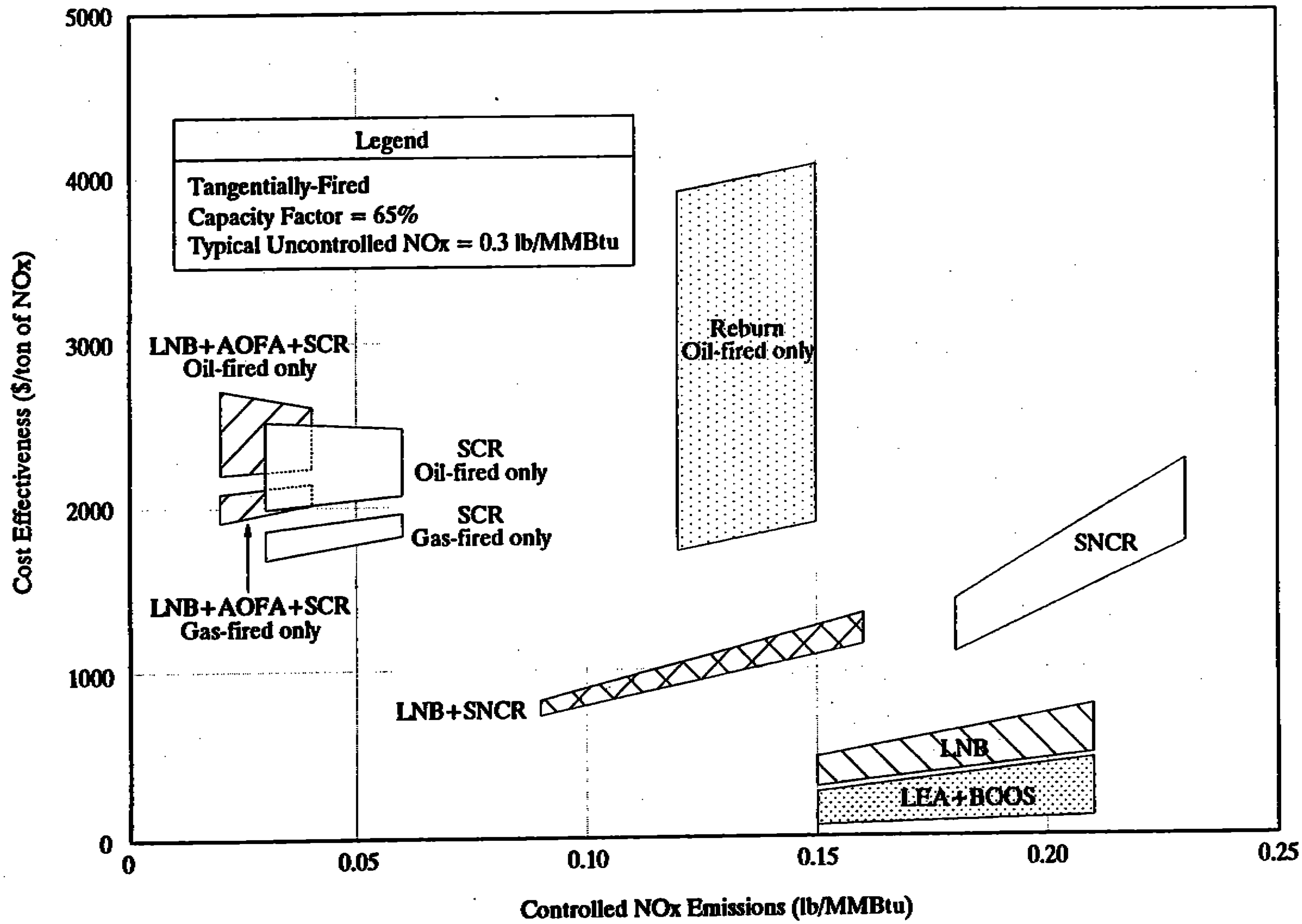


Figure 2-4. NO_x control cost effectiveness for natural gas- and oil-fired tangential boilers.

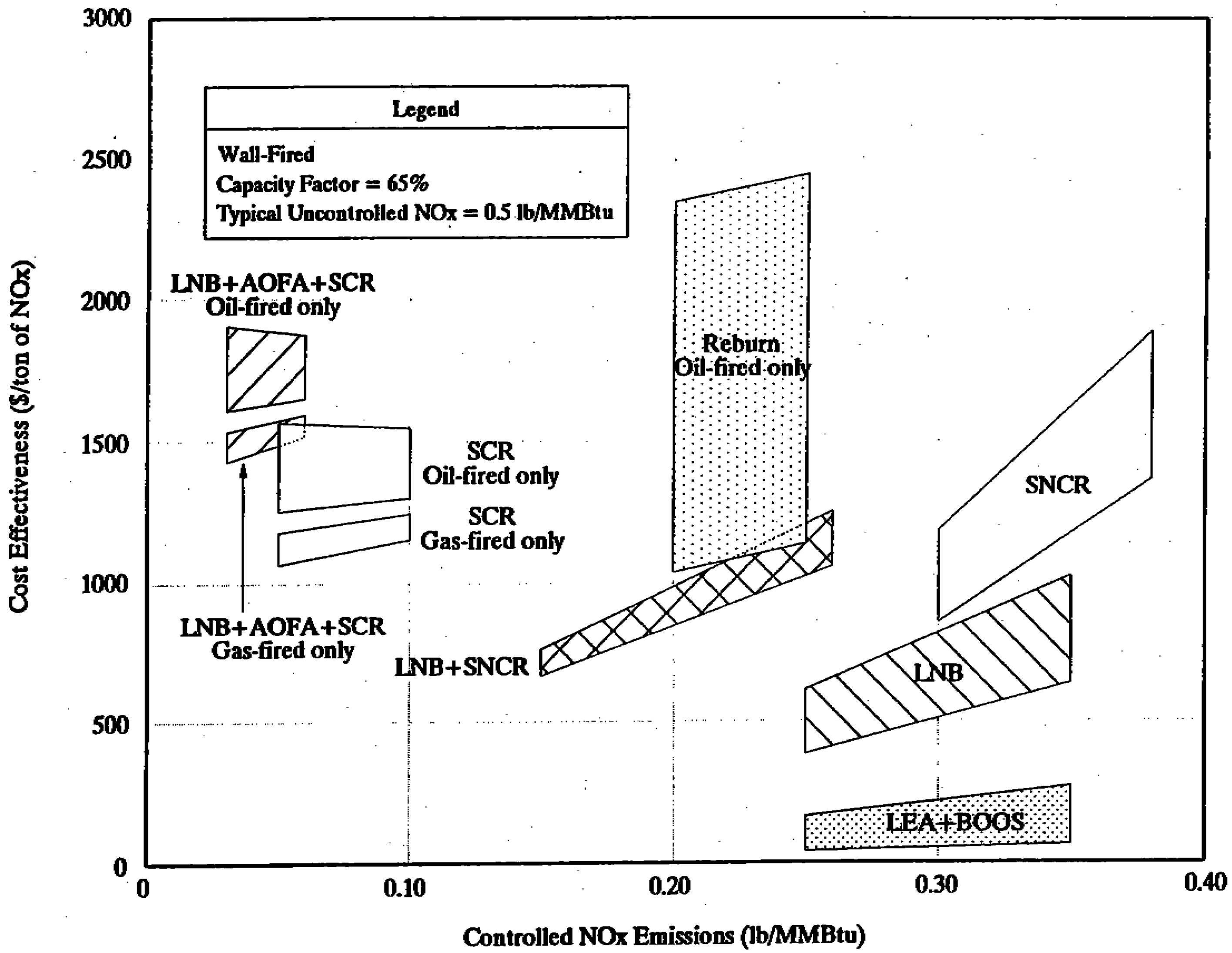


Figure 2-5. NO_x control cost effectiveness for natural gas- and oil-fired wall boilers.

delaying the mixing of fuel with the combustion air. However, this can result in a decrease in boiler efficiency for several reasons. For coal-fired boilers, an increase in carbon monoxide (CO) emissions and unburned carbon (UBC) levels, as well as changes in the thermal profile and heat transfer characteristics of the boiler, may result from combustion controls. For natural gas- and oil-fired boilers, CO emissions could also increase, although adverse effects are infrequently reported from these boilers. The effects from combustion NO_x controls are influenced by boiler design and operational characteristics such as furnace type, fuel type, condition of existing equipment, and age.

Table 2-10 summarizes the impacts from combustion NO_x controls on fossil fuel-fired utility boilers. Based on limited data, the CO emissions increase on most installations with use of operational modifications on coal-fired boilers and decrease on natural gas and oil boilers. There were no reported effects on UBC levels or boiler efficiency with the use of operational modifications.

Overfire air on one coal-fired boiler resulted in a 5 to 85 parts per million (ppm) decrease in CO emissions from uncontrolled levels. The level of CO emissions with OFA on the natural gas- and oil-fired boilers ranged from 26-830 ppm. The UBC level for coal-fired boilers increased approximately two- to three-fold with OFA and the boiler efficiency decreased by 0.4 to 0.7 percentage points.

Low NO_x burners retrofit on coal-fired boilers resulted in an increase of both CO and UBC for most applications, and the boiler efficiency decreased by 0.5 to 1.5 percentage points. For natural gas- and oil-fired boilers, the controlled level of CO was 1 to 220 ppm. There were no reported effects on boiler efficiency for these boilers.

The combination of LNB and OFA on coal-fired boilers resulted in a slight increase in both CO and UBC. The boiler efficiency decreased by 0.2 to 0.9 percentage points. There

TABLE 2-10. SUMMARY OF IMPACTS FROM COMBUSTION NO_x CONTROLS ON FOSSIL FUEL-FIRED UTILITY BOILERS

Control technology	Fuel	Carbon monoxide	Unburned carbon	Boiler efficiency
BOOS, LEA, BF	Coal	One application showed increase of 40-250 ppm.	No reported effects.	No reported effects.
	Gas/Oil	2 applications showed decreases of 100-150 ppm.	No reported effects for oil-firing.	No reported effects.
OFA	Coal	One application showed decrease of 5-85 ppm.	Range increased from 2.3-5.2% to 7.1-10.2%.	Decreased by 0.4-0.7 percentage points.
	Gas/Oil	Controlled levels of 26-830 ppm.	No reported effects for oil-firing.	No reported effects.
LNB	Coal	Ranged increased from 12-60 ppm to 15-86 ppm.	Range increased from 1-7.4% to 1.6-9.0%.	Decreased by 0.5-1.5 percentage points.
	Gas/Oil	Controlled levels of 1-220 ppm.	No reported effects for oil-firing.	No reported effects.
LNB + OFA	Coal	Range increased from 12-30 ppm to 20-45 ppm.	Range increased from 0.4-5% to 0.3-6.8%.	Decreased by 0.2-0.9 percentage points.
	Gas/Oil	No reported effects.	No reported effects for oil-firing.	No reported effects.
Reburn	Coal	Range increased from 60-94 ppm to 50-132 ppm	Range increased from 2.5-23% to 1.5-28%.	Decreased by 0.5-1.5 percentage points
	Oil	No data	No data	No data

were no reported effects on the natural gas- and oil-fired boilers with LNB and OFA.

With reburn applied to coal-fired boilers, both CO and UBC increased and the boiler efficiency decreased by 0.5 to 1.5 percentage points. There were no data available for reburn applied to oil-fired boilers.

2.7.2 Impacts from Flue Gas Treatment Controls

Flue gas treatment controls remove NO_x by a reaction of injected NH_3 or urea in the upper furnace or the convective pass or by a reaction of NH_3 in the presence of a catalyst at lower temperatures. These controls can produce unreacted reagents in the form of NH_3 slip which can be emitted into the atmosphere or can be adsorbed onto the fly ash. The NH_3 slip can also react with sulfur trioxide (SO_3) from firing coal or oil and deposit as ammonium sulfate compounds in downstream equipment. Nitrous oxide (N_2O) emissions are typically higher on boilers with urea-based SNCR systems. Very limited data are available; however, NH_3-based SNCR may yield N_2O levels equal to 4 percent of the NO_x reduced and urea-based SNCR may yield N_2O levels of 7 to 25 percent of the NO_x reduced. Flue gas treatment controls also require additional energy to run pumps, heaters, auxiliary process equipment, and to overcome any additional pressure drop due to the catalyst beds or from downstream equipment that may be plugged. The additional pressure drop from downstream equipment plugging could ultimately affect unit availability.

Table 2-11 summarizes the impacts from SNCR and SCR systems. Increases of CO emissions due to the urea-based SNCR system have been reported since urea (NH_2CONH_2) has CO bound in each molecule injected. If that CO is not oxidized to CO_2, then CO will pass through to the stack. Ammonia-based SNCR does not contain bound CO, so use of NH_3 as an SNCR reagent would not increase stack emissions of either CO or CO_2. The NH_3 slip for these fossil fuel-fired boilers ranged from 10 to 110 ppm. For FBC, the CO emissions were in the range of 10 to 110 ppm and NH_3 slip was in the range of 20 to 30 ppm.

TABLE 2-11. SUMMARY OF IMPACTS FROM FLUE GAS TREATMENT CONTROLS ON FOSSIL FUEL-FIRED UTILITY BOILERS

Application	Control technology	Carbon monoxide	Ammonia slip	Other possible effects
Conventional utility boiler	NH_3-based SNCR	Little or no effect.	10-110 ppm	Nitrous oxide is a possible by-product.
	Urea-bases SNCR	Possible increase[a]	10-110 ppm	Ammonium sulfate compounds may deposit in downstream equipment causing air heater pluggage that degrades unit performance and corrodes air heater baskets.
Fluidized bed combustion	NH_3-based SNCR	10-110 ppm	20-30 ppm	Minor energy losses due to pumps, heaters, and control systems.
Fluidized Bed Combustion	Urea-based SNCR	Data not available.	Data not available.	May elevate levels of NH_3 in the fly ash and scrubber by-products, creating disposal problems at NH_3 slip level above 2 ppm.
Coal & Oil Pilot-Scale	SCR	Data not available.	<20 ppm	Ammonium sulfate compounds may deposit in downstream equipment.
Gas/Oil Full-Scale	SCR	Data not available.	10-40 ppm	Losses due to energy required to overcome catalyst bed pressure drop. May elevate levels of NH_3 in the fly ash, creating disposal problems.

[a]CO data from one application reported increase of 60 to 80 ppm from uncontrolled level.

Limited data were available for installation of SCR in the United States. There were no data for SCR on CO emissions from the pilot- or full-scale applications. The NH_3 slip for the pilot-scale SCR application on coal and oil was less than 20 ppm. The NH_3 slip for one full-scale SCR application on natural gas and oil was in the range of 10 to 40 ppm.

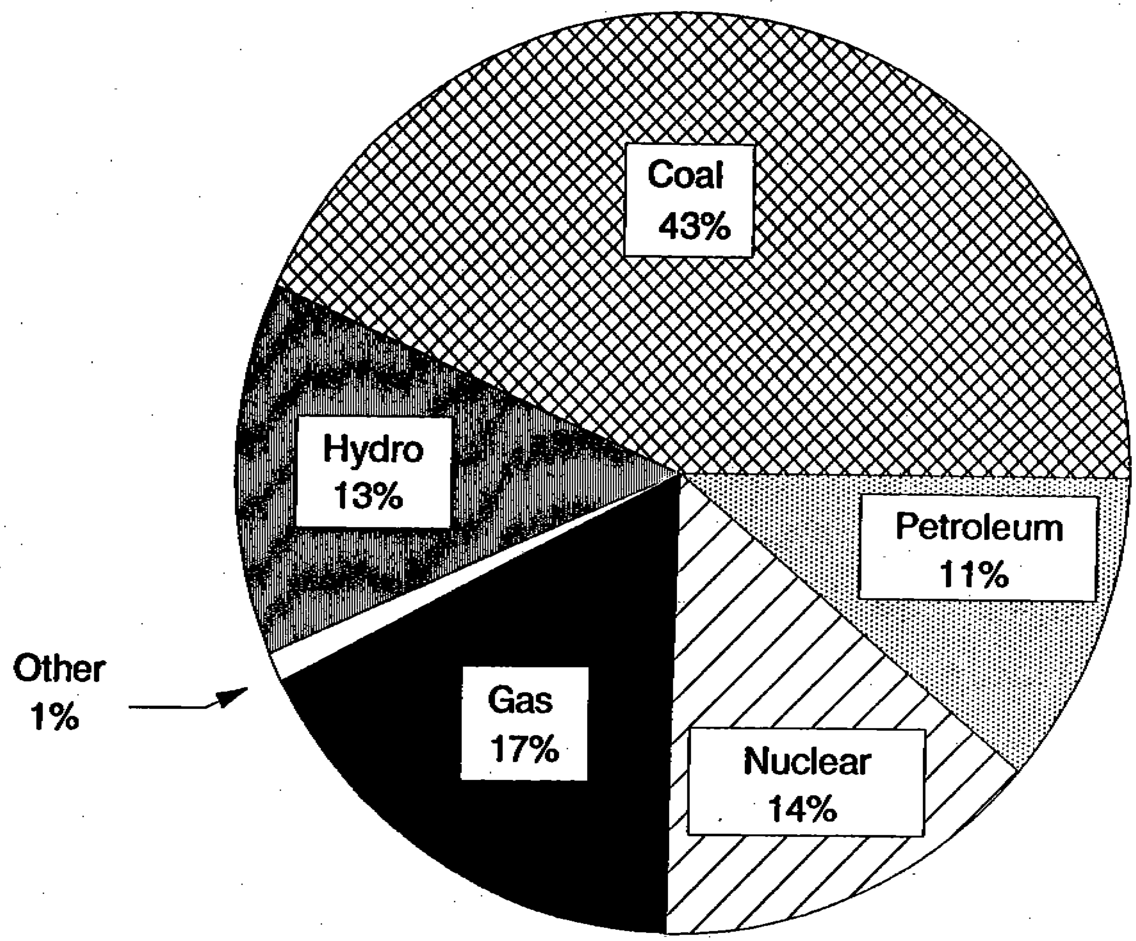
3.0 OVERVIEW AND CHARACTERIZATION OF UTILITY BOILERS

This chapter presents an overview and characterization of utility boilers. The chapter is divided into four main sections: utility boiler fuel use in the United States, fossil fuel characteristics, utility boiler designs, and the impact of fuel properties on boiler design.

3.1 UTILITY BOILER FUEL USE IN THE UNITED STATES

Approximately 71 percent of the generating capability of electrical power plants in the United States is based on fossil fuels, as shown in figure 3-1.[1] Generating capability is the actual electrical generating performance of the unit. The primary fossil fuels burned in electric utility boilers are coal, oil, and natural gas. Of these fuels, coal is the most widely used, accounting for 43 percent of the total U. S. generating capability and 60 percent of the fossil fuel generating capability. Coal generating capacity is followed by natural gas, which represents 17 percent of the total generating capability and 24 percent of the fossil fuel generating capability. Oil represents 11 percent of the total and 15 percent of the fossil fuel generating capability.

As shown in figure 3-2, most of the coal-firing capability is east of the Mississippi River, with the significant remainder being in Texas and the Rocky Mountain region.[2] Natural gas is used primarily in the South Central States and California as shown in figure 3-3.[3] Oil is predominantly used in Florida and the Northeast as shown in figure 3-4.[4] Fuel economics and environmental regulations



Notes: Other includes geothermal, refuse, steam, solar waste heat, wind, & wood. Percentages may not sum to 100% because of independent rounding.

Figure 3-1. Percent generating capability by energy source, as of Decmeber 31, 1990.[1]

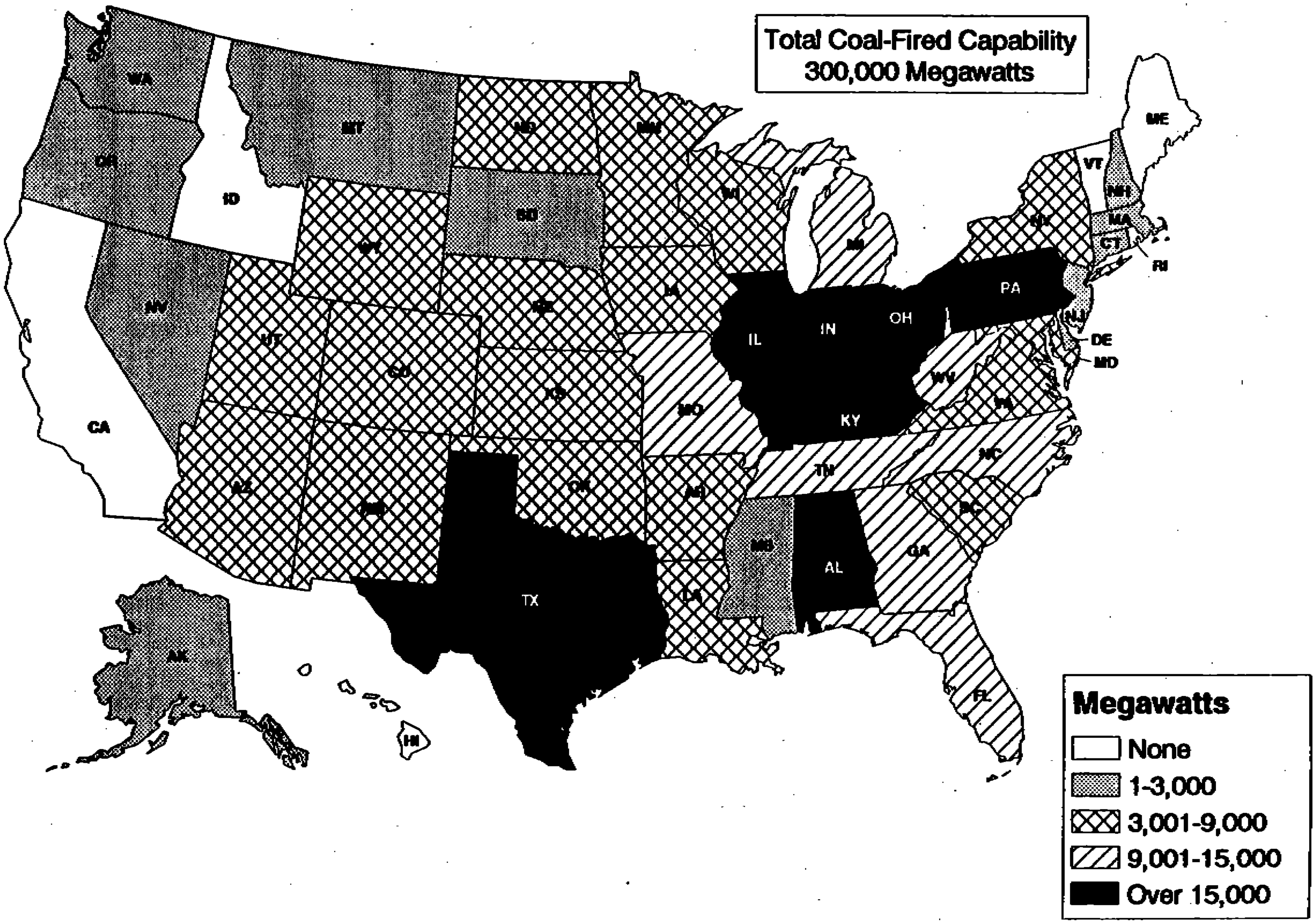


Figure 3-2. Coal-fired generating capability, as of December 31, 1990.[2]

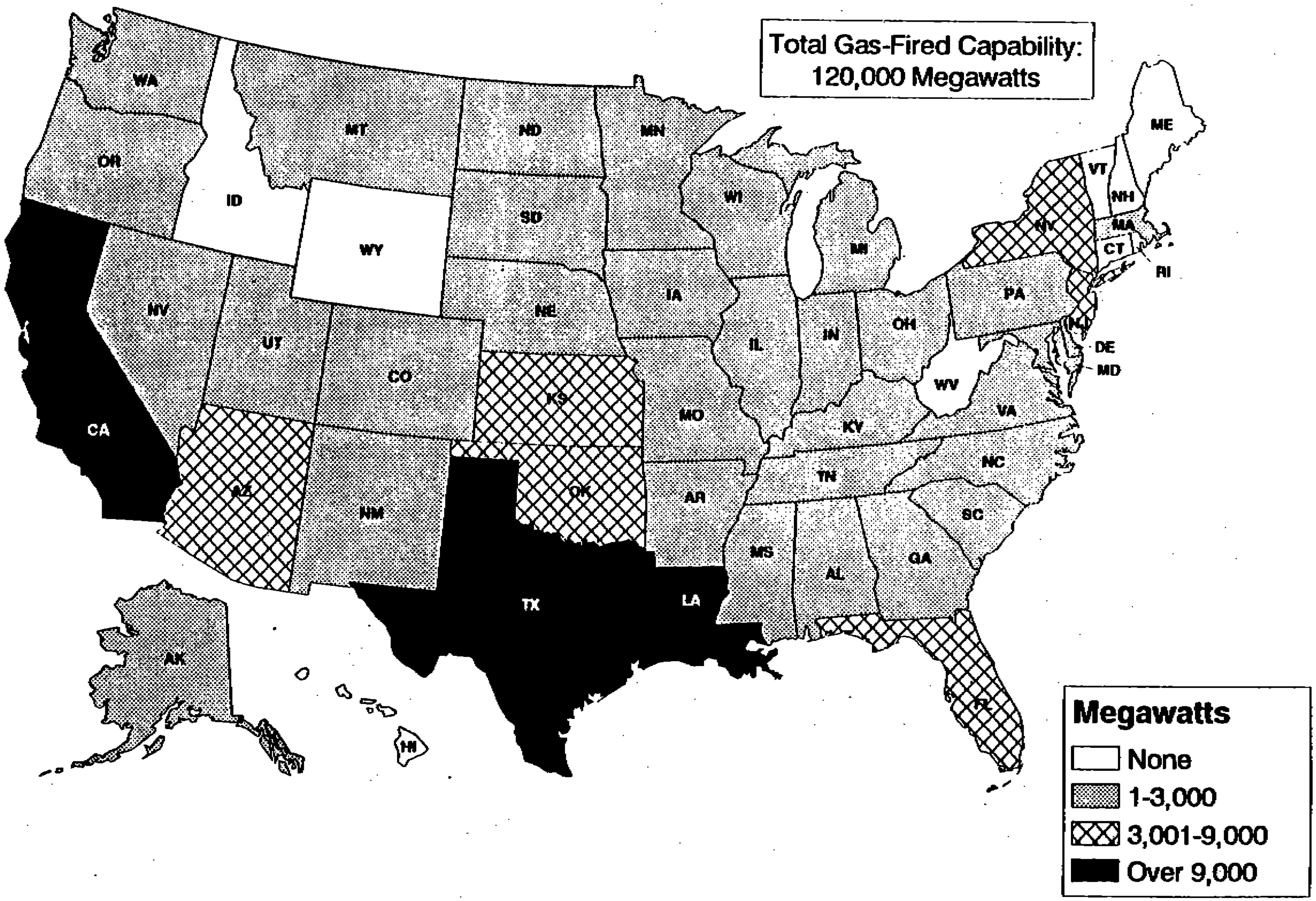


Figure 3-3. Gas-fired generating capability, as of December 31, 1990.[3]

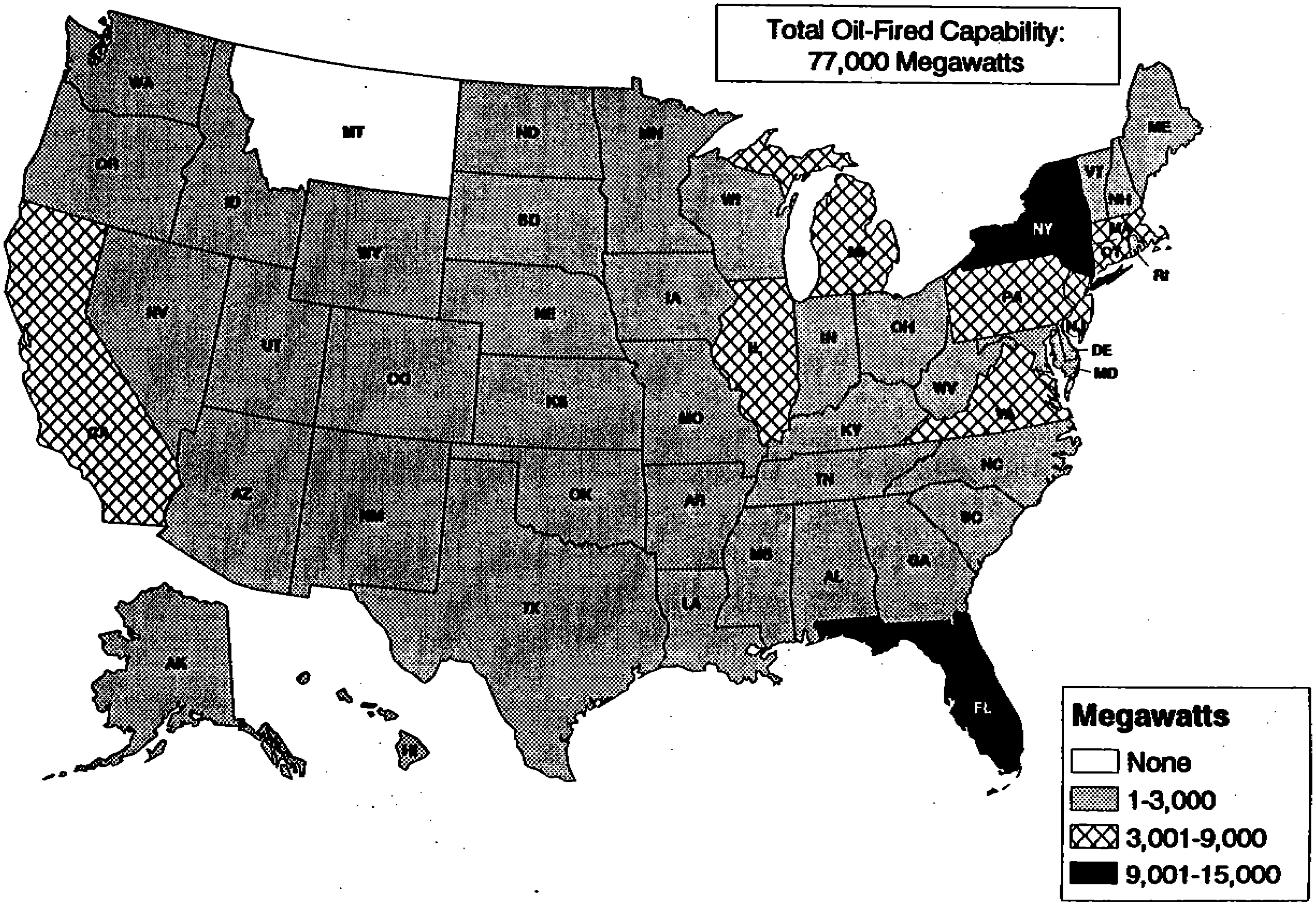


Figure 3-4. Oil-fired generating capability, as of December 31, 1990.[4]

frequently affect regional use patterns. For example, coal is not used in California because of stringent air quality limitations.

3.2 FOSSIL FUEL CHARACTERISTICS

This section contains information on the three fossil fuels used for electric power generation: coal, oil, and natural gas.

3.2.1 Coal

Coals are classified by rank, i.e., according to their progressive alteration in the natural metamorphosis from lignite to anthracite. Volatile matter, fixed carbon, inherent moisture and oxygen are all indicative of rank, but no one item completely defines it. The American Society for Testing and Materials (ASTM) classified coals by rank, according to fixed carbon and volatile matter content, or heating (calorific) value. Calorific value is calculated on a moist, mineral-matter-free basis and shown in table 3-1.[5] The ASTM classification for high rank (older) coals uses volatile matter and fixed carbon contents. The coal rank increases as the amount of fixed carbon increases and the amounts of volatile matter and moisture decrease. Moisture and volatile matter are driven from the coal during its metamorphism by pressure and heat, thus raising the fraction of fixed carbon. These values are not suitable for ranking low rank coals. Lower ranking (younger) coals are classified by calorific (heating) value and caking (agglomerating) properties which vary little for high rank coals but appreciably and systematically for low rank coals.

The components of a coal are customarily reported in two different analyses, known as "proximate" and "ultimate." Proximate analysis separates coal into four fractions: (1) water or moisture; (2) volatile matter, consisting of gases and vapors driven off when coal is heated; (3) fixed carbon, the coke-like residue that burns at higher temperatures after the volatile matter has been driven off;

TABLE 3-1. CLASSIFICATION OF COALS BY RANK[5]

Class and group	Fixed carbon limits, % (dry, mineral-matter-free basis)		Volatile matter limits, % (dry, mineral-matter-free basis)		Calorific value limits, Btu/lb (moist, mineral-matter-free basis)		
	Equal or greater than	Less than	Equal or greater than	Less than	Equal or greater than	Less than	Agglomerating character
I. Anthracitic							
1. Meta-anthracite	98	--	--	2	--	--	nonagglomerating
2. Anthracite	92	98	2	8	--	--	
3. Semianthracite	86	92	8	14	--	--	
II. Bituminous							
1. Low-volatile bituminous coal	78	86	14	22	--	--	
2. Medium volatile bituminous coal	69	78	22	31	--	--	commonly agglomerating
3. High-volatile A bituminous coal	--	69	31	--	14,000	--	
4. High-volatile B bituminous coal	--	--	--	--	13,000	14,000	
5. High-volatile C bituminous coal	--	--	--	--	11,500 10,500	13,000 11,500	agglomerating
III. Subbituminous							
1. Subbituminous A coal	--	--	--	--	10,500	11,500	
2. Subbituminous B coal	--	--	--	--	9,500	10,500	nonagglomerating
3. Subbituminous C coal	--	--	--	--	8,300	9,500	
IV. Lignitic							
1. Lignite A	--	--	--	--	6,300	8,300	nonagglomerating
2. Lignite B	--	--	--	--	--	6,300	

-- = Not applicable.

and (4) mineral impurities, or coal ash, left when the coal is completely combusted.

In addition to proximate analysis, which gives information on the behavior of coal when it is heated, "ultimate analysis" identifies the primary elements in coal. These elements include carbon, hydrogen, nitrogen, oxygen, and sulfur. Ultimate analyses may be given on several bases, according to the application. For coal classification, the moist, mineral-matter-free basis is generally used. For combustion calculations, coal is analyzed as-received, including moisture and mineral matter. Table 3-2 presents sources and analyses of various ranks of as-received coals.[6,7] The nitrogen contents of these coals are generally less than 2 percent and does not vary systematically with coal rank.

Various physical properties of coal such as the type and distribution of mineral matter in the coal and the coal's "slagging" tendencies are of importance when burning coal. Mineral matter influences options for washing the coal to remove ash and sulfur before combustion, the performance of air pollution control equipment, and the disposal characteristics of ash collected from the boiler and air pollution control equipment. Slagging properties influence the selection of boiler operating conditions, such as furnace operating temperature and excess air levels, and the rate and efficiency of coal conversion to usable thermal energy.

3.2.1.1 Anthracite Coal. Anthracite is a hard, slow-burning coal characterized by a high percentage of fixed carbon, and a low percentage of volatile matter. Anthracite coals typically contain 0.8 to 1.0 weight-percent nitrogen.[8] Because of its low volatile matter, anthracite is difficult to ignite and is not commonly burned in utility boilers. Specific characteristics of anthracitic coals are shown in tables 3-1 and 3-2. In the United States, commercial anthracite production occurs almost exclusively in Pennsylvania.

TABLE 3-2. SOURCES AND TYPICAL ANALYSES OF VARIOUS RANKS OF COAL[6,7]

Classification by rank	State	County	Bed	Basis[a]	Proximate, % Moisture	Proximate, % Volatile matter	Proximate, % Fixed carbon	Proximate, % Ash	Ultimate, % Sulfur	Ultimate, % Hydrogen	Ultimate, % Carbon	Ultimate, % Nitrogen	Ultimate, % Oxygen	Calorific value, Btu/lb
Meta-anthracite	RI	Newport	Middle	AR	13.2	2.6	65.3	18.9	0.3	1.9	64.2	0.2	14.5	9,310
				DMMF	--	3.8	96.2	–	0.4	0.6	94.7	0.3	4.0	13,720
Anthracite	PA	Lackawanna	Clark	AR	4.3	5.1	81.0	9.6	0.8	2.9	79.7	0.9	6.1	12,880
				DMMF	–	5.9	94.1	–	0.9	2.8	92.5	1.0	2.8	14,980
Semianthracite	AK	Johnson	Lower Hartshorne	AR	2.6	10.6	79.3	7.5	1.7	3.8	81.4	1.6	4.0	13,880
				DMMF	–	11.7	88.3	–	1.9	3.9	90.6	1.8	1.8	15,430
Low-volatile bituminous	WVa	Wyoming	Pocahontas No. 3	AR	2.9	17.7	74.0	5.4	0.8	4.6	83.2	1.3	4.7	14,400
				DMMF	–	19.3	80.7	–	0.8	4.6	90.7	1.4	2.5	15,690
Medium-volatile bituminous	PA	Clearfield	Upper Kittanning	AR	2.1	24.4	67.4	6.1	1.0	5.0	81.6	1.4	4.9	14,310
				DMMF	-	26.5	73.5	–	1.1	5.2	88.9	1.6	3.2	15,590
High-volatile A bituminous	WVa	Marion	Pittsburgh	AR	2.3	36.5	56.0	5.2	0.8	5.5	78.4	1.6	8.5	14,040
				DMMF	–	39.5	60.5	–	0.8	5.7	84.8	1.7	7.0	15,180
High-volatile B bituminous	KY	Muhlenburg	No. 9	AR	8.5	36.4	44.3	10.8	2.8	5.4	65.1	1.3	14.6	11,680
				DMMF	--	45.0	55.0	–	3.4	5.5	80.6	1.7	8.8	14,460
High-volatile C bituminous	IL	Sangamon	No. 5	AR	14.4	35.4	40.6	9.6	3.8	5.8	59.7	1.0	20.1	10,810
				DMMF	–	46.6	53.4	–	5.0	5.6	78.6	1.3	9.5	14,230
Subbituminous A	WY	Sweetwater	No. 3	AR	16.9	34.8	44.7	3.6	1.4	6.0	60.4	1.2	27.4	10,650
				DMMF	–	43.7	56.3	--	1.8	5.2	76.0	1.5	15.5	13,390
Subbituminous B	WY	Sheridan	Monarch	AR	22.2	33.2	40.3	4.3	0.5	6.9	53.9	1.0	33.4	9,610
				DMMF	--	45.2	54.8	–	0.6	6.0	73.4	1.3	18.7	13,080
Subbituminous C	CO	El Paso	Fox Hill	AR	25.1	30.4	37.7	6.8	0.3	6.2	50.5	0.7	35.5	8,560
				DMMF	--	44.6	55.4	–	0.5	5.0	74.1	1.1	19.3	12,560
Lignite	ND	McLean	Unnamed	AR	36.8	27.8	29.5	5.9	0.9	6.9	40.6	0.6	45.1	7,000
				DMMF	--	46.4	51.6	–	1.6	5.0	70.9	1.1	21.4	12,230

[a]AR = as-received
DMMF = Dry mineral-matter-free basis.

3.2.1.2 Bituminous Coal. By far the largest group, bituminous coals are characterized as having a lower fixed-carbon content, and higher volatile matter content than anthracite. Typical nitrogen levels are 0.9 to 1.8 weight-percent.[8] Specific characteristics of bituminous coals are shown in tables 3-1 and 3-2. Bituminous coals are the primary coal type found in the United States, occurring throughout much of the Appalachian, Midwest, and Rocky Mountain regions. Key distinguishing characteristics of bituminous coal are its relative volatile matter and sulfur content, and its slagging and agglomerating characteristics. As a general rule, low-volatile-matter and low-sulfur-content bituminous coals are found in the Southern Appalachian and the Rocky Mountain regions. Although the amount of volatile matter and sulfur in coal are independent of each other, coals in the northern and central Appalachian region and the Midwest frequently have medium to high contents of both.

3.2.1.3 Subbituminous Coal. Subbituminous coals have still higher moisture and volatile matter contents. Found primarily in the Rocky Mountain region, U. S. subbituminous coals generally have low sulfur content and little tendency to agglomerate. The nitrogen content typically ranges from 0.6 to 1.4 weight-percent.[8] Specific characteristics of subbituminous coals are shown in tables 3-1 and 3-2. Because of the low sulfur content in many subbituminous coals, their use by electric utilities grew rapidly in the 1970's and 1980's when lower sulfur dioxide (SO_2) emissions were mandated. Their higher moisture content and resulting lower heating value, however, influence the economics of shipping and their use as an alternate fuel in boilers originally designed to burn bituminous coals.

3.2.1.4 Lignite. Lignites are the least metamorphesized coals and have a moisture content of up to 45 percent, resulting in lower heating values than higher ranking coals. The nitrogen content of lignites generally range from 0.5

to 0.8 weight-percent.[8] Specific characteristics of lignite are shown in tables 3-1 and 3-2. Commercial lignite production occurs primarily in Texas and North Dakota. Because of its high moisture content and low heating value, lignite is generally used in power plants located near the producing mine.

3.2.2 Oil

Fuel oils produced from crude oil are used as fuels in the electric utility industry. The term "fuel oil" covers a broad range of petroleum products, from a light petroleum fraction similar to kerosene or gas oil, to a heavy residue left after distilling off fixed gases, gasoline, gas oil, and other lighter hydrocarbon streams.

To provide commercial standards for petroleum refining, specifications have been established by the ASTM for several grades of fuel oil and are shown in table 3-3.[9] Fuel oils are graded according to specific gravity and viscosity, the lightest being No. 1 and the heaviest No. 6. Typical properties of the standard grades of fuel oils are given in table 3-4.[10,11]

Compared to coal, fuel oils are relatively easy to burn. Preheating is not required for the lighter oils, and most heavier oils are also relatively simple to handle. Ash content is minimal compared to coal, and the amount of particulate matter (PM) in the flue gas is correspondingly small.

Because of the relatively low cost of No. 6 residual oil compared with that of lighter oils, it is the most common fuel oil burned in the electric utility industry. Distillate oils are also burned, but because of higher cost are generally limited to startup operations, peaking units, or applications where low PM and SO_2 emissions are required.

The U. S. supply of fuel oils comes from both domestic and foreign production. The composition of individual fuel oils will vary depending on the source of the crude oil and

TABLE 3-3. ASTM STANDARD SPECIFICATIONS FOR FUEL OILS[9]

Grade of fuel oil	Flash point, °F (°C)	Pour point, °F (°C)	Water and sediment, % by volume	Carbon residue on 10% bottoms, %	Ash, % by weight	Distillation temperatures, °F (°C) 10% point	Distillation temperatures, °F (°C) 90% point		Saybolt viscosity, sec Universal at 100 °F (38°C)		Saybolt viscosity, sec Furol at 122 °F (50°C)		Kinematic Viscosity, centistokes At 100 °F (38°C)		Kinematic Viscosity, centistokes At 122 °F (50°C)		Gravity, deg API	Copper strip corrosion
	Min.	Max.	Max.	Max.	Max.	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
No. 1	100 (38)	0	trace	0.15	--	420 (215)	--	550 (288)	--	--	--	--	1.4	2.2	--	--	35	No. 3
No. 2	100 (38)	20 (-7)	0.10	0.35	--	--	540 (282)	640 (338)	(32.6)	(37.93)	--	--	2.0	3.6	--	--	30	--
No. 4	130 (55)	20 (-7)	0.50	--	0.10	--	--	--	45	125	--	--	(5.8)	(26.4)	--	--	--	--
No. 5 (Light)	130 (55)	--	1.00	--	0.10	--	--	--	150	300	--	--	(32)	(65)	--	--	--	--
No. 5 (Heavy)	130 (55)	--	1.00	--	0.10	--	--	--	350	750	(23)	(40)	(75)	(162)	(42)	(81)	--	--
No. 6	150 (65)	--	2.00	--	--	--	--	--	(900)	(9000)	45	300	--	--	(92)	(638)	--	--

-- = Data not provided in Reference table.

TABLE 3-4. TYPICAL ANALYSES AND PROPERTIES OF FUEL OILS[10,11]

Grade	No. 1 fuel oil	No. 2 fuel oil	No. 4 fuel oil	No. 5 fuel oil	No. 6 fuel oil
Type	Distillate (kerosene)	Distillate	Very light residual	Light residual	Residual
Color	Light	Amber	Black	Black	Black
API gravity, 60 °F	40	32	21	17	12
Specific gravity, 60/60 °F	0.8251	0.8654	0.9279	0.9529	0.9861
lb/U.S. gallon, 60 °F	6.870	7.206	7.727	7.935	8.212
Viscosity, Centistokes @ 100 °F	1.6	2.68	15.0	50.0	360.0
Pour point, °F	Below zero	Below zero	10	30	65
Temp. for pumping, °F	Atmospheric	Atmospheric	15 (minimum)	35 (minimum)	100
Temp. for atomizing, °F	Atmospheric	Atmospheric	25 (minimum)	130	200
Carbon residue, %	Trace	Trace	2.5	5.0	12.0
Sulfur, %	0.1	0.4-0.7	0.4-1.5	2.0 (maximum)	2.8 (maximum)
Nitrogen, %	<0.01	<0.01	0.1-0.5	0.1-0.5	0.1-0.5
Hydrogen, %	13.2	12.7	11.9	11.7	10.5
Carbon, %	86.5	86.4	86.10	85.55	85.70
Sediment and water, %	Trace	Trace	0.5 (maximum)	1.0 (maximum)	2.0 (maximum)
Ash, %	Trace	Trace	0.02	0.05	0.08
Btu/gallon	137,000	141,000	146,000	148,000	150,000

the extent of refining operations. Because of these factors and the economics of oil transportation, fuel oil supplies vary in composition across the United States, but are relatively uniform with the exception of sulfur content. In general, ash content varies from nil to 0.5 percent, and the nitrogen content is typically below 0.4 weight-percent for grades 1 through 5 and 0.4 to 1.0 weight- percent for grade 6.[8]

3.2.3 Natural Gas

Natural gas is a desirable fuel for steam generation because it is practically free of noncombustible gases and residual ash. When burned, it mixes very efficiently with air, providing complete combustion at low excess air levels and eliminating the need for particulate control systems.

The analyses of selected samples of as-collected natural gas from U. S. fields are shown in table 3-5.[12] Prior to distribution, however, most of the inerts (carbon dioxide [CO_2] and nitrogen), sulfur compounds, and liquid petroleum gas (LPG) fractions are removed during purification processes. As a result, natural gas supplies burned by utilities are generally in excess of 90 percent methane, with nitrogen contents and typically ranging from 0.4 to 0.6 percent.[13,14,15]

Although the free (molecular) hydrogen content of natural gas is low, the total hydrogen content is high. Because of the high hydrogen content of natural gas relative to that of oil or coal, more water vapor is formed during combustion. Because of the latent heat of water, the efficiency of the steam generation is lowered. This decrease in efficiency must be taken into account in the design of the boiler and when evaluating the use of natural gas versus other fuels.

3.3 UTILITY BOILER DESIGNS

The basic purpose of a utility boiler is to convert the chemical energy in a fuel into thermal energy that can be used by a steam turbine. To achieve this objective, two

TABLE 3-5. CHARACTERISTICS OF SELECTED SAMPLES OF NATURAL GAS FROM U. S. FIELDS[12]

Characteristics		Sample no. and source of gas[a] 1 PA	2 So. CA	3 OH	4 LA	5 OK
Analyses						
Constituents, % by vol						
H_2	Hydrogen	Nil	Nil	1.82	Nil	Nil
CH_4	Methane	83.40	84.00	93.33	90.00	84.10
C_2H_4	Ethylene	Nil	Nil	0.25	Nil	Nil
C_2H_6	Ethane	15.80	14.80	Nil	5.00	6.70
CO	Carbon monoxide	Nil	Nil	0.45	Nil	Nil
CO_2	Carbon dioxide	Nil	0.70	0.22	Nil	0.80
N_2	Nitrogen	0.80	0.50	3.40	5.00	8.40
O_2	Oxygen	Nil	Nil	0.35	Nil	Nil
H_2S	Hydrogen sulfide	Nil	Nil	0.18	Nil	Nil
Ultimate, % by wt						
S	Sulfur	Nil	Nil	0.34	Nil	Nil
H_2	Hydrogen	23.53	23.30	23.20	22.68	20.85
C	Carbon	75.25	74.72	69.12	69.26	64.84
N_2	Nitrogen	1.22	0.76	5.76	8.06	12.90
O_2	Oxygen	Nil	1.22	1.58	Nil	1.41
Specific gravity (rel to air)		0.636	0.636	0.567	0.600	0.630
Higher heat value						
Btu/cu ft @ 60 °F & 30 in. Hg		1,129	1,116	964	1,002	974
Btu/lb of fuel		23,170	22,904	22,077	21,824	20,160

[a]Samples as "as-collected," prior to processing.

fundamental processes are necessary: combustion of the fuel by mixing with oxygen, and the transfer of the thermal energy from the resulting combustion gases to working fluids such as hot water and steam. The physics and chemistry of combustion, and how they relate to nitrogen oxides (NO_x) formation, are discussed in chapter 4 of this document. The objective of this section is to provide background information on the basic physical components found in utility boilers and how they work together to produce steam.

3.3.1 Fundamentals of Boiler Design and Operation

A utility boiler consists of several major subassemblies as shown in figure 3-5. These subassemblies include the fuel preparation system, air supply system, burners, the furnace, and the convective heat transfer system. The fuel preparation system, air supply, and burners are primarily involved in converting fuel into thermal energy in the form of hot combustion gases. The last two subassemblies are involved in the transfer of the thermal energy in the combustion gases to the superheated steam required to operate the steam turbine and produce electricity.

The NO_x formation potential of a boiler is determined by the design and operation of the fuel preparation equipment, air supply, burner, and furnace subassemblies. The potential for reducing NO_x after it forms is primarily determined by the design of the furnace and convective heat transfer system and, in some cases, by the operation of the air supply system.

Three key thermal processes occur in the furnace and convective sections of a boiler. First, thermal energy is released during controlled mixing and combustion of fuel and oxygen in the burners and furnace. Oxygen is typically supplied in two, and sometimes three, separate air streams. Primary air is mixed with the fuel before introducing the fuel into the burners. In a coal-fired boiler, primary air is also used to dry and transport the coal from the fuel preparation system (e.g., the pulverizers) to the burners. Secondary air is supplied through a windbox surrounding the burners, and is

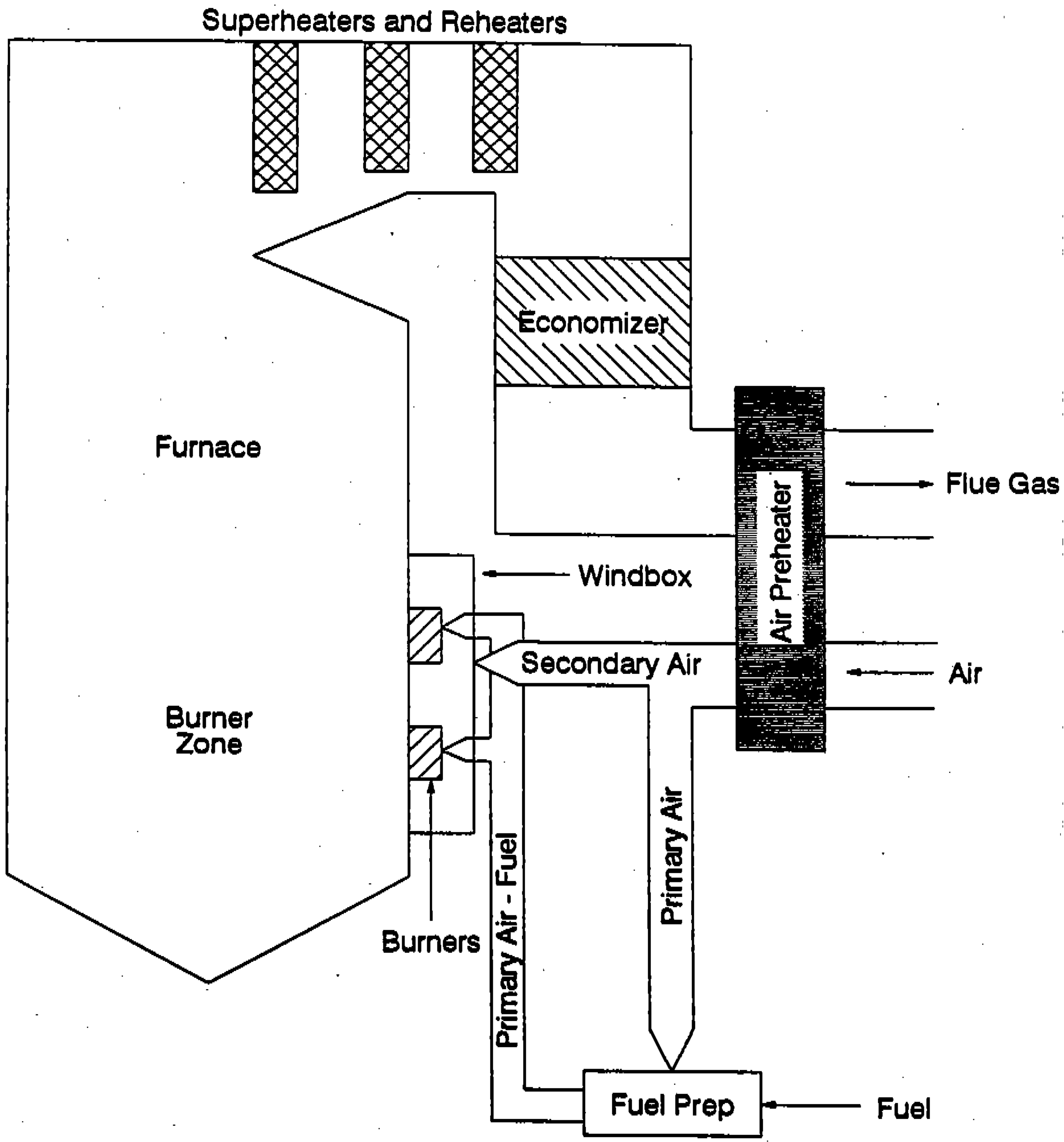


Figure 3-5. Simplified boiler schematic.

mixed with the fuel after the fuel is injected into the burner zone. Finally, some boilers are equipped with tertiary air (sometimes called "overfire air"), which is used to complete combustion in boilers having staged combustion burners. A detailed discussion of the importance of each of these air supplies as it relates to NO_x formation and control is presented in chapter 4.

Utility boiler furnace walls are formed by multiple, closely-spaced tubes filled with high-pressure water. Water flows into these "water tubes" at the bottom of the furnace and rises to the steam drum located at the top of the boiler. In the second key thermal process, a portion of the thermal energy formed by combustion is absorbed as radiant energy by the furnace walls. During the transit of water through the water tubes, the water absorbs this radiant energy from the furnace. Although the temperature of the water within these tubes can exceed 540 ^{o}C (1,000 ^{o}F) at the furnace exit, the pressure within the tubes is sufficient to maintain the water as a liquid rather than gaseous steam.

At the exit to the furnace, typical gas temperatures are 1,100 to 1,300 ^{o}C (2,000 to 2,400 ^{o}F), depending on fuel type and boiler design. At this point, in the third key process, the gases enter the convective pass of the boiler, and the balance of the energy retained by the high-temperature gases is absorbed as convective energy by the convective heat transfer system (superheater, reheater, economizer, and air preheater). In the convective pass, the combustion gases are typically cooled to 135 to 180 ^{o}C (275 to 350 ^{o}F).

The fraction of the total energy that is emitted as radiant energy depends on the type of fuel fired and the temperature within the flame zone of the burner. Because of its ash content, coal emits a significant amount of radiant energy, whereas a flame produced from burning gas is relatively transparent and produces less radiant flux. As a result, coal-fired boilers are designed to recover a significant amount of the total thermal energy formed by combustion through radiant heat transfer to the furnace walls, while gas-fired boilers are designed to recover most of the total thermal energy through convection.

The design and operating conditions within the convective pass of the boiler are important in assessing NO_X control options because two of these options--selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR)--are designed to operate at temperatures found in and following the convective pass.

3.3.2 Furnace Configurations and Burner Types

There are a number of different furnace configurations used in utility boilers. For purposes of presentation, these configurations have been divided into four groups: tangentially-fired, wall-fired, cyclone-fired, and stoker-fired. Wall-fired boilers are further subdivided based on the design and location of the burners.

3.3.2.1 Tangentially-Fired. The tangentially-fired boiler is based on the concept of a single flame zone within the furnace. As shown in figure 3-6, the fuel-air mixture in a tangentially-fired boiler projects from the four corners of the furnace along a line tangential to an imaginary cylinder located along the furnace centerline.[16] As shown in figure 3-7, the burners in this furnace design are in a stacked assembly that includes the windbox, primary fuel supply nozzles, and secondary air supply nozzles.[16]

As fuel and air are fed to the burners of a tangentially-fired boiler and the fuel is combusted, a rotating "fireball" is formed. The turbulence and air-fuel mixing that take place during the initial stages of combustion in a tangentially-fired burner are low compared to other types of boilers. However, as the flames impinge upon each other in the center of the furnace during the intermediate stages of combustion, there is sufficient turbulence for effective mixing and carbon burnout.[17] Primarily because of their tangential firing pattern, uncontrolled tangentially-fired

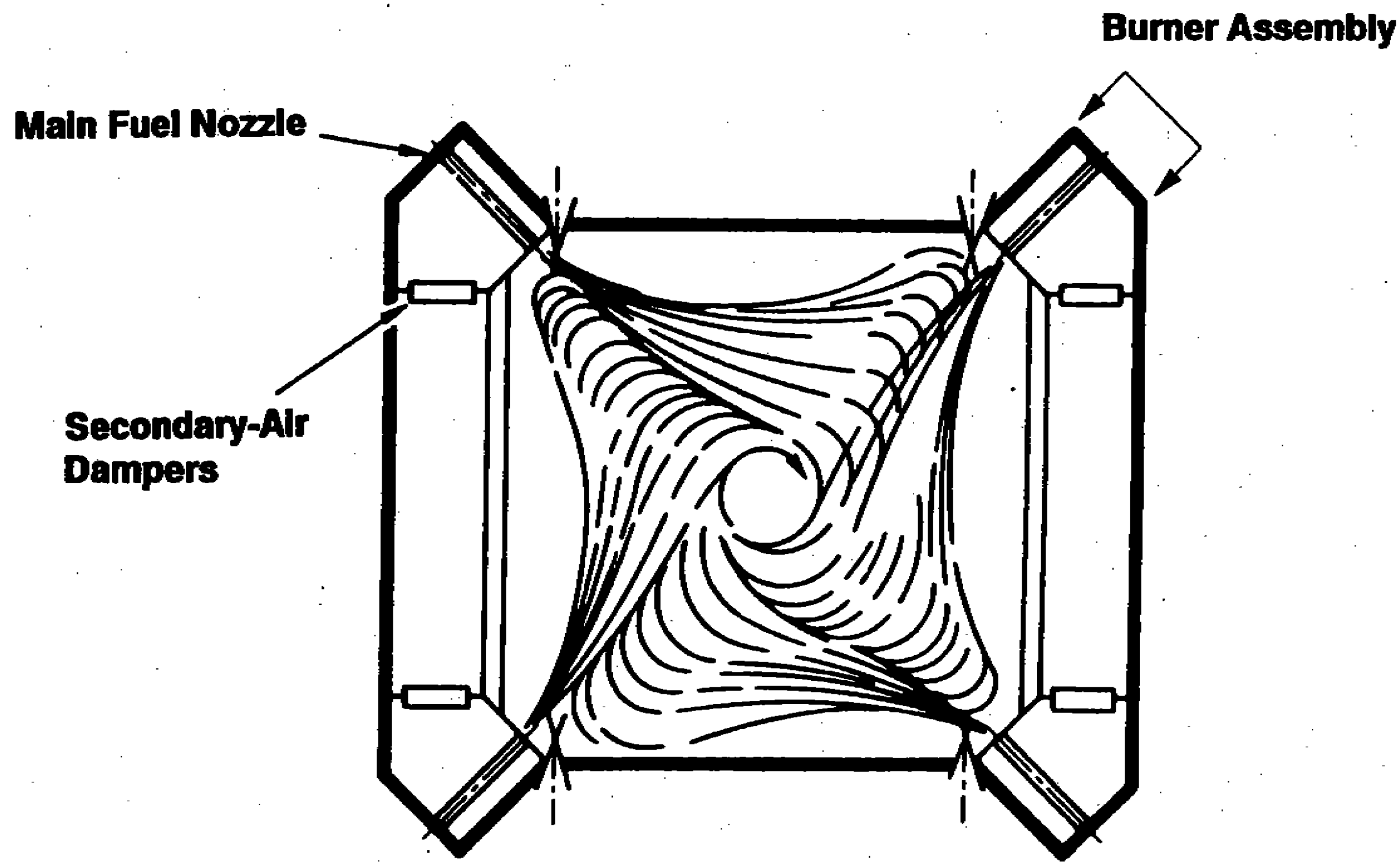


Figure 3-6. Firing pattern in a tangentially-fired boiler.[16]

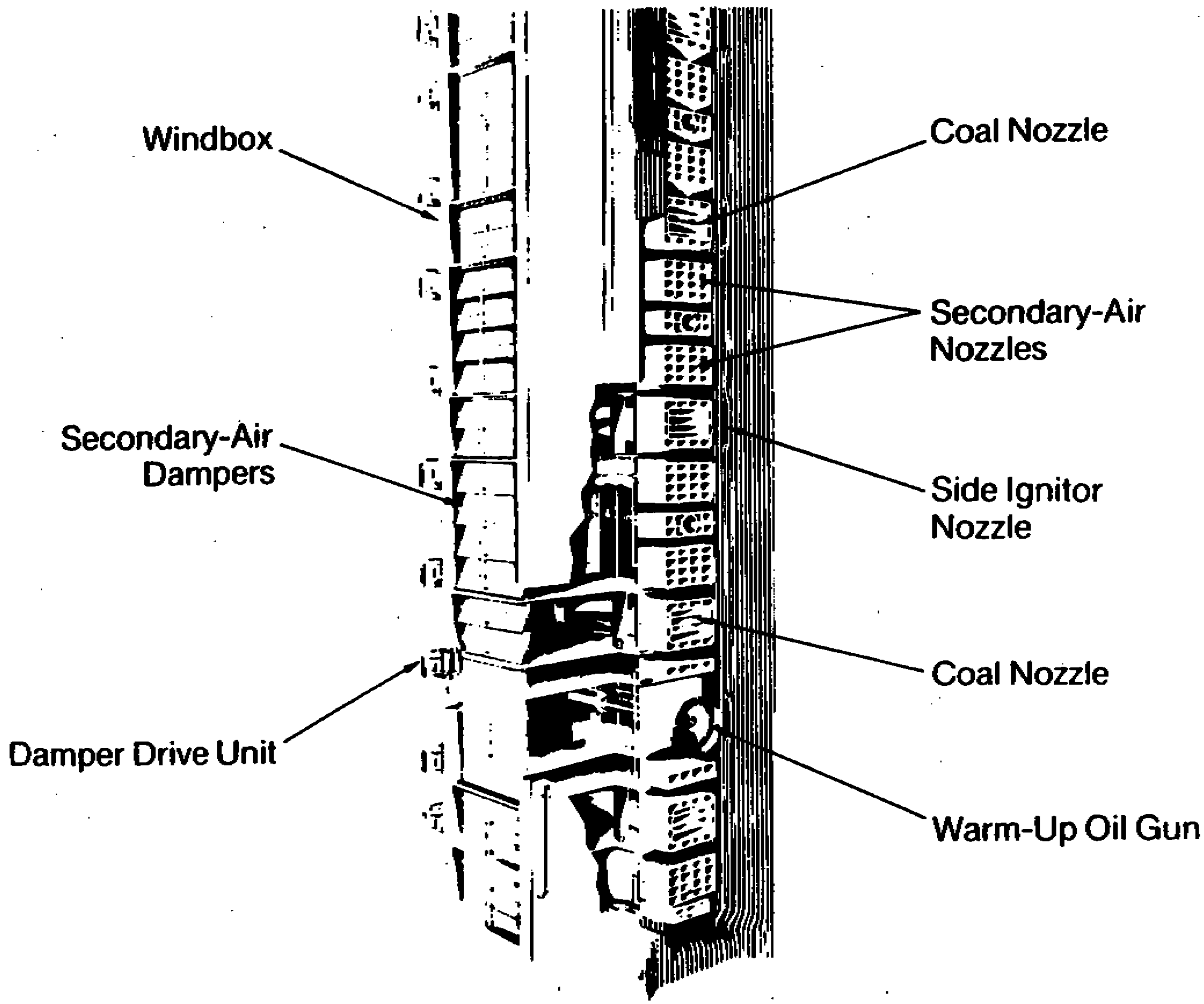


Figure 3-7. Burner assembly of a tangentially-fired boiler.[16]

boilers generally emit relatively lower NO_x than other uncontrolled boiler designs.

The entire windbox, including both the fuel and air nozzles, tilts uniformly. This allows the fireball to be moved up and down within the furnace in order to control the furnace exit gas temperature and provide steam temperature control during variations in load. In addition, the tilts on coal-fired units automatically compensate for the decreases in furnace-wall heat absorption due to ash deposits. As the surfaces of the furnace accumulate ash, the heat absorbed from the combustion products decreases. The burners are then tilted upwards to increase the temperature of the flue gas entering the convective pass of the boiler. Furnace wall fouling will cause the heat to rise in the furnace normally resulting in downward tilts, while fouling in the convective sections can cause the reverse. Also, when convective tube fouling becomes severe, soot blowers are used to remove the coating on the tubes. The sudden increase in heat absorption by the clean tubes necessitates tilting the burners down to their original position. As the fouling of the tubes resumes, the tilting cycle repeats itself.

Tangentially-fired boilers commonly burn coal. However, oil or gas are also burned in tangential burners by inserting additional fuel injectors in the secondary air components adjacent to the pulverized-coal nozzles as shown in figure 3-7.

Approximately 10 percent of the tangentially-fired boilers are twin-furnace design. These boilers, which are generally larger than 400 megawatts (MW), include separate identical furnace and convective pass components physically joined side by side in a single unit. The flue gas streams from each furnace remain separate until joined at the stack.

3.3.2.2 <u>Wall-Fired</u>. Wall-fired boilers are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace. In contrast to tangentially-fired boilers that produce a single flame envelope, or fireball, each of the burners in a wall-fired boiler has a relatively distinct flame zone. Depending on the design and location of the burners, wall-fired boilers can be subcategorized as single-wall, opposed-wall, cell, vertical, arch, or turbo.

3.3.2.2.1 Single wall. The single-wall design consists of several rows of circular-type burners mounted on either the front or rear wall of the furnace. Figure 3-8 shows the burner arrangement of a typical single-wall-fired boiler.[18]

In circular burners, the fuel and primary air are introduced into the burner through a central nozzle that imparts the turbulence needed to produce short, compact flames. Adjustable inlet vanes located between the windbox and burner impart a rotation to the preheated secondary air from the windbox. The degree of air swirl, in conjunction with the flow-shaping contour of the burner throat, establishes a recirculation pattern extending into the furnace. After the fuel is ignited, this recirculation of hot combustion gases back towards the burner nozzle provides thermal energy needed for stable combustion.

Circular burners are used for firing coal, oil, or natural gas, with some designs featuring multi-fuel capability. A circular burner for pulverized coal, oil, and natural gas firing is shown in figure 3-9.[19] To burn fuel oil at the high rates demanded in a modern boiler, circular burners must be equipped with oil atomizers. Atomization provides high oil surface area for contact with combustion air. The oil can be atomized by the fuel pressure or by a compressed gas, usually steam or air. Atomizers that use fuel pressure are generally referred to as uniflow or return flow mechanical atomizers. Steam- and air-type atomizers provide efficient atomization over a wide load range, and are the most commonly used.

In natural gas-fired burners, the fuel can be supplied through a perforated ring, a centrally located nozzle, or

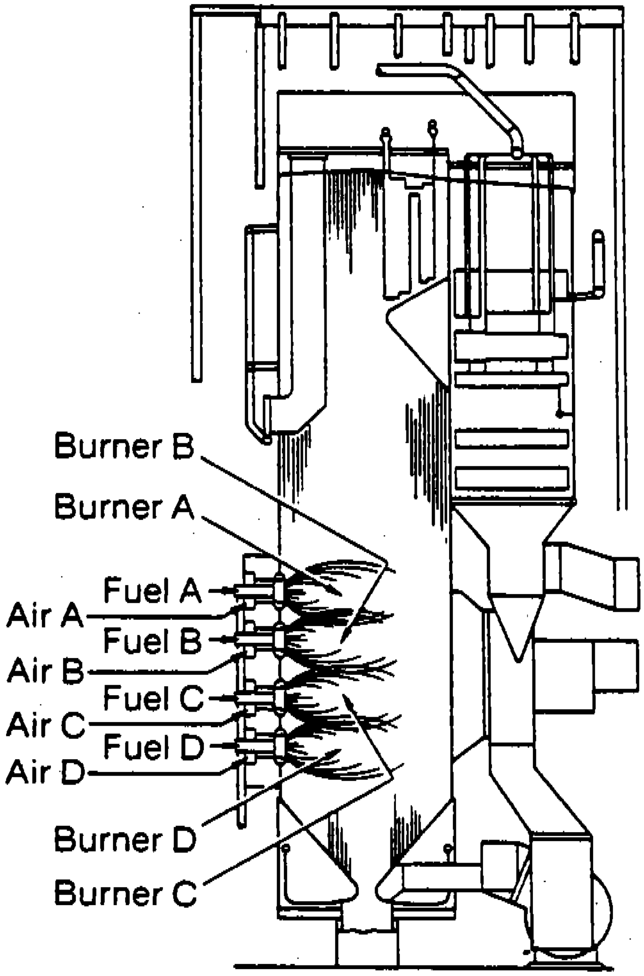


Figure 3-8. Single wall-fired boiler.[18]

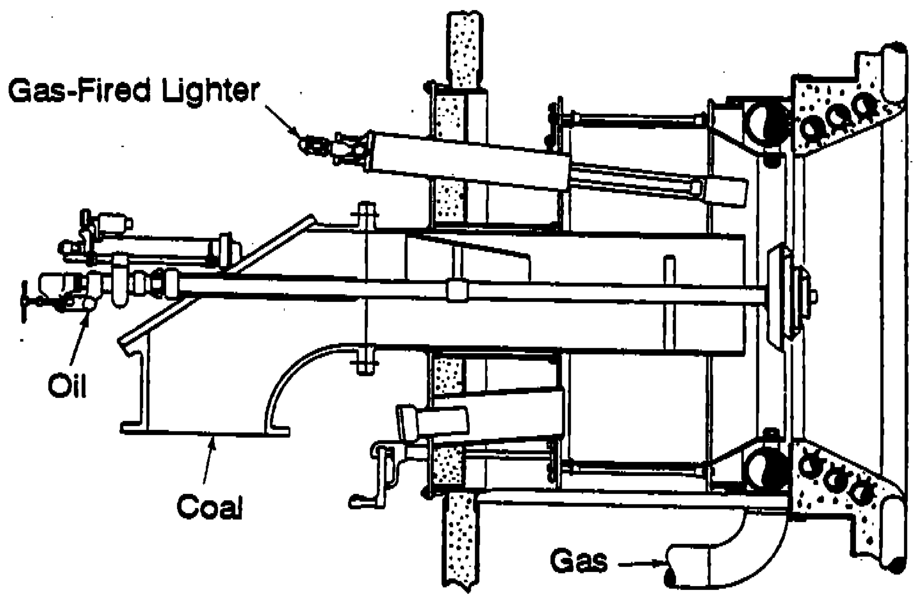


Figure 3-9. Circular-type burner for pulverized coal, oil, or gas.[19]

radial spuds that consist of a gas pipe with multiple holes at the end.

Unlike tangentially-fired boiler designs, the burners in wall-fired boilers do not tilt. Superheated steam temperatures are instead controlled by excess air levels, heat input, flue gas recirculation, and/or steam attemperation (water spray). In general, wall-fired boilers do not incorporate the twin-furnace design.

3.3.2.2.2 Opposed-wall. Opposed-wall-fired boilers are similar in design to single wall-fired units, differing only in that two furnace walls are equipped with burners and the furnace is deeper. The opposed-wall design consists of several rows of circular-type burners mounted on both the front and rear walls of the furnace as shown in figure 3-10.

3.3.2.2.3 Cell. Cell-type wall-fired boilers consist of two or three closely-spaced burners, i.e., the cell, mounted on opposed walls of the furnace. Furnaces equipped with cell burners fire coal, oil, and natural gas. Figure 3-11 shows a natural gas-fired cell burner employing spud-type firing elements.[20] The close spacing of these fuel nozzles generates hotter, more turbulent flames than the flames in circular-type burners, resulting in a higher heat release rate and higher NO_x emission levels than with circular burners. Cell-type boilers typically have relatively small furnace sizes with high heat input.

3.3.2.2.4 Vertical-, arch- and turbo-fired. Vertically-fired boilers use circular burners that are oriented downward, rather than horizontally as with wall-fired boilers. Several vertical-fired furnace designs exist, including roof-fired boilers, and arch-fired and turbo-fired boilers, in which the burners are installed on a sloped section of furnace wall and are fired at a downward angle.

Vertically-fired boilers are used primarily to burn solid fuels that are difficult to ignite, such as anthracite. They require less supplementary fuel than the horizontal wall- or

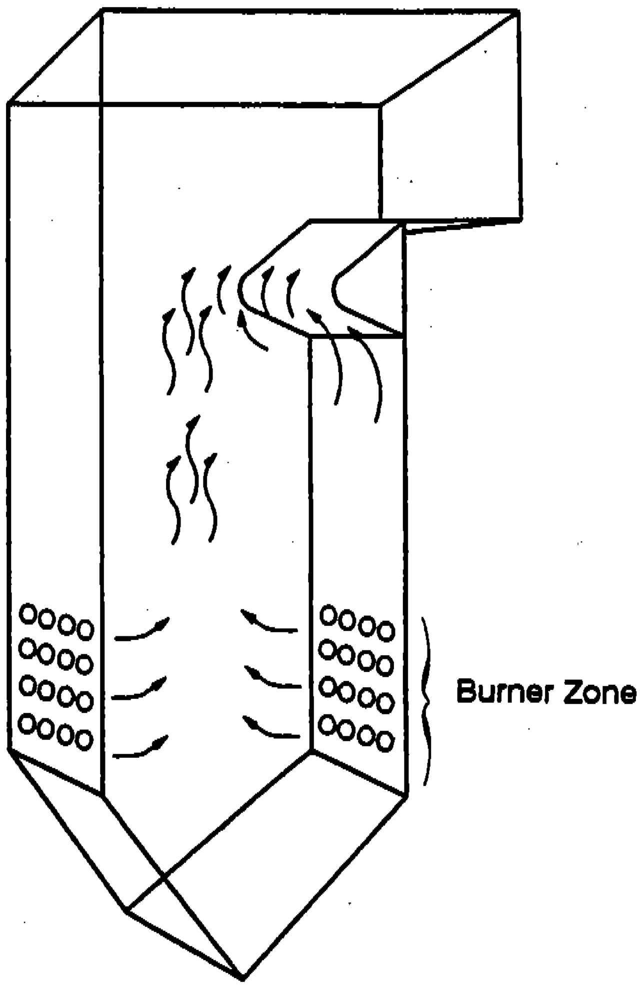


Figure 3-10. Opposed wall-fired boiler.

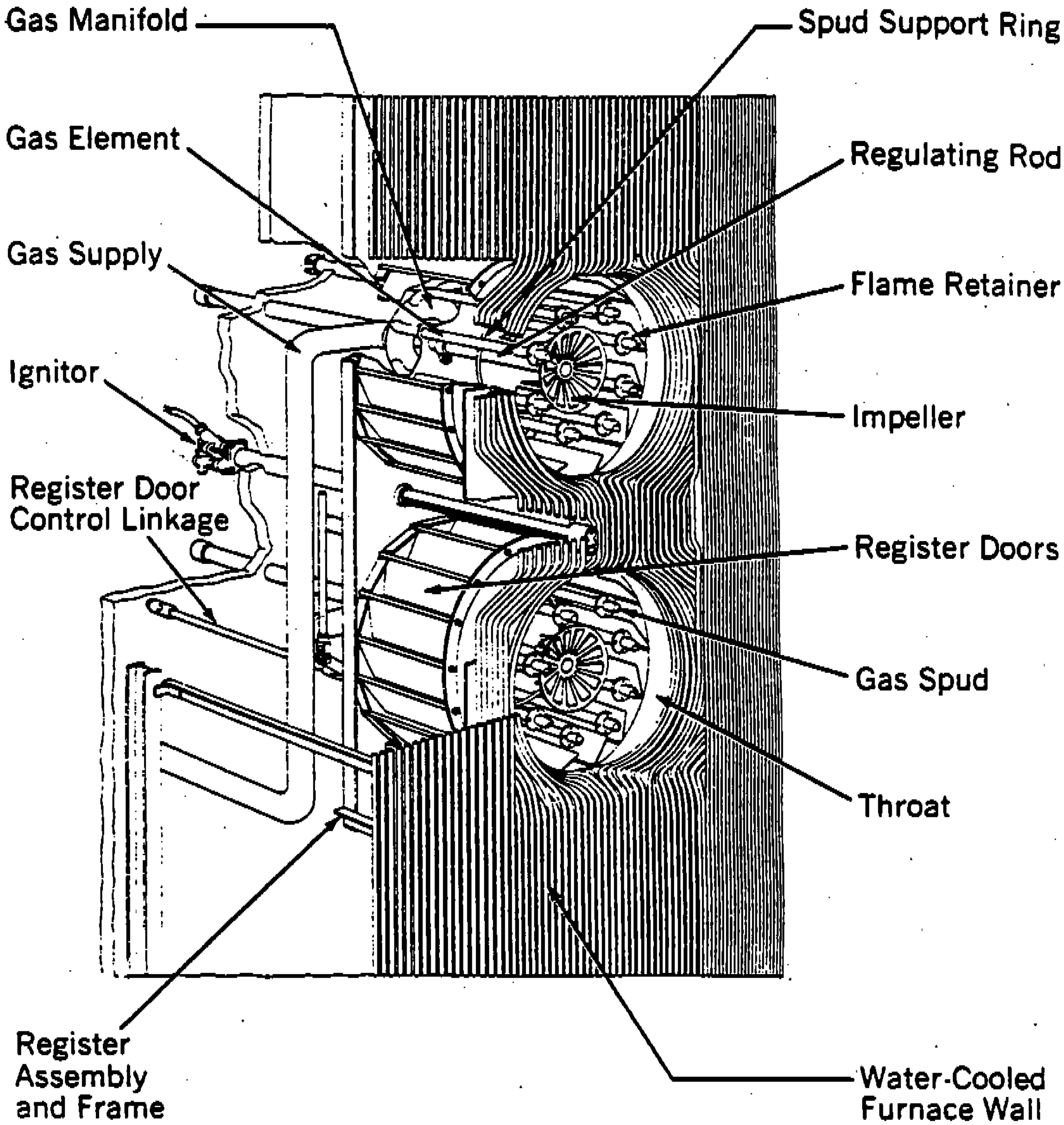


Figure 3-11. Cell burner for natural gas-firing.[20]

tangentially-fired systems, but have more complex firing and operating characteristics.

Figure 3-12 shows an arch-fired boiler where pulverized coal is introduced through the nozzles, with heated combustion air discharged around the fuel nozzles and through adjacent secondary ports.[21] Tertiary air ports are located in rows along the front and rear walls of the lower section of the furnace.

This firing mode generates a long, looping flame in the lower furnace, with the hot combustion products discharging up through the center. Delayed introduction of the tertiary air provides the turbulence needed to complete combustion. The flame pattern ensures that the largest entrained solid fuel particles (i.e., those with the lowest surface area-to-weight ratio) have the longest residence time in the furnace.

Roof-fired boilers are somewhat similar in design, having the burners mounted on the roof of the furnace, but discharge combustion gases through a superheater section located at the bottom of the furnace, rather than through an opening at the top of the boiler. In a coal-fired boiler design, the flames from individual burners do not impinge on each other as in an arch-fired boiler, and residence times in the furnace are shorter.

Turbo-fired boilers are unique because of their venturi-shaped cross-section and directional flame burners as shown in Figure 3-13.[22] In turbo-fired boilers, air and coal are injected downward toward the furnace bottom. Like arch-fired boilers, turbo-fired boilers generate flames that penetrate into the lower furnace, turn, and curl upward. Hot combustion products recirculate from the lower furnace and flow upward past the burner level to the upper furnace, where they mix with the remaining fuel and air. This type of firing system produces long, turbulent flames.

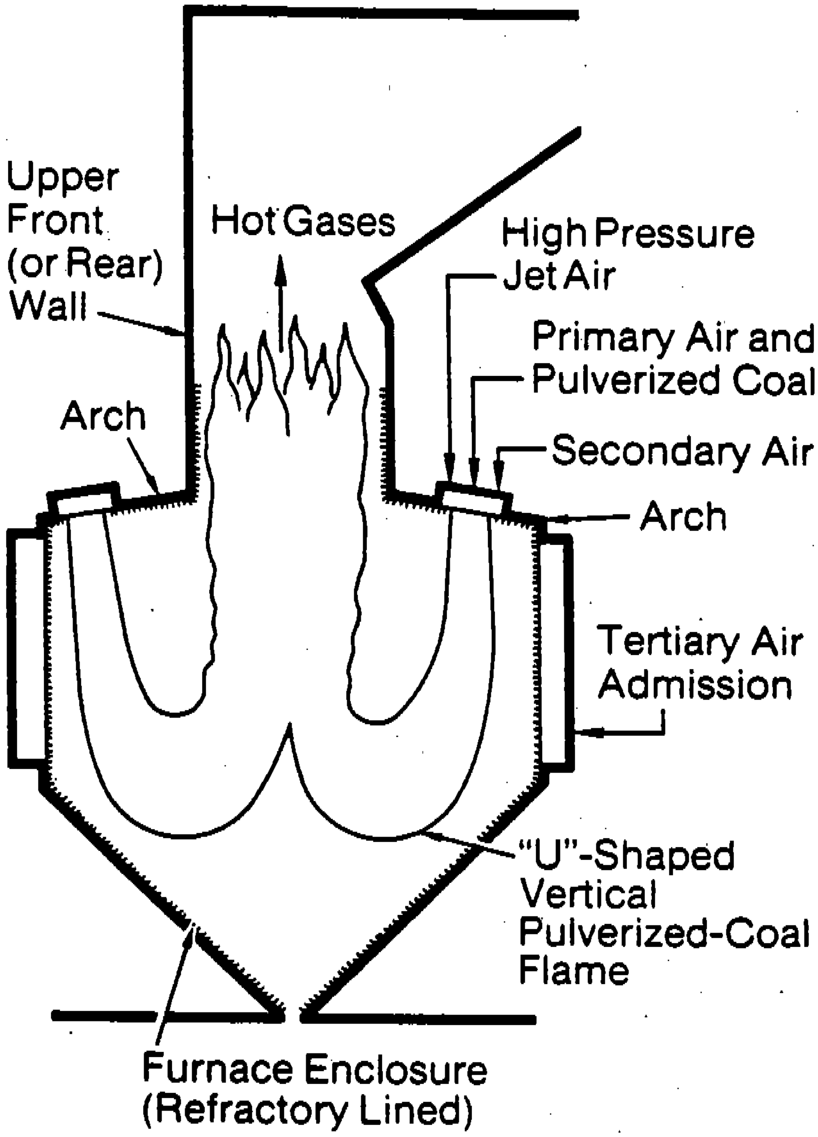


Figure 3-12. Flow pattern in an arch-fired boiler.[21]

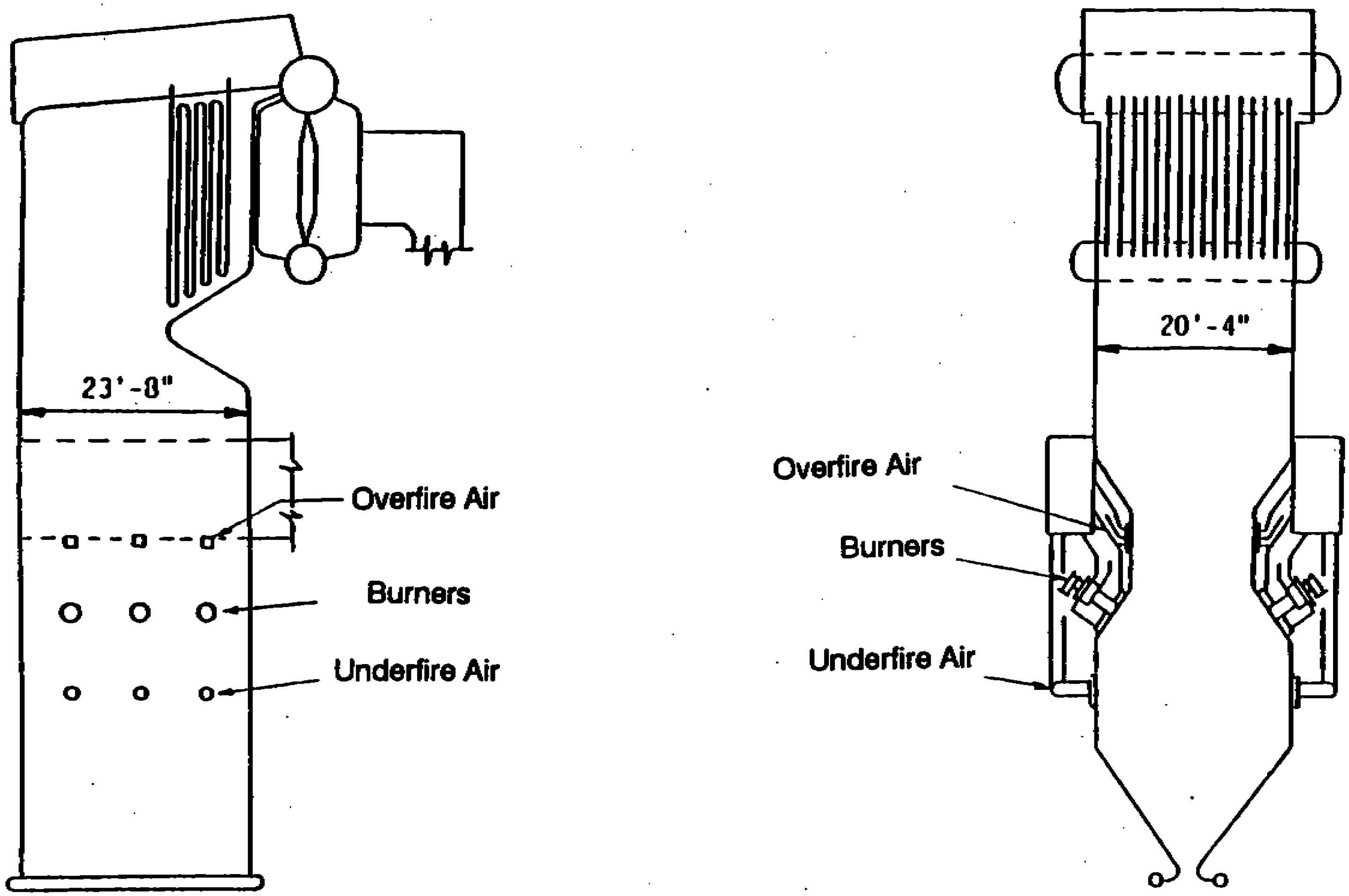


Figure 3-13. Cross section of turbo-fired boiler.[22]

3.3.2.3 Cyclone-Fired. Cyclone-fired boilers burn crushed, rather than pulverized, coal. As shown in figure 3-14, fuel and air are burned in horizontal cylinders, producing a spinning, high-temperature flame.[23] Only a small amount of wall surface is present in the cylinder and this surface is partially insulated by the covering slag layer. Thus, cyclone-fired boilers have a combination of high heat release rate and low heat absorption rates, which results in very high flame temperatures and conversion of ash in the coal into a molten slag. This slag collects on the cylinder walls and then flows down the furnace walls into a slag tank located below the furnace. As a result of the high heat release rate, the cyclone-fired boilers are characterized by high thermal NO_X formation.

Because of their slagging design, cyclone-fired boilers are almost exclusively coal-fired. However, some units are also able to fire oil and natural gas. Figure 3-15 shows the single-wall firing and opposed-wall firing arrangements used for cyclone firing.[24] For smaller boilers, sufficient firing capacity is usually attained with cyclone burners located in only one wall. For large units, furnace width can often be reduced by using opposed firing.

3.3.2.4 Stoker-Fired. There are several types of stoker-fired boilers used by utilities. The most common stoker type is the spreader stoker. Spreader stokers are designed to feed solid fuel onto a grate within the furnace and remove the ash residue.

Spreader stokers burn finely crushed coal particles in suspension, and larger fuel particles in a fuel bed on a grate as shown in figure 3-16.[25] The thin bed of fuel on the grate is fuel-burning and responsive to variations in load. However, relatively low combustion gas velocities through the boiler are necessary to prevent fly ash erosion, which results from high flue-gas ash loadings.

Spreader stokers use continuous-ash-discharge traveling grates, intermittent-cleaning dump grates, or reciprocating

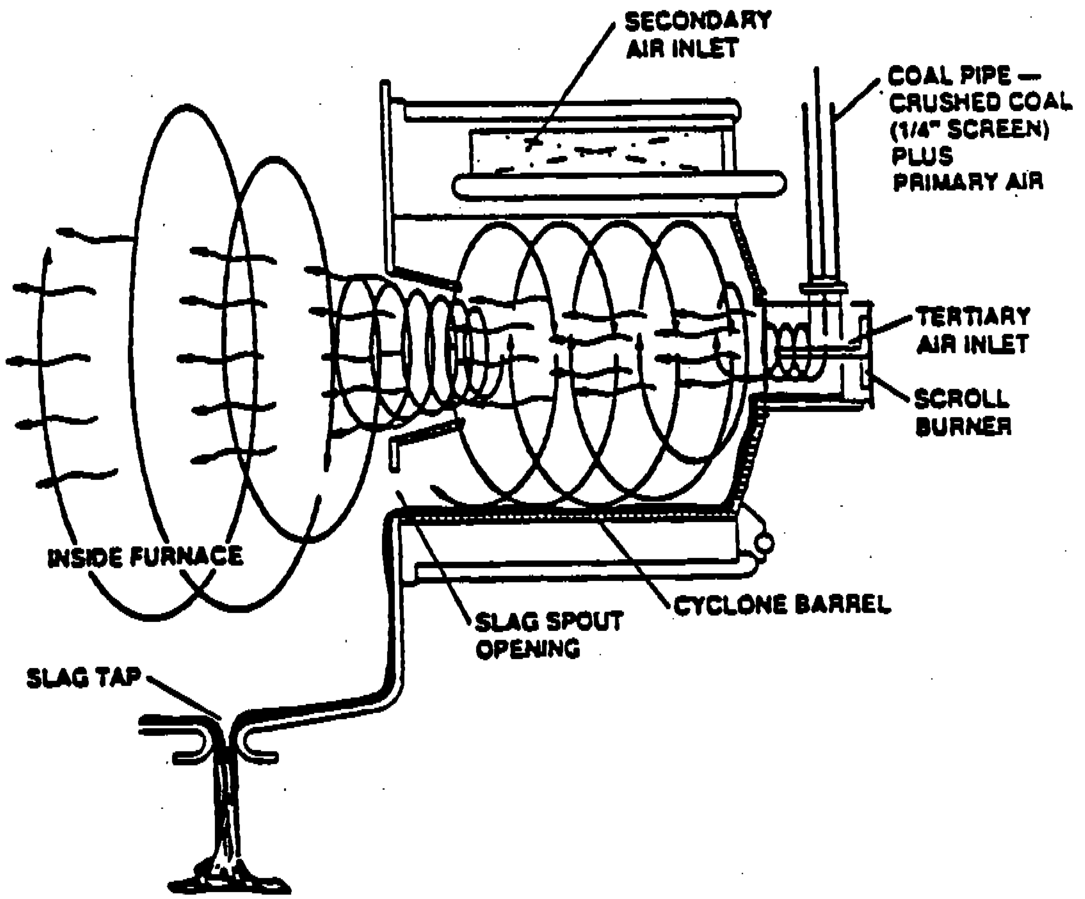


Figure 3-14. Cyclone burner.[23]

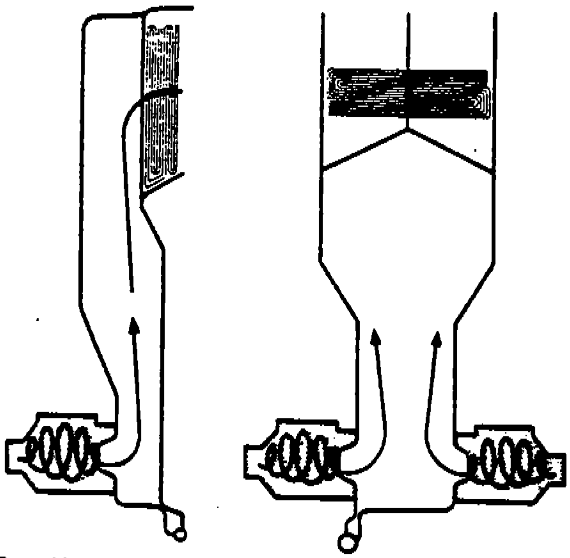


Figure 3-15. Firing arrangements used with cyclone-fired boilers.[24]

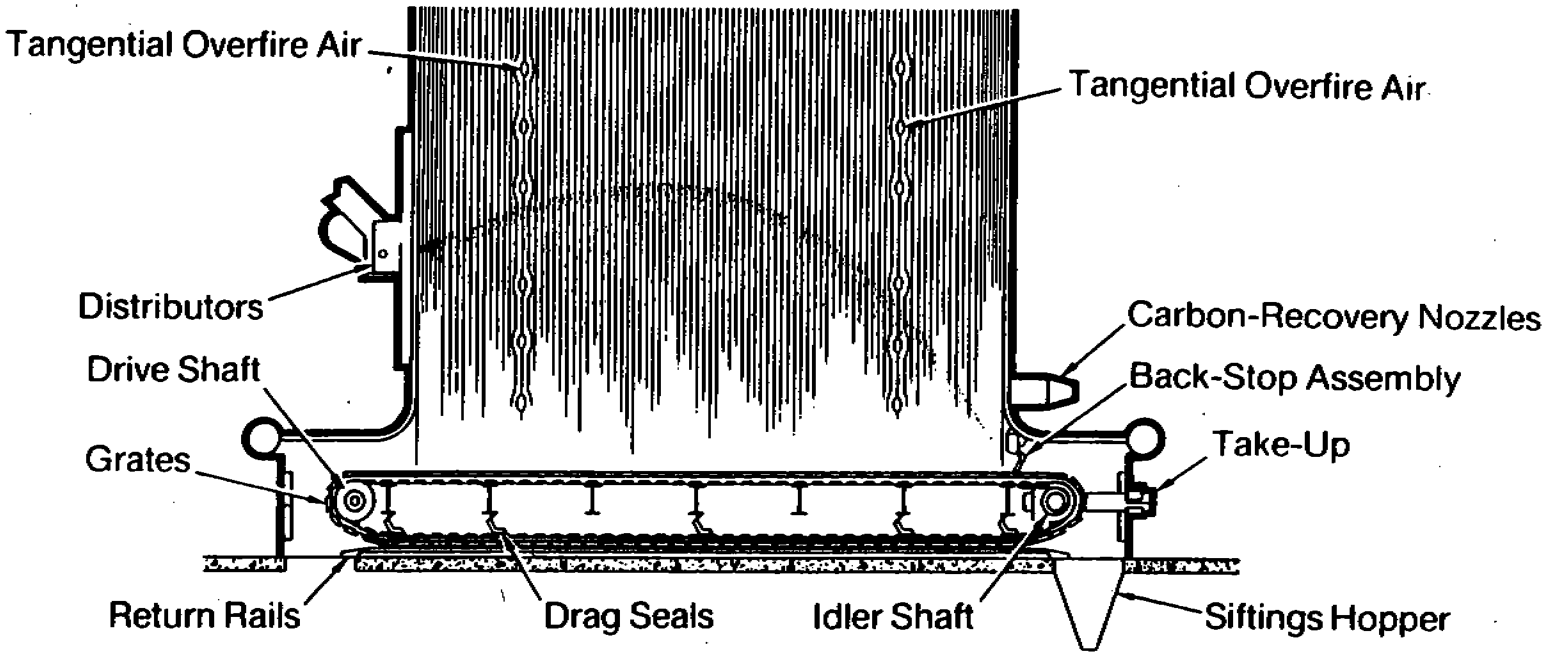


Figure 3-16. Spreader type stoker-fired boiler - continuous ash discharge grate.[25]

continuous-cleaning grates. They are capable of burning all types of bituminous and lignitic coals. Because of material handling limitations, the largest stokers used by utilities are roughly 50 MW or less.

3.3.2.5 Fluidized Bed Combustion Boilers. Fluidized bed combustion (FBC) is an integrated technology for reducing sulfur dioxide (SO_2) and NO_x emissions during the combustion of coal and is an option for repowering or for a new boiler. In a typical FBC boiler, crushed coal in combination with inert material (sand, silica, alumina, or ash) and/or a sorbent (limestone) are maintained in a highly turbulent suspended state by the upward flow of primary air from the windbox located directly below the combustion floor. This fluidized state provides a large amount of surface contact between the air and solid particles, which promotes uniform and efficient combustion at lower furnace temperatures, between 860 and 900 ^{o}C (1,575 and 1,650 ^{o}F) compared to 1,370 and 1,540 ^{o}C (2,500 and 2,800 ^{o}F) for conventional coal-fired boilers. Furnace internals include fluidizing air nozzles, fuel-feed ports, secondary air ports, and waterwalls lined at the bottom with refractory. Once the hot gases leave the combustion chamber, they pass through the convective sections of the boiler which are similar or identical to components used in conventional boilers. Fluidized bed combustion boilers are capable of burning low grade fuels. Unit sizes, as offered by manufacturers, range between 25 and 400 MW. The largest FBC boilers installed are typically closer to 200 MW.

Fluidized bed combustion technologies based on operation at atmospheric and pressurized conditions have been developed. The atmospheric FBC (AFBC) system shown in figure 3-17 is similar to a conventional utility boiler in that the furnace operates at near atmospheric pressure and depends upon heat transfer of a working fluid (i.e., water) to recover the heat released during combustion.[26] Pressurized FBC (PFBC) operates at pressures greater than atmospheric pressure and recovers

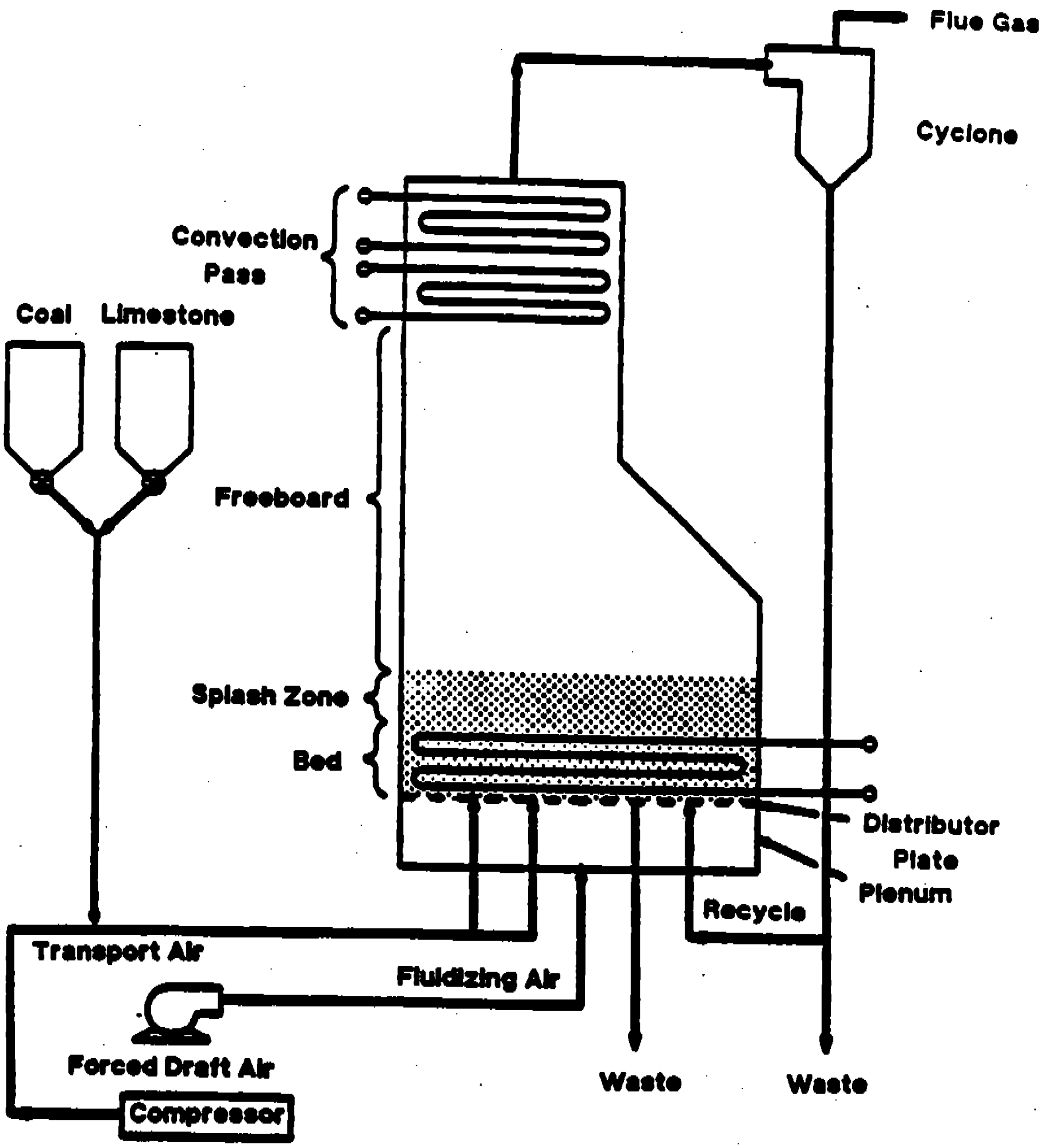


Figure 3-17. Simplified AFBC process flow diagram.[26]

energy through both heat transfer to a working fluid and the use of the pressurized gas to power a gas turbine.

3.3.2.5.1 Atmospheric fluidized bed combustion. There are two major categories of AFBC boilers: the bubbling bed, and the circulating bed designs. In the bubbling bed design, coal and limestone are continuously fed into the boiler from over or under the bed. The bed materials, consisting of unreacted, calcined, and sulfated limestone, coal, and ash, are suspended by the combustion air blowing upwards through the fluidizing air nozzles. The desired depth of the fluidized-bed is maintained by draining material from the bed. Some bed material is entrained in the upflowing flue gas and escapes the combustion chamber. Approximately 80 to 90 percent of this fly ash is collected in the cyclone and is then either discarded or reinjected into the bed. Reinjection of ash increases combustion efficiency and limestone utilization. In general, combustion efficiency increases with longer freeboard residence times and greater ash recycle rates. Fly ash not collected in the cyclone is removed from the flue gas by an electrostatic precipitator (ESP) or fabric filter.

The circulating fluidized bed design is a more recent development in AFBC technology. The two major differences between circulating and bubbling AFBC's are the size of the limestone particles fed to the system, and the velocity of the fluidizing air stream. Limestone feed to a bubbling bed is generally less than 0.1 inches in size, whereas circulating beds use much finer limestone particles, generally less than 0.01 inches. The bubbling bed also incorporates relatively low air velocities through the unit, ranging from 4 to 12 feet per second (ft/sec).[26] This creates a relatively stable fluidized bed of solid particles with a well-defined upper surface. Circulating beds employ velocities as high as 30 ft/sec.[27] As a result, a physically well-defined bed is not formed; instead, solid particles (coal, limestone, ash, sulfated limestone, etc.) are entrained in the transport air/combustion gas stream. These solids are then separated from the combustion gases by a cyclone or other separating device and circulated back into the combustion region, along with fresh coal and limestone. A portion of the collected solids are continuously removed from the system to maintain material balances. Circulating beds are characterized by very high recirculated solids flow rates, up to three orders of magnitude higher than the combined coal/limestone feed rate.[26]

Circulating AFBC's are dominating new FBC installation, in part due to their improved performance and enhanced fuel flexibility.[28] Some specific advantages of circulating bed over bubbling bed designs include:

- Higher combustion efficiency, exceeding 90 percent;
- Greater limestone utilization, due to high recycle of unreacted sorbent and small limestone feed size (greater than 85 percent SO_2 removal efficiency is projected with a Ca/S ratio of about 1.5, with the potential for greater than 95 percent SO_2 removal efficiency);
- Potentially fewer corrosion and erosion problems, compared to bubbling bed designs with in-bed heat transfer surfaces;
- Less dependence on limestone type, since reactivity is improved with the fine particle sizes; and
- Reduced solid waste generation rates, because of lower limestone requirements.

3.3.2.5.2 <u>Pressurized fluidized bed combustion</u>. Pressurized FBC is similar to AFBC with the exception that combustion occurs under pressure. By operating at pressure, it is possible to reduce the size of the combustion chamber and to develop a combined-cycle or turbocharged boiler capable of operation at higher efficiencies than atmospheric systems. The turbocharged boiler approach recovers most of the heat from the boiler through a conventional steam cycle, leaving only sufficient energy in the gas to drive a gas turbine to pressurize the combustion air. The combined cycle system extracts most of the system's energy through a gas turbine followed by a heat recovery steam generator and steam turbine.

3.3.3 Other Boiler Components

This section discuses additional boiler components including pulverizers (fuel preparation system), air supply system, and superheaters/reheaters, economizers, and air heaters (heat transfer system).

3.3.3.1 Pulverizers. Cyclone-fired or stoker-fired boilers use crushed coal, but most other boilers use pulverized coal. The only fuel preparation system discussed here is the pulverizer. Pulverized coal is favored over other forms of coal because pulverized coal mixes more intimately with the combustion air and burns more rapidly. Pulverized coal also burns efficiently at lower excess air levels and is more easily lit and controlled.[29]

To achieve the particle size reduction required for proper combustion in pulverized coal-fired boilers, machines known as pulverizers (also referred to as "mills") are used to grind the fuel. Coal pulverizers are classified according to their operating speed. Low-speed pulverizers consist of a rotating drum containing tumbling steel balls. This pulverizer type can be used with all types of coal, but is particularly useful for very abrasive coals having a high silica content.

Most medium-speed pulverizers are ring-roll and ball-race mill designs, and are used for all grades of bituminous coal. Their low power requirements and quick response to changing boiler loads make them well-suited for utility boiler applications. They comprise the largest number of medium-speed pulverizers, and the largest number of coal pulverizers overall. High-speed pulverizers include impact or hammer mills and attrition mills and are also used for all grades of bituminous coal.

The capacity of a pulverizer is affected by the grindability of the coal and the required fineness. The required fineness of pulverization varies with the type of coal and with the size and type of furnace, and usually ranges from 60 to 75 weight-percent passing through a 200 mesh (74 micrometers [μm]) screen. To ensure minimum carbon loss from the furnace, high-rank coals are frequently pulverized to a finer size than coals of lower rank. When firing certain low-volatile coals in small pulverized coal furnaces, the fineness may be as high as 80 weight-percent through a 200 mesh screen in order to reduce carbon loss to acceptable levels.[30]

Coal enters the pulverizer with air that has been heated to 150 to 400 ^{o}C (300 to 750 ^{o}F), depending on the amount of moisture in the coal. The pulverizer provides the mixing necessary for drying, and the pulverized coal and air mixture then leaves the pulverizer at a temperature ranging from 55 to 80 ^{o}C (130 to 180 ^{o}F).[31]

The two basic methods used for moving pulverized coal to the burners are the storage or bin-and-feeder system, and the direct-fired system. In the storage system, the pulverized coal and air (or flue gas) are separated in cyclones and the coal is then stored in bins and fed to the burners as needed. In direct-fired systems, the coal and air pass directly from the pulverizers to the burners and the desired firing rate is regulated by the rate of pulverizing.

3.3.3.2 Air Supply System. Key air supply system components are fans and windboxes. The purpose of these components are to supply the required volumes of air to the pulverizers and burners, and to transport the combustion gases from the furnace, through the convective sections, and on to the air pollution control equipment and stack.

The fans determine the static pressure of the boiler, which can be characterized as forced-draft, balanced-draft, or induced draft. A forced-draft boiler operates at static pressures greater than atmospheric, a balanced-draft boiler operates with static pressures at or slightly below atmospheric, and an induced-draft boiler operates at less than atmospheric pressure. Four types of fans are used: forced-draft, primary-air, induced-draft, and gas-recirculation.

Forced-draft fans are located at the inlet to the secondary air supply duct. These fans supply the secondary or tertiary air used for combustion. The air is typically routed through the air preheater and then to the windbox. Forced-draft fans are used on both forced-draft and balanced-draft boilers.

Primary air fans are located before or after the fuel preparation systems, and provide primary air to the burners. In pulverized coal boilers, primary air fans are used to supply air to the pulverizers and then to transport the coal/air mixture to the burners. There are two types of primary air fans: mill exhauster fans and cold air fans. A mill exhauster fan is located between the pulverizer and the windbox and pulls preheated combustion air from the secondary air supply duct through the pulverizers. Cold air fans are located before the pulverizers and provide ambient air to the pulverizers through a separate ducting system. Primary air fans are used in all boilers.

Induced-draft fans are generally located just before the stack. These fans pull the combustion gases through the furnace, convective sections, and air pollution control equipment. Induced draft fans are used on balanced-draft boilers to maintain a slightly negative pressure in the furnace. Induced draft fans are used on induced-draft boilers to maintain negative static pressure. In this arrangement, the induced-draft fan are also designed with sufficient static head to pull secondary air through the air preheater and windbox.

Gas recirculation fans are used to transport partially cooled combustion gases from the economizer outlet back to the furnace. Gas recirculation can be used for several purposes, including control of steam temperatures, heat absorption rates, and slagging. It is also sometimes used to control flame temperatures, and thereby reduce NO_x formation on gas- and oil-fired boilers.

The second part of the air supply system is the windbox. A windbox is essentially an air plenum used for distributing secondary air to each of the burners. The flow of air to individual burners is controlled by adjustable air dampers. By opening or closing these dampers, the relative flow of air to individual burners can be changed. To increase or decrease the total air flow to the furnace, the differential pressure between the windbox and furnace is changed by adjusting the fans. In boilers having tertiary air injection, tertiary air can be supplied from the windbox supplying secondary air or by a separate windbox. Separate windboxes allow greater control of the tertiary air supply rate.

3.3.3.3 <u>Superheaters/Reheaters</u>. To produce electricity, a steam turbine converts thermal energy (superheated steam) into mechanical energy (rotation of the turbine and electrical generator shaft). The amount of electricity that can be produced by the turbine-generator system is directly related to the amount of superheat in the steam. If saturated steam is utilized in a steam turbine, the work done results in a loss of energy by the steam and subsequent condensation of a portion of the steam. This moisture, in the form of condensed water droplets, can cause excessive wear of the turbine blades. If, however, the steam is heated above the saturation temperature level (superheated), more useful energy is available prior to the point of excessive steam condensation in the turbine exhaust.[32]

To provide the additional heat needed to superheat the steam recovered from the boiler steam drum, a superheater is installed in the upper section of the boiler. In this area of the boiler, flue gas temperatures generally exceed 1,100 ^{o}C (2,000 ^{o}F). The superheater transfers this thermal energy to the steam, superheating it. The steam is then supplied to the turbine. In some turbine designs, steam recovered from the turbine after part of its available energy has been used is routed to a reheater located in the convective pass just after the superheater. The reheater transfers additional thermal energy from the flue gas to the stream, which is supplied to a second turbine.

Superheaters and reheaters are broadly classified as convective or radiant, depending on the predominate mechanism of heat transfer to the absorbing surfaces. Radiant superheaters usually are arranged for direct exposure to the furnace gases and in some designs form a part of the furnace enclosure. In other designs, the surface is arranged in the form of tubular loops or platens of wide lateral spacing that extend into the furnace. These surfaces are exposed to high-temperature furnace gases traveling at relatively low speeds, and the transfer of heat is principally by radiation.

Convective-type superheaters are more common than the radiant type. They are installed beyond the furnace exit in the convection pass of the boiler, where the gas temperatures are lower than those in the furnace. Tubes in convective superheaters are usually arranged in closely-spaced tube banks that extend partially or completely across the width of the gas stream, with the gases flowing through the relatively narrow spaces between the tubes. The principal mechanism of heat transfer is by convection.[33]

The spacing of the tubes in the superheater and reheater is governed primarily by the type of fuel fired. In the high-gas-temperature zones of coal-fired boilers, the adherence and accumulation of ash deposits can reduce the gas flow area and, in some cases, may completely bridge the space between the tubes. Thus, in coal-fired boilers, the spaces between tubes in the tube banks are increased to avoid excess pressure drops and to ease ash removal.[33] However, because the combustion of oil and natural gas produces relatively clean flue gases that are free of ash, the tubes of the superheaters and reheaters can be more closely spaced in coal- and natural gas-fired boilers and the superheaters and reheaters themselves are more compact.

3.3.3.4 Economizers. Economizers improve boiler efficiency by recovering heat from the moderate-temperature combustion gases after the gases leave the superheater and reheater.

Economizers are vertical or horizontal tube banks that heat the water feeding the furnace walls of the boiler. Economizers receive water from the boiler feed pumps at a temperature appreciably lower than that of saturated steam. Economizers are used instead of additional steam-generating surface because the flue gas at the economizer is at a temperature below that of saturated steam. Although there is not enough heat remaining in the flue gases for steam generation at the economizer, the gas can be cooled to lower temperatures for greater heat recovery and economy.

3.3.3.5 Air Preheaters. Air preheaters are installed following the economizer to further improve boiler efficiency by transferring residual heat in the flue gas to the incoming combustion air. Heated combustion air accelerates flame ignition in the furnace and accelerates coal drying in coal-fired units.

In large pulverized coal boilers, air heaters reduce the temperature of the flue gas from 320 to 430 °C (600 to 800 °F) at the economizer exit. Air preheaters reduce the temperature to 135 to 180 °C (275 to 350 °F). This energy heats the combustion air from about 25 °C (80 °F) to between 260 and 400 °C (500 and 750 °F).[34]

3.4 IMPACT OF FUEL PROPERTIES ON BOILER DESIGN

3.4.1 Coal

Regardless of the fineness of pulverization, coal fed to the boiler essentially retains its as received mineral content (ash). In a dry-ash or dry-bottom furnace, nearly all of the ash particles are formed in suspension, and roughly 80 percent leave the furnace entrained in the flue gas. Slag-tap or wet-bottom furnaces operate at higher temperatures and heat-release rates and, as a result, a portion of the ash particles become molten, coalesce on the furnace walls, and drain to the furnace bottom. In this case, approximately 50 percent of the ash may be retained in the furnace, with the other 50 percent leaving the unit entrained in the flue gas.[35] Because of their high heat release rates, wet-bottom furnaces generally have higher thermal NO_x formation than dry-bottom furnaces.

Because longer reaction time is required for the combustion of coal, furnaces for firing coal are generally larger than those used for burning oil or natural gas. The characteristics of the coal, which varies with rank, determines the relative increase in furnace size shown in figure 3-18.[36] Furnaces firing coals with low volatile contents or high moisture or ash levels are larger than those firing high volatile content coals. In addition, the characteristics of the coal ash and the desired operating temperature of the furnace will influence furnace size. The furnace must be large enough to provide the furnace retention time required to burn the fuel completely and cool the combustion products. This is to ensure that the gas temperature at the entrance to the convective pass is well below the ash-softening temperature of the coal and the metalurigical limits of the superheater tubes.

3.4.2 Oil/Gas

Oil-fired boilers do not require as large a furnace volume as coal-fired boilers to ensure complete burning. Because atomization of oil provides a greater amount of fuel reaction surface for combustion than pulverization of coal, furnace residence times can be shorter. In addition, the relatively low ash content of oil essentially eliminates the slagging problems that can occur in a small coal-fired furnace.[37]

Similarly, because the combustion gases contain less entrained ash, the convective pass of oil-fired boilers can be

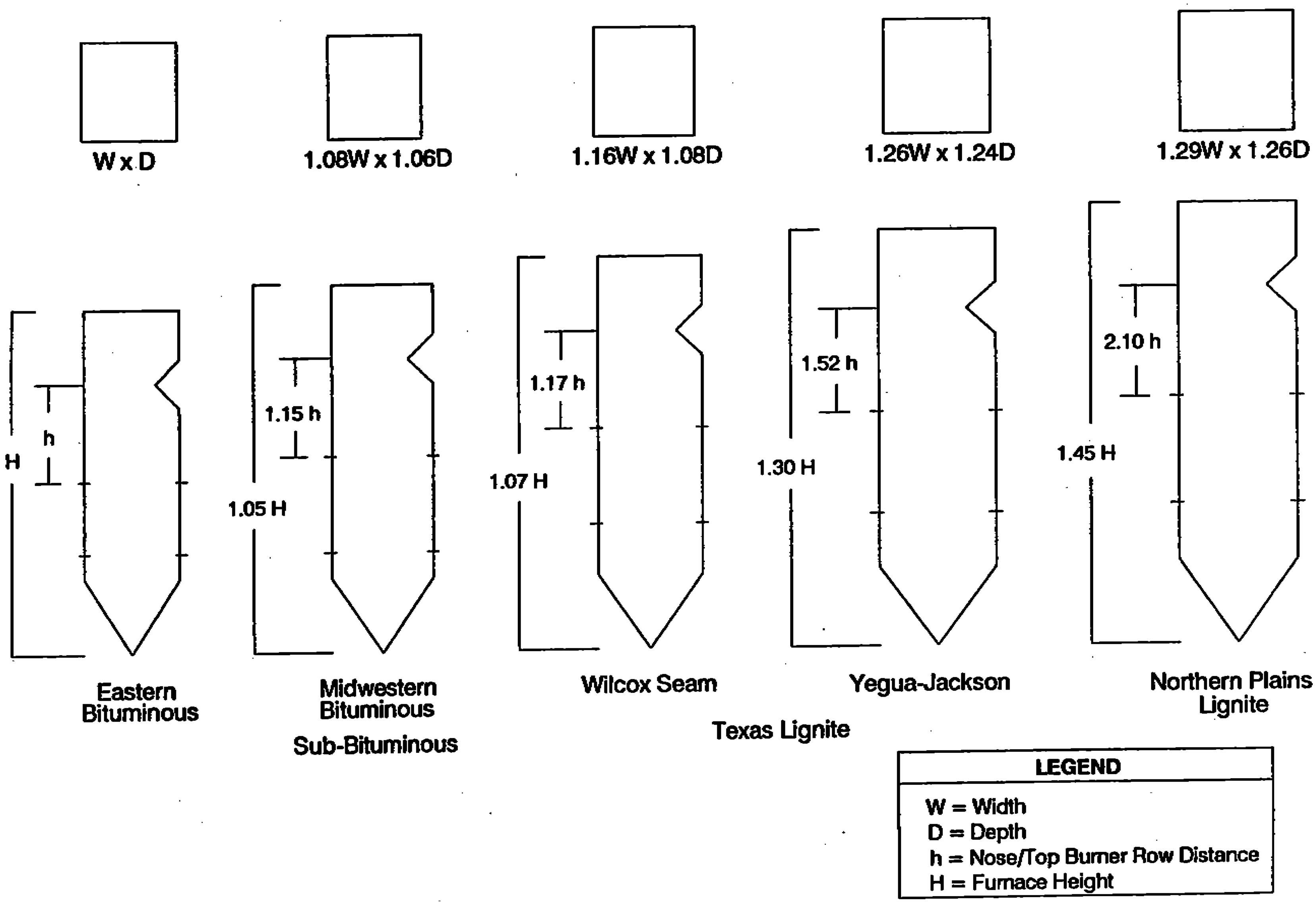


Figure 3-18. Effect of coal rank on furnace sizing.[36]

more compact, with more closely spaced tubes in the superheater and reheater sections. In addition, oil-fired units operate at lower excess air levels than coal-fired boilers; up to 20 percent less air volume per unit heat input is required for oil firing.[37]

The more compact design of oil-burning furnaces has an effect on NO_x emissions from oil-fired units. Even though the nitrogen content of the oil is generally lower than that of coal, higher flame temperatures result in increased formation of thermal NO_x. This thermal NO_x contribution can more than offset the lower fuel NO_x contribution from the oil.[37]

Gas-fired boilers are similar in design to oil-fired boilers, as many gas-fired boilers were intended to fire oil as a supplementary fuel. Boilers that are strictly gas-fired have the smallest furnace volumes of all utility boilers, because of the rapid combustion, low flame luminosity, and ash free content of natural gas. Because the nitrogen content of natural gas is low, its combustion produces minimal fuel NO_x. However, the compact furnaces and resulting high heat release rates of gas-fired boilers can generate high levels of thermal NO_x.[38]

Some furnaces were originally designed and operated as coal-fired furnaces and then converted to oil- and gas-fired furnaces. Furnaces designed to burn coal have larger volumes than furnaces originally designed to burn oil and/or natural gas fuel. As a result, the furnace heat release rate is lower, and NO_x emissions from the converted furnaces may be lower.

Figure 3-19 shows the comparative sizes of coal, oil, and natural gas utility boilers of the same generation rating.[39] The differences in the designs are attributed to the heat transfer characteristics of the fuels. The type of fuel being burned directly influences the furnace dimensions, distance above the top row of burners and the convective pass, furnace bottom design, location of burners in relation to the furnace

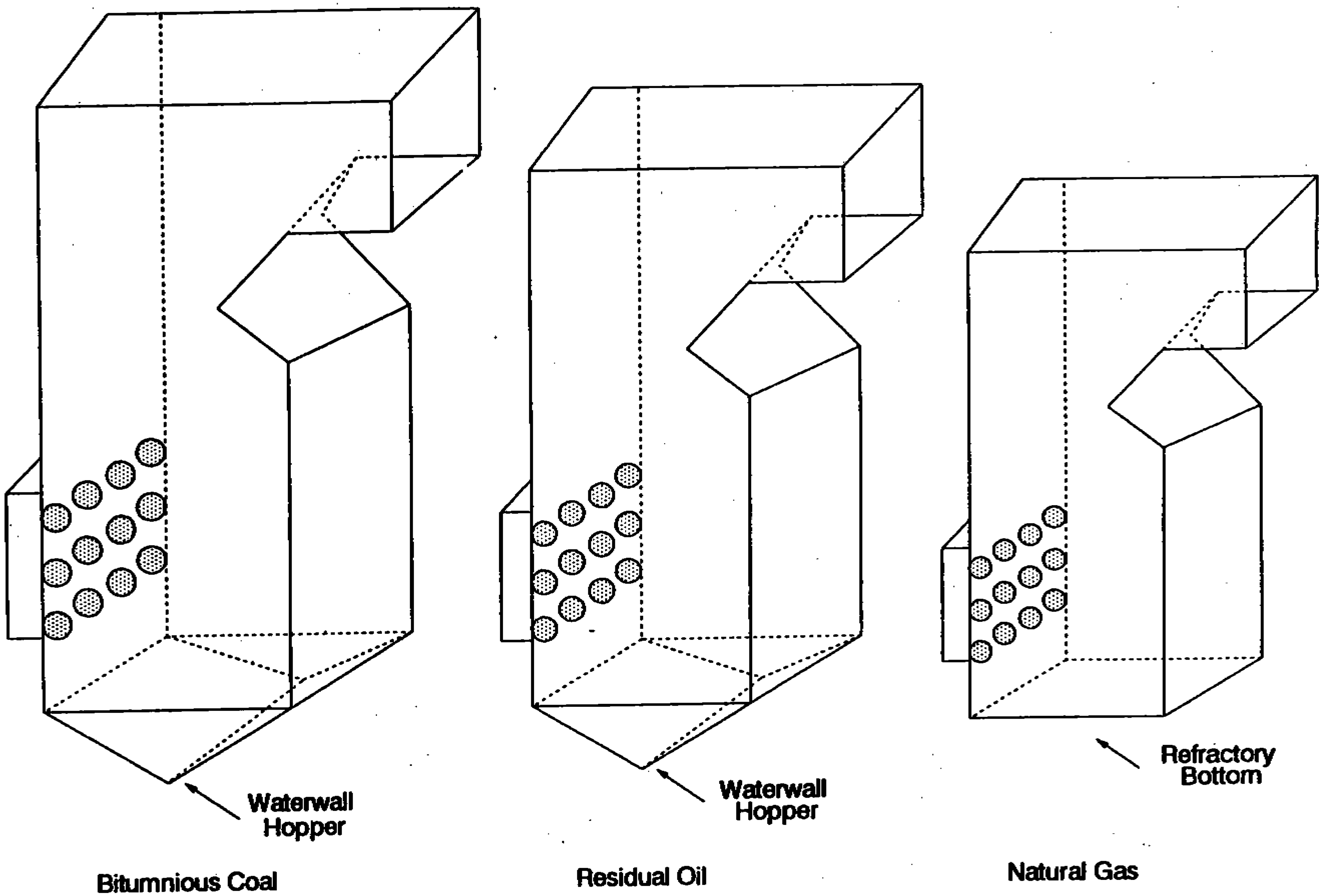


Figure 3-19. Comparative physical sizes of utility boilers firing different fuels.[39]

bottom, and design of the convective pass all are influenced by the type of fuel being burned.[40]

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4.0 CHARACTERIZATION OF NO_x EMISSIONS

Nitrogen oxide (NO_x) emissions from combustion devices are comprised of nitric oxide (NO) and nitrogen dioxide (NO_2). For most combustion systems, NO is the predominant NO_x species. This chapter discusses how differences in boiler design, fuel characteristics, and operating characteristics can affect NO_x emissions. Additionally, this chapter presents uncontrolled/baseline NO_x emission levels from various utility boilers.

4.1 NO_x FORMATION

The formation of NO_x from a specific combustion device is determined by the interaction of chemical and physical processes occurring within the furnace. This section discusses the three principal chemical processes for NO_x formation. These are: (1) "thermal" NO_x, which is the oxidation of atmospheric nitrogen; (2) "prompt" NO_x, which is formed by chemical reactions between hydrocarbon fragments and atmospheric nitrogen; and (3) "fuel" NO_x, which is formed from chemical reactions involving nitrogen atoms chemically bound within the fuel.

4.1.1 Thermal NO_x Formation

"Thermal" NO_x results from the oxidation of atmospheric nitrogen in the high-temperature post-flame region of a combustion system. During combustion, oxygen radicals are formed and attack atmospheric nitrogen molecules to start the reactions that comprise the thermal NO_x formation mechanism:

$$O + N_2 \rightleftarrows NO + N \qquad (4\text{-}1)$$

$$N + O_2 \rightleftarrows NO + O \qquad (4\text{-}2)$$

$$N + OH \rightleftarrows NO + H \qquad (4\text{-}3)$$

The first reaction (equation 4-1) is generally assumed to determine the rate of thermal NO_x formation because of its high activation energy of 76.5 kcal/mole. Because of this reaction's high activation energy, NO_x formation is slower than other combustion reactions causing large amounts of NO to form only after the energy release reactions have equilibrated (i.e., after combustion is "complete"). Thus, NO formation can be approximated in the post-combustion flame region by:

$$[NO] = ke^{-K/T}\ [N_2]\ [O_2]^{1/2}\ t \qquad (4\text{-}4)$$

where:

[ ] are mole fractions,

k and K are reaction constants,

T is temperature, and t is time.

The major factors that influence thermal NO_x formation are temperature, oxygen and nitrogen concentrations, and residence time. If temperature, oxygen concentrations, or nitrogen concentrations can be reduced quickly after combustion, thermal NO_x formation is suppressed or "quenched".

Of these four factors, temperature is the most important. Thermal NO_x formation is an exponential function of temperature (equation 4-4). One of the fundamental parameters affecting temperature is the local equivalence ratio[a]. Flame temperature peaks at equivalence ratios near one as shown in figure 4-1.[1] If the system is fuel-rich, then there is not sufficient oxygen to burn all the fuel, the energy release is not maximized, and peak temperatures decrease. If the system is fuel-lean, there are additional combustion gases to absorb heat from the combustion reactions, thus decreasing peak temperatures. A premixed flame[b] may exist in a wide range of

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[a]Equivalence ratio is defined as the fuel/oxidizer ratio divided by the stoichiometric fuel/oxidizer ratio. The equivalence ratio is given the symbol ϕ.

[b]A premixed flame exists when the reactants are mixed prior to chemical reaction.

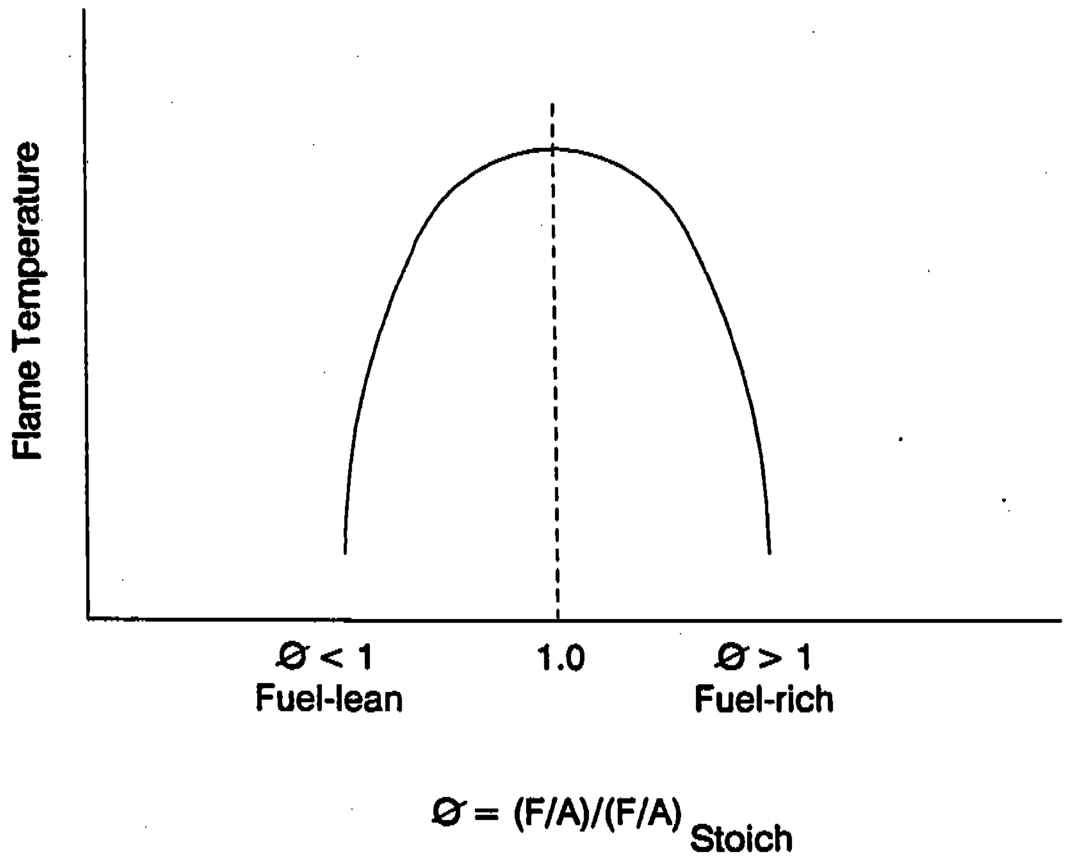

Figure 4-1. Variation of flame temperature with equivalence ratio[1]

equivalence ratios, and thus premixed flames have a wide range of peak temperatures. However, a non-premixed flame[c] will generally react near an equivalence ratio of one, causing high peak temperatures.

For utility boilers, the temperature is also related to the heat release per unit of burner zone volume. Units with large heat release rates per unit volume, may experience higher temperatures, creating higher NO_x levels.

4.1.2 Prompt NO_x Formation

Prompt NO_x formation is the formation of NO_x in the combustion system through the reactions of hydrocarbon fragments and atmospheric nitrogen. As opposed to the slower thermal NO_x formation, prompt NO_x formation is rapid and occurs on a time scale comparable to the energy release reactions (i.e., within the flame). Thus, it is not possible to quench prompt NO_x formation in the manner by which thermal NO_x formation is quenched. However, the contribution of prompt NO_x to the total NO_x emissions of a system is rarely large.[2]

Although there is some uncertainty in the detailed mechanisms for prompt NO_x formation, it is generally believed that the principal product of the initial reactions is hydrogen cyanide (HCN) or CN radicals, and that the presence of hydrocarbon species is essential for the reactions to take place.[3] The following reactions are the most likely initiating steps for prompt NO_x:[4]

$$CH + N_2 \rightleftarrows HCN + N \tag{4-5}$$

$$CH_2 + N_2 \rightleftarrows HCN + NH \tag{4-6}$$

The HCN radical is then further reduced to form NO and other nitrogen oxides.

Measured levels of prompt NO_x for a number of hydrocarbon compounds in a premixed flame show that the maximum prompt NO_x is reached on the fuel-rich side of stoichiometry.[5] On the

[c]A non-premixed flame exists where the reactants must diffuse into each other during chemical reaction.

fuel-lean side of stoichiometry, few hydrocarbon fragments are free to react with atmospheric nitrogen to form HCN, the precursor to prompt NO_x. With increasingly fuel-rich conditions, an increasing amount of HCN is formed, creating more NO_x. However, above an equivalence ratio of approximately 1.4, there are not enough O radicals present to react with HCN and form NO, so NO levels decrease.

4.1.3 Fuel NO_x Formation

The oxidation of fuel-bound nitrogen is the principal source of NO_x emissions in combustion of coal and some oils. All indications are that the oxidation of fuel-bound nitrogen compounds to NO is rapid and occurs on a time scale comparable to the energy release reactions during combustion. Thus, as with prompt NO_x, the reaction system cannot be quenched as it can be for thermal NO_x.

Although some details of the kinetic mechanism for conversion of fuel nitrogen to NO_x are unresolved at the present time, the sequence of kinetic processes is believed to be a rapid thermal decomposition of the parent fuel-nitrogen species, such as pyridine, picoline, nicotine, and quinoline, to low molecular weight compounds, such as HCN, and subsequent decay of these intermediates to NO or nitrogen (N_2). In stoichiometric or fuel-lean situations, the intermediates will generally react to form NO over N_2, whereas in fuel-rich systems, there is evidence that the formation of N_2 is competitive with the formation of NO. This may, in part, be the cause of high NO_x emissions in fuel-lean and stoichiometric mixtures and lower NO_x emissions in fuel-rich systems.

Several studies have been conducted to determine factors that affect fuel NO_x emissions. One study on coal combustion found that under pyrolysis conditions, 65 percent of the fuel nitrogen remained in the coal after heating to 750 °C (1,380 °F) but only 10 percent remained at 1,320 °C (2,400 °F).[6] This suggests that the formation of NO_x may depend upon the availability of oxygen to react with the nitrogen during coal devolitization and the initial stages of combustion. If the mixture is fuel-rich, the formation of N_2 may compete with the formation of NO, thus reducing NO_x emissions. If the mixture is fuel-lean, the formation of NO will be dominant, resulting in greater NO_x emissions than under fuel-rich conditions. This also implies that the subsequent burning of the devolatilized coal char will have little effect on the formation of NO.

Although the combustion study was for coal, it is probable that the formation of fuel NO_x from oil is also related to the vaporous reactions of nitrogen compounds. Although the nitrogen-containing compounds in coal vaporize at varying rates prior to completing combustion, the nitrogen-containing compounds in oil are of similar molecular weight to other compounds in the oil, and thus vaporize at rates similar to the other species in the oil.

The nitrogen content of the fuel affects the formation of fuel NO_x. Tests of burning fuel oils in a mixture of oxygen and carbon dioxide (to exclude thermal NO_x) show a strong correlation between the percentage of nitrogen in the oil and fuel NO_x formation as shown in figure 4-2a.[7] However, the percentage of fuel nitrogen converted to NO_x is not constant, but decreases with increasing fuel nitrogen as shown in figure 4-2b.[7] For coal, there is no readily apparent correlation between the quantity of fuel nitrogen and fuel NO_x as shown in figure 4-3.[8] Note, however, that most of the tested coals contained approximately 1.0 percent nitrogen or higher, whereas many oils contain less than 1.0 percent nitrogen. The differences in the rates of conversion of fuel nitrogen to NO_x may be due to the different nitrogen levels in oil and coal.

During another study, fuel NO_x was measured in a large tangentially-fired coal utility boiler. Figure 4-4 shows that fuel NO_x formation correlated well with the fuel oxygen/ nitrogen ratio), which suggests that fuel oxygen (or some

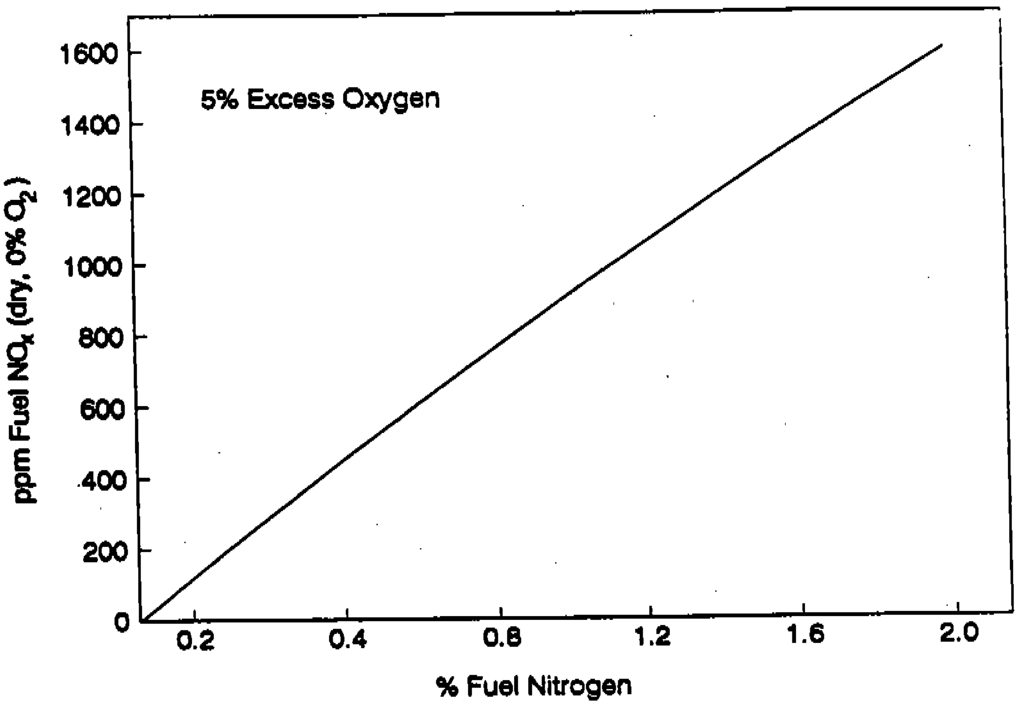

Figure 4-2a. Comparison of fuel NO_X to fuel nitrogen.[7]

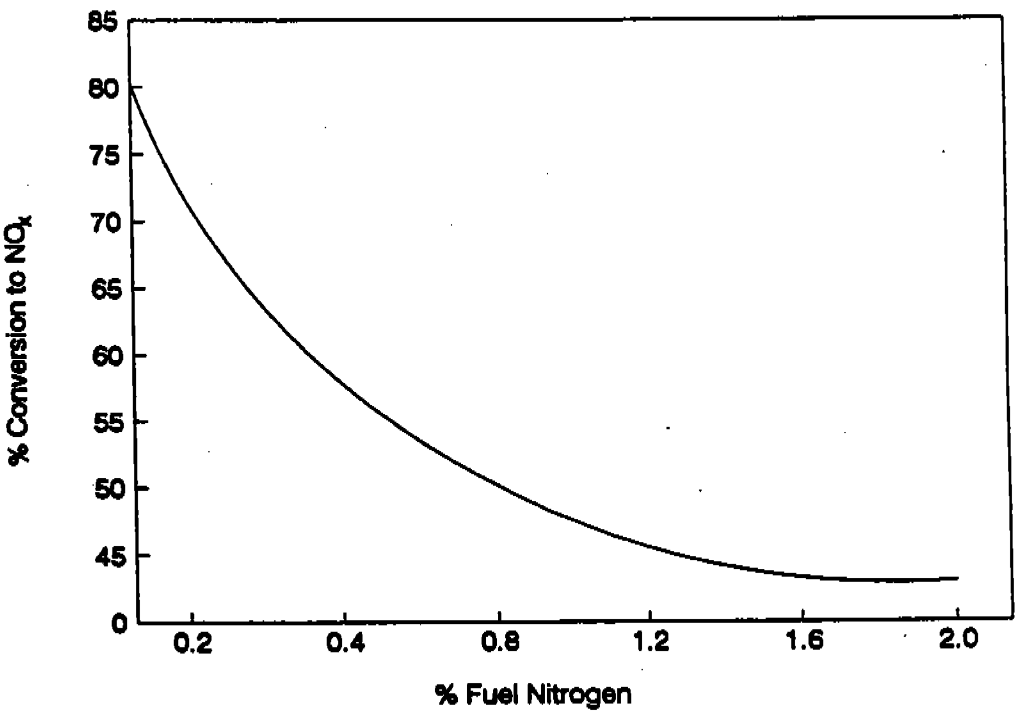

Figure 4-2b. Percent conversion of nitrogen to fuel NO_X.[7]

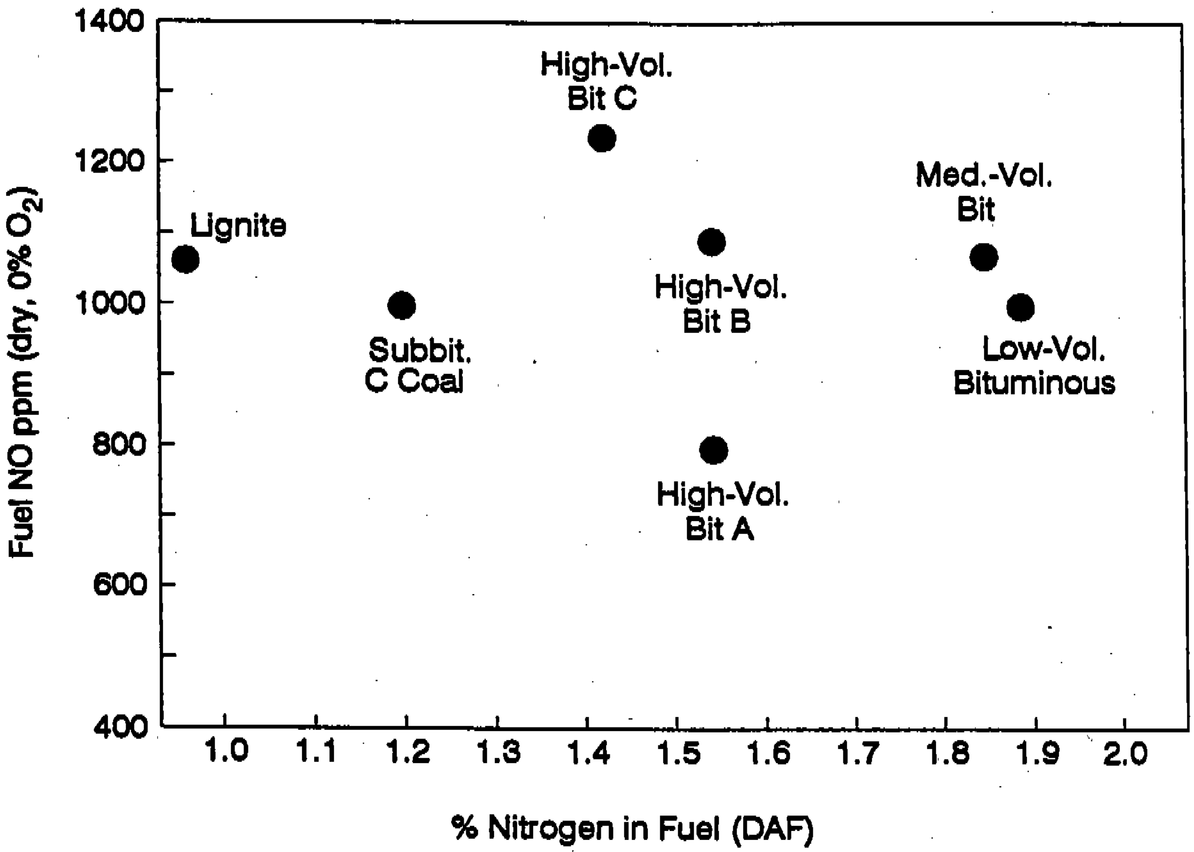

Figure 4-3. Fuel nitrogen oxide to fuel nitrogen content-pulverized coal, premixed.[8]

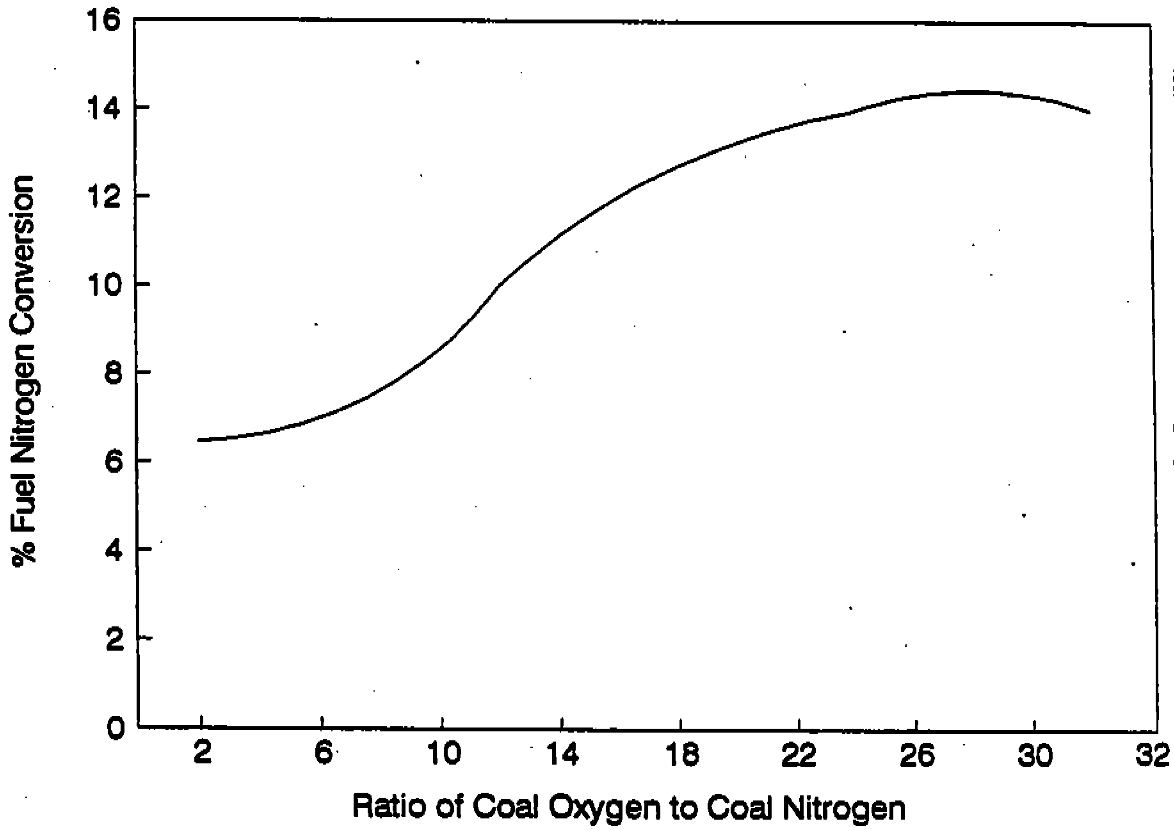

Figure 4-4. Fuel-bound nitrogen-to-nitrogen oxide in pulverized-coal combustion.[9]

other fuel property that correlates well with fuel oxygen) influences the percentage of fuel nitrogen converted to fuel NO_x.[9] This corresponds to previous observations that greater levels of NO_x are found in fuel-lean combustion environments.

4.2 Factors that Affect NO_x Emissions

The formation of thermal, prompt, and fuel NO_x in combustion systems is controlled by the interplay of equivalence ratio with combustion gas temperature, residence time, and turbulence (sometimes referred to as the "three Ts"). Of primary importance are the localized conditions within and immediately following the flame zone where most combustion reactions occur. In utility boilers, the equivalence ratio and the three Ts are determined by factors associated with burner and boiler design, fuel characteristics, and boiler operating conditions. This section discusses how boiler design, fuel characteristics, and boiler operating characteristics, can influence baseline (or uncontrolled) NO_x emission rates.

4.2.1. Boiler Design Characteristics

There are a number of different furnace configurations used in utility boilers. These include tangential, wall, cyclone, and stoker designs. Background information on each of these boiler designs is presented in chapter 3. Each configuration has design characteristics that partially determine the uncontrolled NO_x emissions of the boiler.

4.2.1.1 Tangentially-Fired. The burners in tangentially-fired furnaces are incorporated into stacked assemblies that include several levels of primary fuel nozzles interspersed with secondary air supply nozzles and warmup guns. The burners inject stratified layers of fuel and secondary air into a relatively low turbulence environment. The stratification of fuel and air creates fuel-rich regions in an overall fuel-lean environment. Before the layers are mixed, ignition is initiated in the fuel-rich region. Near the highly turbulent center fireball, cooler secondary air is quickly mixed with the burning fuel-rich region, insuring complete combustion.

The off-stoichiometric combustion reduces local peak temperatures and thermal NO_x formation. In addition, the delayed mixing of fuel and air provides the fuel-nitrogen compounds a greater residence time in the fuel-rich environment, thus reducing fuel NO_x formation.

4.2.1.2 Wall Units. There are several types of dry-bottom and wet-bottom wall-fired units, including single, opposed, cell, vertical, arch, and turbo. In general, wet-bottom units will have higher NO_x emissions than corresponding dry-bottom units because of higher operating temperatures, although other factors, such as fuel type and furnace operating conditions, may affect individual unit NO_x emission levels.

4.2.1.2.1 Single and opposed. Single-wall units consist of several rows of circular burners mounted on either the front or rear wall of the furnace. Opposed-wall units also use circular burners, but have burners on two opposing furnace walls and have a greater furnace depth.

Circular burners introduce a fuel-rich mixture of fuel and primary air into the furnace through a central nozzle. Secondary air is supplied to the burner through separate adjustable inlet air vanes. In most circular burners, these air vanes are positioned tangentially to the burner centerline and impart rotation and turbulence to the secondary air. The degree of air swirl, in conjunction with the flow-shaping contour of the burner throat, establishes a recirculation pattern extending several burner throat diameters into the furnace. The high levels of turbulence between the fuel and secondary air streams creates a nearly stoichiometric combustion mixture. Under these conditions, combustion gas temperatures are high and contribute to thermal NO_x formation. In addition, the high level of turbulence causes the amount of time available for fuel reactions under reducing conditions to be relatively short, thus increasing the potential for formation of fuel NO_x.

4.2.1.2.2 Cell. Cell-type units consist of two or three vertically-aligned, closely-spaced burners, mounted on opposed walls of the furnace. Cell-type furnaces have highly turbulent, compact combustion regions. This turbulence promotes fuel-air mixing and creates a near stoichiometric combustion mixture. As described above, the mixing facilitates the formation of both fuel and thermal NO_x. In addition, the relative compactness of the combustion region creates a high heat release rate per unit volume. This will cause local temperatures to increase even further, causing thermal NO_x to increase due to its exponential dependency on local temperature (equation 4-4).

4.2.1.2.3 Vertical-, arch-, and turbo-fired. Vertical and arch-fired boilers have burners that are oriented downward. Typically, these units are used to burn solid fuels that are difficult to ignite, such as anthracite. Pulverized coal is introduced through nozzles and pre-heated secondary air is discharged through secondary ports. The units have long, looping flames directed into the lower furnace. Delayed introduction of the tertiary air provides the necessary air to complete combustion. The long flames allow the heat release to be spread out over a greater volume of the furnace, resulting in locally lower temperatures. The lower turbulence allows the initial stages of combustion to occur in fuel-rich environments. As a result, fuel NO_x and thermal NO_x are reduced.

Turbo-fired units have burners on opposing furnace walls and have a furnace depth similar to opposed-wall units. The turbo burners are angled downward and typically are less turbulent than the circular burners in opposed-wall units. The lower turbulence delays the mixing of the fuel and air streams, allowing the combustion products a greater residence time in reducing conditions, thus potentially reducing fuel NO_x.[10]

4.2.1.3 Cyclone-Firing. Cyclones are wet-bottom furnaces, in which fuel and air are introduced into a small, highly turbulent combustion chamber. Because of the design of the burner assembly, heat transfer to cooler boiler surfaces is delayed, resulting in very high burner operating temperatures. The combination of high temperatures and near stoichiometric to slightly lean mixtures encourages both thermal and fuel NO_x formation.

4.2.1.4 Stoker-Firing. Stokers are generally low capacity boilers which burn crushed coal particles in suspension, while larger particles are burned in a fuel bed on a grate. They typically have low gas velocities through the boiler in order to prevent fly ash erosion and are operated with high levels of excess air to insure complete combustion and to maintain relatively low grate temperatures. The low NO_x emissions are believed to be a function of the lower furnace temperatures [~1,090 °C (~2,000 °F), compared to 1,370 to 1,570 °C (2,500 to 2,800 °F)] in other boiler types.

4.2.2 Fuel Characteristics

In the combustion of "clean" fuels (fuels not containing nitrogen compounds, such as natural gas)[d], the thermal mechanism is typically the principal source of nitrogen oxide emissions. However, as the nitrogen content of the fuel increases (table 4-1), significant contributions from the fuel nitrogen mechanism to total nitrogen oxide occur.[11] Thus, the nitrogen content of the fuel is a partial indicator of NO_x emission potential.

Obviously, design characteristics may dictate the type of fuel used in a given boiler. Natural gas is a vapor, oil is a liquid, and coal a solid. The injection methods of the three types of fuels are fundamentally different due to their different physical states. However, some units have multifuel capability. Boilers originally designed for coal have larger

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[d]The nitrogen present in natural gas exists almost exclusively as elemental nitrogen and not as organic nitrogen compounds.

TABLE 4-1. TYPICAL FUEL NITROGEN CONTENTS OF FOSSIL FUELS[11]

Fuel	Nitrogen (wt. %)
Natural gas	0 - 0.2
Light distillate oils (#1, 2)	0 - 0.4
Heavy distillate oils (#3 - 5)	0.3 - 1.4
Residual oils	0.3 - 2.2
Subbituminous coals	0.8 - 1.4
Bituminous coals	1.1 - 1.7

furnace volumes than boilers originally designed for oil or gas as shown in figure 4-5.[12] As a result, less thermal NO_X is formed during oil or gas combustion in multifuel boilers and these boilers are more amenable for NO_X controls due to the larger furnace volumes.

4.2.3 Boiler Operating Conditions

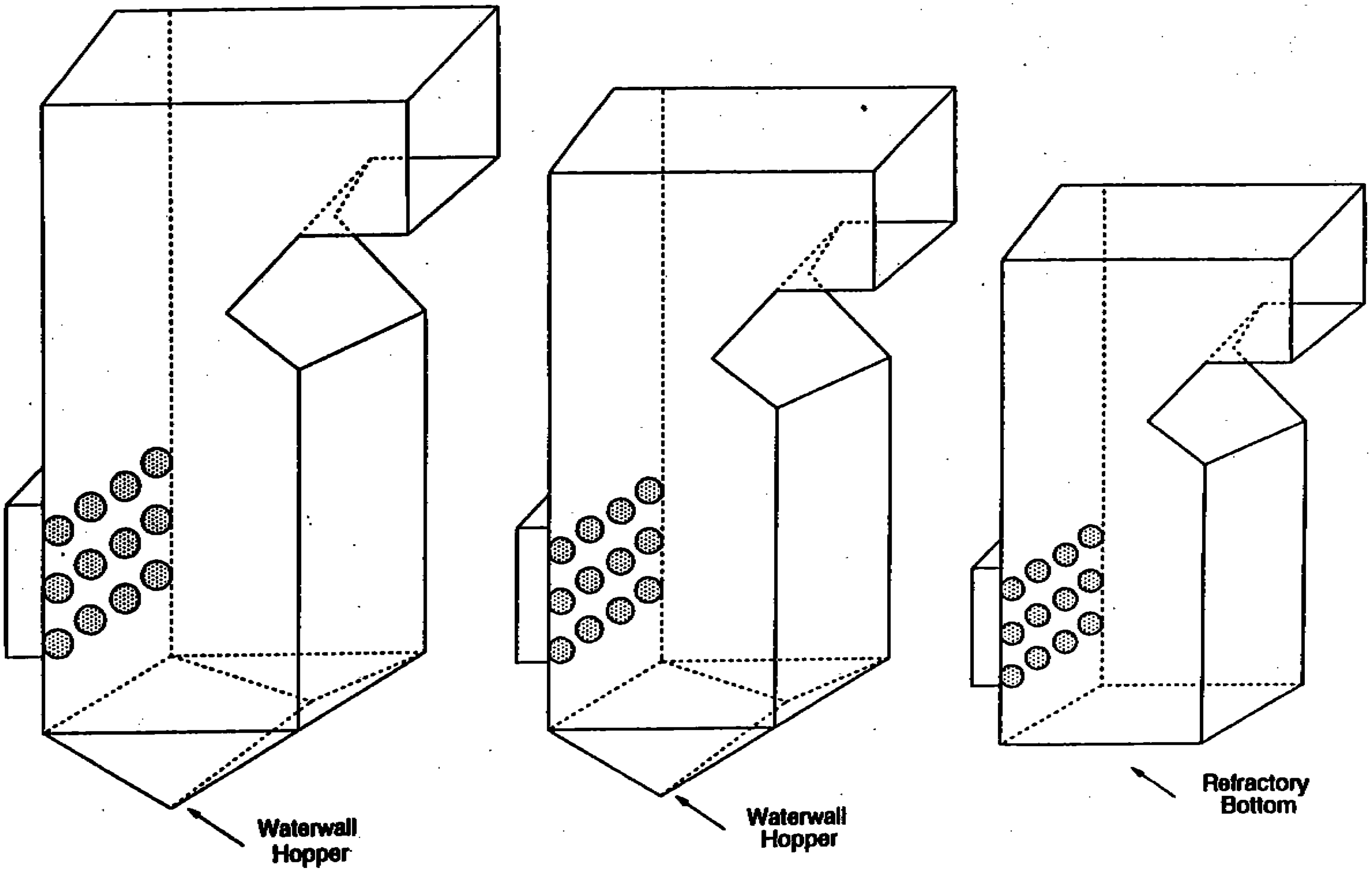
During the normal operation of a utility boiler, factors that affect NO_X continuously change as the boiler goes through its daily operating cycle. During a daily operating cycle, the following factors may change and affect NO_X formation:

- Operating load,
- Excess oxygen,
- Burner secondary air register settings, and
- Mill operation.

All these parameters either directly or indirectly influence the NO_X emissions from utility boilers. For the most part, these parameters are within the control of the boiler operator. Sometimes they are controlled based on individual operator preference or operating practices, and at other times are dictated by boiler operating constraints. While operating load influences NO_X emissions, it is obviously not a practical method of NO_X control except in severe instances.

The effect of excess oxygen or burner secondary air register settings on NO_X emissions can vary. Altering the excess oxygen levels may change flame stoichiometry. Increasing secondary air flow may increase entrainment of cooler secondary air into the combustion regime, lowering local temperatures, and increase fuel and air mixing, altering equivalence ratio. The net result of both actions may be either to raise or lower NO_X emissions, depending on other unit-specific parameters.

A frequently overlooked influence on NO_X emissions for coal units is the mill pattern usage. Figure 4-6 illustrates the impact of operating with various mill-out-of-service patterns on NO_X emissions.[13] This data is from a 365 megawatt (MW) single-wall coal-fired unit, operating at 250 MW (68 percent



Note: Same Btu input.

Figure 4-5. Comparative physical sizes of utility boilers firing different fuels.[12]

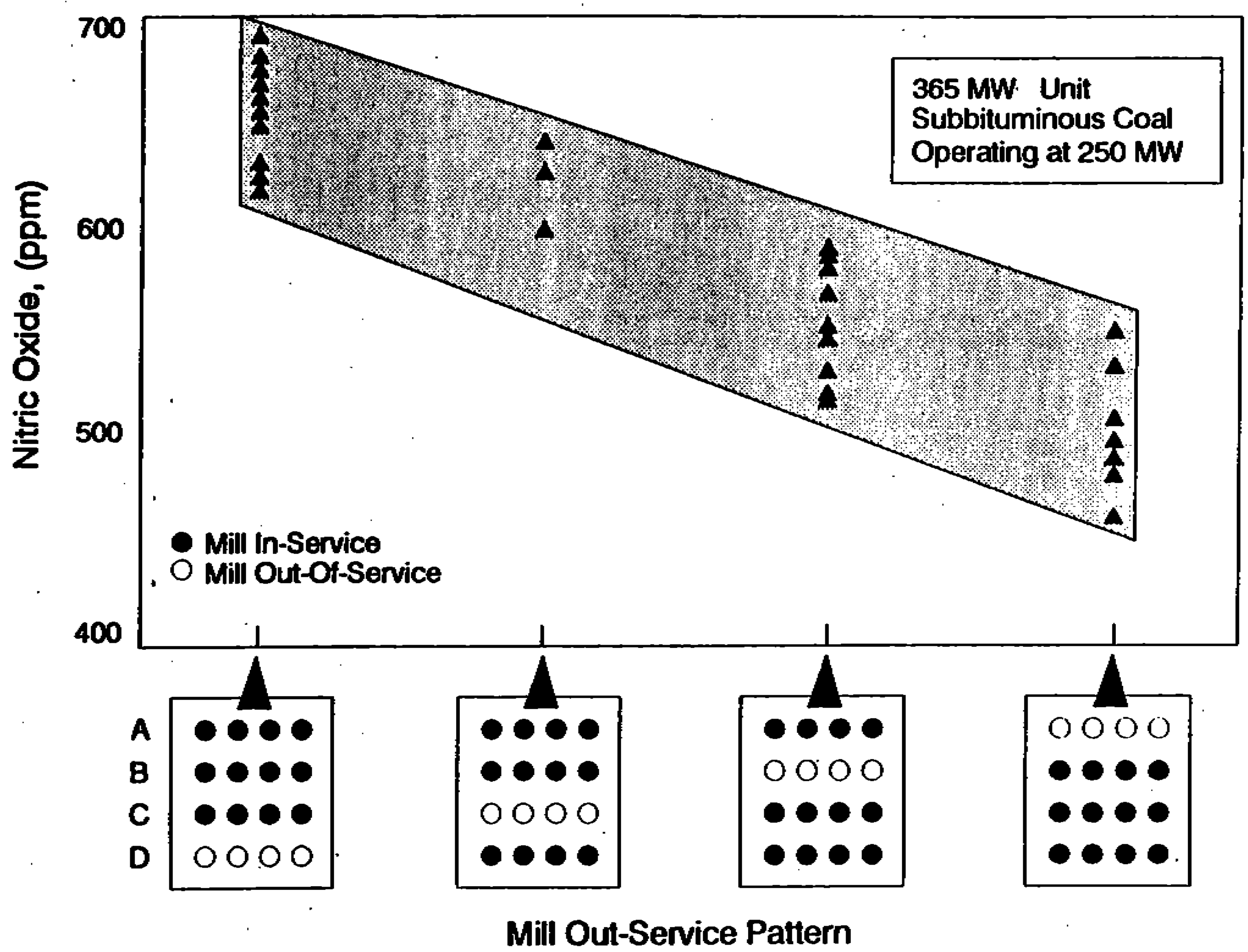


Figure 4-6. Effect of mill pattern usage on nitrogen oxide emissions.[13]

load), and firing subbituminous coal. The NO_x emission level varies by as much as 25 percent depending upon which mills are operational. This is because when operating at a fixed load and with the top mill out-of-service, the lower mills operate at a higher coal-to-air ratio, creating fuel-rich regions. The secondary air from the top mill insures complete combustion. If the bottom mill is out-of-service, the advantages of stratified combustion using overfire air to insure complete combustion are reduced, resulting in increased NO_x formation. Biasing fuel to the lower mills can also be used to create a similar combustion environment.

4.3 UNCONTROLLED/BASELINE EMISSION LEVELS

4.3.1 Conventional Boilers

As discussed in section 4.2, NO_x emission rates are a function of burner and boiler design, operating conditions, and fuel type. Because pre-NSPS boilers were not designed to minimize NO_x emissions, their NO_x emission rates are indicative of uncontrolled emission levels. Boilers covered by subpart D[14] (boilers that commenced construction between August 17, 1971 and September 17, 1978) or subpart Da[15] (boilers that commenced construction on or after September 18, 1978) were required to install NO_x control equipment to meet these NSPS. To define baseline emissions from these units, the NSPS limit and emissions data from NURF were examined. Data for uncontrolled NO_x emissions received through questionnaires to utilities are presented in chapter 5.

The tables in the following subsections summarize typical, low, and high NO_x emission rates on a lb/MMBtu basis for each of the principal boiler types used to combust coal, oil, and gas. Emissions data from the National Utility Reference File (NURF),[16] AP-42[17], and the EPA[18] were examined to estimate uncontrolled NO_x emission rates for pre-NSPS boilers. The typical uncontrolled levels reflect the mode, or most typical value, for the NO_x emissions data in NURF and the EPA, and are generally consistent with AP-42 values when assuming a heating value for coal of 11,000 Btu/lb, for oil of 140,000 Btu/gal, for natural gas of 1,000 Btu/scf. Also, data obtained from numerous utilities and reported in chapter 5 was used for comparison purposes. The low and high estimates reflect the upper and lower range of emissions expected on a short-term basis for most units of a given fuel and boiler type. Based on unit-specific design and operating conditions; however, actual NO_x emissions from individual boilers may be outside this range. Averaging time can also influence NO_x emission rates. For example, a boiler that can achieve a particulate NO_x limit on a rolling 30-day basis may not be able to achieve the same NO_x limit on a 24-hour basis.

4.3.1.1 Coal-Fired Boilers. Table 4-2 shows typical, low, and high uncontrolled/baseline NO_x emission rates for pre-NSPS, subpart D, and subpart Da coal-fired utility boilers. The applicable subpart D and subpart Da standards are also listed in the table.

The pre-NSPS units are subdivided into tangential, dry-bottom wall, wet-bottom wall, cell, and cyclone units. The emission rates shown are generally consistent with corresponding AP-42 emission rates. The tangential units generally have the lowest emissions (0.7 lb/MMBtu typical), and the cyclone units have the highest (1.5 lb/MMBtu typical). Pre-NSPS units account for approximately 80 percent of the total number of coal-fired utility boilers in the United States.

Following proposal of subpart D, essentially all new coal-fired utility boilers were tangential-fired or wall-fired. The subpart D units are subdivided into these two categories. The tangential units generally have lower NO_x emission rates than the wall units. The typical emission rates for the tangential units is 0.5 lb/MMBtu and the typical emission rates for the wall units is 0.6 lb/MMBtu, both of which are below the subpart D standard of 0.7 lb/MMBtu.

The subpart Da units are also subdivided into tangential, wall, and stoker units. As with the subpart D units, the tangential units generally exhibit lower emission rates than

TABLE 4-2. UNCONTROLLED/BASELINE NO_x EMISSION LEVELS FOR COAL-FIRED BOILERS[a]

Boiler Type	NO_x Emission Levels (lb NO_x/MMBtu)			
	Typical[b]	Low	High	Standard
Pre-NSPS				
Tangential	0.7	0.4	1.0	N/A
Wall, dry	0.9	0.6	1.2	N/A
Wall, wet	1.2	0.8	2.1	N/A
Cell	1.0	0.8	1.8	N/A
Cyclone	1.5	0.8	2.0	N/A
Vertical, dry	0.9	0.6	1.2	N/A
Subpart D				
Tangential	0.5	0.3	0.7	0.7
Wall, dry	0.6	0.3	0.7	0.7
Subpart Da				
Tangential	0.45	0.35	0.6	0.6/0.5[c]
Wall, dry	0.45	0.35	0.6	0.6/0.5[c]
Stoker	0.50	0.3	0.6	0.6/0.5[c]

[a]NO_x emission rates for pre-NSPS units are classified as "Uncontrolled", because these units were not designed to minimize NO_x emissions. The NO_x emission rates listed for subpart D and Da units are classified as "Baseline", because many of these units include the use of NO_x control techniques.

[b]Typical level is based on the mode, or most typical, NO_x emission rate of boilers as reported in NURF, the EPA, AP-42, and utilities.

[c]NSPS subpart Da standard of 0.6 lb NO_x/MMBtu is applicable to bituminous and anthracite coal-fired boilers, a standard of 0.5 lb NO_x/MMBtu is applicable to subbituminous coal-fired boilers.

N/A = not applicable.

the wall units and the typical emission rates of both type units (approximately 0.45 lb/MMBtu) meet the subpart Da standard. The stoker units have a typical emission rate of 0.50 lb/MMBtu and also meet the subpart Da standard.[19]

4.3.1.2 Natural Gas-Fired Boilers. Table 4-3 shows typical, low, and high uncontrolled/baseline NO_X emission rates for pre-NSPS, subpart D, and subpart Da natural gas-fired utility boilers. The applicable subpart D and subpart Da standards are also listed in the table.

The pre-NSPS units are subdivided into tangential and wall units. The emission rates shown are generally consistent with corresponding AP-42 emission rates. The tangential units generally have the lowest emissions (0.3 lb/MMBtu), and the wall units are slightly higher (0.5 lb/MMBtu).

The subpart D and subpart Da units are not subdivided into specific unit types. The typical emission rates of the units meet the applicable NSPS standard of 0.2 lb/MMBtu.

4.3.1.3 Oil-Fired Boilers. Table 4-4 shows typical, low, and high uncontrolled/baseline NO_X emission rates for pre-NSPS, subpart D, and subpart Da oil-fired utility boilers. The applicable subpart D and subpart Da standards are also listed in the table.

The pre-NSPS units are subdivided into tangential, vertical, and wall units. The emission rates shown are generally consistent with corresponding AP-42 emission rates. The tangential units generally have the lowest emissions (0.3 lb/MMBtu), and the vertical units are the highest (0.75 lb/MMBtu).

The subpart D and subpart Da units are not subdivided into specific unit types. The typical emission rates of the subpart D units are 0.25 lb/MMBtu and the typical emission rates of the subpart Da units are also 0.25 lb/MMBtu which meet, or are below, the applicable NSPS standard.

4.3.2 Fluidized Bed Boilers

Fluidized bed combustion boilers are inherently low NO_X emitters due to the relatively low combustion temperatures.

TABLE 4-3. UNCONTROLLED/BASELINE NO_x EMISSION LEVELS FOR NATURAL GAS BOILERS[a]

Boiler Type	NO_x Emission Levels (lb NO_x/MMBtu)			
	Typical[b]	Low	High	Standard
Pre-NSPS				
Tangential	0.3	0.1	0.5	N/A
Wall, single	0.5	0.1	1.0	N/A
Wall, opposed	0.9	0.4	1.8	N/A
Subpart D				
All boiler types	0.2	0.1	0.2	0.2
Subpart Da				
All boiler types	0.2	0.1	0.2	0.2

[a]NO_x emission rates for pre-NSPS units are classified as "Uncontrolled", because these units were not designed to minimize NO_x emissions. The NO_x emission rates listed for subpart D and Da units are classified as "Baseline", because many of these units include the use of NO_x control techniques.

[b]Typical level is based on the mode, or most typical, NO_x emission rate of boilers are reported in NURF, the EPA, AP-42, and utilities.

N/A = not applicable.

TABLE 4-4. UNCONTROLLED/BASELINE NO_x EMISSION LEVELS FOR OIL-FIRED BOILERS[a]

Boiler Type	NO_x Emission Levels (lb NO_x/MMBtu)			
	Typical[b]	Low	High	Standard
<u>Pre-NSPS</u>				
Tangential	0.3	0.2	0.4	N/A
Wall	0.5	0.2	0.8	N/A
Vertical	0.75	0.5	1.0	N/A
<u>Subpart D</u>				
All boiler types	0.25	0.2	0.3	0.3
<u>Subpart Da</u>				
All boiler types	0.25	0.2	0.3	0.3

[a]NO_x emission rates for pre-NSPS units are classified as "Uncontrolled", because these units were not designed to minimize NO_x emissions. The NO_x emission rates listed for subpart D and Da units are classified as "Baseline", because many of these units include the use of NO_x control techniques.

[b]Typical level is based on the mode, or most typical, NO_x emission rate of boilers are reported in NURF, the EPA, AP-42, and utilities.

N/A = not applicable.

Table 4-5 shows typical, low, and high NO_x emission rates for fluidized bed combustion (FBC) boilers with and without selective noncatalytic reduction (SNCR) for NO_x control. The typical NO_x emissions from an FBC without SNCR is 0.19 lb/MMBtu whereas the typical NO_x emissions from an FBC with SNCR as original equipment is 0.07 lb/MMBtu. An influential factor on the NO_x emissions of an FBC boiler is the quantity of calcium oxide, used for SO_2 emissions control, present in the bed material. Higher quantities of calcium oxide result in higher base emissions of NO_x. Therefore, as SO_2 removal requirements increase, base NO_x production will increase. This linkage between SO_2 removal and base NO_x production is important in understanding NO_x formation in FBC boilers.

TABLE 4-5. NO_x EMISSION LEVELS FOR FLUIDIZED BED COMBUSTION BOILERS

Classification	NO_x Emission Levels (lb NO_x/MMBtu)		
	Typical[a]	Low	High
Combustion controls only	0.19	0.1	0.26
With SNCR[b]	0.07	0.03	0.1

[a]Typical level is based on the mode, or most typical, NO_x emission rate of FBC boilers reporting data.

[b]Fluidized bed combustion boilers with SNCR for NO_x control as original equipment.

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5.0 NO_x EMISSION CONTROL TECHNIQUES

This chapter describes the methods of reducing nitrogen oxide (NO_x) emissions from new and existing fossil fuel-fired utility boilers. All of the methods can be grouped into one of two fundamentally different techniques--combustion controls and post-combustion controls (flue gas treatment).

Combustion controls reduce NO_x emissions by suppressing NO_x formation during the combustion process while post-combustion controls reduce NO_x emissions after its formation. Combustion controls are the most widely used method of controlling NO_x formation in utility boilers. Several combustion controls can be used simultaneously to further reduce NO_x emissions. Flue gas treatment methods can often achieve greater NO_x control than combustion controls, but have not been applied to many utility boilers in the United States. Combinations of flue gas treatment controls and combustion controls can be applied to maximize NO_x reduction; however, there are even fewer U. S. applications of this type. The types of NO_x controls currently available for fossil fuel-fired utility boilers are presented in table 5-1.

This chapter describes NO_x control technologies for fossil fuel-fired utility boilers, factors affecting the performance of these controls, and levels of performance for these controls. Section 5.1 presents controls for coal-fired boilers. Section 5.2 presents combustion controls for natural gas- and oil-fired boilers. Section 5.3 presents post-combustion flue gas treatment controls.

TABLE 5-1. NO_x EMISSION CONTROL TECHNOLOGIES FOR FOSSIL FUEL UTILITY BOILERS

NO_x control options	Fuel applicability
Combustion Modifications	
Operational Modifications - Low excess air - Burners-out-of-service - Biased burner firing	Coal, natural gas, oil
Overfire Air	Coal, natural gas, oil
Low NO_x Burners (except cyclone furnaces)	Coal, natural gas, oil
Low NO_x burners and overfire air	Coal, natural gas, oil
Reburn	Coal, natural gas, oil
Flue gas recirculation	Natural gas, oil
Postcombustion Flue Gas Treatment Controls	
Selective noncatalytic reduction	Coal, natural gas, oil
Selective catalytic reduction	Coal, natural gas, oil

5.1 COMBUSTION CONTROLS FOR COAL-FIRED UTILITY BOILERS

There are several combustion control techniques for reducing NO_x emissions from coal-fired boilers:

- Operational Modifications
  - Low excess air (LEA);
  - Burners-out-of-service (BOOS); and
  - Biased burner firing (BF);
- Overfire air (OFA);
- Low NO_x burners (LNB); and
- Reburn.

Operational modifications such as LEA, BOOS, and BF are all relatively simple and inexpensive techniques to achieve some NO_x reduction because they only require changing certain boiler operation parameters rather than making hardware modifications. These controls are discussed in more detail in section 5.1.1.

Overfire air and LNB are combustion controls that are gaining more acceptance in the utility industry due to increased experience with these controls. There are numerous ongoing LNB demonstrations and retrofit projects on large coal-fired boilers; however, there are only a couple of projects in which LNB and OFA are used as a retrofit combination control. Both OFA and LNB require hardware changes which may be as simple as replacing burners or may be more complex such as modifying boiler pressure parts. These techniques are applicable to most coal-fired boilers except for cyclone furnaces. Overfire air and LNB will be discussed in sections 5.1.2 and 5.1.3, respectively.

Reburn is another combustion hardware modification for controlling NO_x emissions. There are four full-scale retrofit demonstrations on U. S. coal-fired utility boilers. Reburn will be discussed in section 5.1.5.

5.1.1 Operational Modifications

5.1.1.1 Process Description. Several changes can be made to the operation of some boilers which can reduce NO_x emissions. These include LEA, BOOS, and BF. While these changes may be rather easily implemented, their applicability and effectiveness in reducing NO_x may be very unit-specific. For example, some boilers may already be operating at the lowest excess air level possible or may not have excess pulverizer capacity to bias fuel or take burners out of service. Also, implementing these changes may reduce the operating flexibility of the boiler, particularly during load fluctuations.

Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. With less oxygen (O_2) available in the combustion zone, both thermal and fuel NO_x formation are inhibited. A range of optimum O_2 levels exist for each boiler and is inversely proportional to the unit load. Even at stable loads, there are small variations in the O_2 percentages which depend upon overall equipment condition, flame stability, and carbon monoxide (CO) levels. If the O_2 level is reduced too low, upsets can occur such as smoking or high CO levels.[1]

Burners-out-of-service involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This is accomplished by removing the pulverizer (or mill) that provides fuel to the upper row of burners from service and keeping the air registers open. The balance of the fuel is redirected to the lower burners, creating fuel-rich conditions in those burners. The remaining air required to complete combustion is introduced through the upper burners. This method simulates air staging, or overfire air conditions, and limits NO_x formation by lowering the O_2 level in the burner area.

Burners-out-of-service can reduce the operating flexibility of the boiler and can largely reduce the options available to a coal-fired utility during load fluctuations. Also, if BOOS is improperly implemented, stack opacity and CO levels may increase. The success of BOOS depends on the initial NO_x level; therefore, higher initial NO_x levels promote higher NO_x reduction.[2]

Biased burner firing consists of firing the lower rows of burners more fuel-rich than the upper row of burners. This may be accomplished by maintaining normal air distribution in all the burners and injecting more fuel through the lower burners than through the upper burners. This can only be accomplished for units that have excess mill capacity; otherwise, a unit derate (i.e., reduction in unit load) would occur. This method provides a form of air staging and limits fuel and thermal NO_x formation by limiting the O_2 available in the firing zone.

5.1.1.2 Factors Affecting Performance. Implementation of LEA, BOOS, and BF technologies involve changes to the normal operation of the boiler. Operation of the boiler outside the "normal range" may result in undesirable conditions in the furnace (i.e., slagging in the upper furnace), reduced boiler efficiency (i.e., high levels of CO and unburned carbon [UBC]), or reductions in unit load.

The appropriate level of LEA is unit-specific. Usually at a given load, NO_x emissions decrease as excess air is decreased. Lower than normal excess air levels may be achievable for short periods of time; however, slagging in the upper furnace or high CO levels may result with longer periods of LEA. Therefore, the minimum excess air level is generally defined by the acceptable upper limit of CO emissions and high emissions of UBC, which signal a decrease in boiler efficiency. Flame instability and slag deposits in the upper furnace may also define the minimum excess air level.[3]

The applicability and appropriate configuration of BOOS are unit-specific and load dependent. The mills must have excess capacity to process more fuel to the lower burners. Some boilers do not have excess mill capacity; therefore, full load may not be achievable with a mill out of service. Also, the upper mill and corresponding burners would be required to operate at full capacity during maintenance periods for mills that serve the lower burners. The BOOS pattern may not be constant. For example, a BOOS pattern at low load may be very different than that at high load.[1]

The same factors affecting BOOS also applies to BF, but to a lesser degree. Because all mills and burners remain in service for BF, it is not necessary to have as much excess mill capacity as with BOOS. Local reducing conditions in the lower burner region caused by the fuel-rich environment associated with BOOS and BF may cause increased tube wastage. Additionally, increased upper furnace slagging may occur because of the lower ash fusion temperature associated with reducing conditions.

5.1.1.3 Performance of Operational Modifications. Table 5-2 presents data from four utility boilers that use operational modifications to reduce NO_x emissions. Three of the boilers, (Crist 7, Potomac River 4, and Johnsonville) are not subject to new source performance standards (NSPS) and do not have any NO_x controls; Mill Creek 3 and Conesville 5 are subject to subpart D standards; and Hunter 2 is subject to subpart Da standards. Mill Creek 3 has dual-register burners (early LNB), Conesville 5 has OFA ports, and Hunter 2 has OFA and LNB in order to meet the NSPS NO_x limits. The data presented show only the effect of reducing the excess air level on three of these units. On one unit (Crist 7), the fuel was biased in addition to lowering the excess air.

As shown in table 5-2, LEA reduced NO_x emissions by as much as 21 percent from baseline levels for the subpart D and subpart Da units. These three units had uncontrolled NO_x levels of 0.63 to 0.69 pound per million British thermal unit (lb/MMBtu) and were reduced to 0.53 to 0.56 lb/MMBtu with LEA. For several units at the Johnsonville plant, LEA reduced the NO_x levels to 0.4-0.5 lb/MMBtu, or 10-15 percent while BOOS reduced the NO_x to 0.3-0.4 lb/MMBtu or 20-35 percent. A boiler tuning program at Potomac River 4 reduced NO_x by

TABLE 5-2. PERFORMANCE OF OPERATIONAL MODIFICATIONS ON U. S. COAL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c]	Length of test[d]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
TANGENTIALLY-FIRED BOILERS, BITUMINOUS COAL										
Potomac Electric Power Co.	Potomac River 4 (Pre)	108	ABB-CE	Tuned	Short	100 60	0.62 0.59	0.39 0.34	37 42	4
Tenn. Valley Authority	Johnsonville (1-6) (Pre)	120	ABB-CE	LEA BOOS	Short Short	UNK[e] 83	0.5-0.55 0.5-0.55	0.43-0.5 0.34-0.4	10-15 20-35	5
Columbus Southern Power Co.	Conesville 5 (D)	420	ABB-CE	LEA	Short	80-100	0.69	0.53	21[f]	6
Utah Power and Light Co.	Hunter 2 (Da)	446	ABB-CE	LEA	Short	100	0.64	0.55	14[g]	7
Tenn Valley Authority	Johnsonville (1-6)	120	ABB-CE	BOOS	Short	83	0.50-0.55	0.34-0.40	20-35	5
WALL-FIRED BOILERS, BITUMINOUS COAL										
Louisville Gas and Electric Co.	Mill Creek 3 (D)	420	B&W.	LEA	Short	80-100	0.63	0.56	10	6
Gulf Power Co.	Crist 7 (Pre)	500	FW	BF + LEA	Short	80-100	1.27	1.00	21	6

[a]Standard: Da = Subpart Da; D = Subpart D; and Pre = Pre-NSPS

[b]OEM = Original equipment manufacturer; ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock & Wilcox; and FW = Foster Wheeler

[c]Type Control: LEA = Low Excess Air; BOOS = Burners-Out-Of-Service; BF = Biased Burner Firing; and Tuned = Boiler tuning.

[d]Short = Short-term test data, i.e., hours.

[e]UNK = Unknown.

[f]NO_x reductions are from lowering boiler oxygen levels from 5.0 percent to 3.5 percent.

[g]NO_x reductions are from lowering boiler oxygen levels from 4.5 percent to 3.5 percent.

approximately 40 percent and consisted of a combination of lowering the excess air, improving mill performance, optimizing burner tilt, and biasing the fuel and air.

A combination of BF and LEA on Crist 7 shows approximately 21 percent reduction in NO_x emissions. This unit had high uncontrolled NO_x emissions of 1.27 lb/MMBtu; therefore, the NO_x level was only reduced to 1.0 lb/MMBtu with BF and LEA. The baseline or uncontrolled NO_x level did not seem to influence the percent NO_x reduction; however, all these units are less than 20 years old and may be more amenable to changing operating conditions than older boilers that have smaller furnace volumes and outdated control systems and equipment.

5.1.2 Overfire Air

5.1.2.1 Process Description. Overfire air is a combustion control technique whereby a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. The total amount of combustion air fed to the furnace remains unchanged. In the typical boiler shown in figure 5-1a, all the air and fuel are introduced into the furnace through the burners, which form the main combustion zone. For an OFA system such as in figure 5-1b, approximately 5 to 20 percent of the combustion air is injected above the main combustion zone to form the combustion completion zone.[8] Since OFA introduces combustion air at two different locations in the furnace, this combustion hardware modification is also called air staging.

Overfire air limits NO_x emissions by two mechanisms: (1) suppressing thermal NO_x formation by partially delaying and extending the combustion process, resulting in less intense combustion and cooler flame temperatures, and (2) suppressing fuel NO_x formation by lowering the concentration of air in the burner combustion zone where volatile fuel nitrogen is evolved.[8]

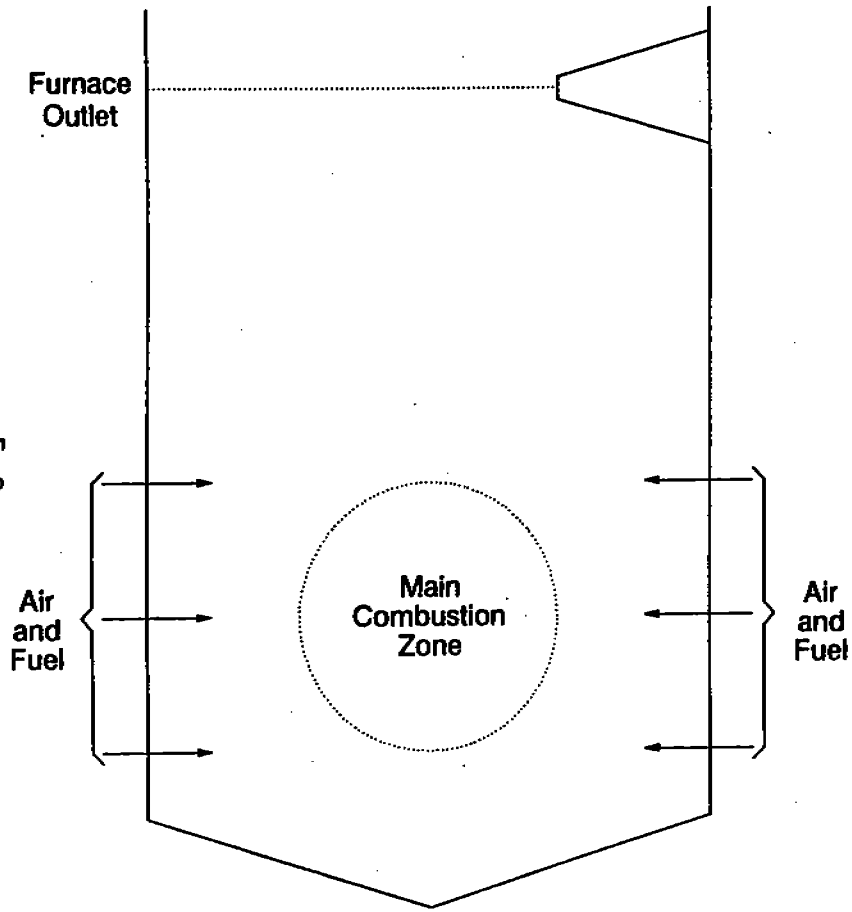


Figure 5-1a. Typical opposed wall-fired boiler.[8]

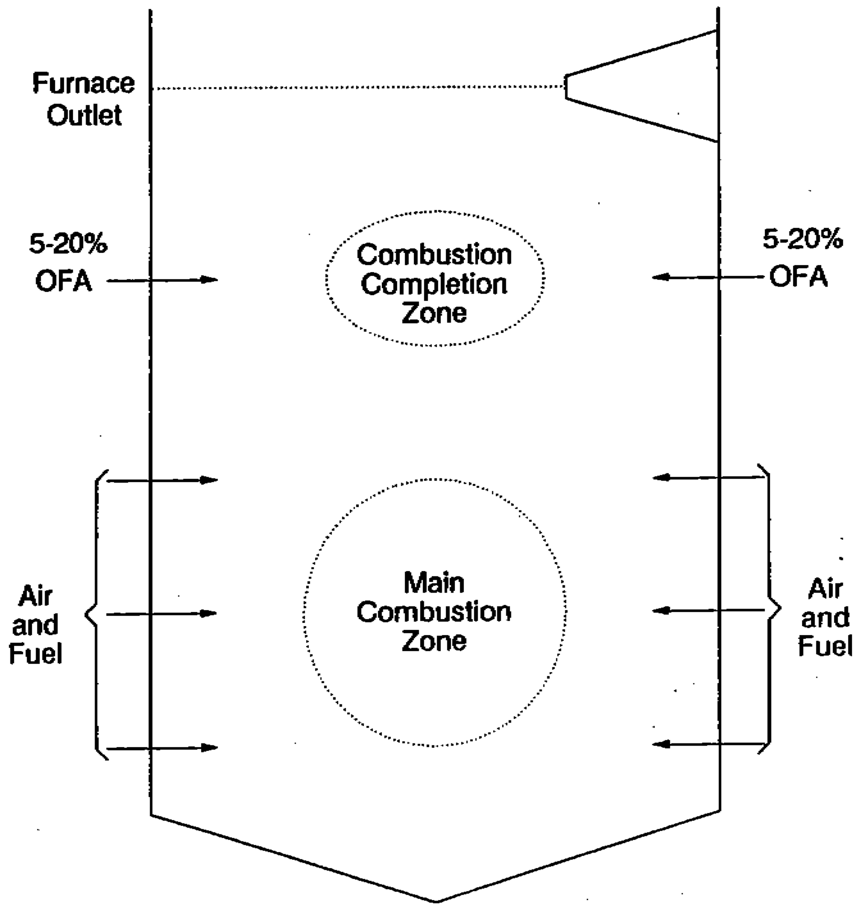


Figure 5-1b. Opposed wall-fired boiler with overfire air.[8]

Overfire air can be applied to tangentially-fired, wall-fired, turbo, and stoker boilers. However, OFA is not used on cyclone boilers and other slag-tapping furnaces because it can alter the heat release profile of the furnace, which can greatly change the slagging characteristics of the boiler. Overfire air was incorporated into boiler designs as a NO_x control to meet the subpart D and subpart Da standards. The OFA was used in both wall and tangential designs.

Many pre-NSPS boilers were designed with small furnaces and limited space between the top row of burners and the convective pass, thus precluding installation of OFA on these units. Overfire air retrofits are often unfeasible for these boilers because overfire air mixing and carbon burnout must be completed within this limited space. For units where retrofitting is feasible, the structural integrity of the burner wall, interference with other existing equipment, the level of NO_x reduction required, and economics determine the number and arrangement of OFA ports.

5.1.2.1.1 Wall-fired boilers. There are two types of OFA for wall-fired boilers which are typically referred to as conventional OFA and advanced OFA (AOFA). Conventional OFA systems such as in figure 5-2a direct a percentage of the total combustion air--less than 20 percent--from the burners to ports located above the top burners.[9] Because air for conventional OFA systems is taken from the same windbox, ability to control air flow to the OFA ports may be limited.

Advanced OFA systems have separate windboxes and ducting, and the OFA ports can be optimally placed to achieve better air mixing with the fuel-rich combustion products. The AOFA systems as shown in figure 5-2b usually inject more air at greater velocities than conventional OFA systems, giving improved penetration of air across the furnace width and greater NO_x reduction.[9]

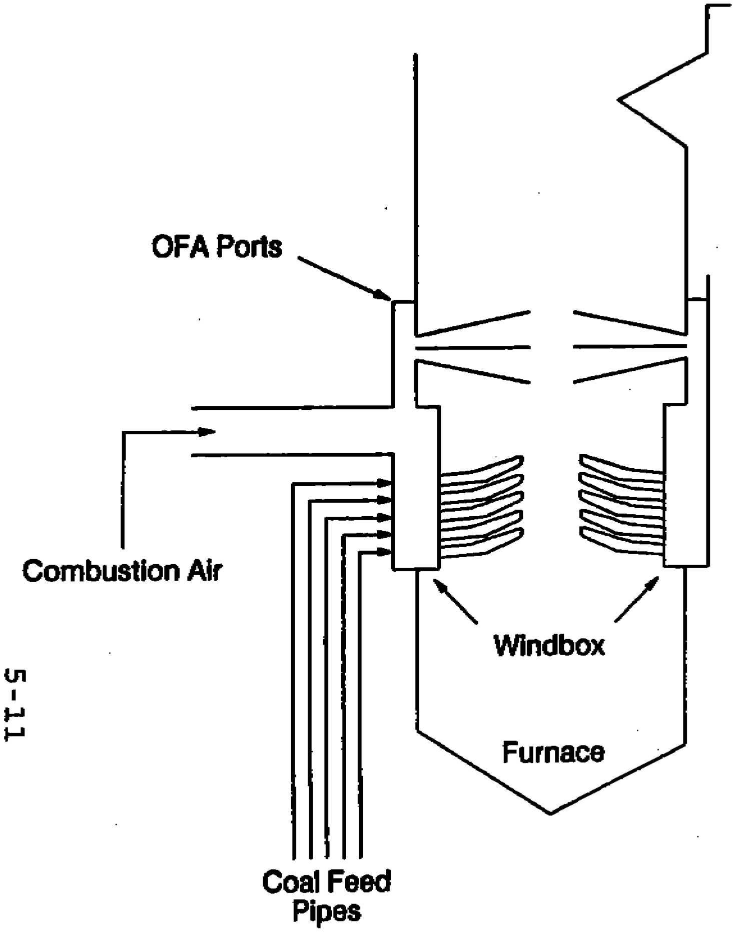


Figure 5-2a. Conventional overfire air on an opposed wall-fired boiler.[9]

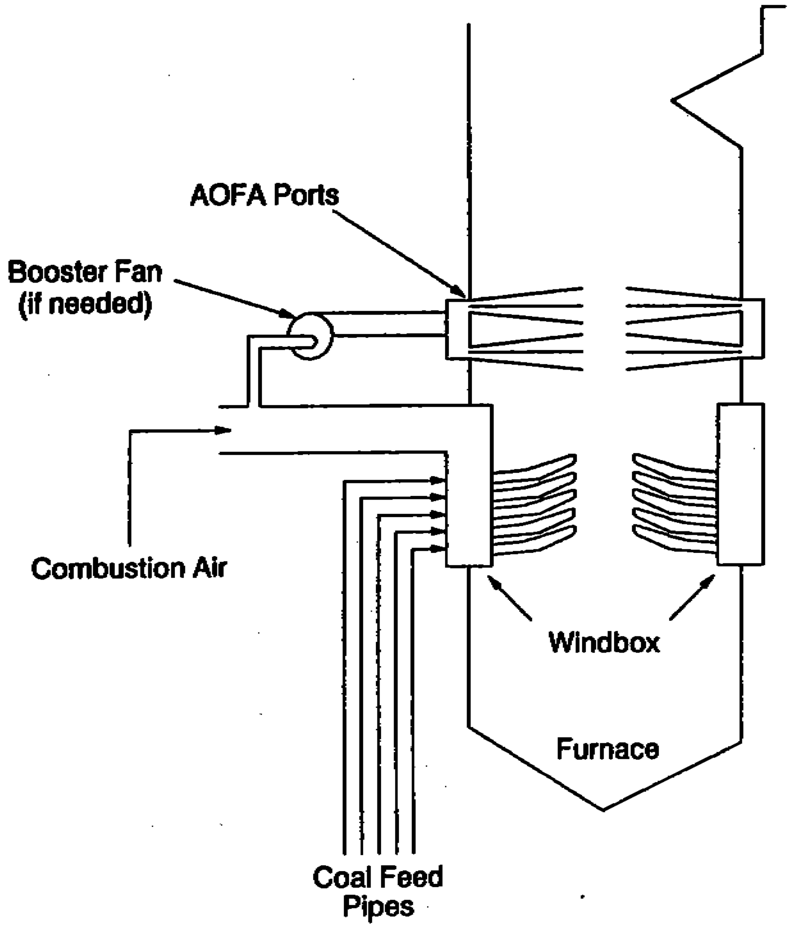


Figure 5-2b. Advanced overfire air on an opposed wall-fired boiler.[9]

5.1.2.1.2 Tangentially-fired boilers. Overfire air systems for tangentially-fired boilers are shown in figure 5-3 and are typically referred to as close-coupled OFA (CCOFA) and separated OFA (SOFA). The CCOFA, analogous to conventional OFA for wall-fired boilers, directs a portion of the total combustion air from the burners to ports located above the top burner in each corner. The SOFA systems are analogous to AOFA for wall-fired boilers and have a separate windbox and ducting. In some cases, the close-coupled OFA may be used in combination with separated OFA as described in section 5.1.4.

5.1.2.2 Factors Affecting Performance. Some OFA systems cause an increase of incomplete combustion products (UBC, CO, and organic compounds), tube corrosion, and upper furnace ash deposits (slagging and fouling). The number, size, and location of the OFA ports as well as the OFA jet velocity must be adequate to ensure complete combustion.

To have effective NO_x reduction, AOFA and SOFA systems must have adequate separation between the top burner row and the OFA ports. However, efficient boiler operation requires maximizing the residence time available for carbon burnout between the OFA ports and the furnace exit, which means locating the AOFA or SOFA ports as close to the burners as practical.[10] These conflicting requirements must be considered when retrofitting and operating boilers with these types of OFA systems.

Increasing the amount of OFA, can reduce NO_x emissions; however, this means that less air (O_2) is available in the primary combustion zone. The resulting reducing atmosphere in the lower furnace can lead to increased corrosion and change furnace heat release rates and flue gas exit temperature.

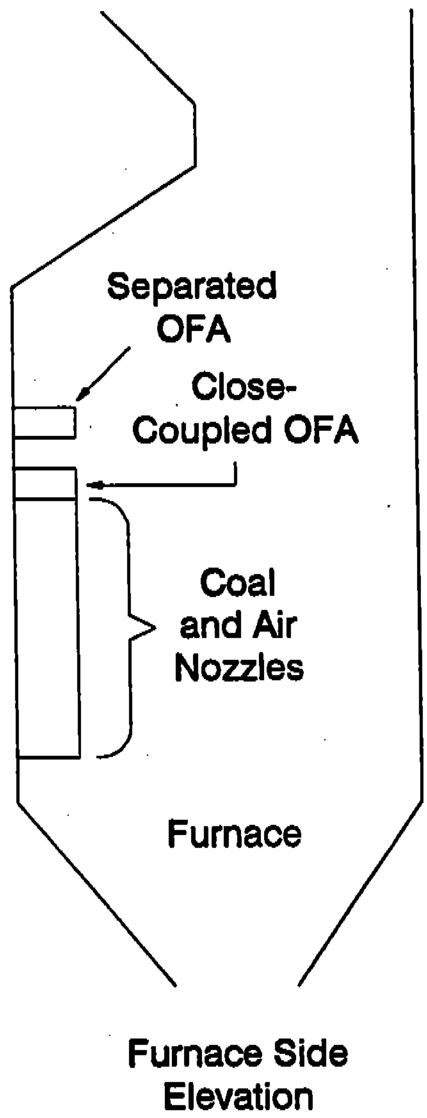


Figure 5-3. Tangential boiler windbox/burner arrangement with overfire air systems.

5.1.2.3 Performance of Overfire Air. The performance of several OFA systems is shown in table 5-3. The table contains two tangentially-fired boilers (one pre-NSPS with SOFA and one subpart Da with CCOFA) and two wall-fired boilers (one pre-NSPS with AOFA and one subpart Da with OFA).

Hennepin 1 is a 75 megawatt (MW) pre-NSPS boiler that has a retrofit natural gas reburn system. The OFA ports are part of the reburn system and are located higher above the top row of burners than a typical OFA system retrofit. The gas reburn system was not in operation when this data was collected.[11] Hunter 2 is a 446 MW subpart Da boiler that has CCOFA ports that are typical of OFA systems for this vintage boiler.[7] Both of the tangential boilers had similar uncontrolled NO_x levels in the range of 0.58 to 0.64 lb/MMBtu. With the SOFA and CCOFA systems, the NO_x was reduced by approximately 20 percent, to 0.46 to 0.50 lb/MMBtu.

The OFA applications on wall-fired boilers include a retrofit of AOFA on Hammond 4 and an original installation on Pleasants 2. Both short-term and long-term data are shown for Hammond 4. The short-term emission levels for any boiler can be very different from the corresponding long-term levels; however, for Hammond 4, the short-term and long-term emissions are similar. Normally, the differences in long-term and short-term data may be the result of the boiler being operated at a specific test condition with a number of variables (i.e., load, boiler O_2, mill pattern) held constant. The long-term data represents the "typical" day-to-day variations in NO_x emissions under normal operating conditions.

The short-term data for Hammond 4 show controlled NO_x emissions of 0.9 lb/MMBtu across the load range, representing a 10 to 25 percent NO_x reduction. The long-term data for Hammond 4 show similar reductions of 11 to 24 percent across the load range. The controlled NO_x emission level for the pre-NSPS wall-fired boilers is nearly twice as high as the NO_x

TABLE 5-3. PERFORMANCE OF OFA ON U. S. COAL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (Vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
TANGENTIALLY-FIRED BOILERS, BITUMINOUS COAL										
Illinois Power Co.	Hennepin 1 (Pre)	75	ABB-CE	SOFA[f] (EERC)	Short	100	0.58	0.46	21	11
Utah Power & Light Co.	Hunter 2 (D)	446	ABB-CE	CCOFA (ABB-CE)	Short	80	0.64	0.50	22	7
WALL-FIRED BOILERS, BITUMINOUS COAL										
Georgia Power Co.	Hammond 4 (Pre)	500	FW	AOFA (FW)	Short Short Short	100 80 60	1.20 1.00 1.00	0.90 0.90 0.90	25 10 10	12
					Long Long Long	100 80 60	1.23 1.09 0.98	0.94 0.90 0.87	24 17 11	13
Monongahela Power Co.	Pleasants 2 (Da)	684	FW	OFA[g] (FW)	Short	100	0.95	0.70	26	14

[a]Standard: D = Subpart D; Da = Subpart Da; and Pre = Pre-NSPS

[b]OEM = Original Equipment Manufacturer; ABB-CE = Asea Brown Boveri-Combustion Engineering; FW = Foster Wheeler

[c]Type Control: AOFA = Advanced Overfire Air; CCOFA = Close-coupled Overfire Air; OFA = Overfire Air; and SOFA = Separated Overfire Air

[d]Vendor: Vendor of NO_x control. EERC = Energy and Environmental Research Corporation. Refer to note "b" for others.

[e]Long = Long-term CEM data, i.e., mean hourly average for 4-5 month period; and Short = Short-term test data, i.e., hours.

[f]OFA part of natural gas reburn system and are located higher above burners than typical OFA ports.

[g]OFA ports were original equipment and are no longer in use.

levels for tangential boilers due to the higher uncontrolled NO_x level and burner/boiler design.

The OFA system at Pleasants 2 reduced NO_x to approximately 0.7 lb/MMBtu (representing 26 percent NO_x reduction) at full load. Pleasants 2 is a subpart Da boiler with the OFA system as original equipment. The furnace volume for this boiler is much larger than that in pre-NSPS boilers. The controlled level is higher than for tangential boilers due to the higher uncontrolled NO_x level and burner/boiler design. The uncontrolled data represents operation when the OFA system was closed. The OFA system alone did not reduce NO_x to the required NSPS levels and was subsequently closed off when the LNB were upgraded.[12]

5.1.3 Low NO_x Burners

5.1.3.1 Process Description. Low NO_x burners have been developed by many boiler and burner manufacturers for both new and retrofit applications. Low NO_x burners limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion process in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding one or more of the following conditions:

1. Reduced O_2 in the primary combustion zone, which limits fuel NO_x formation;
2. Reduced flame temperature, which limits thermal NO_x formation; and
3. Reduced residence time at peak temperature, which limits thermal NO_x formation.

While tangential boilers have "coal and air nozzles" rather than "burners" as in wall-fired boilers, the term "LNB" is used for both tangential and wall applications in this document. Low NO_x burner designs can be divided into two general categories: "delayed combustion" and "internal staged." Delayed combustion LNB are designed to decrease flame turbulence (thus delaying fuel/air mixing) in the primary combustion zone, thereby establishing a fuel-rich condition in the initial stages of combustion. This design departs from traditional burner designs, which promote rapid combustion in turbulent, high-intensity flames. The longer, less intense flames produced with delayed combustion LNB inhibit thermal NO_x generation because of lower flame temperatures. Furthermore, the decreased availability of O_2 in the primary combustion zone inhibits fuel NO_x conversion. Thus, delayed combustion LNB control both thermal and fuel NO_x.

Internally staged LNB are designed to create stratified fuel-rich and fuel-lean conditions in or near the burner. In the fuel-rich regions, combustion occurs under reducing conditions, promoting the conversion of fuel nitrogen (N_2) to N_2 and inhibiting fuel NO_x formation. In the fuel-lean regions, combustion is completed at lower temperatures, thus inhibiting thermal NO_x formation.

Low NO_x burners are widely used in both wall- and tangentially fired utility boilers and are custom-designed for each boiler application. In many cases, the LNB and air register will have the same dimensions as the existing burner system and can be inserted into the existing windbox and furnace wall openings. However, in other cases, waterwall and windbox modifications require pressure part changes to obtain the desired NO_x reductions.

5.1.3.1.1 <u>Wall-fired boilers</u>. A number of different LNB designs have been developed by burner manufacturers for use with wall-fired boilers. Several of these designs are discussed below.

The Controlled Flow/Split Flame™ (CF/SF) burner shown in figure 5-4 is an internally-staged design which stages the secondary air and primary air and fuel flow within the burner's throat.[10] The burner name is derived from the operating functions of the burner: (1) controlled flow is

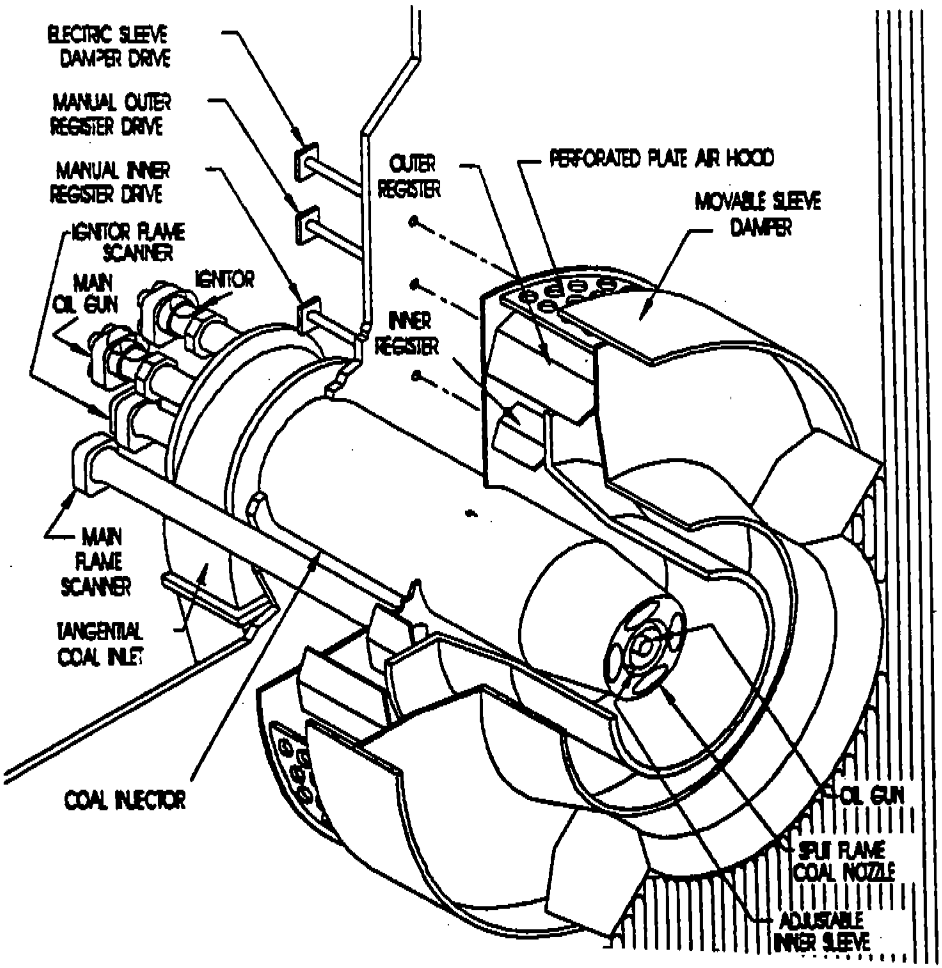


Figure 5-4. Controlled Flow/Split Flame™ low NO_x burner.[10]

achieved by the dual register design, which provides for the control of the inner and outer air swirl, allowing independent control of the quantity of secondary air to each burner, and (2) the split-flame is accomplished in the coal injection nozzle, which segregates the coal into four concentrated streams. The result is that volatiles in the coal are released and burned under more reducing conditions than would otherwise occur without the split flame nozzle. Combustion under these conditions converts the nitrogen species contained in the volatiles to N_2, thus reducing NO_x formation.[10]

The Internal Fuel Staged™ (IFS) burner, shown in figure 5-5, is similar to the CF/SF burner.[10] The two designs are nearly identical, except that the split-flame nozzle has been replaced by the IFS nozzle, which generates a coaxial flame surrounded by split flames.

The Dual Register Burner - Axial Control Flow™ (DRB-XCL) wall-fired LNB operates on the principle of delayed combustion. The burner diverts air from the central core of the flame and reduces local stoichiometry during coal devolatization to minimize initial NO_x formation. The DRB-XCL is designed for use without compartmented windboxes, and the flame shape can be tuned to fit the furnace by use of impellers. As shown in figure 5-6, the burner is equipped with fixed spin vanes in the outer air zone that move secondary air to the periphery of the burner.[15] Also, adjustable spin vanes are located in the outer- and inner-air zones of the burner. The inner spin vane adjusts the shape of the flame, which is typically long. The outer spin vane imparts swirl to the flame pattern. The flame stabilizing ring at the exit of the coal nozzle enhances turbulence and promotes rapid devolatization of the fuel. An air-flow measuring device located in the air sleeve of each burner provides a relative indication of air flow through each burner and is used to detect burner-to-burner flow imbalances within the windbox.[15]

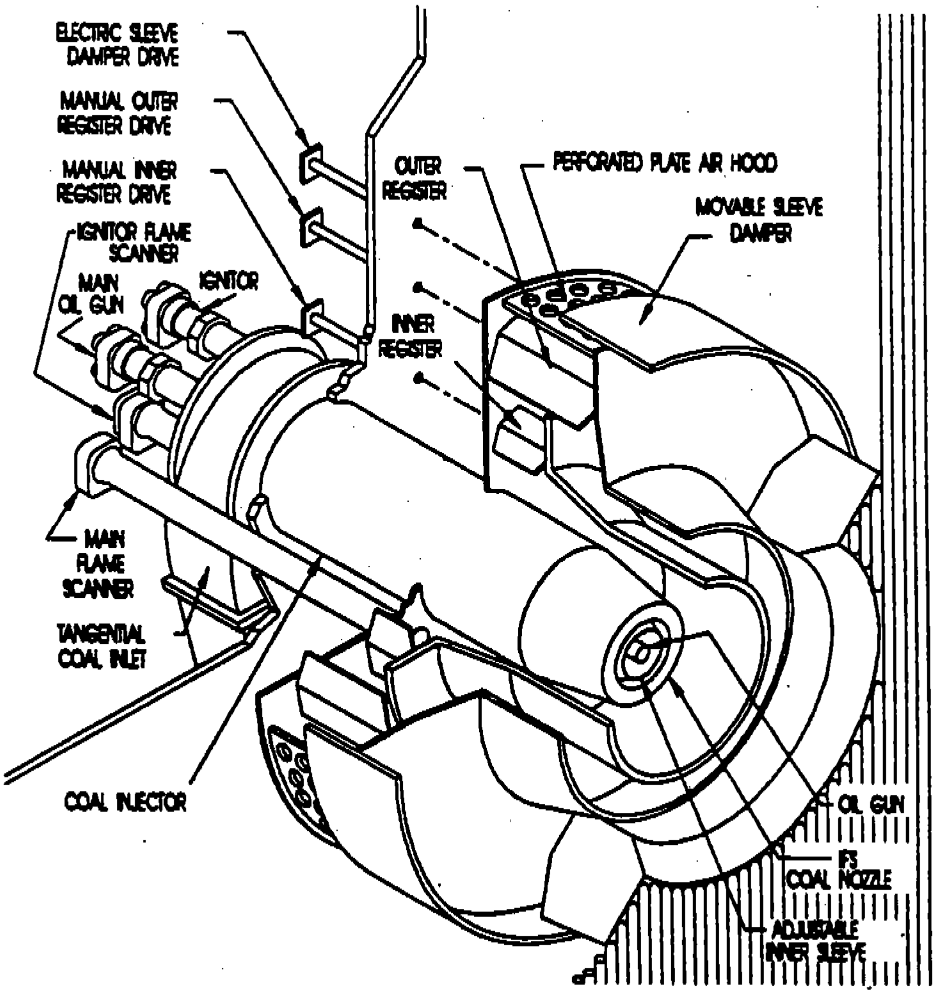
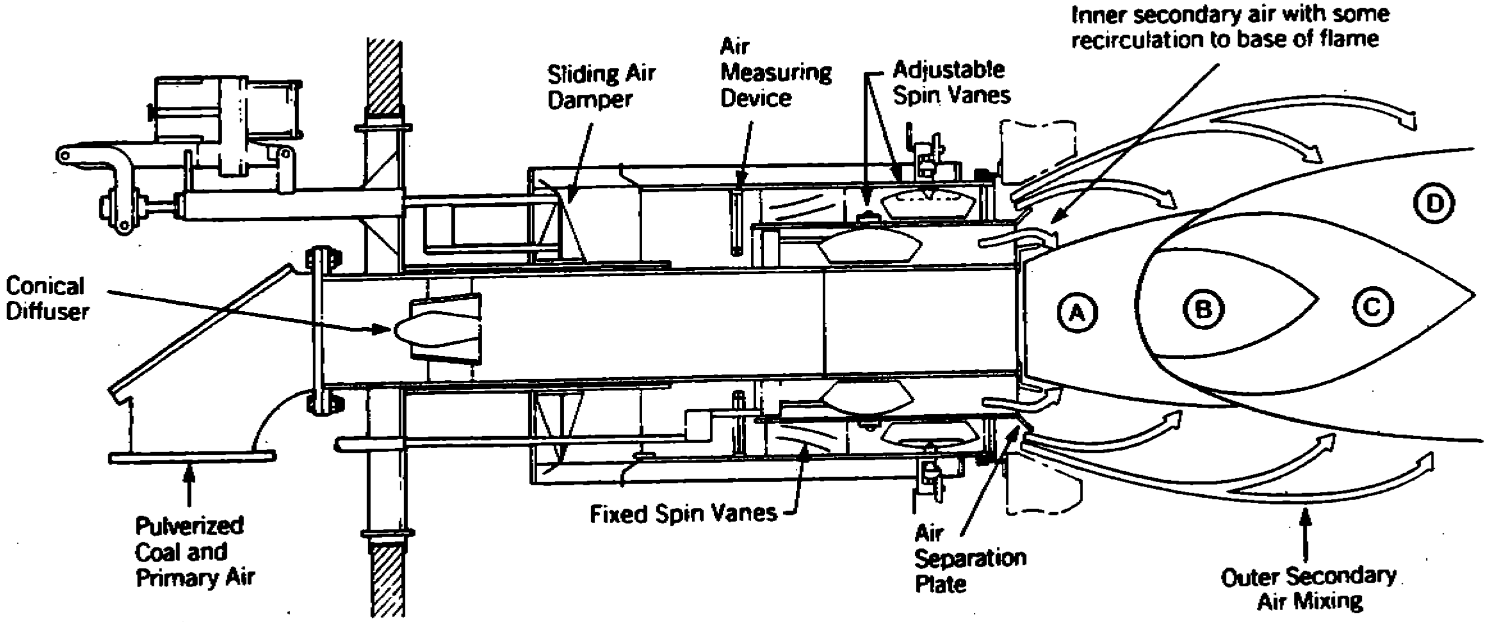


Figure 5-5. Internal Fuel Staged™ low NO_x burner.[10]



Ⓐ High temperature – fuel rich devolatilization zone

Ⓑ Production of reducing species

Ⓒ NO_x decomposition zone

Ⓓ Char oxidizing zone

Figure 5-6. Dual Register Burner-Axial Control Flow™ low NO_x burner.[15]

The RO-II burner consists of a single air inlet, dual-zone air register, tangential inlet coal nozzle, and a flame-stabilizing nozzle tip. Figure 5-7 shows the key components of the burner.[16] Combustion air is admitted to both zones of the air register and the tangential inlet produces a swirling action. The swirling air produces a "forced vortex" air flow pattern and around the coat jet. This pattern creates local staging of combustion by controlling the coal/air mixing, thus reducing NO_x formation.[16]

The Controlled Combustion Venturi™ (CCV) burner for wall-fired boilers is shown in figure 5-8.[17] Nitrogen oxide control is achieved through the venturi coal nozzle and low swirl coal spreader located in the center of the burner. The venturi nozzle concentrates the fuel and air in the center of the coal nozzle, creating a very fuel-rich mixture. As this mixture passes over the coal spreader, the blades divide the coal stream into four distinct streams, which then enter the furnace in a helical pattern. Secondary air is introduced to the furnace through the air register and burner barrel. The coal is devolatized at the burner exit in an fuel-rich primary combustion zone, resulting in lower fuel NO_x conversion. Peak flame temperature is also lowered, thus suppressing the thermal NO_x formation.[17]

The Low NO_x Cell Burner™ (LNCB), developed for wall-fired boilers equipped with cell burners, is shown in figure 5-9.[15] Typically, in the LNCB design, the original two coal nozzles are replaced with a single enlarged injection nozzle in the lower throat and a secondary air injection port in the upper throat, which essentially acts as OFA. However, in some cases, it may be reversed with some of the fuel-rich burners in the upper throat and some of the air ports in the lower throat to prevent high CO and hydrogen sulfide (H_2S) levels. The exact configuration depends on the boiler. The flame shape is controlled by an impeller at the exit of the fuel nozzle and by adjustable spin vanes in the secondary air zone.

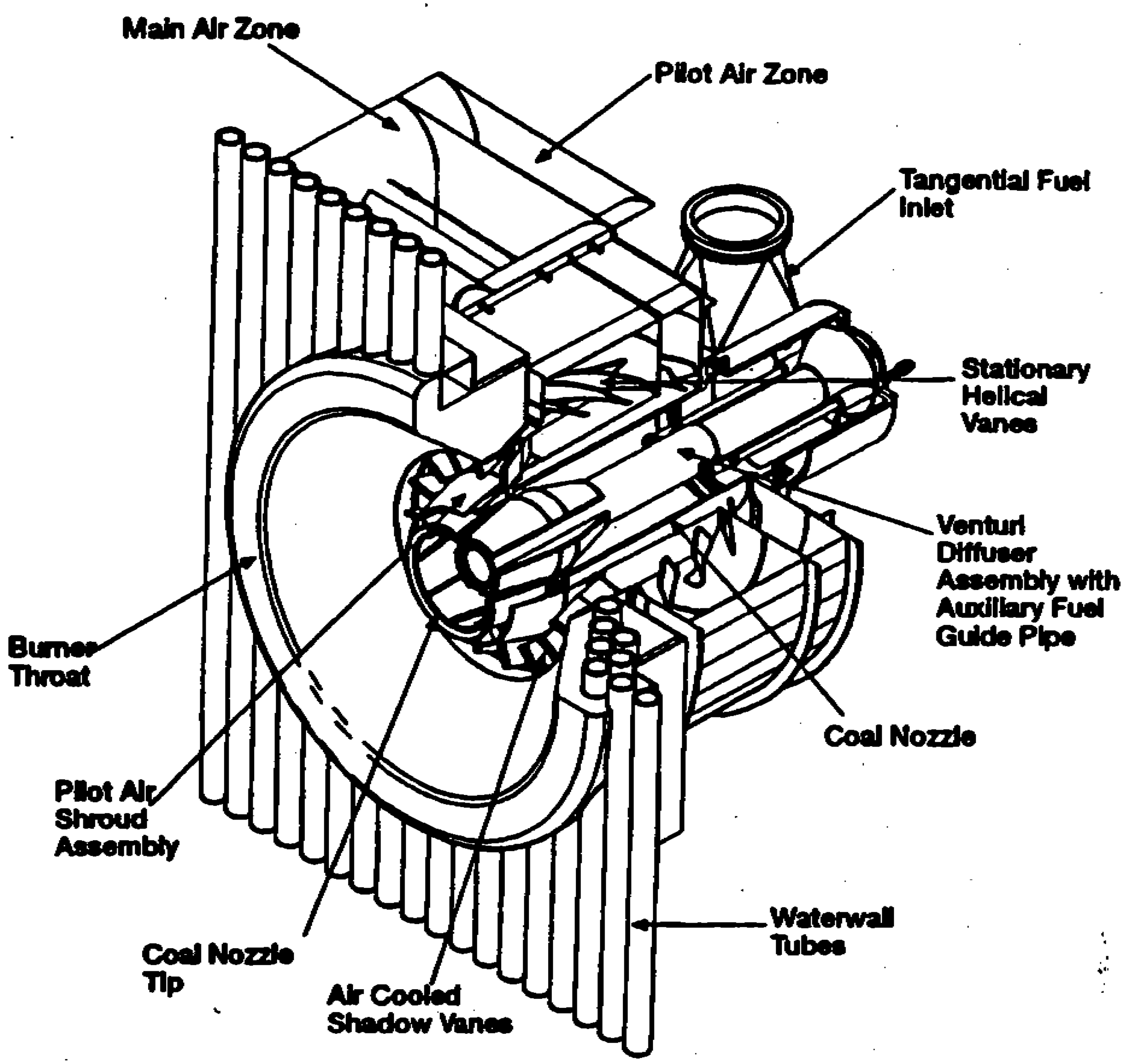


Figure 5-7. Isometric drawing of RO-II burner low NO_X coal burner.[16]

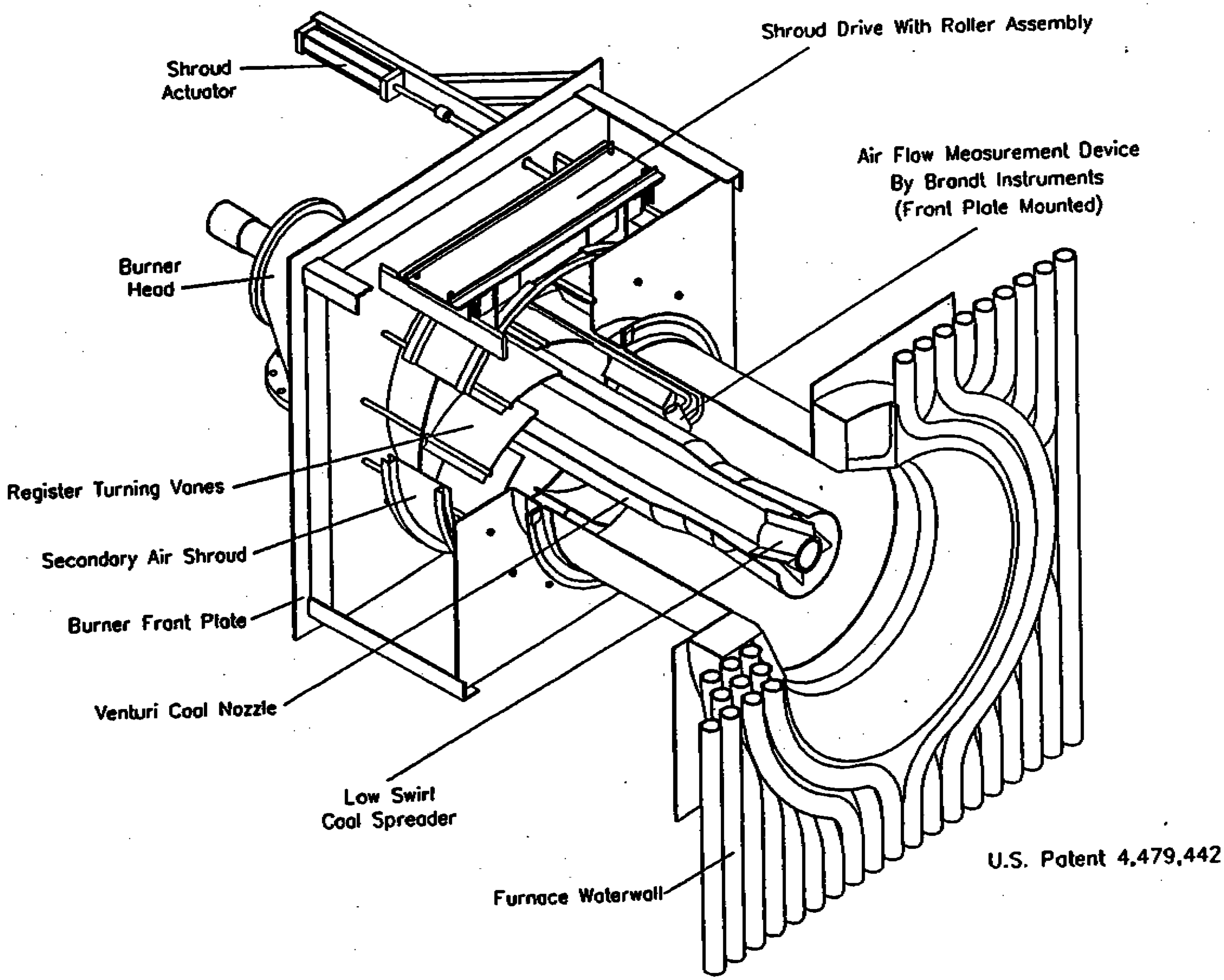


Figure 5-8. Controlled Combustion Venturi™ low NO_x burner.[17]

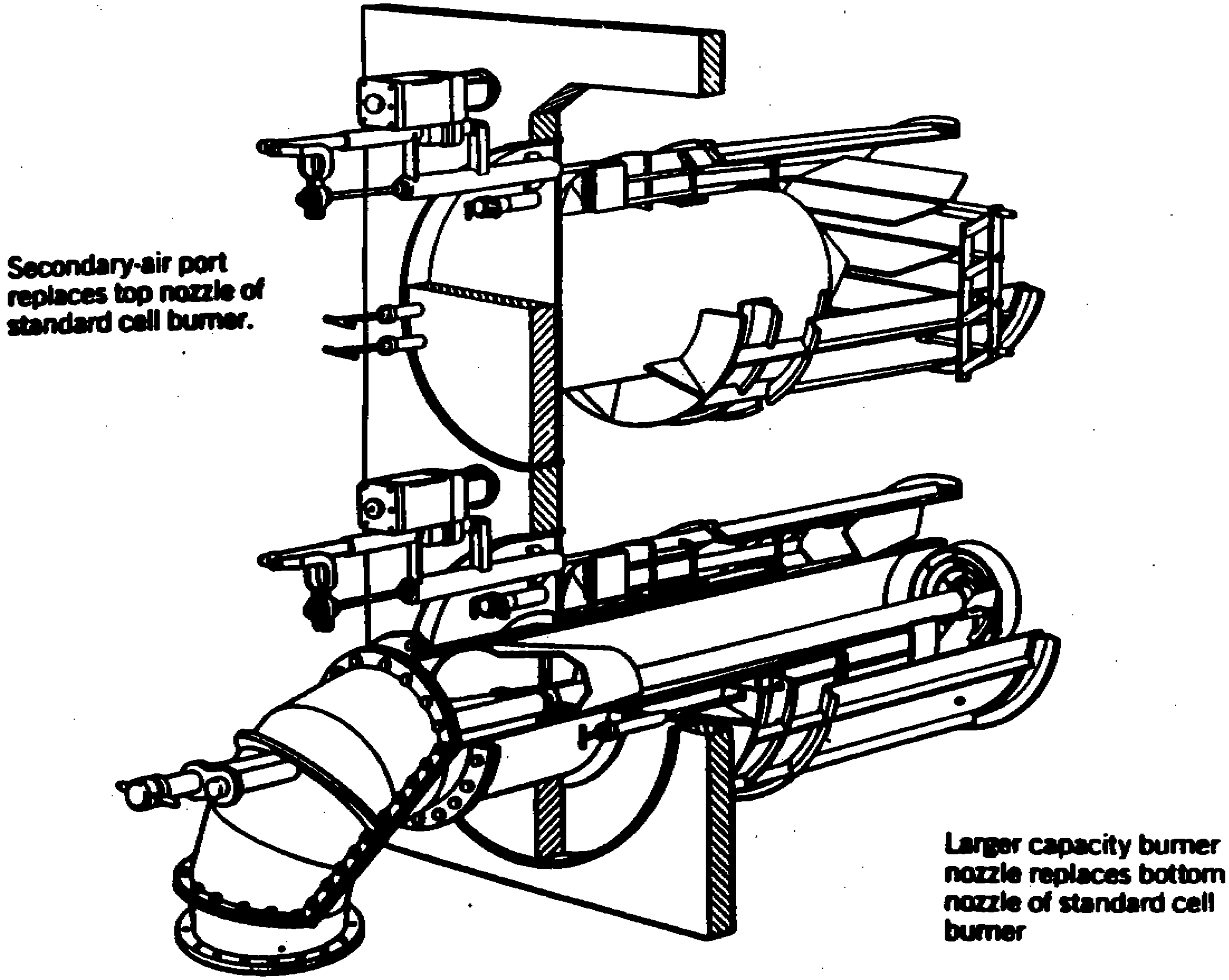


Figure 5-9. Low NO_X Cell Burner™ [15].

During firing, the lower fuel nozzle operates in a fuel-rich condition, with the additional air entering through the upper air port. Sliding dampers mounted in the upper and lower throats balance the secondary air flow.[15]

The Tertiary Staged Venturi™ (TSV) burner shown in figure 5-10 was designed for turbo, down-fired, and arch-fired boilers.[17] Similar to the CCV design, the TSV burner features a venturi shaped coal nozzle and low swirl coal spreader, but uses additional tertiary air and an advanced air staging system. The principles used to reduce NO_X are the same used with the CCV burner.[17]

5.1.3.1.2 Tangentially-fired boilers. A number of different LNB designs have been developed by burner manufacturers for use in tangentially-fired boilers. Several of these designs are discussed in this section. The traditional burner arrangement in tangentially-fired boilers consists of corner-mounted vertical burner assemblies from which fuel and air are injected into the furnace as shown in figure 5-11a.[18] The fuel and air nozzles are directed tangent to an imaginary circle in the center of the furnace, generating a rotating fireball in the center of the boiler as shown in figure 5-11b.[18] Each corner has its own windbox that supplies primary air through the air compartments located above and below each fuel compartment.

In the early 1980's, the low NO_X concentric firing technique was introduced for tangentially-fired boilers and is shown in figure 5-12a.[18] This technique changes the air flow through the windbox; however, the primary air is not affected. A portion of the secondary air is directed away from the fireball and toward the furnace wall as shown in figure 5-12b.[18] The existing coal nozzles in the burner compartments are replaced with "flame attachment" nozzle tips that accelerate the devolitization of the coal. This configuration suppresses NO_X emissions by providing an O_2 richer environment along the furnace walls. This can also

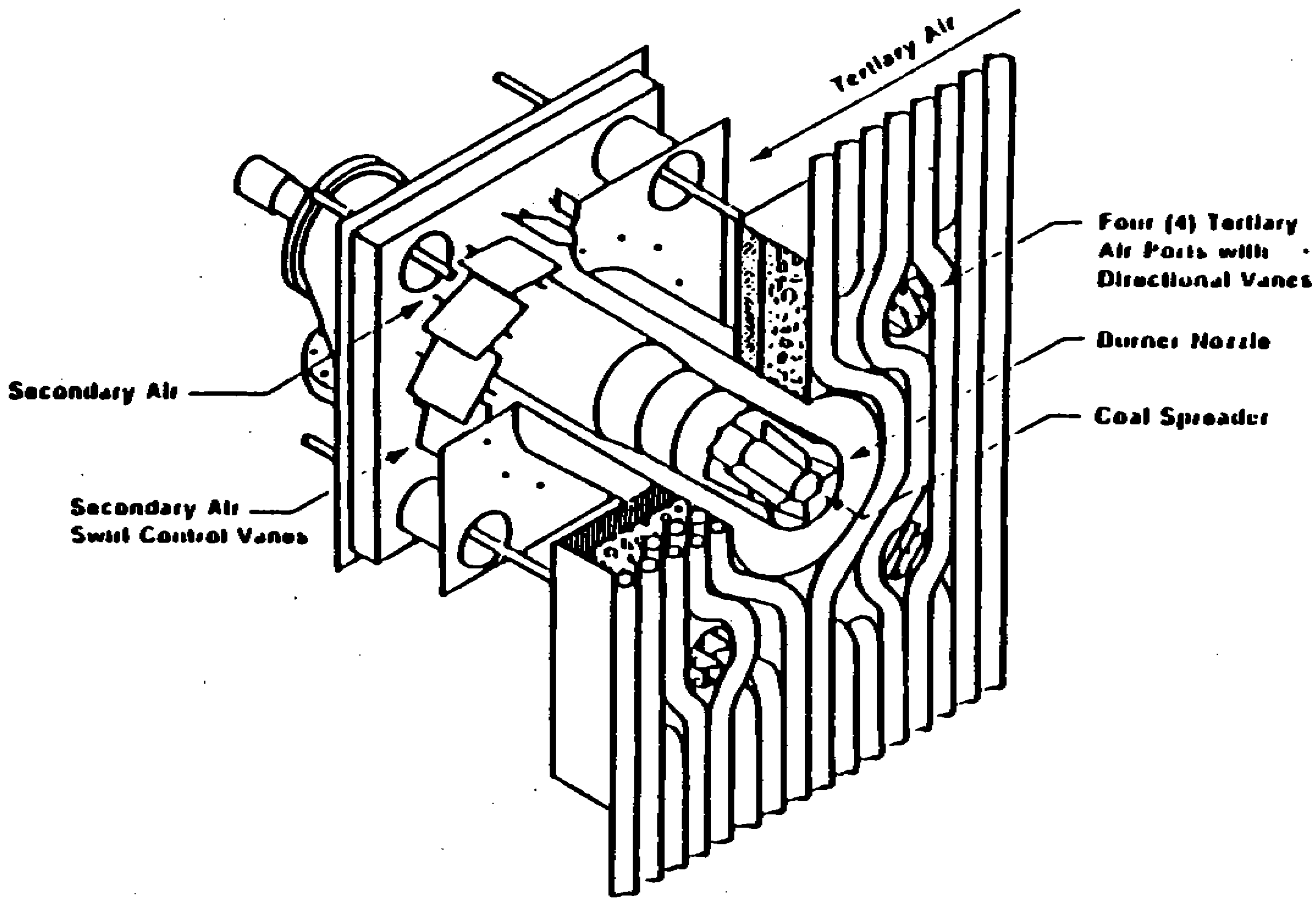


Figure 5-10. Low NO_x Tertiary Staged Venturi™ burner.[17]

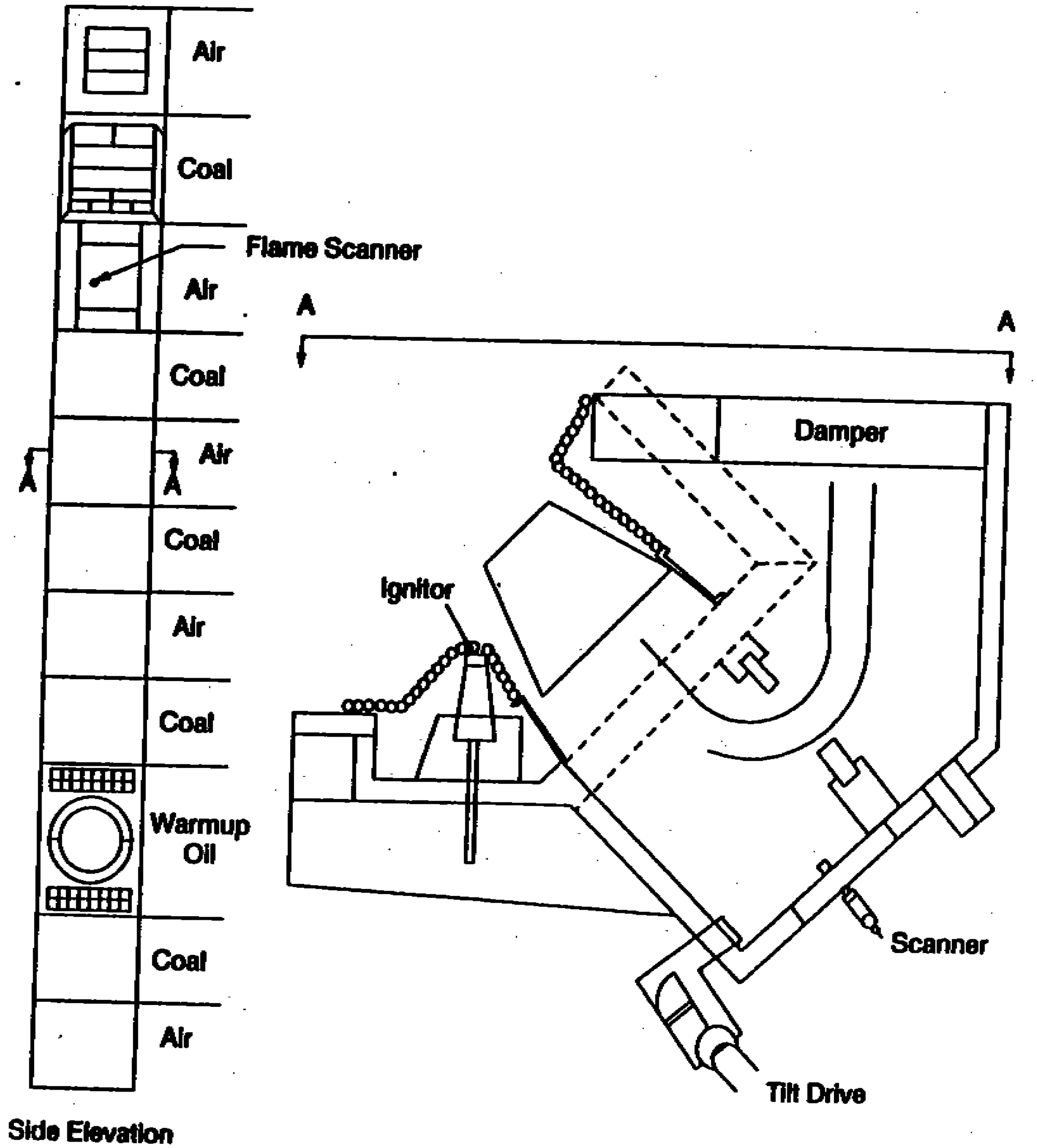


Figure 5-11a. Typical fuel and air compartment arrangement for a tangentially-fired boiler.[18]

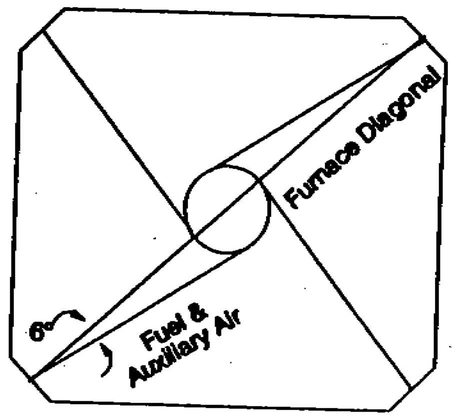


Figure 5-11b. Plan view of fuel and air streams in a typical tangentially-fired boiler.[18]

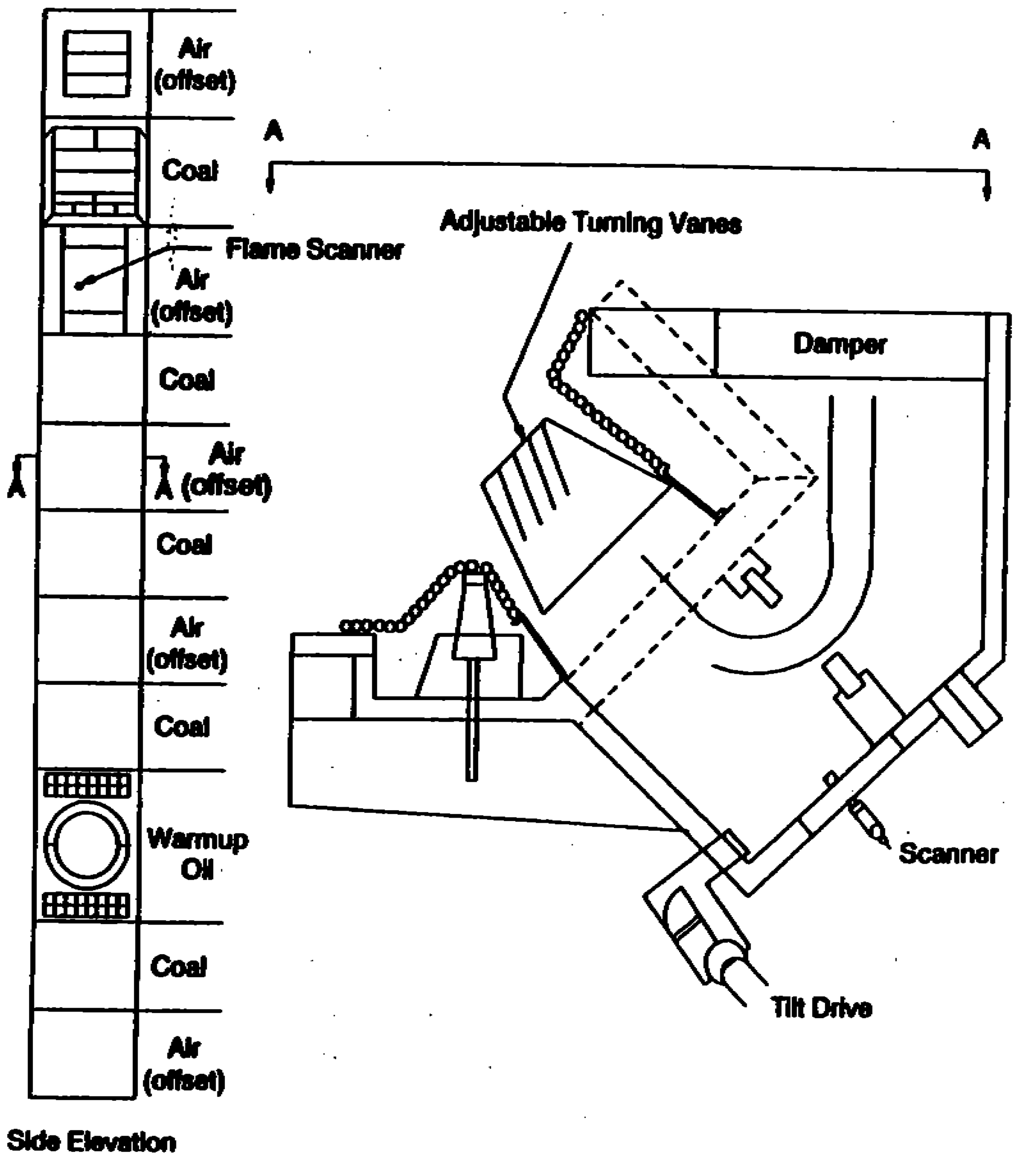


Figure 5-12a. Low NO_x Concentric Firing System™ fuel and air compartment arrangement.[18]

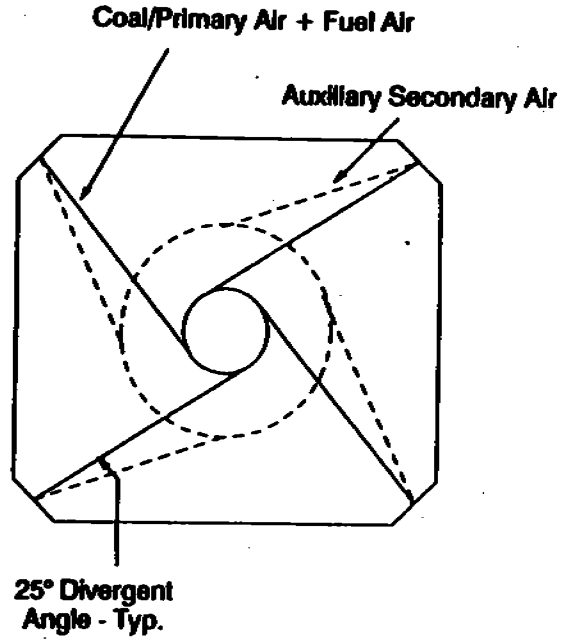


Figure 5-12b. Plan view of low NO_x Concentric Firing System™.[18]

reduce the slagging and tube corrosion problems often associated with combustion slagging.

To retrofit existing tangentially-fired boilers with concentric firing, all of the air and fuel nozzles must be replaced. However, structural, windbox, or waterwall changes may not be required. Several systems are available that use the concentric firing technique in combination with OFA. These systems are classified as a family of technologies called the Low NO_x Concentric Firing System™ (LNCFS) and are discussed in section 5.1.4 (LNB + OFA)

The Pollution Minimum™ (PM) burner has also been developed for tangentially-fired boilers. Although a PM burner system has been retrofitted in one boiler, this burner will probably only be used for new applications in the future because of the extensive modifications required to the fuel piping. As shown in figure 5-13, the PM burner system uses a coal separator that aerodynamically divides the primary air and coal into two streams, one fuel-rich and the other fuel-lean.[18] Thus, NO_x emissions are reduced through controlling the local stoichiometry in the near-burner zone.

The retrofit of a PM burner involves installing new windboxes and auxiliary firing equipment, upgrading the existing control system, and modifying the waterwall and coal piping. The PM burner is used with conventional and advanced OFA systems.[18] These systems are discussed in section 5.1.5.1.

5.1.3.1.3 Cyclone-fired boilers. There are currently no LNB available for cyclone-fired boilers. As discussed in chapter 3, cyclones boilers are slag-tapping furnaces, in which the fuel is fired in cylindrical chambers rather than with conventional burners. In addition, cyclone boilers are inflexible to modification because of rigid operating specifications. Proper furnace temperature and high heat release rates are required to maintain effective slag-tapping in the furnace. Operating experiences suggest that these

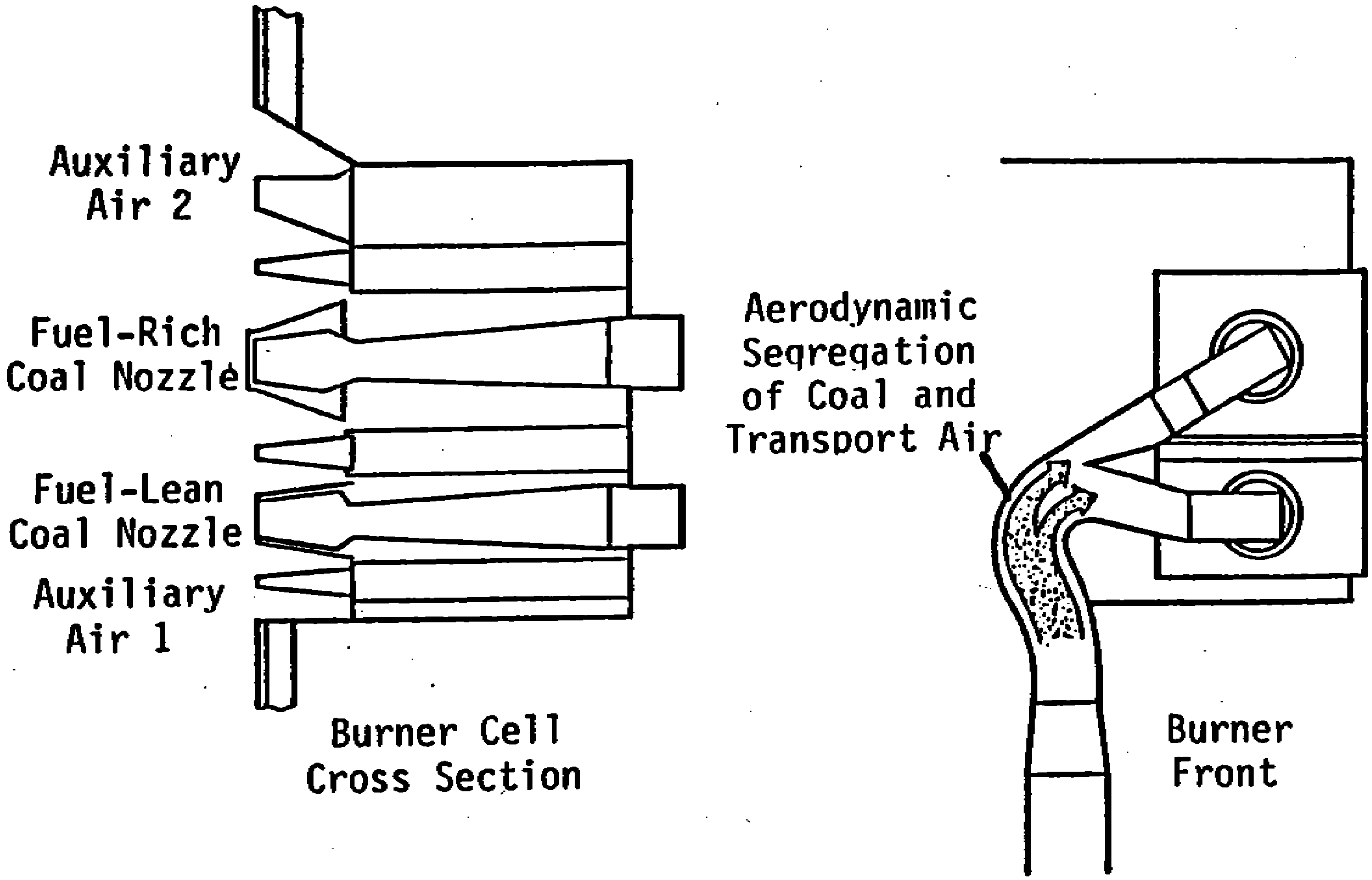


Figure 5-13. Low NO_x Pollution Minimum™ burner.[18]

parameters cannot be altered in a cyclone boiler to the degree required for adequate NO_x control.[11]

5.1.3.2 Factors Affecting Performance. The effectiveness of LNB, especially for retrofit cases, depends on a number of site-specific parameters. Low NO_x burners are generally larger than conventional burners and require more precise control of fuel/air distribution. Their performance depends partially on increasing the size of the combustion zone to accommodate longer flames. Because of this, LNB are expected to be less effective when retrofit on relatively small furnaces.

In order to retrofit LNB in wall-fired boilers, the existing burners must be removed and replaced. In some cases, some of the waterwall tubes may have to be bent in order to install the larger LNB. Also, the LNB may have longer flames that could impinge on the opposite furnace wall and superheater tubes which can be a problem for boilers with small furnace depths. Potential solutions to flame impingement include adjusting velocities of the coal or primary air, adjusting secondary air, and/or relocating some superheater tubes. Boilers with very small furnaces may have to be derated in order to prevent flame impingement at full load.

To retrofit a tangentially-fired boiler, the existing fuel and air nozzles must be removed and replaced. For some tangentially-fired LNB systems, the new air and fuel nozzles and CCOFA can be placed in the existing windbox opening. To retrofit SOFA, new openings must be made above the existing windbox.

The fuel-rich operating conditions of LNB generate localized reducing conditions in the lower furnace region and can increase the slagging tendency of the coal. To reduce this potential for slagging, some combustion air can be diverted from the burner and passed over the furnace wall surfaces, providing a boundary air layer that maintains an oxidizing atmosphere close to the tube walls. The generally longer flames of some LNB will tend to increase furnace exit and superheat/reheat tube temperatures. Some LNB operate with a higher pressure drop or may require slightly higher excess air levels in the furnace at full load to ensure good carbon burnout, thus increasing fan requirements.

Another consideration in retrofitting LNB is modifying the windbox. Modifications may include the addition of dampers and baffles for better control of combustion air flow to burner rows and combustion air distribution to burners within a row. Also, the windbox must be large enough to accommodate the LNB. If the existing windbox requires substantial modifications to structural components, major re-piping, and/or windbox replacement, retrofitting LNB may not be feasible.

5.1.3.3 Performance of Low NO_x Burners

5.1.3.3.1 Retrofit applications. The performance of retrofit LNB is presented in table 5-4. There are two tangentially-fired units listed that have retrofit LNCFS I technology which incorporates CCOFA within the original windbox opening. For this reason, the LNCFS I technology is included in the LNB section. One tangential unit, Lansing Smith 2, is a pre-NSPS unit while the other, Hunter 2, is a subpart Da unit. Both of these boilers fire bituminous coal.

Short-term controlled data for Lansing Smith 2 ranged from 0.39 to 0.43 lb/MMBtu across the load range. Long-term controlled NO_x emissions (mean values of hourly averages for 2 to 3 months) for Lansing Smith 2 were similar to short-term data and averaged 0.41 lb/MMBtu at near full-load conditions with LNCFS I as compared to an uncontrolled level of 0.64 lb/MMBtu. At 70 percent load, the controlled NO_x level decreased slightly to 0.4 lb/MMBtu.

The long-term data from Lansing Smith 2 shows 36 to 37 percent NO_x reduction, whereas the short-term data shows 41 to 48 percent reduction. The long-term data is probably more representative of actual day-to-day NO_x emission levels during

TABLE 5-4. PERFORMANCE OF LNB RETROFIT ON U. S. COAL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
TANGENTIALLY-FIRED BOILERS, BITUMINOUS COAL										
Gulf Power Co.	Lansing Smith 2 (Pre)	200	ABB-CE	LNCFS I (ABB-CE)	Short Short Short	100 70 60	0.73 0.68 0.65	0.39 0.40 0.43	45 48 41	19
					Long[f] Long[f] Long[f]	100 70 60	0.64 0.63 0.62	0.41 0.40 0.39	36 37 37	13
Pacific Power & Light Co.	Hunter 2 (D)	446	ABB-CE	LNCFS I (ABB-CE)	Short	100 70	0.64	0.35	45	7
					Long	70	--	0.41	--	7
Tennessee Valley Authority	Gallatin 4 (Pre)	328	ABB-CE	LNCFS I (ABB-CE)	Short	--	0.55-0.65	0.45-0.55	10-20	20
WALL-FIRED BOILERS, BITUMINOUS COAL										
Ohio Edison Co.	Edgewater 4 (Pre)	105	B&W	XCL (B&W)	Short Short Short	100 78 63	0.85 0.80 0.67	0.52 0.46 0.39	39 43 42	21
Alabama Power Co.	Gaston 2 (Pre)	272	B&W	XCL (B&W)	Short Short Short	100 70 50	0.78 0.69 0.60	0.39 0.37 0.34	46 41 43	22
					Long[f] Long[f] Long[f]	100 70 50	0.76 0.72 0.65	0.40 0.38 0.36	47 47 45	13
Central IL Light Co.	Duck Creek 1 (Pre)	441	RS	CCV (RS)	Short	100	1.11	0.55	50	23
Tennessee Valley Authority	Johnsonville 8 (Pre)	125	FW	IFS (FW)	Short	100	1.0 0.95-1.05	0.45 0.44-0.60	55	20,24, 25

TABLE 5-4. PERFORMANCE OF LNB RETROFIT ON U. S. COAL-FIRED UTILITY BOILERS (Continued)

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
WALL-FIRED BOILERS, BITUMINOUS COAL (Continued)										
Tennessee Valley Authority	Colbert 3 (Pre)	200	B&W	IFS (FW)	Short	100	0.77	0.40	48	25
					Long	--	--	0.45	--	5
Georgia Power Co.	Hammond 4 (Pre)	500	FW	CF/SF (FW)	Short Short	100 60	1.20 1.00	0.65 0.50	50 50	12
					Long[f] Long[f] Long[f]	100 80 60	1.23 1.09 0.98	0.69 0.57 0.47	44 48 52	13
Monogahela Power Co.	Pleasants 2 (Da)	626	FW	CF/SF (FW)	Short Short Short	100 84 72	0.95 -- --	0.45 0.33 0.34	53 -- --	14
					Long[g]	--	--	0.33-0.45	--	26
Board of Public Utilities	Quindaro 2 (D)	137	RS	RO-II (ABB-CE)	Short	90 70 55	-- -- --	0.53 0.51 0.45	-- -- --	16
WALL-FIRED BOILERS, SUBBITUMINOUS COAL										
Public Service Co. of CO	Cherokee 3 (Pre)	172	B&W	IFS (FW)	Short	90	0.73	0.50	31	27
Arizona Public Service Co.	Four Corners 3 (Pre)	253	FW	CF/SF (FW)	Short Short	100 70	-- --	0.58 0.51	-- --	28
					Long[f]	--	--	0.45-0.60	--	28
Public Service Co. of NM	San Juan 1 (Pre)	361	FW	CF/SF (FW)	Short	100	0.95	0.40	58	29

TABLE 5-4. PERFORMANCE OF LNB RETROFIT ON U. S. COAL-FIRED UTILITY BOILERS (Concluded)

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
WALL-FIRED BOILERS, SUBBITUMINOUS COAL (Continued)										
Consumers Power Co.	J.H. Campbell 3 (D)	778	FW	CF/SF (FW)	Short	100	0.58-0.60[h]	0.39-0.46[h]	30-41	30
					Long[g]	80-100	0.38-0.60	0.40-0.60	--	30
Arizona Public Service Co.	Four Corners 4[i] (Pre)	818	B&W	CF/SF (FW)	Short Short Short	103 70 50	1.15 0.98 0.67	0.49 0.70 0.62	57 29 7	31
					Long[g]	--	--	0.5-0.65	--	31
Arizona Public Service Co.	Four Corners 5[i] (Pre)	818	B&W	CF/SF (FW)	Short	93	1.15	0.57	50	31
					Long[g]	--	--	0.5-0.65	--	31
Board of Public Utilities	Quindaro 2 (D)	137	RS	RO-II (ABB-CE)	Short	90 70 55	-- -- --	0.35 0.27 0.28	-- -- --	16
CELL BOILERS, BITUMINOUS COAL										
Dayton Power & Light Co.	JM Stuart 4 (Pre)	610	B&W	LNCB (B&W)	Short Short Short	100 75 57	1.22 0.92 0.70	0.55 0.42 0.37	55 54 47	32, 33

[a]Standard: D = Supart D; Da = Subpart Da; and Pre = Pre-NSPS
[b]OEM = Origianl Equipment Manufactuer; ABB-CE = Asea Brown Boveri - Combustion Engineering; B&W = Babcock & Wilcox; FW = Foster Wheeler; and RS = Riley Stoker.
[c]Type Control: CCV = Controlled Combustion Venturi Low NO_x Burner; CF/SF = Controlled Flow/Split Flame Low NO_x Burner; IFS = Internal Fuel Staged Low NO_x Burner; LNCB = Low NO_x Cell Burner; LNCFSI = Low NO_x Concentric Firing System, Level 1, with close-coupled overfire air; and XCL = Axial Controlled Low NO_x Burner
[d]Vendor: Vendor of NO_x control. Refer to note "b".
[e]Long = Long-term CEM data, i.e., 2-6 months. Short = Short-term test data, i.e., hours.
[f]Long = Mean value of hourly averages for 2-6 months.
[g]Long = Range of hourly averages.
[h]Uncontrolled emissions are with OFA and controlled NO_x emissions are with LNB alone.
[i]Originally 3-nozzle cell burner that has had burner pattern changed to standard opposed-wall configuration.
-- = Data not available

normal boiler operation than the short-term data taken during specific test conditions. Lansing Smith 2 is also evaluating LNCFS II and III as part of a U.S. Department of Energy (DOE) Innovative Clean Coal Technology project. The results from the LNCFS II and III demonstrations are presented in section 5.1.4.3.1.

For Hunter 2, the uncontrolled level of 0.64 lb/MMBtu represents operation with original burners but without the OFA. The LNCFS I system reduced the NO_x to 0.35 lb/MMBtu at full-load during short-term tests (45 percent NO_x reduction). The long-term data (4 sets of 30-day rolling averages) taken during normal low NO_x operation indicates an emission level of 0.41 lb/MMBtu at an average 70 percent load. The average NO_x reduction for these units was 35 to 45 percent with LNCFS I technology which is similar to the results at Lansing Smith.

There are eight wall-fired boilers noted on table 5-4 that fire bituminous coal. Of these, two pre-NSPS boilers have been retrofit with the XCL™ burner. Edgewater 4 and Gaston 2 had uncontrolled NO_x emissions in the range of 0.76 to 0.85 lb/MMBtu at full-load and were reduced to 0.4 to 0.52 lb/MMBtu with the XCL™ burner (39 to 47 percent). Figure 5-14 shows trends in controlled NO_x levels for Edgewater 4, Gaston 2, Four Corners 3 and 4, Hammond 4, and Pleasants 2 as a function of boiler load. Typically, at higher loads the controlled NO_x is higher. The short-term controlled NO_x emissions from both Edgewater and Gaston reduced as the load decreased. The CCV™ burner reduced uncontrolled NO_x emissions of 1.1 lb/MMBtu by 50 percent to 0.55 lb/MMBtu (Duck Creek 1).

For the two units with the IFS™ burner, the NO_x emissions were reduced 48 to 55 percent. One of these boilers (Johnsonville 8) had an uncontrolled NO_x level of 1.0 lb/MMBtu and was reduced by 55 percent whereas the other (Colbert 3) had a lower uncontrolled NO_x level of 0.77 lb/MMBtu and was reduced by only 48 percent.

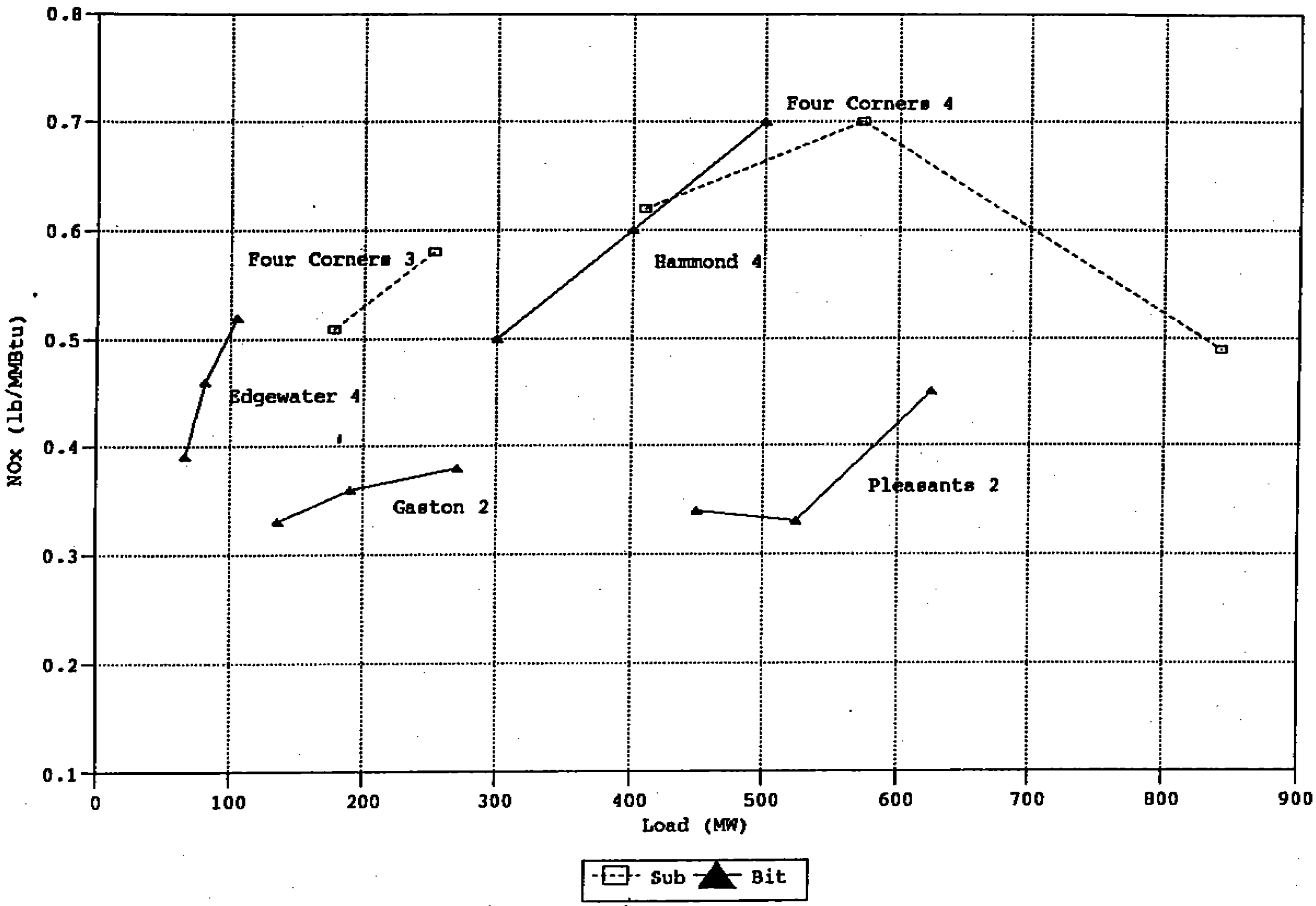


Figure 5-14. Short-term controlled NO_x emissions from wall-fired boilers with retrofit LNB.

For the pre-NSPS boiler retrofit with the CF/SF™ burner (Hammond 4), the NO_x was reduced from uncontrolled levels of approximately 1.2 lb/MMBtu by 45 to 50 percent to 0.6 lb/MMBtu (short-term test data) and 0.7 lb/MMBtu (long-term test data). The subpart Da unit (Pleasants 2) had uncontrolled NO_x emissions of 0.95 lb/MMBtu and was reduced to 0.45 lb/MMBtu with the CF/SF™ burner (53 percent reduction). This unit was also originally equipped with OFA ports which were closed off when the new LNB were installed. The uncontrolled NO_x level of 0.95 lb/MMBtu is from a short-term test without OFA. As figure 5-3 shows, the NO_x emissions from Hammond and Pleasants decreased as the load decreased.

One boiler, Quindaro 2, was retrofitted with the RO-II LNB. Testing was conducted with both a bituminous and a subbituminous coal. Uncontrolled NO_x levels were not measured and the controlled NO_x levels at full-load while firing bituminous coal was 0.53 lb/MMBtu and 0.45 lb/MMBtu at half-load.

There are seven boilers on table 5-4 that fire subbituminous coal, five of which have been retrofitted with the CF/SF™ burner, one with the IFS burner, and one with the RO-II burner. Two of the units, Four Corners 4 and 5, were originally 3-nozzle cell units and the burner pattern was changed to a "standard" opposed-wall configuration during the retrofit. Therefore, these units are not typical of a direct plug-in LNB retrofit.

The NO_x emissions at Cherokee 3 were reduced from 0.73 lb/MMBtu with the IFS burner to 0.5 lb/MMBtu, or 31 percent. This boiler also has a natural gas reburn system; however, this data is without reburn. The NO_x emissions at Four Corners 3 were reduced to approximately 0.6 lb/MMBtu with the CF/SF™ burner. Neither the uncontrolled level nor the percent reduction were reported.

The San Juan 1 unit was designed to meet an emission limit of 0.7 lb/MMBtu but was unable to meet this level with

OFA alone. The NO_x was reduced from 0.95 lb/MMBtu (with OFA) to a controlled level of 0.4 lb/MMBtu (with LNB), or 58 percent reduction. San Juan 1 had fairly high uncontrolled NO_x levels which may be a factor in attaining the high percent reduction.

The short-term controlled NO_x emissions for the subpart D unit (J.H. Campbell 3) was 0.39 to 0.46 lb/MMBtu at full-load with the CF/SF™ burner. This unit was originally equipped with OFA ports which were subsequently closed off when the new LNB were installed. The uncontrolled NO_x emissions are with the OFA in service. By installing LNB on this unit and closing the existing OFA ports, approximately 30-40 percent NO_x reduction was achieved.

At Four Corners 4 and 5, the NO_x was reduced from an uncontrolled level of 1.15 lb/MMBtu to controlled levels of 0.49 to 0.57 lb/MMBtu (short-term) and 0.5 to 0.65 lb/MMBtu (long-term). This corresponds to 50 to 57 percent reduction. Since these units were originally cell boilers, they had higher uncontrolled NO_x emissions than the standard wall-fired boiler configuration, and subsequently higher controlled NO_x emissions.

Quindaro 2 was retrofitted with the RO-II LNB and tested with both bituminous and subbituminous coal. On subbituminous coal, the NO_x emissions were reduced to 0.35 lb/MMBtu at full-load and to 0.28 lb/MMBtu at half-load. The one cell-fired boiler (JM Stuart 4) shown on table 5-4 fires bituminous coal and had high (short-term) uncontrolled NO_x emissions of 0.70 to 1.22 lb/MMBtu across the load range. After retrofitting the LNCB, the NO_x was reduced to 0.37 to 0.55 lb/MMBtu (47 to 55 percent). The LNCB is a direct burner replacement and the boiler remains in a cell unit configuration.

To summarize, the tangentially-fired boilers that fire bituminous coal had uncontrolled NO_x emissions in the range of 0.62 to 0.64 lb/MMBtu and were reduced by 35 to 45 percent with the LNCFS I technology to controlled levels of 0.35 to

0.4 lb/MMBtu (long-term data). The wall-fired boilers that fire bituminous coal had uncontrolled NO_x emissions in the range of 0.75 to 1.2 lb/MMBtu and were reduced by 40 to 50 percent with LNB to controlled levels of 0.4 to 0.7 lb/MMBtu (long-term data). The wide range of NO_x emissions is due to factors such as boiler age, boiler and burner design, heat release rates, and furnace volume. And, the wall-fired boilers that fire subbituminous coal had uncontrolled NO_x emissions of 0.6 to 1.2 lb/MMBtu and were reduced by 40 to 60 percent to controlled levels of 0.4 to 0.6 lb/MMBtu. The wide range of uncontrolled NO_x emissions is due to the original cell configuration of two boilers (high uncontrolled NO_x levels), boiler and burner design, heat release rates, and furnace volume.

5.1.3.3.2 New units. This section provides information on NO_x emissions from new boilers subject to NSPS subpart Da standards with LNB as original equipment. The performance of original LNB on 9 new tangentially-fired and 12 new wall-fired boilers is presented in table 5-5. The tangentially-fired boilers have CCOFA within the main windbox opening and for this reason, it is included in the LNB section. The wall-fired boilers have LNB only.

Short-term averages of NO_x emissions from the tangential units firing bituminous coal and operating at near full-load range from 0.41 to 0.51 lb/MMBtu at near full-load conditions. For the subbituminous coal-fired tangential boilers, the NO_x emissions ranged from 0.35 to 0.42 lb/MMBtu. And, the NO_x emissions from the lignite-fired boilers ranged from 0.46 to 0.48 lb/MMBtu. As shown in figure 5-15, the NO_x emissions for three tangential units increased when operated at low loads.

Short-term averages of NO_x emissions from the wall-fired units firing bituminous coal range from 0.28 to 0.52 lb/MMBtu at near full-load conditions. For the subbituminous coal-fired wall boilers, the NO_x emissions ranged from 0.26 to 0.47 lb/MMBtu whereas the lignite-fired boiler was

TABLE 5-5. PERFORMANCE OF LNB ON NEW U. S. COAL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Year online	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test (hrs)	Capacity tested (%)	NO_x emissions (lb/MMBtu)	Reference
TANGENTIALLY-FIRED BOILERS, BITUMINOUS COAL									
N. Indiana Public Service Co.	R.M. Schahfer 17 (Da)	1983	393	ABB-CE	LNB/CCOFA (ABB-CE)	6 2 5	95 79 58	0.43 0.42 0.60	34
N. Indiana Public Service Co.	R.M. Schahfer 18 (Da)	1986	393	ABB-CE	LNB/CCOFA (ABB-CE)	5 5 6	96 70 51	0.41 0.29 0.50	34
Tampa Electric Co.	Big Bend 4 (Da)	1985	455	ABB-CE	LNB/CCOFA (ABB-CE)	--	96	0.41	35
S. Carolina Public Service	Cross 2 (Da)	1984	500	ABB-CE	LNB/CCOFA (ABB-CE)	1 1 1	100 95 92	0.51 0.52 0.50	36
TANGENTIALLY-FIRED BOILERS, SUBBITUMINOUS COAL									
Muscatine Power & Water	Muscatine 9 (Da)	1983	161	ABB-CE	LNB/CCOFA (ABB-CE)	4 2 4	107 70 40	0.38 0.44 0.66	37
Lower CO River Authority	Fayette 3 (Da)	1988	440	ABB-CE	LNB/CCOFA (ABB-CE)	6	97	0.42	38
Houston Lighting & Power Co.	W.A. Parrish 8 (Da)	1982	615	ABB-CE	LNB/CCOFA (ABB-CE)	--	98	0.35	39
TANGENTIALLY-FIRED BOILERS, LIGNITE COAL									
Houston Lighting & Power Co.	Limestone 1 (Da)	1985	810	ABB-CE	LNB/CCOFA (ABB-CE)	--	100	0.48	40
Houston Lighting & Power Co.	Limestone 2 (Da)	1986	810	ABB-CE	LNB/CCOFA (ABB-CE)	--	97	0.46	40

TABLE 5-5. PERFORMANCE OF LNB ON NEW U. S. COAL-FIRED UTILITY BOILERS (Continued)

Utility	Unit (standard)[a]	Year online	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test (hrs)	Capacity tested (%)	NO_x emissions (lb/MMBtu)	Reference
WALL-FIRED BOILERS, BITUMINOUS COAL									
Southern Indiana Gas & Electric	AB Brown 2 (Da)	1986	265	B&W	DRB (B&W)	6	91	0.39	41
Utah Power & Light	Hunter 3 (Da)	1983	430	B&W	DRB (B&W)	10	100	0.39	42
Orlando Utility Commission	CH Stanton 1 (Da)	1987	464	B&W	LNB (B&W)	8	100	0.42	43
Baltimore Gas & Electric	Brandon Shores 1 (Da)	1984	670	B&W	DRB (B&W)	3	100	0.50	44
Baltimore Gas & Electric	Brandon Shores 2 (Da)	1991	670	B&W	DRB (B&W)	3	100	0.52	45
Los Angeles Dept. of Water & Power	Intermountain 1 (Da)	1986	900	B&W	DRB (B&W)	4 2 2	94 71 48	0.33 0.30 0.29	46
Cincinnati Gas & Electric	Zimmer 1 (Da)	1991	1300	B&W	DRB (B&W)	3	107	0.40	47
Nevada Power Co.	Reid Gardner 4 (Da)	1983	301	FW	CF/SF (FW)	6	100	0.28	48
Big River Electric Corp.	DB Wilson 1 (Da)	1986	440	FW	CF/SF (FW)	4	111 65	0.4 0.33	49

TABLE 5-5. PERFORMANCE OF LNB ON NEW U. S. COAL-FIRED UTILITY BOILERS (Concluded)

Utility	Unit (standard)[a]	Year online	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test (hrs)	Capacity tested (%)	NO_x emissions (lb/MMBtu)	Reference
WALL-FIRED BOILERS, SUBBITUMINOUS COAL									
Sunflower Electric Power Corp.	Holcomb 1 (Da)	1983	348	B&W	DRB (B&W)	1	93	0.26-0.34	50
Tri-State Generation and Trans. Assoc.	Craig 3 (Da)	1984	448	B&W	DRB (B&W)	6	89	0.36	51
Sierra Pacific Power Co.	North Valmy 2 (Da)	1985	284	FW	LNB (FW)	2	95	0.47	52
WALL-FIRED BOILERS, LIGNITE COAL									
Central LA Electric Co.	Dolet Hills 1 (Da)	1986	695	B&W	DRB (B&W)	1	97	0.39	53

[a]Standard: Da = Subpart Da.

[b]OEM = Original Equipment Manufacturer; ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock & Wilcox; and FW = Foster Wheeler

[c]Control Type: DRB = Dual Register Burner; CF/SF = Controlled Flow/Split Flame; and LNB/CCOFA = Low NO_x Burners with Close-Coupled Overfire Air.

[d]Vendors: Vendor of NO_x control. Refer to note "b".

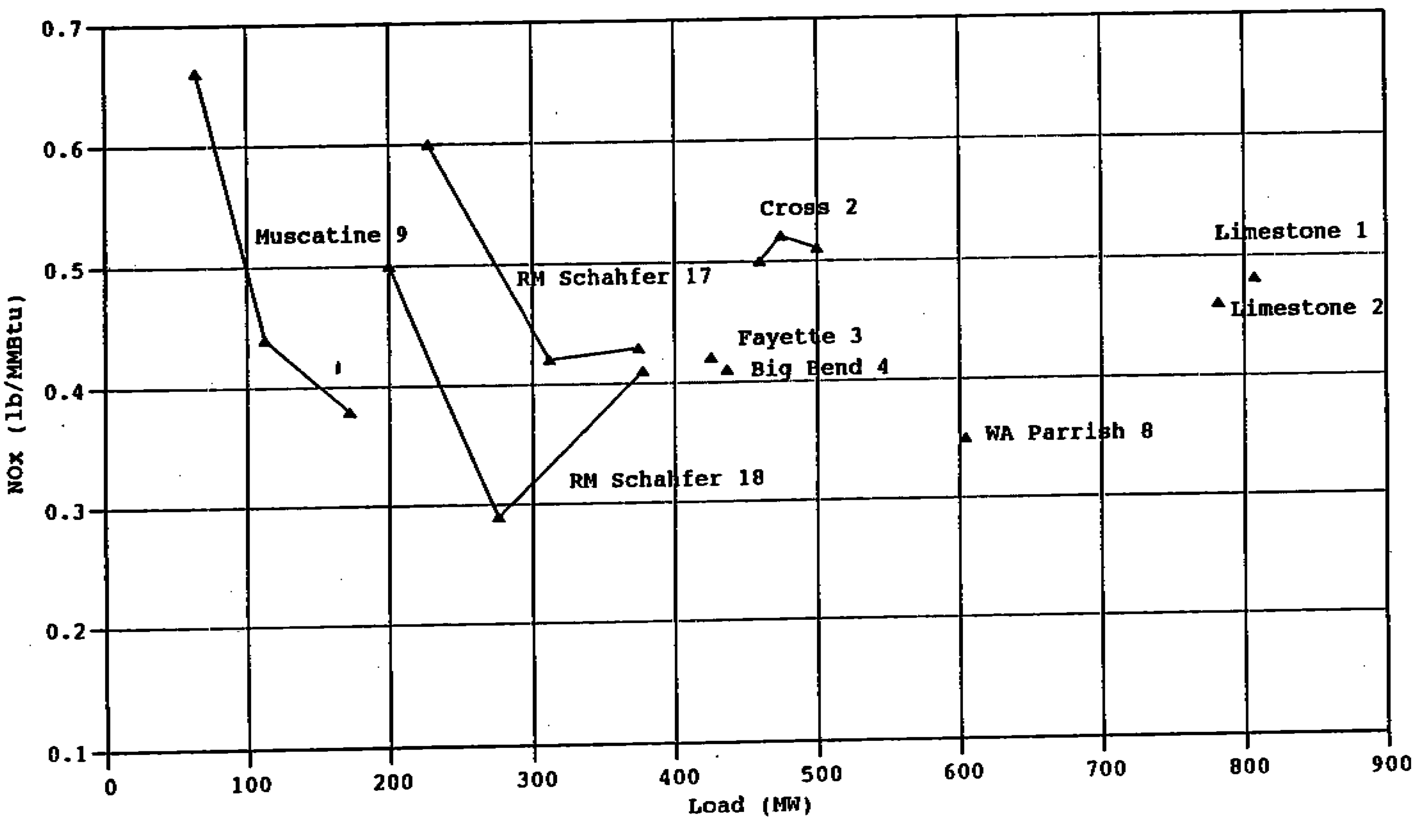


Figure 5-15. NO_x emissions from new tangentially-fired boilers with LNB + CCOFA.

0.39 lb/MMBtu. Two wall units reported NO_x at lower loads and as shown in figure 5-16, the NO_x decreased as load decreased.

5.1.4 <u>Low NO_x Burners and Overfire Air</u>

5.1.4.1 <u>Process Description</u>. Low NO_x burners and OFA are complementary combustion modifications for NO_x control that incorporate both the localized staging process inherent in LNB designs and the bulk-furnace air staging of OFA. When OFA is used with LNB, a portion of the air supplied to the burners is diverted to OFA ports located above the top burner row. This reduces the amount of air in the burner zone to an amount below that required for complete combustion. The final burn-out of the fuel-rich combustion gases is delayed until the OFA is injected into the furnace. Using OFA with LNB decreases the rate of combustion, and a less intense, cooler flame results, which suppresses the formation of thermal NO_x.

In wall-fired boilers, LNB can be coupled with either OFA or AOFA. Figure 5-17 shows a schematic of a wall-fired boiler with AOFA combined with LNB.[54] Section 5.1.2 describes both OFA and AOFA systems.

In tangentially-fired boilers, OFA is incorporated into the LNB design, forming a LNB and OFA system. These systems use CCOFA and/or SOFA and are classified as a family of technologies called LNCFS. There are three possible LNCFS arrangements shown in figure 5-18.[55] For LNCFS Level I, CCOFA is integrated directly into the existing windbox by exchanging the highest coal nozzle with the air nozzle immediately below it. This configuration requires no major modifications to the boiler or windbox geometry. In LNCFS Level II, SOFA is used above the windbox. The air supply ductwork for the SOFA is taken from the secondary air duct and routed to the corner of the furnace above the existing windbox. The inlet pressure of the SOFA system can be increased above the primary windbox pressure using dampers downstream of the takeoff in the secondary air duct. The quantity and velocity of the SOFA injected into the furnace can be higher than those levels

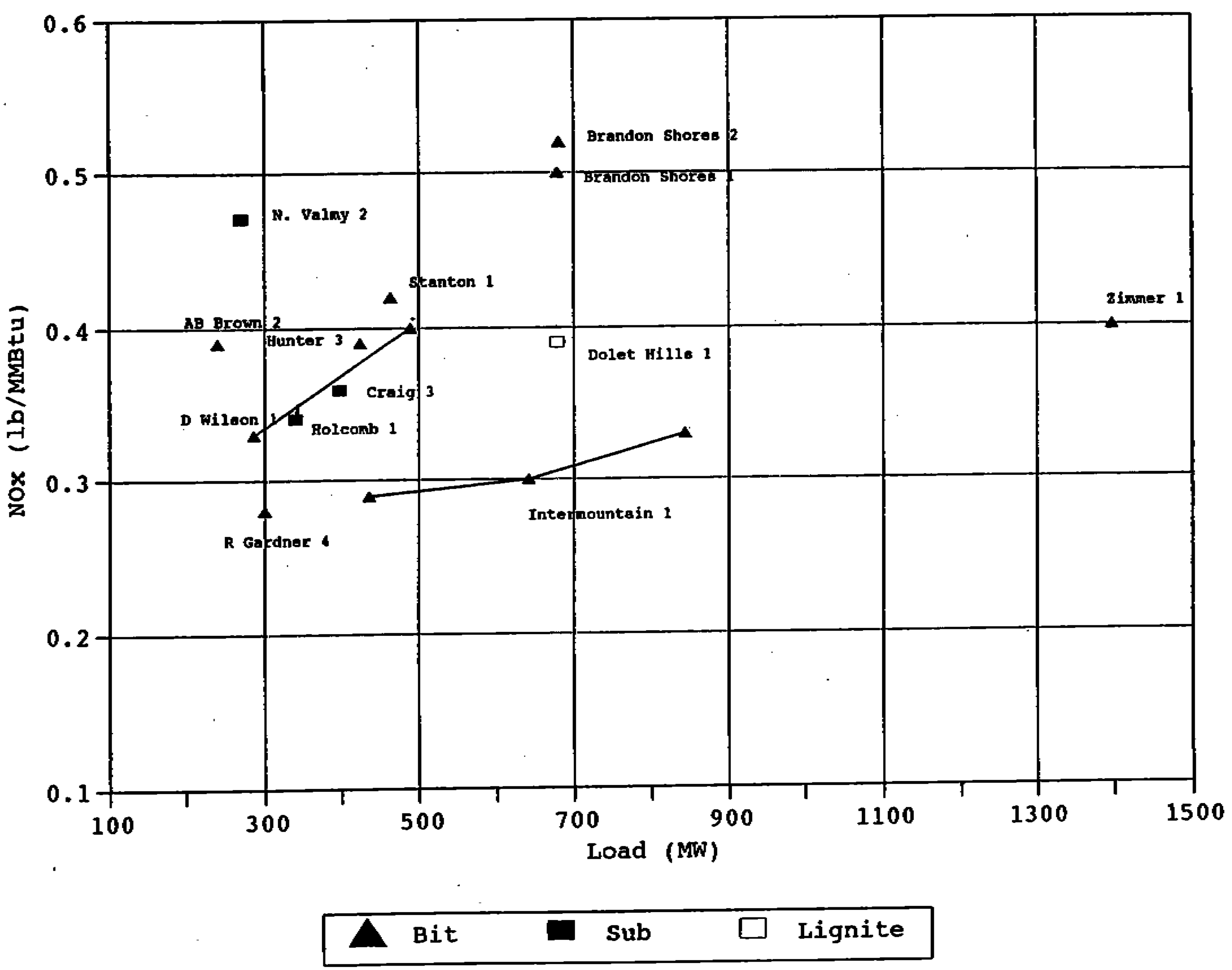


Figure 5-16. NO_x emissions from new wall-fired boilers with LNB.

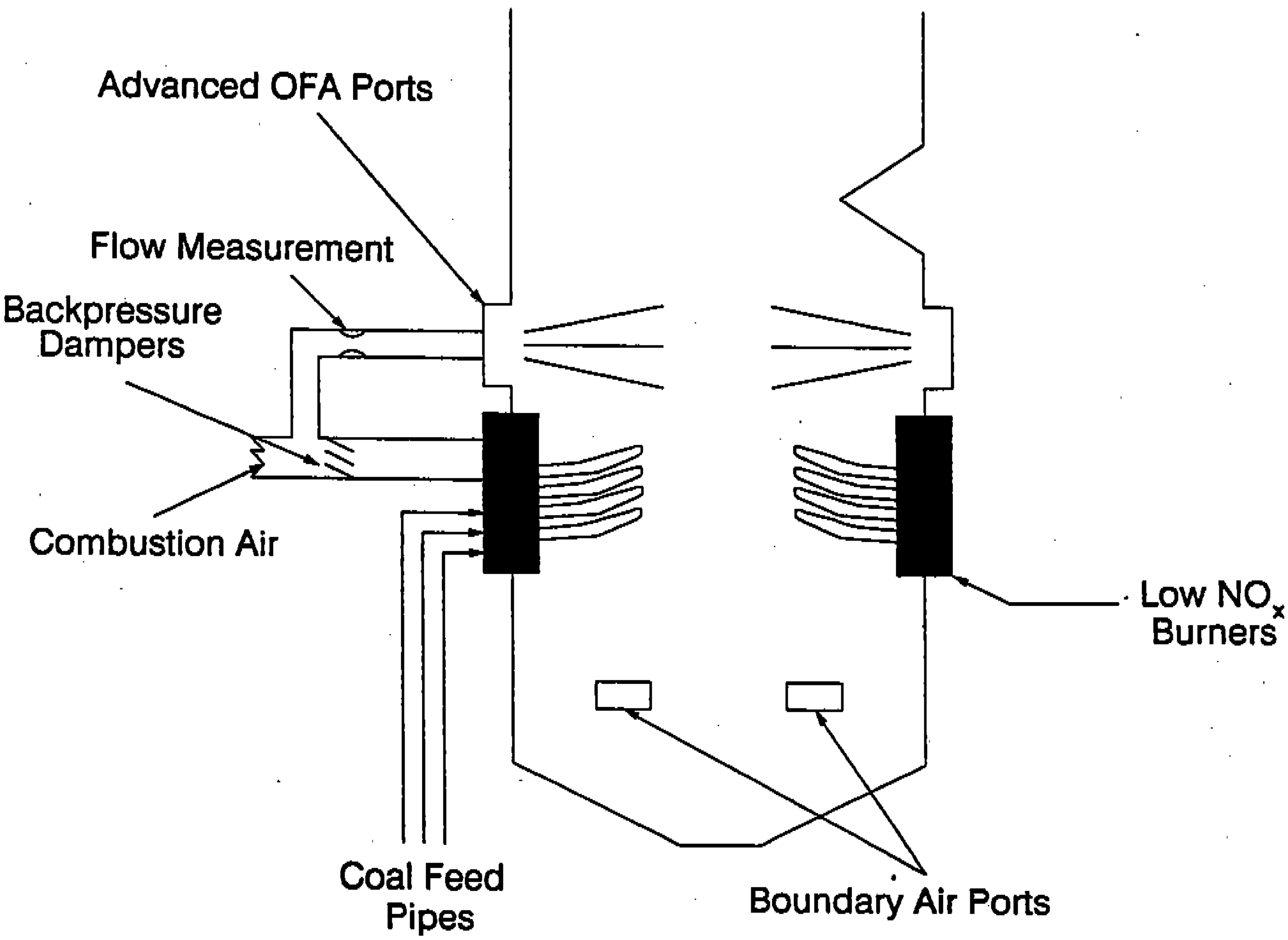


Figure 5-17. Advanced OFA system with LNB.[54]

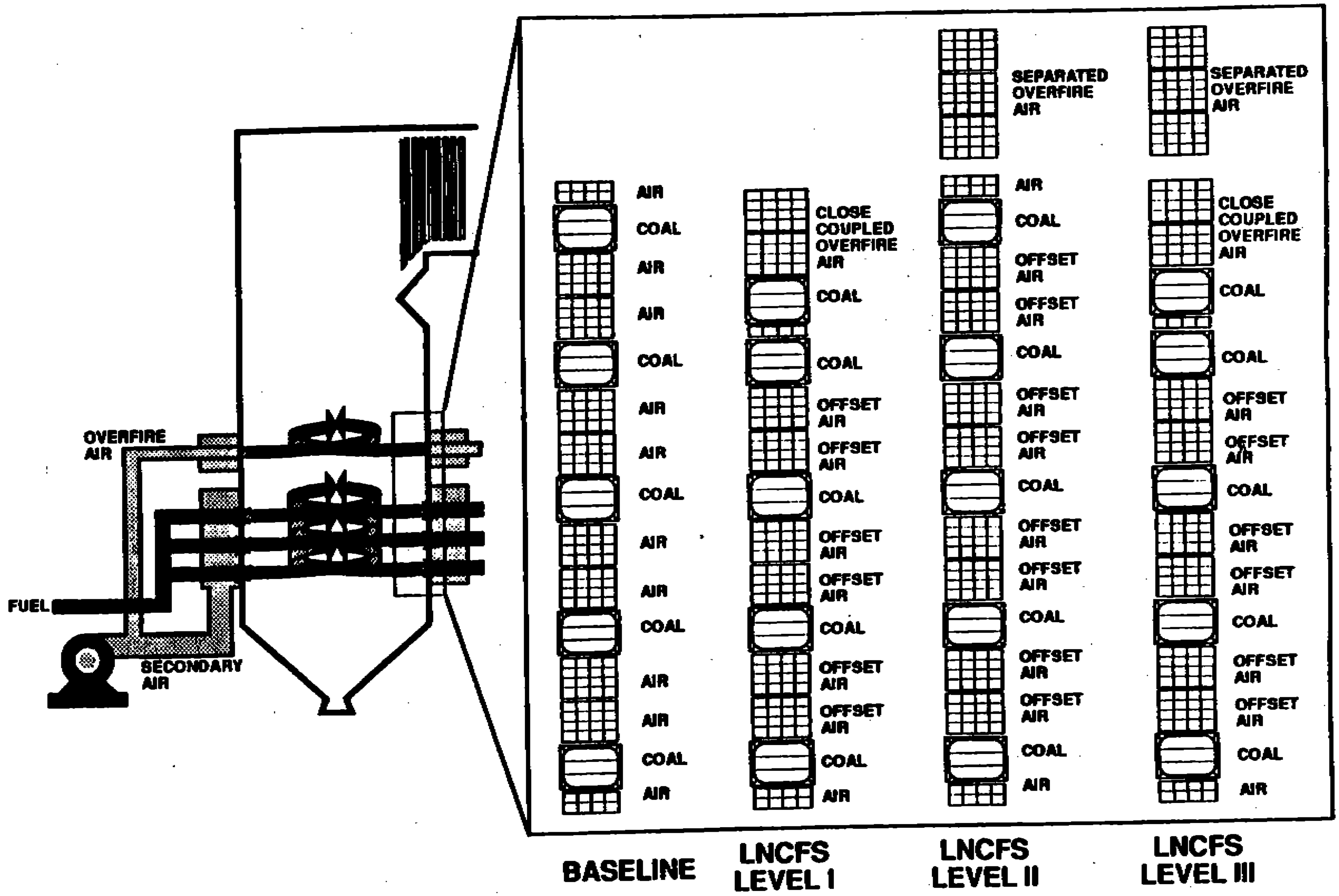


Figure 5-18. Low NO_x concentric firing systems.[55]

possible with CCOFA, providing better mixing. The LNCFS Level III uses both CCOFA and SOFA for maximum control and flexibility of the staging process. Process descriptions of OFA and LNB are discussed in detail in sections 5.1.2.1 and 5.1.3.1 of this document.

5.1.4.2 Factors Affecting Performance. Design and operational factors affecting the NO_x emission control performance of combined LNB + OFA are the same as those discussed in sections 5.1.2.3 and 5.1.3.2, for the individual controls.

5.1.4.3 Performance of Low NO_x Burners and Overfire Air.

5.1.4.3.1 Retrofit applications. The results from several different types of retrofit LNB + OFA systems presented in table 5-6. The uncontrolled and controlled NO_x emission data presented in this table are averages from short-term tests (i.e., hours) or from longer periods (i.e., 2 to 4 months). All the boilers shown but one are pre-NSPS units. The LNCFS II system incorporates SOFA while the LNCFS III incorporates both CCOFA and SOFA. The PM system incorporates SOFA. The dual register LNB (DRB-XCL) and the CF/SF LNB on the wall-fired boilers also incorporate OFA.

For the three boilers with LNCFS II systems firing bituminous coal, the short-term controlled NO_x emissions range from 0.28 lb/MMBtu (Cherokee 4) to 0.4 lb/MMBtu (Lansing Smith 2) at full-load conditions. Long-term data for Lansing Smith 2 show 0.41 lb/MMBtu at full-load. At lower loads, the short-term controlled NO_x emissions range from a low of 0.33 (Cherokee 4) to a high of 0.75 lb/MMBtu (Valmont 5). Long-term data at reduced load for Lansing Smith 2 shows NO_x emissions of approximately 0.4 lb/MMBtu. The range of NO_x reduction for LNCFS II technology was approximately 35 to 50 percent at full-load.

For the boiler firing bituminous coal with LNCFS III systems (Lansing Smith 2), the short-term controlled NO_x emissions were 0.36 lb/MMBtu at full-load conditions while the long-term NO_x emissions for Lansing Smith 2 were

TABLE 5-6. PERFORMANCE OF LNB + OFA RETROFIT ON U. S. COAL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
TANGENTIALLY-FIRED BOILERS, BITUMINOUS COAL										
Public Service Co. of CO	Valmont 5 (Pre)	165	ABB-CE	LNCFS II (ABB-CE)	Short Short Short	106 73 50	0.66 0.65 1.03	0.32 0.48 0.75	52 26 27	56
Gulf Power Co.	Lansing Smith 2[i] (Pre)	200	ABB-CE	LNCFS II (ABB-CE)	Short Short Short	100 70 60	0.73 0.68 0.65	0.40 0.40 0.38	45 41 41	19
					Long Long Long	100 70 60	0.64 0.63 0.62	0.41 0.39 0.40	36 38 35	13, 55
Public Service Co. of CO	Cherokee 4 (Pre)	350	ABB-CE	LNCFS II (ABB-CE)	Short Short Short	100 70 43	0.52 0.45 0.51	0.28 0.31 0.33	46 31 35	57
Gulf Power Co.	Lansing Smith 2 (Pre)	200	ABB-CE	LNCFS III (ABB-CE)	Short Short Short	100 70 60	0.73 0.68 0.65	0.36 0.34 0.32	51 50 51	19
					Long Long Long	100 70 60	0.64 0.63 0.62	0.34 0.34 0.37	48 47 39	13, 55

TABLE 5-6. PERFORMANCE OF LNB + OFA RETROFIT ON U. S. COAL-FIRED UTILITY BOILERS (Continued)

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
TANGENTIALLY-FIRED BOILERS, BITUMINOUS/SUBBITUMINOUS BLEND										
Union Electric Co.	Labadie 4 (Pre)	620	ABB-CE	LNCFS III (ABB-CE)	Short Short Short	100 60 25	0.69 0.50 0.54	0.45 0.45 0.45	35 10 17	58
TANGENTIALLY-FIRED BOILERS, SUBBITUMINOUS COAL										
Kansas Power and Light Co.	Lawrence 5 (Pre)	448	ABB-CE	PM + OFA (CE-MHI)	Short	80	0.49	0.25	49[f]	59
					Long Long	50 33	0.47 0.49	0.19 0.14	60 71	59
PSI Energy Inc.	Gibson 1 (Pre)	668	FW	Atlas + OFA	Short	100	1.20-1.30	0.74-0.80	~38	60
PSI Energy Inc.	Gibson 3 (D)	668	FW	Atlas + OFA	Short	100	0.55-0.80	0.34-0.50	~38	60
WALL-FIRED BOILER, BITUMINOUS COAL										
Georgia Power Co.	Hammond 4 (Pre)	500	FW	CF/SF + AOFA	Short	90 60	1.20 1.00	0.5 0.5	58 50	61

TABLE 5-6. PERFORMANCE OF LNB + OFA RETROFIT ON U. S. COAL-FIRED UTILITY BOILERS (Concluded)

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
WALL-FIRED BOILER, BITUMINOUS COAL (Continued)										
Ohio Edison Co.	W.H. Sammis 6 (Pre)	623	B&W	DRB-XCL + SOFA (B&W)	Short	96 58	1.14-1.40 0.49	0.33-0.35 0.31	60-70 37	62, 63
ROOF-FIRED BOILER, SUBBITUMINOUS										
Public Service Co. of CO	Arapahoe 4 (Pre)	100	B&W	DRB-XCL + OFA (B&W)	Short	100 80 60	1.10 1.07 1.00	0.35 0.33 0.40	68 69 60	64

[a]Standard: Pre = Pre-NSPS

[b]OEM = Original Equipment Manufacturer. ABB-CE = Asea Brown Boveri - Combustion Engineering; B&W = Babcock and Wilcox; FW = Foster Wheeler.

[c]Control Type: DRB-XCL + SOFA = Dual Register-Axial Control with Separated Overfire Air; LNCFS II = Low NO_x Concentric Firing System, Level II, with separated overfire air; LNCFS III = Low NO_x Concentric Firing System, Level III, with close-coupled and separated overfire air; and PM = Pollution Minimum Burner; Atlas = Phoenix Combustion Atlas LNB; CF/SF + AOFA = Controlled Flow/Split Flame with advanced OFA.

[d]Vendors: CE-MHI = Combustion Engineering - Mitsubishi Heavy Industries. Refer to note "b" for others.

[e]Long = Long-term CEM data, i.e., 2-4 months. Short = Short-term test data, i.e., hours.

[f]Different coal was burned during the baseline testing (uncontrolled) and 49 percent reduction may not be an accurate depiction of the retrofit.

0.34 lb/MMBtu. At lower loads, the short-term NO_x emissions ranged from 0.32 to 0.45 lb/MMBtu while long-term data ranged from 0.34 to 0.37 lb/MMBtu. The range of NO_x reduction for the LNCFS III technology on bituminous coal was approximately 50 percent at full-load.

One boiler with LNCFS III technology (Labadie 4) burned a blend of bituminous and subbituminous coal. The short-term uncontrolled NO_x emissions were 0.54 to 0.69 lb/MMBtu across the load range and were reduced to 0.45 lb/MMBtu, or 10 to 35 percent. The LNCFS III system on Labadie 4 is still being tuned and long-term data are not yet available.

For the one boiler with the PM™ burner system firing subbituminous coal, the short-term controlled NO_x emissions at near full-load were 0.25 lb/MMBtu (49 percent NO_x reduction) and 0.14 to 0.19 lb/MMBtu (60 to 71 percent NO_x reduction) at lower loads. However, the baseline and post-retrofit coals are very different and the 49 percent reduction may not be an accurate depiction of the capabilities of the retrofit. The uncontrolled NO_x for Lawrence 5 was relatively consistent at 0.47 to 0.49 lb/MMBtu across the load range. However, the controlled NO_x was much less at the lower loads. This was due to the operators becoming familiar with the operation of the PM system and being able to greatly reduce excess air levels at the lower loads.[59]

Two similar tangentially-fired boilers (Gibson 1 and 3) have been retrofitted with the Atlas LNB with OFA. For both cases, the NO_x was reduced approximately 40 percent. Figure 5-19 shows that short-term controlled NO_x emissions across the load range for the tangential units with retrofit LNB + OFA. Several boilers (Labadie 4, Lansing Smith 2, and Cherokee 4) had NO_x emissions that increased or decreased slightly over the load range. However, one unit, Valmont 5, had substantially higher uncontrolled and controlled NO_x emissions at the lower loads. This may be due to the need for higher excess air levels at lower loads to maintain reheat and

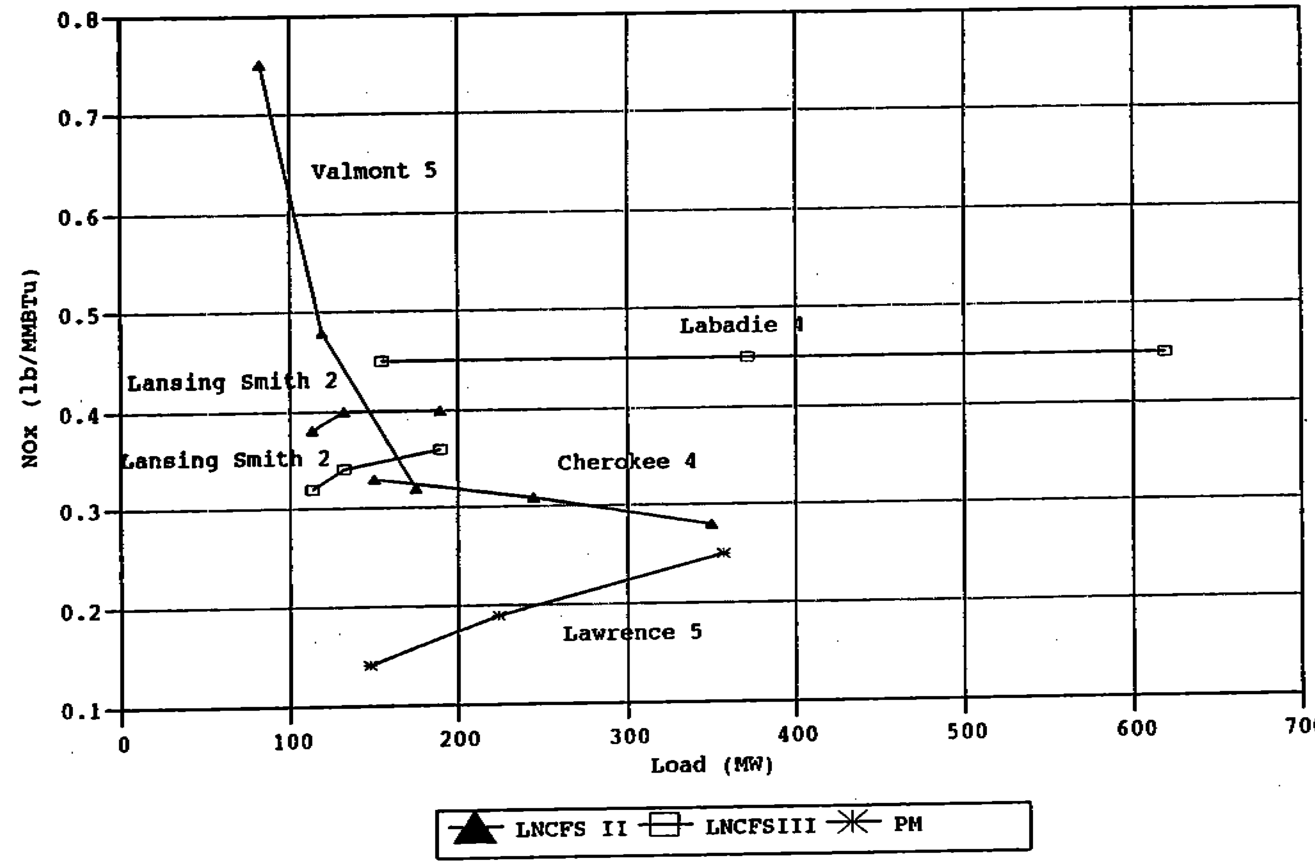


Figure 5-19. NO_x emissions from tangentially-fired boilers with retrofit LNB + OFA

superheat steam temperatures. To maintain the steam temperatures, the main coal and air nozzles tilt upward and this may contribute to the higher NO_x emissions at the lower loads. As previously mentioned, the NO_x decreased for the PM burner applications.

The wall-fired unit firing bituminous coal, W.H. Sammis 6, was originally a two-nozzle cell unit. The burner pattern was changed to a conventional opposed wall pattern during the installation of the LNB + SOFA system. The uncontrolled NO_x emissions at near full-load ranged from 1.1 to 1.4 lb/MMBtu, which is typical of cell boilers. With the DRB-XCL + SOFA, the NO_x emissions were reduced to approximately 0.35 lb/MMBtu, or 60 to 70 percent reduction. At reduced load, the uncontrolled NO_x level of 0.49 lb/MMBtu was reduced by 37 percent to 0.31 lb/MMBtu.

One roof-fired boiler is shown in table 5-6. Arapahoe 4 has completed an extensive retrofit of an DRB-XCL + OFA system. The uncontrolled NO_x level of 1.1 lb/MMBtu was reduced to 0.35 lb/MMBtu (68 percent) at full-load. At lower loads, the NO_x reduction was 60-70 percent. This boiler is also demonstrating SNCR as part of the U.S. DOE Innovative Clean Coal Technology program. The results of the combined control is presented in section 5.3.3.3.

To summarize, the LNCFS II technology reduced NO_x emissions by 40 to 50 percent and the LNCFS III technology reduced NO_x by 50 percent on bituminous coal-fired boilers. The LNCFS III technology reduced NO_x by 10 to 35 percent on a boiler firing a blend of bituminous and subbituminous coal. The PM™ burner reduced NO_x by 50 to 60 percent at full-load on subbituminous coal. And the combination of DRB-XCL + SOFA reduced NO_x by 65 to 70 percent on a wall-fired boiler firing bituminous coal. The Atlas LNB + OFA reduced NO_x by approximately 40 percent on a wall-fired boiler firing subbituminous coal.

5.1.4.3.2 New units. This section provides information on NO_x emissions from relatively new boilers with original LNB + OFA systems. The performance of original LNB + OFA on two new wall-fired boilers firing bituminous coal is given in table 5-7. Short-term averages of NO_x emissions for the units operating at near full-load range from 0.51 lb/MMBtu (Endicott Jr. 1) to 0.56 lb/MMBtu (Seminole 1). At lower loads, the NO_x ranged from 0.42 to 0.49 lb/MMBtu for Seminole 1.

5.1.5 Reburn and Co-Firing

5.1.5.1 Process Descriptions. Reburn is a combustion hardware modification in which the NO_x produced in the main combustion zone is reduced downstream in a second combustion zone. This is accomplished by withholding up to 40 percent of the heat input at the main combustion zone at full-load and introducing that heat input above the top row of burners to create a reburn zone. The reburn fuel (which may be natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone where the NO_x formed in the main combustion zone is reduced to nitrogen and water vapor. The fuel-rich combustion gases leaving the reburn zone are completely combusted by injecting overfire air (called completion air when referring to reburn) above the reburn zone. Figure 5-20 presents a simplified diagram of conventional firing and gas reburning applied to a wall-fired boiler.[67]

In reburning, the main combustion zone operates at normal stoichiometry (about 1.1 to 1.2) and receives the bulk of the fuel input (60 to 90 percent heat input). The balance of the heat input (10 to 40 percent) is injected above the main combustion zone through reburning burners or injectors. The stoichiometry in the reburn zone is in the range of 0.85 to 0.95. To achieve this, the reburn fuel is injected at a stoichiometry of 0.2 to 0.4. The temperature in the reburn

TABLE 5-7. PERFORMANCE OF LNB + OFA ON NEW U. S. COAL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Year online	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test (hrs)	Capacity tested (%)	NO_x emissions (lb/MMBtu)	Reference
WALL-FIRED BOILERS, BITUMINOUS COAL									
Michigan South Central Power Agency	Endicott Jr. 1 (Da)	1982	55	Bit.	DRB + OFA (B&W)	6	58	0.51	65
Seminole Electric Coop.	Seminole 1 (Da)	1984	680	Bit.	CF/SF + OFA (FW)	1 1	93 74	0.56 0.42-0.49	66

[a]Standard: Da = Subpart Da

[b]OEM = Original Equipment Manufacturer

[c]Control Type:
CF/SF + OFA = Controlled Flow/Split Flame LNB with OFA
DRB + OFA = Dual Register Burner with Overfire Air

[d]Vendors:
B&W = Babcock & Wilcox
FW = Foster Wheeler

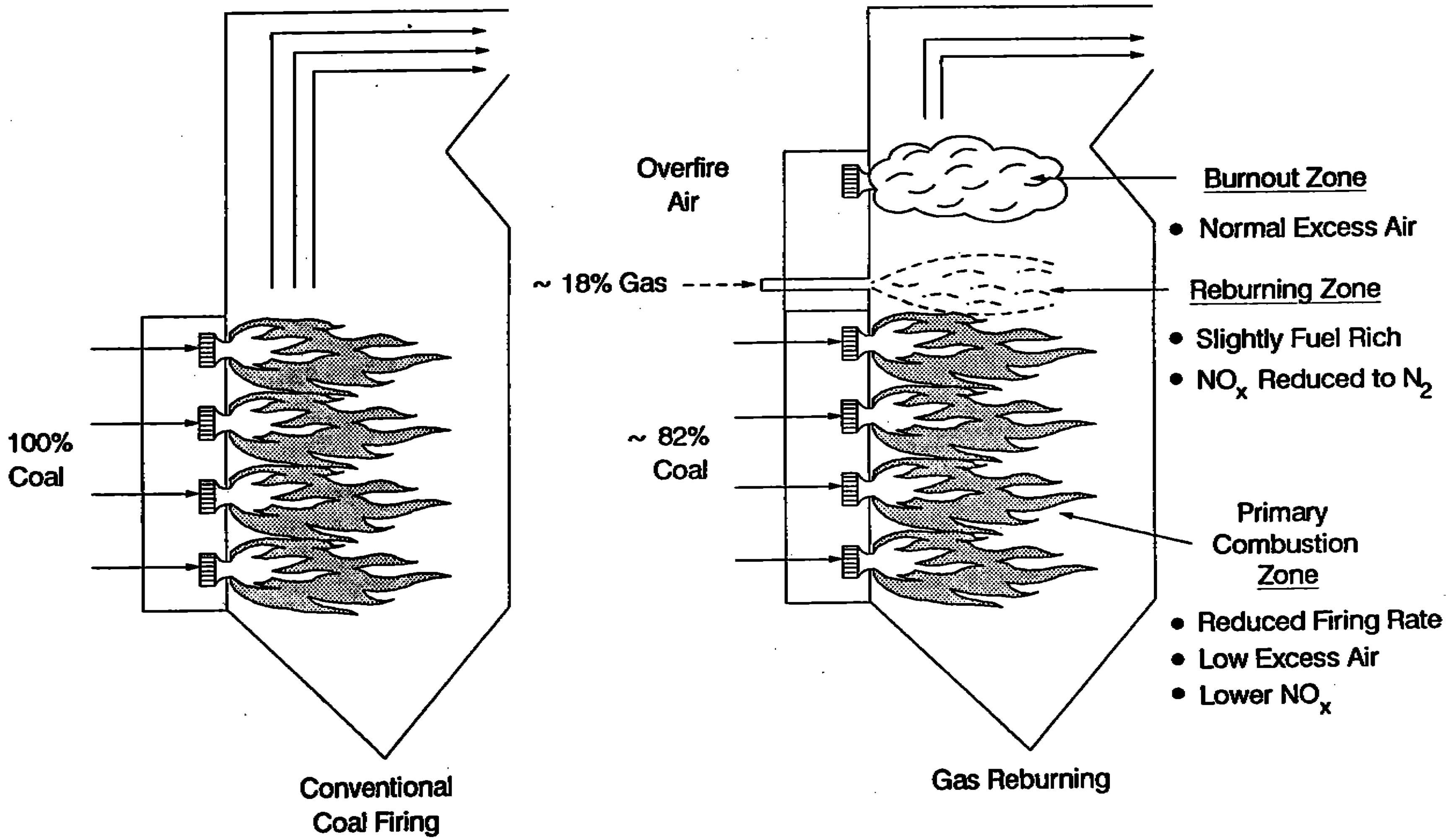


Figure 5-20. Application of natural gas reburn on a wall-fired boiler.[67]

zone must be above 980 ^oC (1,800 ^oF) to provide an environment for the decomposition of the reburn fuel.[68]

Any unburned fuel leaving the reburn zone is then burned to completion in the burnout zone, where overfire air (15 to 20 percent of the total combustion air) is introduced. The overfire air ports are designed for adjustable air velocities to optimize the mixing and complete burnout of the fuel before it exits the furnace.

The kinetics involved in the reburn zone to reduce NO_x are complex and not fully understood. The major chemical reactions are the following:[68]

$$CH_4 \xrightarrow{\text{heat}/O_2\text{ deficient}} \bullet CH_3 + \bullet H \text{ (hydrocarbon radicals)} \qquad (5\text{-}1)$$

The reaction process shown in equation 5-1 is initiated by hydrocarbon formation in the reburn zone. Hydrocarbon radicals are released due to the pyrolysis of the fuel in an O_2 deficient, high-temperature environment. The hydrocarbon radicals then mix with the combustion gases from the main combustion zone and react with NO to form (CN) radicals and other stable products (equations 5-2 to 5-4).[68]

$$\bullet CH_3 + NO \rightarrow HCN + H_2O \qquad (5\text{-}2)$$

$$N_2 + \bullet CH_3 \rightarrow \bullet NH_2 + HCN \qquad (5\text{-}3)$$

$$\bullet H + HCN \rightarrow \bullet CN + H_2 \qquad (5\text{-}4)$$

The CN radicals and the other products can then react with NO to form N_2, thus completing the major NO_x reduction step (equations 5-5 to 5-7).[68]

$$NO + \bullet NH_2 \rightarrow N_2 + H_2O \qquad (5\text{-}5)$$

$$NO + \bullet CN \rightarrow N_2 + CO \qquad (5\text{-}6)$$

$$NO + CO \rightarrow N_2 + \ldots. \qquad (5\text{-}7)$$

An O_2 deficient environment is important. If O_2 levels are high, the NO_x reduction mechanism will not occur and other reactions will predominate (equations 5-8 to 5-9).[68]

$$CN + O_2 \rightarrow CO + NO \qquad (5\text{-}8)$$

$$NH_2 + O_2 \rightarrow H_2O + NO \qquad (5\text{-}9)$$

To complete the combustion process, air must be introduced above the reburn zone. Conversion of (HCN) and ammonia compounds in the burnout zone may regenerate some of the decomposed NO_x by equations 5-10 to 5-11:[68]

$$HCN + 5/4\ O_2 \rightarrow NO + CO + 1/2\ H_2O \qquad (5\text{-}10)$$

$$NH_3 + 5/4\ O_2 \rightarrow NO + 3/2\ H_2O \qquad (5\text{-}11)$$

The NO_x may continue to be reduced by the HCN and NH_3 compounds in equations 5-12 to 5-13:[68]

$$HCN + 3/4\ O_2 \rightarrow 1/2\ N_2 + CO + 1/2\ H_2O \qquad (5\text{-}12)$$

$$NH_3 + 3/4\ O_2 \rightarrow 1/2\ N_2 + 3/2\ H_2O \qquad (5\text{-}13)$$

Reburning may be applicable to many types of boilers firing coal, oil, or natural gas as primary fuels in the boiler. However, the application and effectiveness are site-specific because each unit is designed to achieve specific steam conditions and capacity. Also, each unit is designed to handle a specific coal of range of coals. The type of reburn fuel can be the same as the primary fuel or a different fuel. For coal-fired boilers, natural gas is an attractive reburn fuel because it is nitrogen-free and therefore provides a greater potential NO_x reduction than a reburn fuel with a higher nitrogen content.[69] Natural gas must be supplied via pipeline and many plants utilize natural gas as ignition or startup fuel, space heating, or for firing other units. If natural gas is not available on-site, a pipeline would need to be installed; however, oil or pulverized coal may be used as alternative reburn fuels.[67]

As shown in figure 5-21, reburning may be applicable to cyclone furnaces that may not be adaptable to other NO_x reduction techniques such as LNB, LEA, or OFA without creating other operational problems.[69] Cyclone furnaces burn crushed coal rather than pulverized coal, and pulverizers would be required if coal is used as the reburn fuel.

Reburning does not require any changes to the existing burners or any major operational changes. The major requirement is that the fuel feed rate to the main combustion

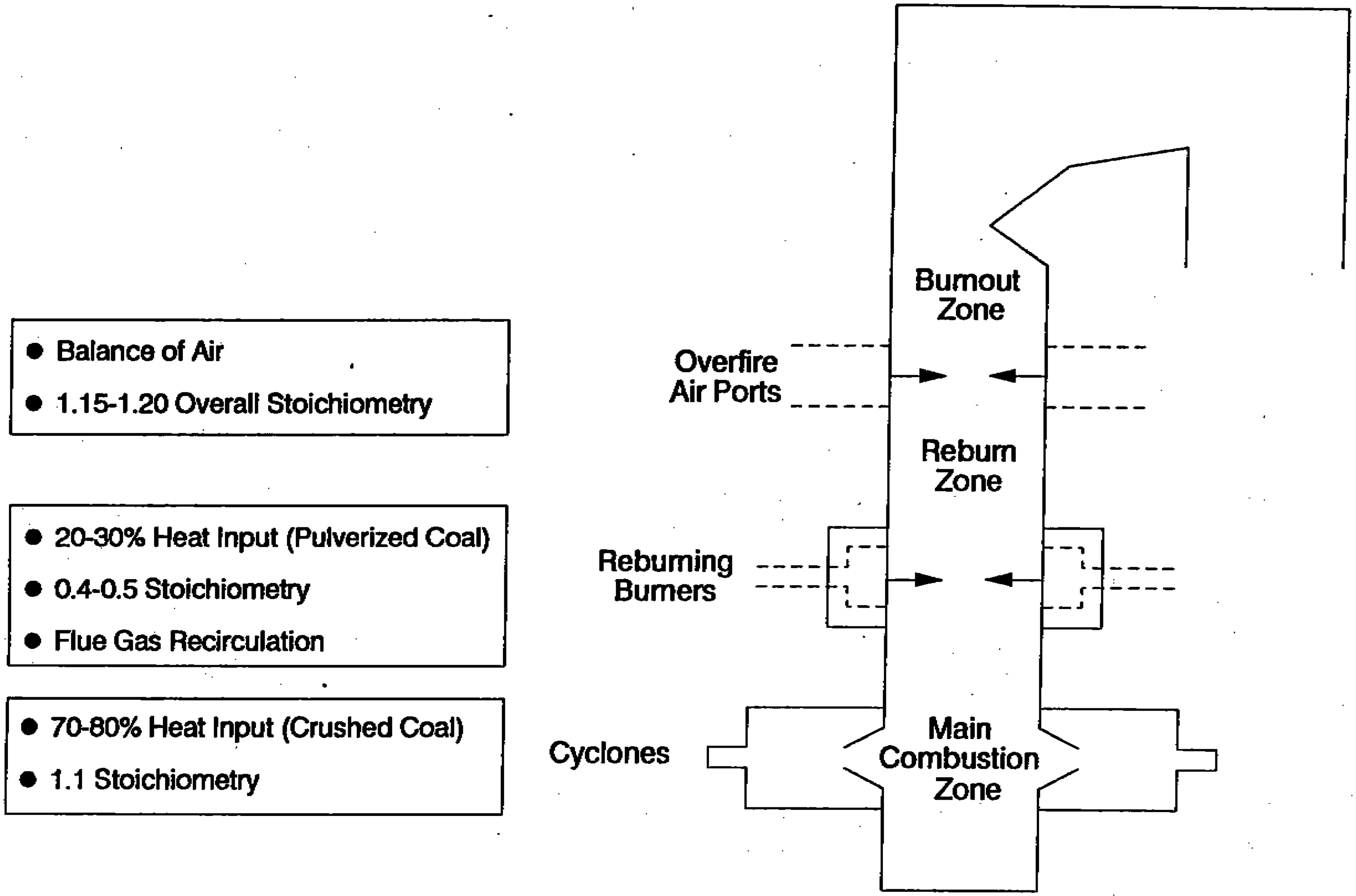


Figure 5-21. Application of reburn on a cyclone furnace.[69]

zone be reduced and an equivalent amount of fuel (on a heat input basis) be fed to the reburn burners in the reburn zone. Reburn fuel heat input usually accounts for no more than 20 percent with natural gas or oil as the reburn fuel and usually no more than 35 percent with coal as the reburn fuel.

Several reburning systems are available from different vendors for coal-fired applications. Key components of these reburn systems include reburn fuel burners for coal or oil reburn fuel or injectors for natural gas reburn fuel and associated piping and control valves. The Digital Control System is also a necessary part of the reburn system. If flue gas is used as the reburn fuel carrier gas, then fans, ductwork, controls, dampers, and a windbox are also needed in the reburn zone. Key components of the burnout zone include ductwork, control dampers, a windbox, and injectors or air nozzles. Injectors for the reburn fuel and overfire air require waterwall modifications for installation of the ports.

Natural gas co-firing consists of injecting and combusting natural gas near or concurrently with the main coal, oil, or natural gas fuel. At many sites, natural gas is used during boiler start-up, stabilization, or as an auxiliary fuel. Co-firing may have little impact to the overall boiler performance since the natural gas is combusted at the same locations as the main fuel. Figure 5-22 shows an example of a co-firing application on a wall-fired boiler.[70]

5.1.5.2 Factors Affecting Performance. The reburn system design and operation can determine the effectiveness of a reburn application. Reburn must be designed as a "system" so that the size, number, and location of reburn burners and overfire air ports are optimized. A successful design can be accomplished through physical and numerical modeling. The system must be capable of providing good mixing in the reburn burnout zones, so that maximum NO_x reduction and complete fuel burnout is achieved. Also, penetration of the reburn fuel into hot flue gas must be accurately directed because over-

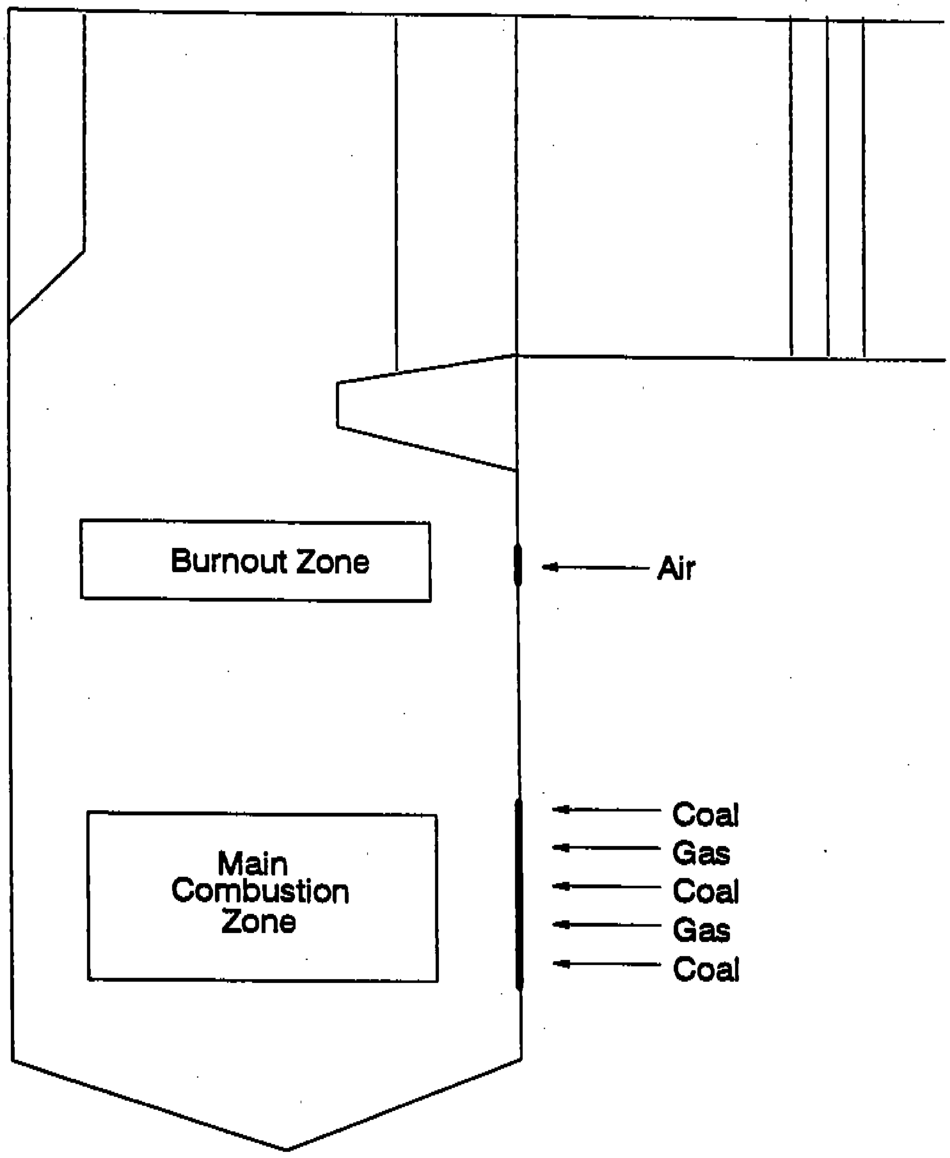


Figure 5-22. Gas cofiring applied to a wall-fired boiler.[70]

penetration or under-penetration could result in tube wastage and flame instability.[68]

Operational parameters that affect the performance of reburn include the reburn zone stoichiometry, residence time in the reburn zone, reburn fuel carrier gas, and the temperature and O_2 level in the burnout zone. Decreasing the reburn zone stoichiometry can reduce NO_x emissions. However, decreasing the stoichiometry requires adding a larger portion of fuel to the reburn zone, which can adversely affect upper furnace conditions by increasing the furnace exit gas temperature.

As previously described, flue gas may be used to inject the reburn fuel into the reburn zone. Flue gas recirculation (FGR) rate to the reburning burners can affect NO_x reduction. Coal reburning is more sensitive to the FGR rate than natural gas or oil reburning, possibly because of coal nitrogen in the reburning coal portions. When FGR is not used, NO_x is formed through the volatile flame attached to the reburn burner. However when FGR is used, mixing is improved and the NO_x formation in the volatile reburning flame is reduced.

A main controlling factor in reducing NO_x emissions with reburn is the residence time in the reburn zone. The reburn fuel and combustion gases from the main zone must be mixed thoroughly for reactions to occur. If thorough mixing occurs, the residence time in this zone can be minimized.[68] The furnace size and geometry determines the placement of reburn burners and overfire air ports, which will ultimately influence the residence time in the reburn zone.

The temperature and O_2 levels in the burnout zone are important factors for the regeneration or destruction of NO_x in this area. Low temperature and O_2 concentrations promote higher conversion of nitrogen compounds to elemental nitrogen. However, high carbon losses occur at low concentrations of O_2 and lower temperatures. The burnout zone also requires sufficient residence time for O_2 to mix and react with combustibles from the furnace before entering the convective pass to reduce unburned carbon.[68]

5.1.5.3 Performance of Reburn. Results from two natural gas and one pulverized coal reburn retrofit installation are given in table 5-8. All three boilers burn bituminous coal. For the natural gas reburn application on a tangentially-fired boiler (Hennepin 1) firing bituminous coal, the short-term data indicate that NO_x emissions at full-load are 0.22 lb/MMBtu, corresponding to a 63 percent reduction. The long-term data collected during 3 to 55 hour periods averaged 0.23 lb/MMBtu at loads of 53 to 100 percent. This unit averaged 60 percent NO_x reduction.

There is one application of natural gas reburn on a wall-fired boiler, Cherokee 3, and this unit also has retrofit LNB with reburn, the NO_x was reduced approximately 60 percent to 0.2 lb/MMBtu from the control levels with LNB.

For the natural gas reburn on a cyclone boiler, Niles 1, the long-term data indicate NO_x emissions are in the range of 0.50 to 0.60 lb/MMBtu at 75 to 100 percent load. Niles reported that maximum NO_x reductions (approximately 50 percent) are only achievable at, or near, maximum load capacity because as the load was reduced, the reburn performance degraded and could not be operated at less than 75 percent load. This is due to the reburn-fuel mixing limitations and temperatures required to enable the slag to run in the furnace. This situation may be boiler- or fuel-specific.

There was a substantial buildup of slag on the back wall at Niles (even covering the reburn ports) and substantial changes had to be made to the reburn equipment design. After all the changes were made in design and optimization of the system was completed, the full-load NO_x reduction at Niles averaged 47 percent at full load and 36 percent at 75 percent load. There was no NO_x reduction noted at less than

TABLE 5-8. PERFORMANCE OF REBURN AND CO-FIRING ON U. S. COAL-FIRED UTILITY BOILERS

Utility	Unit (standard[a])	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
TANGENTIALLY-FIRED BOILERS, BITUMINOUS COAL										
Illinois Power Co.	Hennepin 1 (Pre)	75	ABB-CE	NGR (EERC)	Short[e] Long[f]	100 53-100	0.59 0.57	0.22 0.23	63 60	71
TANGENTIALLY-FIRED BOILERS, SUBBITUMINOUS COAL										
Kansas Power & Light	Lawrence 5 (Pre)	448	ABB-CE	Gas Co-firing	Short Short	55-65 55-65	0.22-0.24 0.22-0.24	0.15-0.18 0.14	20-30 35	70
WALL-FIRED BOILERS, SUBBITUMINOUS COAL										
Public Service Co. of CO	Cherokee 3 (Pre)	172	B&W	IFS + NGR	Short[e]	90	0.50	0.20	60	72
CYCLONE-FIRED BOILERS, BITUMINOUS COAL										
Wisconsin Power and Light Co.	Nelson Dewey 2 (Pre)	110	B&W.	Coal Reburn (B&W)	Short[e] Short[e] Short[e]	100 74 50	0.83 0.72 0.69	0.39 0.36 0.44	53 50 36	73, 74
Ohio Edison Co.	Niles 1 (Pre)	114	B&W	NGR (ABB-CE)	Long[g] Long[g] Long[g] Long[g]	100 85 79 75[h]	0.95 0.95 0.91 0.90	0.50 0.54 0.60 0.58	47 43 34 36	75

[a]Standard: Pre = Pre-NSPS
[b]OEM = Original Equipment Manufacturer
[c]Control Type: Coal Reburn = Pulverized Coal Reburn; and NGR = Natural Gas Reburn.
[d]Vendors: ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock and Wilcox; and EERC = Energy and Environmental Research Corporation
[e]Hours.
[f]3-55 hours.
[g]6-8 days.
[h]Reburn system could not be operated below 75 percent load.

75 percent load. The reburn system was removed in August 1992, 2 years after installation.

The remaining reburn application is a pulverized coal reburn system on a cyclone boiler (Nelson Dewey 2). The short-term NO_x emissions at full-load were 0.38 lb/MMBtu (55 percent NO_x reduction) when burning bituminous coal. As noted with the previous application, the NO_x emissions were reduced at mid-load levels and then increased at low loads. At 73 percent load, the NO_x emissions were 0.35 lb/MMBtu (36 percent reduction) and at half load, the NO_x emissions were 0.49 lb/MMBtu. It was reported that when burning a western, Powder River Basin Coal, a 50 percent reduction was achieved over the load range. This further emphasis that the NO_x reduction with reburn is both fuel- and boiler-specific. The results of the reburn applications are shown in figure 5-23.

The one co-firing application on table 5-8 is Lawrence 5. Lawrence 5 was retrofitted with the PM LNB system in 1987 and consists of five levels of PM coal nozzles. Full-load natural gas firing is available through natural gas elevations between the coal elevations. Separated OFA is also part of the PM LNB system. By selective co-firing with 10 percent natural gas, the NO_x was reduced 29 to 30 percent from the controlled levels with the PM LNB system. With 20 percent co-firing, the NO_x was reduced an additional 5 percent.

5.1.6 Low NO_x Burners and Reburn

5.1.6.1 Process Description. Reburn technology can also be combined with LNB to further reduce NO_x emissions through additional staging of the combustion process. This staging is accomplished by reducing the fuel fed to the LNB to approximately 70-85 percent of the normal heat input and introducing the remainder of the fuel in the reburn zone. Combustion of the unburned fuel leaving the reburn zone is then completed in the burnout zone, where additional combustion air is introduced. Detailed descriptions of LNB

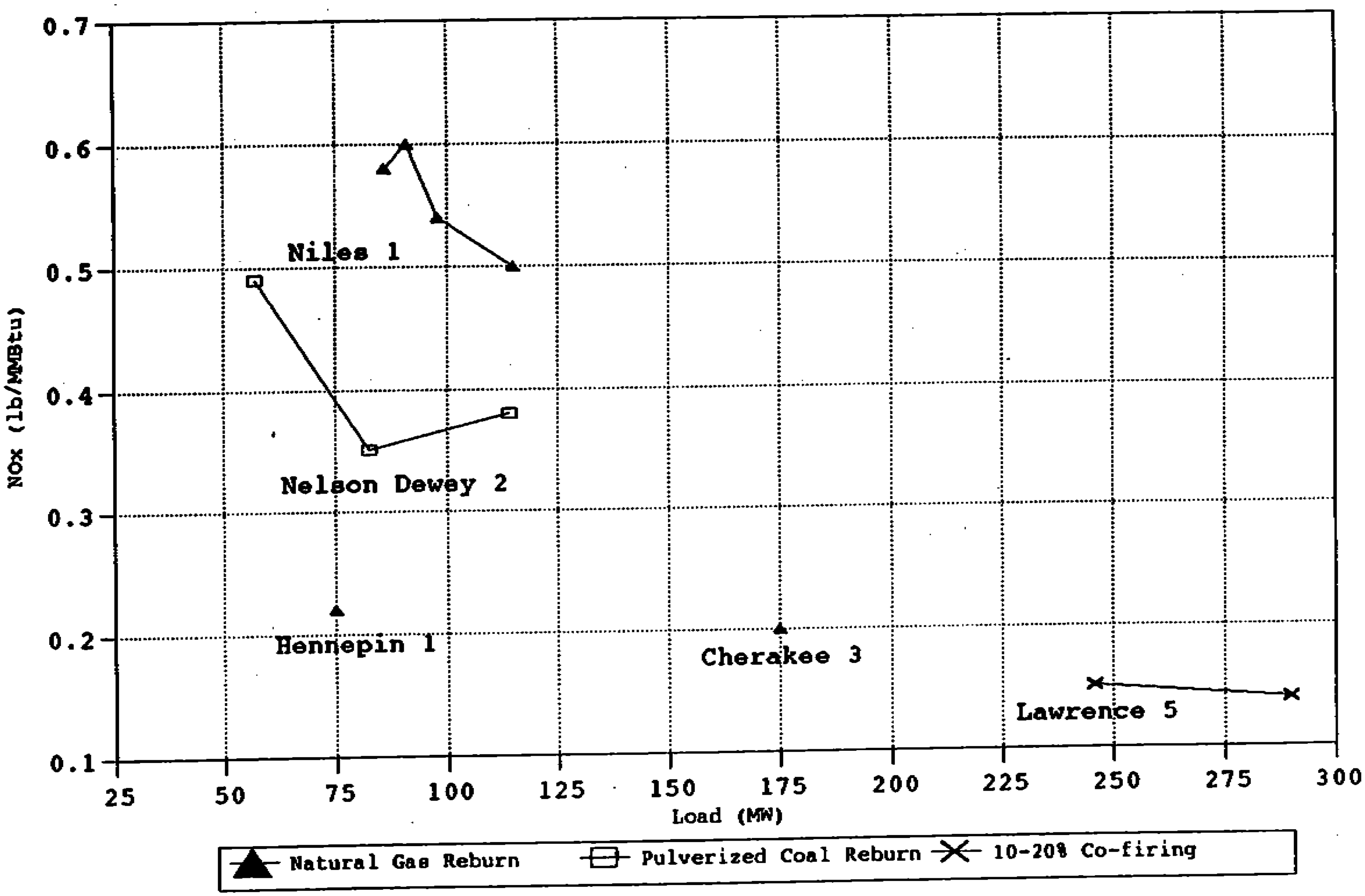


Figure 5-23. Controlled NO_X emissions from coal-fired boilers with retrofit reburn systems.

and reburn technology are provided in sections 5.1.3.1 and 5.1.5.1, respectively.

5.1.6.2 Factors Affecting Performance. Design and operational factors affecting the NO_x emission control performance of combined LNB and reburn systems are the same as discussed in sections 5.1.3.2 and 5.1.5.2, for the individual controls.

5.1.6.3 Performance of Low NO_x Burners and Reburn. There is one application of LNB and natural gas reburn on a coal-fired boiler at the Public Service Company of Colorado's Cherokee Station Unit 3. This is a U.S. DOE Innovative Clean Coal Technology Project on a 150 MW pre-NSPS wall-fired boiler that was predicting a 75-percent decrease in NO_x emissions.[76] Short-term test data shows an overall 72 percent reduction from uncontrolled levels. The NO_x was reduced by 31 percent with LNB to 0.5 lb/MMBtu and by 60 percent with reburn to 0.2 lb/MMBtu.

5.2 COMBUSTION CONTROLS FOR NATURAL GAS- AND OIL-FIRED UTILITY BOILERS

Most of the same NO_x control techniques used in coal-fired utility boilers are also used in natural gas- and oil-fired utility boilers. These techniques include operational modifications such as LEA, BOOS, and BF; OFA; LNB; and reburn. However, in natural gas- and oil-fired boilers, a combination of these controls is typically used rather than singular controls. Refer to section 5.1 for a general discussion of these NO_x controls. Additionally, windbox FGR is a combustion control that is used on natural gas- and oil-fired boilers that is not used on coal-fired boilers. Windbox FGR will be described in section 5.2.2.

5.2.1 Operational Modifications

5.2.1.1 Process Description. Operational modifications are more widely implemented to reduce NO_x emissions from natural gas- and oil-fired utility boilers than from coal-fired boilers. Because the nitrogen content of natural gas and oil is low compared to coal, the majority of the NO_x emitted from natural gas and oil-fired boilers is the result of thermal NO_x generation, which can be minimized by reducing the available O_2 and the peak temperature in the combustion zone. Since operational modifications promote these conditions, and natural gas and oil combustion is less sensitive than coal to variations in operating parameters, operational modifications are effective, low-cost NO_x control techniques for natural gas- and oil-fired boilers.

The process descriptions of LEA, BOOS, and BF are the same for natural gas- and oil-fired boilers as for coal-fired boilers as was discussed in section 5.1.1.1.

5.2.1.2 Factors Affecting Performance. As discussed in section 5.1.1.2, implementation of LEA, BOOS, and BF techniques involve changes to the normal operations of the boiler, which may result in undesirable side-effects. As mentioned above, natural gas- and oil-fired boilers are less sensitive to operation outside the "normal range." However, the factors affecting the performance of operational modifications in natural gas- and oil-fired boilers are similar to those discussed for coal-fired units.

The appropriate level of LEA for natural gas- and oil-fired boilers is unit specific. Usually, however, LEA levels are lower than can be achieved with coal-fired boilers because flame instability and furnace slagging do not determine minimum excess air levels in natural gas- and oil-fired boilers. The LEA levels in these boilers are typically defined by the acceptable upper limit of CO and UBC emissions.

Although NO_x reductions can be achieved with BOOS and BF, these operational modifications often slightly degrade the performance of the boiler because excess air levels must be sufficiency high enough to prevent elevated levels of CO, hydrocarbons, and unburned carbon emissions resulting from abnormal operating conditions. For this reason, monitoring flue gas composition, especially O_2 and CO concentrations, is very important when employing operational modifications for

NO_x control. Because flame instability can occur, the BOOS or BF pattern, including the degree of staging of each of the burners still in service, must be appropriate for optimal boiler performance.

During BOOS operation, the air admitted through the upper burner to complete the fuel burnout is generally at low preheat levels and low supply pressure (windbox pressure), so it mixes inefficiently with the combustion products, causing high CO emissions or high excess air operation. If the boiler is operated at high excess air levels to maintain reasonable CO emission levels, the degree of combustion staging and NO_x control is reduced. Operating at high excess O_2 also reduces boiler efficiency. Therefore, a trade-off between low NO_x emissions and high boiler efficiency must be managed.[77]

With BF, the fuel-lean burners provide a combustion zone with a preheated source of O_2 to complete the oxidation of the unburned fuel from the first combustion zone. The preheating of this O_2 source enhances the penetration and mixing of this additional O_2 and promotes the complete burnout of fuel at lower excess air levels. In addition, the combustion stoichiometry in the second combustion zone is more uniform, reducing the O_2 imbalances experienced with BOOS operation.[77]

5.2.1.3 Performance of Operation Modifications. Table 5-9 presents data for BOOS, LEA, and combination of BOOS and LEA for natural gas and oil wall-fired boilers. For the single oil-fired boiler (Kahe 6), BOOS reduced the NO_x emissions from 0.81 lb/MMBtu to 0.50 lb/MMBtu (38 percent). For the natural gas-fired boiler (Alamitos 6), BOOS reduced the NO_x from 0.90 lb/MMBtu to 0.19 lb/MMBtu (79 percent).

For LEA application on two wall-fired boilers firing natural gas (S.R. Berton 2 and Deepwater 9), the NO_x was reduced to levels of 0.24 to 0.28 lb/MMBtu (7 to 40 percent). Combining LEA + BOOS on natural gas-fired boilers reduced the NO_x emissions to 0.24 to 0.52 lb/MMBtu (39 to 67 percent).

TABLE 5-9. PERFORMANCE OF BOOS + LEA ON U. S. NATURAL GAS- AND OIL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c]	Length of test[d]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
WALL-FIRED BOILERS, FUEL OIL										
Hawaiian Electric Co.	Kahe 6 (D)	146	B&W	BOOS	Short	92	0.81	0.50	38	78
WALL-FIRED BOILERS, NATURAL GAS										
Southern California Edison Co.	Alamitos 6 (Pre)	495	B&W	BOOS	Short	100	0.90[e]	0.19	79	79
Houston Lighting & Power Co.	S.R. Bertron 2 (Pre)	180	RS	LEA	Short	100	0.30	0.28	7	1
Houston Lighting & Power Co.	Deepwater 9 (Pre)	185	RS	LEA	Short	100	0.40	0.24	40	1
Houston Lighting & Power Co.	S.R. Bertron 1 (Pre)	180	ABB-CE	LEA + BOOS	Short	100	1.03	0.34	67	1
Houston Lighting & Power Co.	W.A. Parrish 1 (Pre)	183	ABB-CE	LEA + BOOS	Short	100	0.85	0.29	66	1
Houston Lighting & Power Co.	W.A. Parrish 2 (Pre)	183	ABB-CE	LEA + BOOS	Short	100	0.73	0.24	67	1
Houston Lighting & Power Co.	W.A. Parrish 3 (Pre)	290	FW	LEA + BOOS	Short	100	0.73	0.21	71	1
TURBO-FIRED BOILERS, NATURAL GAS										
Houston Lighting & Power Co.	Webster 3 (Pre)	390	Natural Gas	LEA + BOOS	Short	100	0.85	0.52	39	1

[a]Standard: Da = Subpart Da; and Pre = Pre-NSPS
[b]OEM = Original Equipment Manufacturer; ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock & Wilcox; FW = Foster Wheeler; and RS = Riley Stoker
[c]Type Control: BOOS = Burners-out-of-service; and LEA = Low Excess Air
[d]Short = Short-term test data, i.e., hours.
[e]Value is an estimate, based on historical data

In general, the higher the baseline NO_x emissions, the higher percent NO_x reduction was achieved with this type of operational modifications. While some boilers may have achieved higher reductions in NO_x emissions, proper implementation of BOOS + LEA may achieve 30 to 50 percent reduction with no major increase in CO or particulate emissions. However, effectiveness of BOOS is boiler-specific and not all boilers may be amenable to the distortion in fuel/air mixing pattern imposed by BOOS due to their design type or fuel characteristics. Boilers originally designed for coal and then converted to fuel-oil firing may better accommodate BOOS (and LEA) than boilers with smaller furnaces.

5.2.2 Flue Gas Recirculation

5.2.2.1 Process Description. Flue gas recirculation is a flame-quenching strategy in which the recirculated flue gas acts as a thermal diluent to reduce combustion temperatures. It also reduces excess air requirements, thereby reducing the concentration of O_2 in the combustion zone. As shown in figure 5-24, FGR involves extracting a portion of the flue gas from the economizer or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both.[79] To reduce NO_x, the flue gas is injected into the windbox. For coal-fired boilers operating at peak boiler capacity, flue gas is commonly readmitted through the furnace hopper or above the windbox to control the superheater steam temperature; however, this method of FGR does not reduce NO_x emissions. Windbox FGR is most effective for reducing thermal NO_x only and is not used for NO_x control on coal-fired boilers in which fuel NO_x is a major contributor.

The degree of FGR is variable (10 to 20 percent of combustion air) and depends upon the output limitation of the forced draft (FD) fan (i.e., combustion air source which directly feeds the boiler). This is particularly true for units in which FGR was originally installed for steam temperature control rather than for NO_x control.[80] The FGR

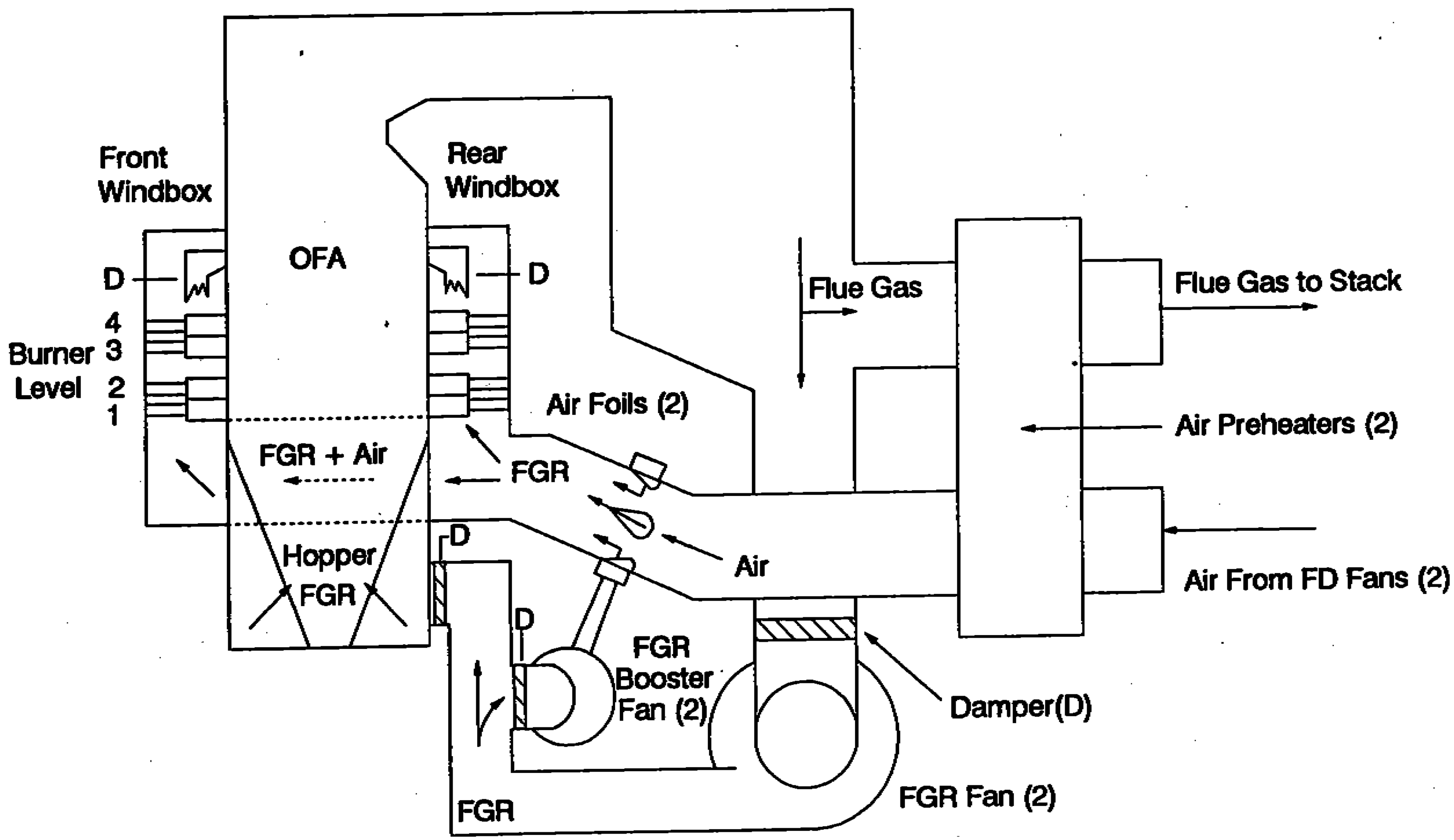


Figure 5-24. Flue gas recirculation system.[79]

fans are located between the FD fans and the burner windbox. The FGR is injected into the FD fan ducting and then distributed within the windbox to the burners. As the fan flow is increased, the pressure within the furnace increases. At some level, the fans are unable to provide sufficient combustion air to the windbox. This results in overpressurization of the boiler and a possible unit de-rate.[1]

5.2.2.2 Factors Affecting Performance. To maximize NO_x reduction, FGR is routed through the windbox to the burners, where temperature suppression can occur within the flame. The effectiveness of the technique depends on the burner heat release rate and the type of fuel being burned. When burning heavier fuel oils, less NO_x reduction would be expected than when burning natural gas because of the higher nitrogen content of the fuel.

Flue gas recirculation for NO_x control is more attractive for new boilers than as a retrofit. Retrofit hardware modifications to implement FGR include new ductwork, a recirculation fan, devices to mix flue gas with combustion air, and associated controls. In addition, the FGR system itself requires a substantial maintenance program due to the high temperature environment and potential erosion from entrained ash.

5.2.2.3 Performance of Flue Gas Recirculation. Table 5-10 presents data for FGR applied to one tangentially-fired boiler and three wall-fired boilers. It should be noted that FGR is usually used in combination with other modifications or controls (i.e., LEA, BOOS, OFA, or LNB) and little data are available for FGR alone. At full-load, the FGR reduced NO_x emissions to 0.42 lb/MMBtu on the wall-fired boiler firing fuel oil for a NO_x reduction of 48 percent. Flue gas recirculation applied to a tangentially-fired boiler firing natural gas reduced NO_x by 25 to 50 percent across the load range with FGR on wall-fired boilers firing natural gas, the NO_x reduced by more than 50 percent.

TABLE 5-10. PERFORMANCE OF FGR ON U. S. NATURAL GAS- AND OIL-FIRED BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	References
TANGENTIALLY-FIRED BOILERS, NATURAL GAS										
Southern Cal. Edison Co.	Etiwanda 3 (Pre)	320	ABB-CE	FGR	Short	100 50 20	0.08 0.04 0.03	0.06[f] 0.02[f] 0.02[f]	25 50 33	81
WALL-FIRED BOILERS, FUEL OIL										
Hawaiian Electric Co.	Kahe 6 (D)	146	B&W	FGR (B&W)	Short	92	0.81	0.42	48	78
WALL-FIRED BOILERS, NATURAL GAS										
Southern Cal. Edison Co.	Alamitos 6 (Pre)	495	B&W	FGR	Short	100	0.19[g]	0.08[g]	58	79
Southern Cal. Edison Co.	Alamitos 6 (Pre)	495	B&W	FGR	Short	100	0.22[h]	0.10[h]	54	79

[a]Standard: Da = Subpart Da; and Pre = Pre-NSPS

[b]OEM = Original Equipment Manufacturer; and B&W = Babcock & Wilcox.

[c]Type Control: FGR = Flue Gas Recirculation

[d]Vendors: B&W = Babcock & Wilcox

[e]Short = Short-term test data, i.e., hours.

[f]Increased flue gas recirculation rate.

[g]Estimated uncontrolled emissions with BOOS only. Controlled emissions with BOOS and FGR.

[h]Extrapolated uncontrolled emissions with LNB only. Controlled emissions with LNB and FGR.

5.2.3 Overfire Air

5.2.3.1 Process Description. The same types of OFA systems are used for natural gas- and oil-firing as was described for coal-firing in section 5.1.2.1.

5.2.3.2 Factors Affecting Performance. Boilers characterized by small furnaces with high heat release rates typically have insufficient volume above the top burner row to accommodate OFA ports and still complete combustion within the furnace. With some units, retrofitting with OFA would make it necessary to derate and modify the superheater tube bank to minimize changes in the heat absorption profile of the boiler. For these small boilers, BOOS can offer similar NO_x reduction at a fraction of the cost.

The factors that affect OFA performance for natural gas- and oil-fired boilers are the same as those described for coal-fired boilers in section 5.1.2.2.

5.2.3.3 Performance of Overfire Air. Data for OFA on natural gas-fired boilers are presented in table 5-11. These units were typically operated with LEA; therefore, the controlled NO_x emissions are for OFA + LEA. For the tangentially-fired boilers, the NO_x was reduced to 0.11 to 0.19 lb/MMBtu at full-load with OFA + LEA (10 to 46 percent reduction). The wall-fired boiler had a higher uncontrolled NO_x level and was reduced to 0.54 lb/MMBtu with OFA + LEA (48 percent reduction). The OFA application on a wall-fired boiler firing fuel oil was approximately 20 percent.

5.2.4 Low NO_x Burners

5.2.4.1 Process Description. The fundamental NO_x reduction mechanisms in natural gas- and oil-fired LNB are essentially the same as those in coal-fired LNB discussed in section 5.1.3.1. However, many vendors of LNB for oil- and natural gas-fired boilers incorporate FGR as an integral part of the LNB. Low NO_x burners are appealing options for natural gas- and oil-fired utility boilers because they can eliminate many of the boiler operating flexibility restraints associated with BOOS, BF, and OFA.

TABLE 5-11. PERFORMANCE OF OFA + LEA ON U. S. NATURAL GAS- AND OIL-FIRED BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c]	Length of test[d]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
WALL-FIRED BOILERS, FUEL OIL										
Hawaiian Electric Co.	Kahe 6 (D)	146	B&W	OFA + LEA	Sort	92	0.51[e]	0.4[e]	21	78
TANGENTIALLY-FIRED BOILERS, NATURAL GAS										
Houston Lighting & Power Co.	S.R. Berton 3 (Pre)	240	ABB-CE	OFA + LEA	Short	100	0.21	0.19	10	82
Houston Lighting & Power Co.	S.R. Berton 4 (Pre)	240	ABB-CE	OFA + LEA	Short	100	0.19	0.11	42	82
Houston Lighting & Power Co.	T.H. Warton 2 (Pre)	240	ABB-CE	OFA + LEA	Short	100	0.22	0.12	46	82
WALL-FIRED BOILERS, NATURAL GAS										
Houston Lighting & Power Co.	P.H. Robinson 3 (Pre)	490	FW	OFA + LEA	Short	100	1.03	0.54	48	82

[a]Standard: Pre = Pre-NSPS

[b]OEM = Original Equipment Manufacturer; ABB-CE = Asea Brown Boveri-Combustion Engineering; and FW = Foster Wheeler

[c]Type Control: LEA = Low Excess Air; and OFA = Overfire Air

[d]Short = Short-term test data, i.e., hours.

[e]Uncontrolled NO_x is with LNB and controlled is with LNB + OFA.

5.2.4.1.1 Wall-fired boilers. As with coal-fired LNB, there are a number of different natural gas- and oil-fired LNB available from manufacturers. Several of these are discussed below.

The wall-fired ROPM™ burner for natural gas- or oil-firing is shown in figure 5-25.[83] Combustion in a ROPM™ burner is internally staged, and takes place in two different zones; one under fuel-rich conditions and the other under fuel-lean conditions. Gaseous fuel burns under pre-mixed conditions in both the fuel-lean and fuel-rich zones. With liquified fuels, however, burning occurs under diffused-flame conditions in the fuel-rich mixture to maintain a stable flame.

The natural gas-fired ROPM™ burner generates a fuel-rich flame zone surrounded by a fuel-lean zone. The burner register is divided into two sections. Natural gas and combustion air supplied via an internal cylindrical compartment produces the fuel-rich flame. The fuel and air supplied via the surrounding annular passage produces the fuel-lean zone.[83]

The oil-fired ROPM™ burner uses a unique atomizer that sprays fuel at two different spray angles, creating two concentric hollow cones. The inner cone creates a fuel-rich flame zone; the outer cone forms the fuel-lean flame zone. The inner fuel-rich flame zone has diffusion flame characteristics that help maintain overall flame stability. The ROPM™ burner technology generally relies on a combination of ROPM™ burners and FGR to achieve NO_X reductions.[83]

The Dynaswirl™ burner for wall-fired boilers divides combustion air into several component streams and controls injection of fuel into the air streams at selected points to maintain stable flames with low NO_X generation. Figure 5-26 schematically illustrates the internal configuration of the burner.[79] For natural gas-firing, fuel is introduced through six pipes, or pokers, fed from an external manifold. The

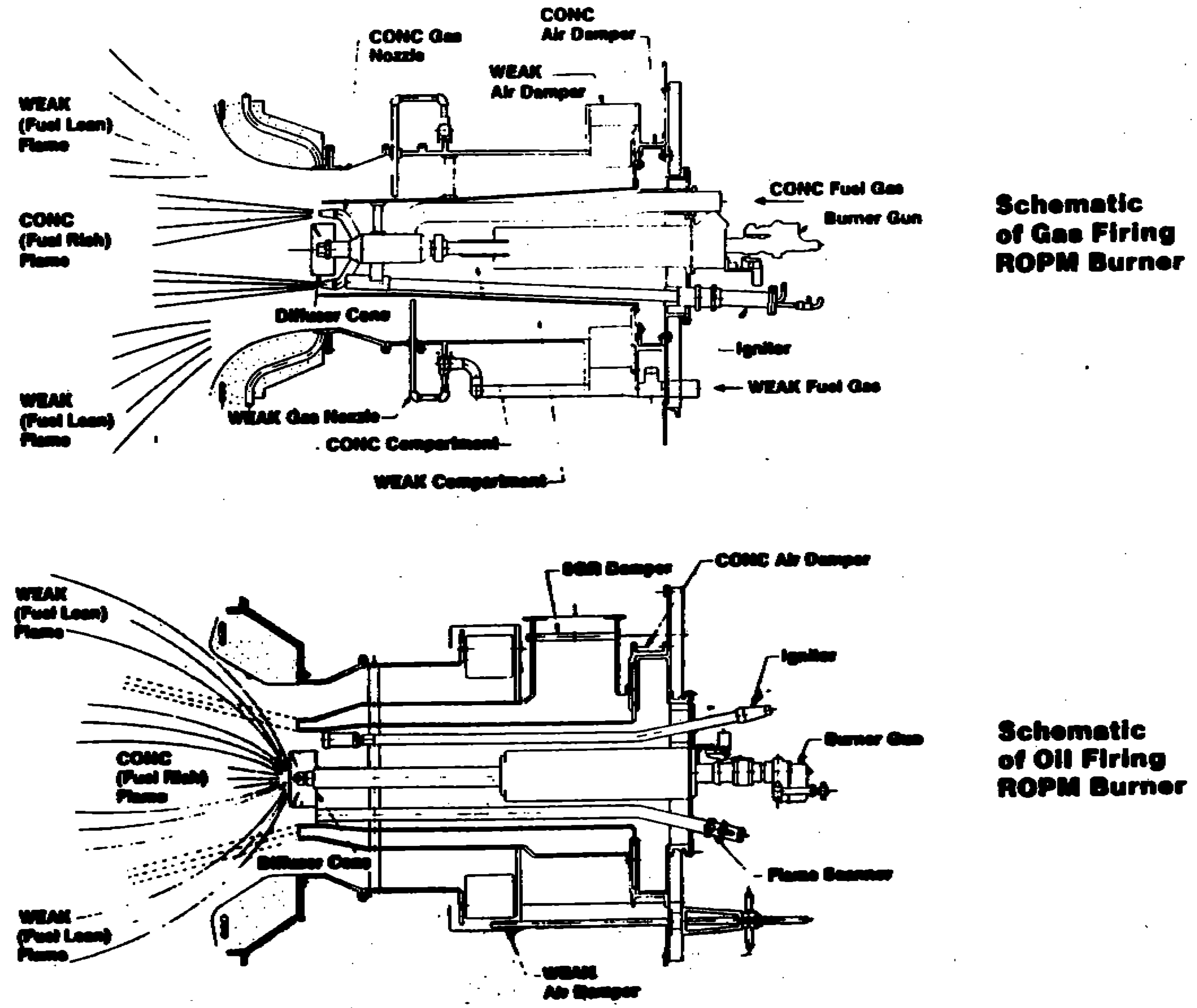


Figure 5-25. ROPM™ burner for natural gas- and oil-fired boilers.[83]

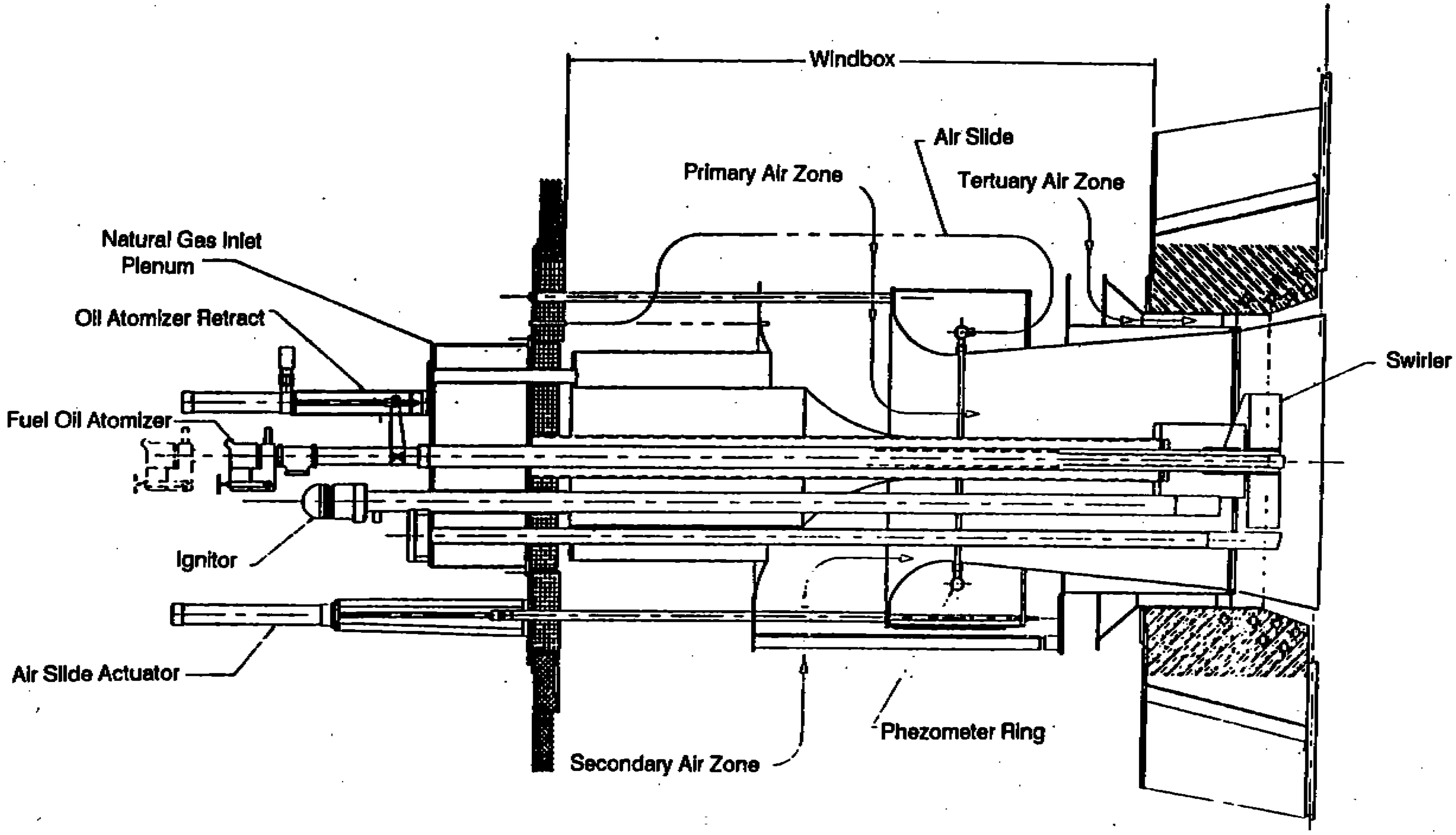


Figure 5-26. Dynaswirl™ low NO_x burner.[79]

pokers have skewed, flat tips perforated with numerous holes and directed inward toward the burner centerline. Primary air flows down the center of the burner venturi around the center-fired gas gun, where it mixes with this gas to form a stable flame. Secondary air flows among the outer walls of the venturi, where it mixes with gas from the gas pokers and is ignited by the center flame.[79]

The Internal Staged Combustion™ (ISC) wall-fired LNB incorporates LEA in the primary combustion zone, which limits the O_2 available to combine with fuel nitrogen. In the second combustion stage, additional air is added downstream to form a cooler, O_2-rich zone where combustion is completed and thermal NO_x formation is limited. The ISC design, shown in figure 5-27, can fire natural gas or oil.[84]

The wall-fired Primary Gas - Dual Register Burner™ (PG-DRB), shown in figure 5-28, was developed to improve the NO_x reduction capabilities of the standard DRB.[15] The PG-DRB can be used in new or retrofit applications. The system usually includes FGR to the burner and to the windbox, with OFA ports installed above the top burner row. "Primary gas" is recirculated flue gas that is routed directly to each PG-DRB and introduced in a dedicated zone surrounding the primary air zone in the center of the burner. The recirculated gas inhibits the formation of thermal and fuel NO_x by reducing peak flame temperature and O_2 concentration in the core of the flame. The dual air zones surrounding the PG zone provide secondary air to control fuel and air mixing and regulate flame shape.

In addition to the DRB XCL-PC™ burner for coal-fired boilers, the XCL burner, as shown in figure 5-29, is also available for wall-fired boilers burning natural gas and oil.[15] This design enables the use of an open windbox (compartmental windbox is unnecessary). Air flow is controlled by a sliding air damper and swirled by vanes in the dual air zones.

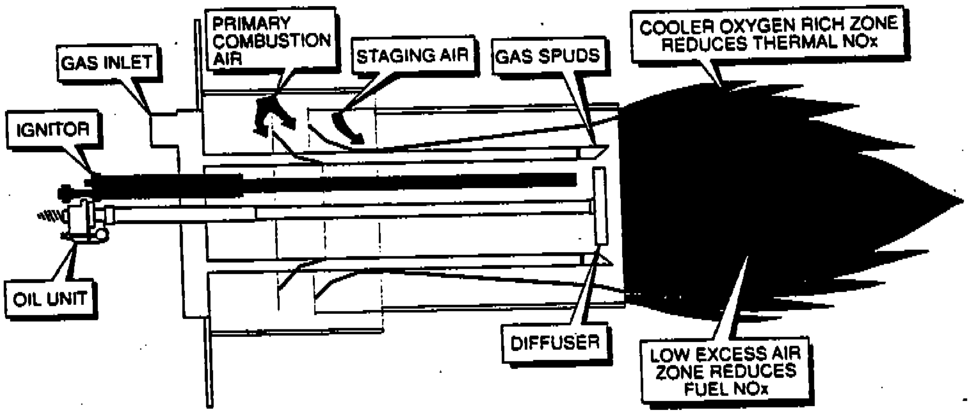


Figure 5-27. Internal Staged Combustion™ low NO_x burner.[84]

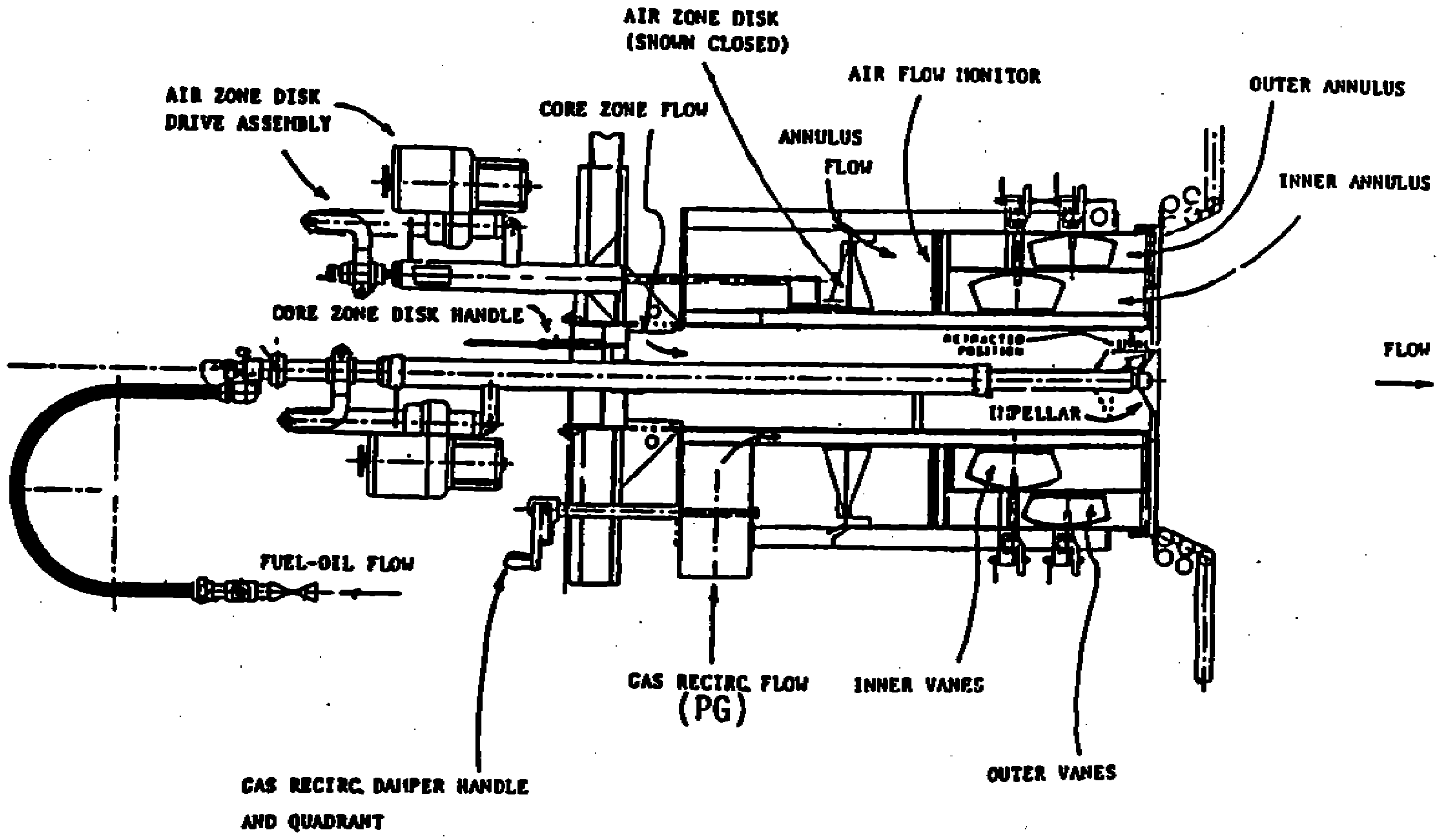


Figure 5-28. Primary Gas-dual Register™ low NO_x burner.[15]

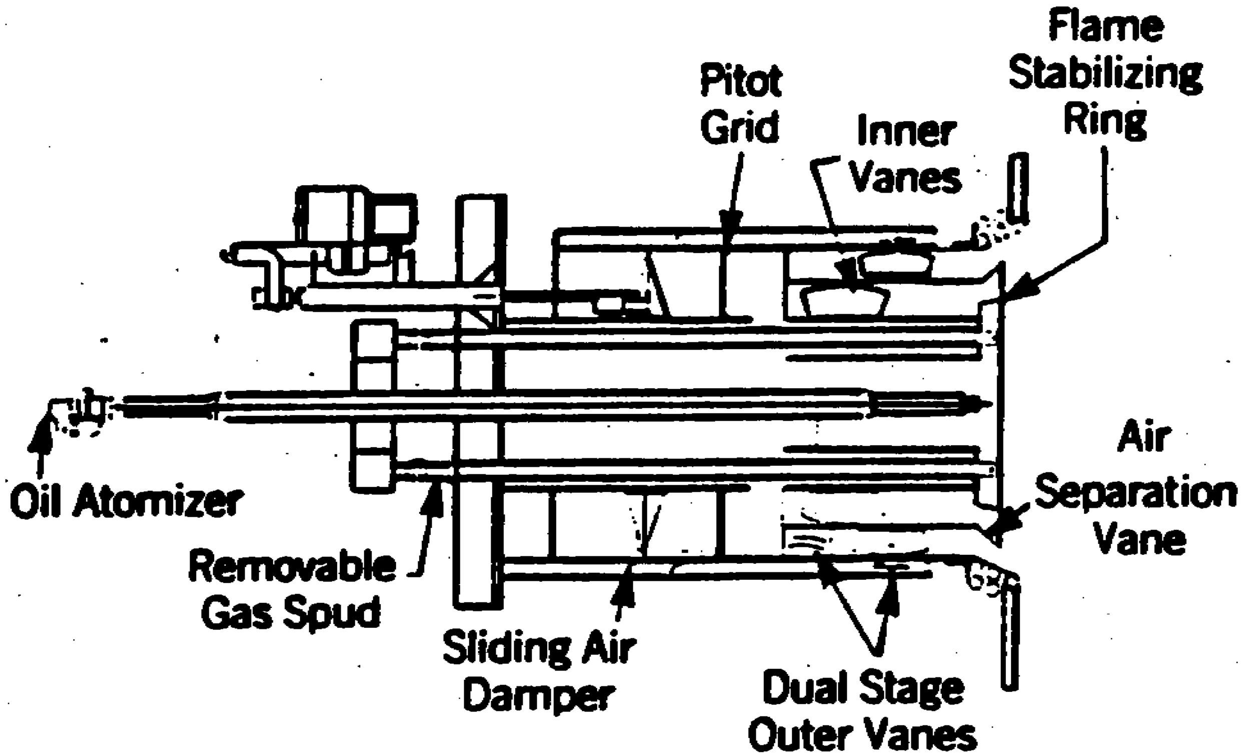


Figure 5-29. Axial Control™ Flow low NO_X burner for gas and oil.[15]

The Swirl Tertiary Separation™ (STS) burner for natural gas- and oil-fired retrofits is shown in figure 5-30.[85] In this design, the internal staging of primary and secondary air can be adjusted depending on required NO_x control and overall combustion performance. The ability to control swirl of the primary and secondary air streams independently provides flexibility in controlling flame length and shape, and ensures flame stability under low-NO_x firing conditions. A separate recirculated flue gas stream forms a distinct separate layer between the primary and secondary air. This separating layer of inert flue gas delays the combustion process, reducing peak flame temperatures and reducing the oxygen concentration in the primary combustion zone. Therefore, the separation layer controls both thermal and fuel NO_x formation.[85]

5.2.4.1.2 <u>Tangentially-fired boilers</u>. The tangentially-fired Pollution Minimum™ (PM) burner is shown in figure 5-31.[83] The burners are available for natural gas or oil firing. Both designs are internally staged, and incorporate FGR within the burners.

The gas-fired PM burner compartment consists of two fuel lean nozzles separated by one fuel-rich nozzle. Termed "GM" (gas mixing), this LNB system incorporates FGD by mixing a portion of the flue gas with combustion air upstream of the burner. When necessary, FGR nozzles are installed between two adjacent PM burner compartments, and a portion of the recirculated gas is injected via these nozzles.[83]

The oil-fired PM burner consists of one fuel nozzle surrounded by two separated gas recirculation (SGR) and air and GM nozzles. Within each fuel compartment a single oil gun with a unique atomizer sprays fuel at two different spray angles. The outer fuel spray passes through the SGR streams produce the fuel-lean zones. The inner concentric spray produces the fuel-rich zones between adjacent SGR nozzles. The SGR creates a boundary between the rich and lean flame

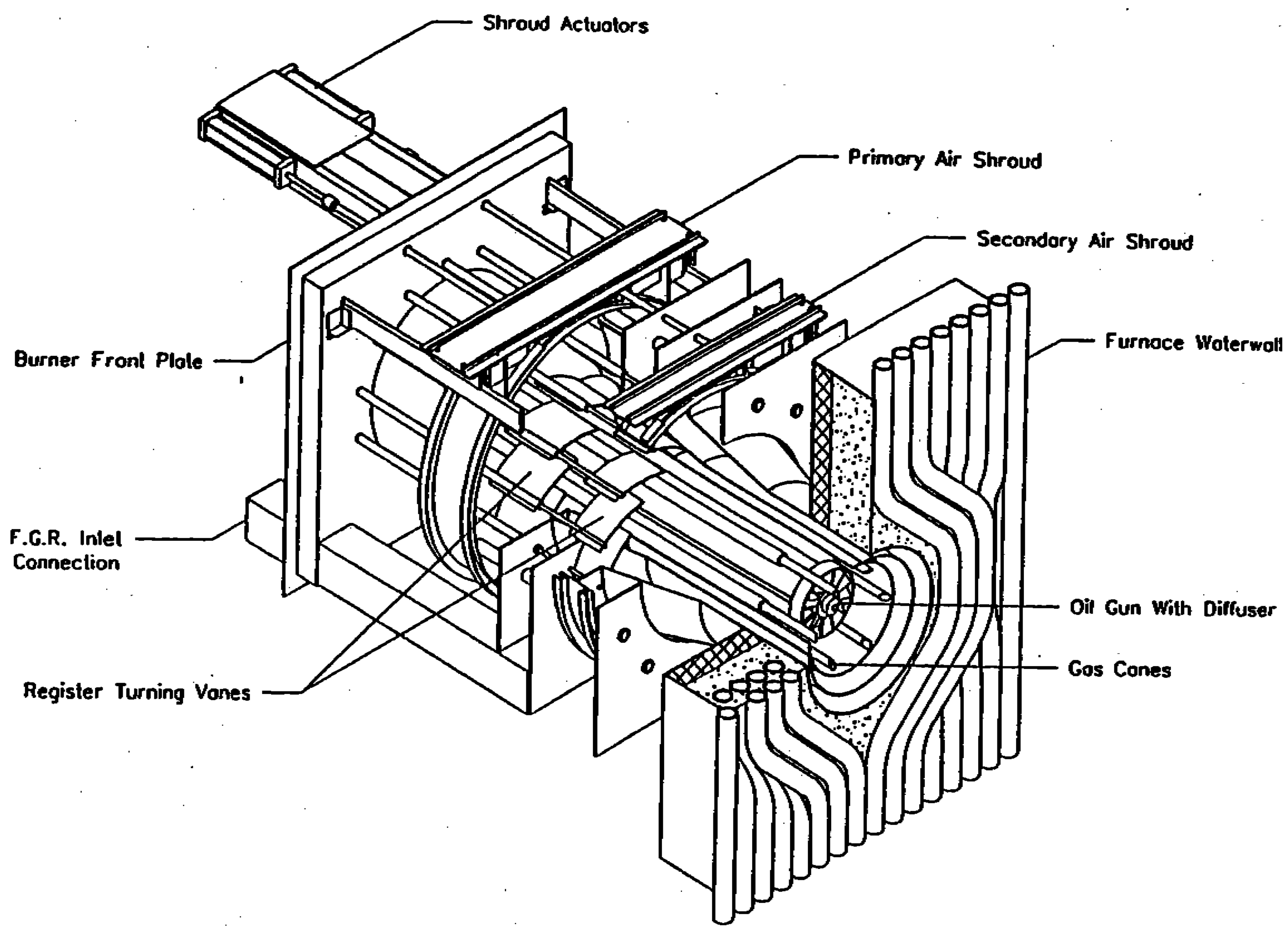
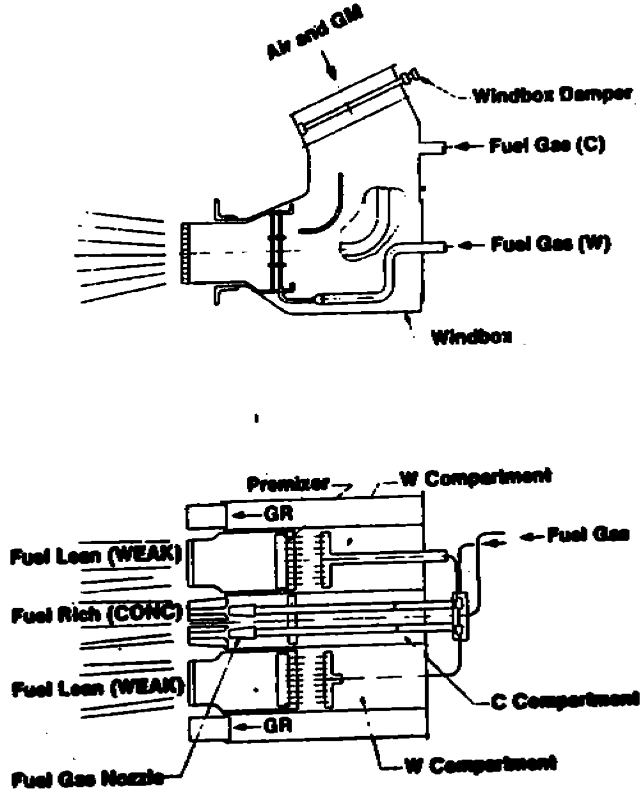
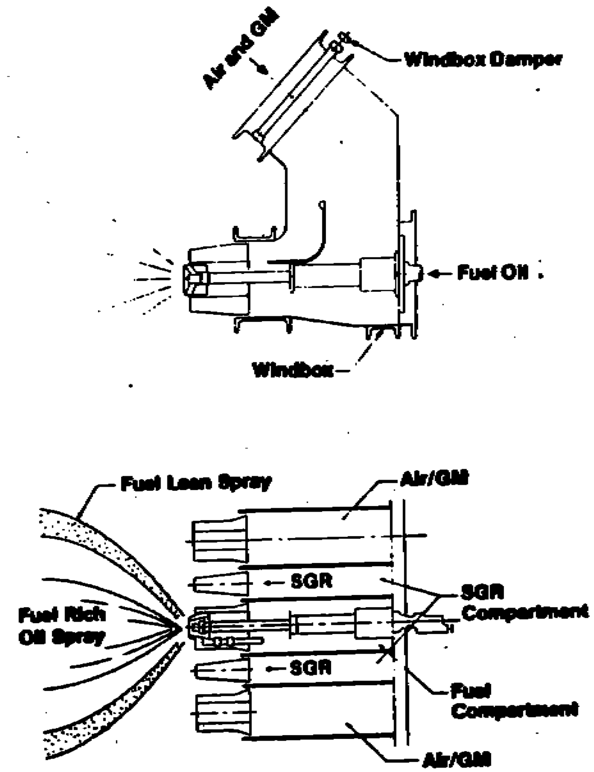


Figure 5-30. Low NO_x Swirl Tertiary Separation™ low NO_x burner.[85]



Schematic of Gas Firing PM Burner



Schematic of Oil Firing PM Burner

Figure 5-31. Pollution Minimum™ burner for natural gas- and oil-fired boilers.[83]

zones, thereby maintaining the NO_x reducing characteristics of both flames.[83]

5.2.4.2 Factors Affecting Performance. The factors affecting the performance of oil- and gas-fired LNB are essentially the same as those for coal-fired LNB discussed in section 5.1.3.2 of this document. However, the overall success of NO_x reduction with LNB may also be influenced by fuel grade and boiler design. For example, the most successful NO_x reductions are on natural gas and light fuel oil firing and on boilers initially designed for specific fuel use patterns. Also, boilers originally designed with larger furnace volumes per unit output would be more conducive to NO_x reduction with LNB than a smaller furnace.

Other factors affecting performance are the burner atomizer design which is critical for controlling NO_x and minimizing opacity. By improving atomization quality, there is a greater margin for variabilities in the boiler operation and fuel properties.

5.2.4.3 Performance of Low NO_x Burners. Table 5-12 presents data for LNB on natural gas- and oil-fired boilers. Three oil-fired boilers (Kahe 6, Port Everglades 3 and 4) had uncontrolled NO_x emissions in the range of 0.74 to 0.81 lb/MMBtu. With LNB, the NO_x was reduced to 0.51 to 0.56 lb/MMBtu which corresponds to a 28 to 35 percent reduction. The remaining oil-fired boiler, Northside 3, originally had OFA and was retrofit with LNB capable of burning either oil or gas. While the LNB were intended to accommodate the OFA, opacity exceedances occurred and the OFA ports were closed. Therefore, it is not possible to determine the percent reduction from this LNB retrofit.

For two wall-fired boilers firing natural gas (Port Everglades 3 and 4), the NO_x was reduced from uncontrolled levels of 0.52 to 0.57 lb/MMBtu to approximately 0.4 lb/MMBtu (23 to 33 percent reduction). For Alamitos 5, the NO_x was reduced 40 to 60 percent across the load range with LNB.

TABLE 5-12. PERFORMANCE OF LNB ON U. S. NATURAL GAS- AND OIL-FIRED BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
WALL-FIRED BOILERS, FUEL OIL										
Hawaiian Electric Co.	Kahe 6 (D)	146	B&W	PG-DRB (B&W)	Short	92	0.81	0.56	31	78
Florida Power & Light	Port Everglades 3 (Pre)	400	FW	Dynaswirl (Todd)	Short	96	0.74	0.53	28	86
Florida Power & Light	Port Everglades 4 (Pre)	400	FW	Dynaswirl (Todd)	Short	96	0.79	0.51	35	86
Jacksonville Electric Authority	Northside 3 (Pre)	518	RS	Dual Fuel (NEI)	Short	87	--	0.29[f]	--	87
WALL-FIRED BOILERS, NATURAL GAS										
Florida Power & Light	Port Everglades 3 (Pre)	400	FW	Dynaswirl (Todd)	Short	96	0.52	0.40	23	86
Florida Power & Light	Port Everglades 4 (Pre)	400	FW	Dynaswirl (Todd)	Short	96	0.57	0.38	33	86
Southern Cal. Edison Co.	Alamitos 5 (Pre)	480	B&W	AUS	Short	100 40	0.08-0.12 0.04-0.06	0.05 0.025	38-58 38-58	88
Southern Cal. Edison Co.	Alamitos 6 (Pre)	495	B&W	Dynaswirl (Todd)	Short	100	0.90[g]	0.22[h]	75	79
Jacksonville Electric Authority	Northside 3 (Pre)	518	RS	Dual Fuel (NEI)	Short	89	--	0.26	--	87

[a]Standard: Da = Subpart Da; Pre = Pre-NSPS
[b]OEM = Original Equipment Manufacturer; B&W = Babcock & Wilcox; FW = Foster Wheeler; RS = Riley Stoker
[c]Type Control: Dynaswirl = Todd Dynaswirl Low NO_x Burner; PG-DRB = Primary Gas-Dual Register Burner; AUS = Applied Utility Systems
[d]Vendors: B&W = Babcock & Wilcox; NEI = NEI Internal Combustion Limited; Todd = Todd Combustion.
[e]Short = Short-term test data, i.e., hours.
[f]Originally had OFA. Controlled emissions were with retrofit LNB only.
[g]Value is an estimate, based on historical data.
[h]Value is extrapolated from test data.
--Data not available.

Alamitos 6 had higher uncontrolled NO_x emissions (estimated to be 0.9 lb/MMBtu) and was reduced 75 percent to 0.22 lb/MMBtu. Again, it is not possible to determine the percent reduction for Northside 3 with these data.

To summarize, LNB retrofit on wall-fired boilers firing oil resulted in controlled NO_x emissions of approximately 0.5 to 0.55 lb/MMBtu. On wall-fired boilers firing natural gas, LNB typically resulted in controlled NO_x emissions of 0.2 to 0.4 lb/MMBtu. The lower controlled NO_x for the natural gas boilers is probably a result of the lower uncontrolled emissions.

5.2.5 Reburn

Although reburn may be applicable to oil-fired boilers, retrofit applications have been limited to large units in Japan. Reburning is not expected to be used on natural gas fired units, because other techniques such as FGR, BOOS, and OFA are effective and do not need the extensive modifications that reburn systems may require. However, gas reburn on a dual-fuel boiler (coal/gas) has been evaluated.

5.2.5.1 Process Description. The process description of reburn for natural gas- or oil-fired boilers is the same as was described for coal-fired boilers in section 5.1.5.1.

5.2.5.2 Factors Affecting Performance. The factors affecting the performance of reburn for natural gas- or oil-fired boilers are the same as was described for coal-fired boilers in section 5.1.5.2. Additionally, natural gas produces higher flue gas temperatures than when firing coal; therefore, the heat absorption profile in the furnace may change.

5.2.5.3 Performance of Reburn. There are no retrofits of reburn on oil-fired utility boilers in the United States; therefore, performance data are not available. Gas reburn has been tested on Illinois Power's Hennepin Unit 1 while firing natural gas as the main fuel. Hennepin Unit 1 is a 71 MW tangential boiler capable of firing coal or natural gas. The uncontrolled NO_x emissions when firing natural gas were approximately 0.14 lb/MMBtu at full-load and 0.12 lb/MMBtu at 60 percent load. The NO_x emissions were reduced by 37 percent at full-load to 0.09 lb/MMBtu. At reduced load, the NO_x emissions were reduced by 58 percent to 0.05 lb/MMBtu.[89]

5.2.6 Combinations of Combustion Controls

5.2.6.1 Process Descriptions. Large NO_x reductions can be obtained by combining combustion controls such as FGR, BOOS, OFA, and LNB. The types of combinations applicable to a given retrofit are site-specific and depend upon uncontrolled levels and required NO_x reduction, boiler type, fuel type, furnace size, heat release rate, firing configuration, ease of retrofit, and cost. The process descriptions for the individual controls are found in section 5.1.

5.2.6.2 Factors Affecting Performance. The same basic factors affecting the performance of individual combustion controls will apply to these controls when they are used in combination. Section 5.1 describes the factors affecting the individual NO_x controls.

5.2.6.3 Performance of Combination of Combustion Modifications. Short-term data for various combinations of NO_x controls for natural gas- and oil-fired boilers are given in table 5-13. Results are given for one tangential boiler firing natural gas, several combinations of controls on two wall-fired boilers firing fuel oil, and several combinations on wall boilers firing natural gas. For the tangential boiler firing natural gas (Pittsburgh 7), the NO_x emissions were reduced from 0.95 lb/MMBtu with FGR + OFA to 0.1 lb/MMBtu at full-load (89 percent reduction).

For Kahe 6 (with the original burners), the NO_x emissions were reduced from 0.81 lb/MMBtu with FGR + BOOS to 0.28 lb/MMBtu for a 65-percent reduction. As was shown in sections 5.2.1.3 and 5.2.2.3 (Refer to tables 5-9 and 5-10), BOOS alone on this unit reduced NO_x to 0.50 lb/MMBtu (38 percent) and FGR alone reduced NO_x to 0.42 lb/MMBtu (48 percent). The combination of LNB and FGR on Kahe 6

TABLE 5-13. PERFORMANCE OF COMBINATIONS OF COMBUSTION CONTROLS ON U. S. NATURAL GAS- AND OIL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
TANGENTIALLY-FIRED BOILERS, NATURAL GAS										
Pacific Gas & Electric	Pittsburg 7 (Pre)	745	ABB-CE	FGR + OFA	Short	100 50 30	0.95 0.42 0.23	0.10 0.06 0.03	89 86 87	90, 91
WALL-FIRED BOILERS, FUEL OIL										
Hawaiian Electirc Co.	Kahe 6 (D)	146	B&W	FGR + BOOS (B&W)	Short	92	0.81	0.28	65	78
Hawaiian Electirc Co.	Kahe 6 (D)	146	B&W	LNB + FGR (B&W)	Short	92	0.81	0.43	47	78
Hawaiian Electirc Co.	Kahe 6 (D)	146	B&W	LNB + OFA (B&W)	Short	92	0.81	0.28	65	78
Pacific Gas & Electric Co.	Contra Costa 6 (Pre)	345	B&W	FGR + OFA	Short Short Short	100 50 25	0.55 0.17 0.10	0.19 0.16 0.10	65 6 0	90, 91
Hawaiian Electirc Co.	Kahe 6 (D)	146	B&W	LNB + OFA + FGR (B&W)	Short	92	0.81	0.19	76	78
WALL-FIRED BOILERS, NATURAL GAS										
Pacific Gas & Electric Co.	Pittsburg 6 (Pre)	330	B&W	FGR + OFA	Short Short Short	100 50 32	0.90 0.41 0.26	0.16 0.14 0.13	82 66 50	90, 91
Pacific Gas & Electric Co.	Contra Costa 6 (Pre)	345	B&W	FGR + OFA	Short	100	0.55	0.24	57	90, 91
Southern California Edison Co.	Alamitos 6 (Pre)	495	B&W	FGR + BOOS	Short	100	--	0.08	91	79

TABLE 5-13. PERFORMANCE OF COMBINATIONS OF COMBUSTION CONTROLS ON U. S. NATURAL GAS- AND OIL-FIRED UTILITY BOILERS (Concluded)

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c] (vendor)[d]	Length of test[e]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
WALL-FIRED BOILERS, NATURAL GAS (Continued)										
Pacific Gas & Electric Co.	Moss Landing 7 (Pre)	750	B&W	FGR + BOOS	Short Short Short	100 80 60	1.80 1.30 0.88	0.15 0.06 0.08	92 95 91	90, 91
Southern California Edison Co.	Alamitos 6 (Pre)	495	B&W	LNB + FGR (Todd)	Short	100	--	0.1	89	79
Southern California Edison Co.	Ormond Beach 2 Pre)	800	B&W	LNB + FGR (Todd)	Short Short Short	87 70 50	-- -- --	0.13 0.07 0.04	-- -- --	79
Southern California Edison Co.	Alamitos 6 (Pre)	495	B&W	LNB + FGR + BOOS (Todd)	Short	100	--	0.06	93	79
Southern California Edison Co.	Ormond Beach 2 (Pre)	800	B&W	LNB + FGR + BOOS (Todd)	Short Short	87 70	-- --	0.12 0.06	-- --	79

[a]Standard: D = Subpart D; Da = Subpart Da; and Pre = Pre-NSPS

[b]OEM = Original Equipment Manufacturer; ABB-CE = Asea Brown Boveri-Combustion Engineering; and B&W = Babcock & Wilcox.

[c]Type Control: BOOS = Burners-out-of-service; FGR = Flue Gas Recirculation; LEA = Low Excess Air; LNB = Low NO_x Burners; and OFA = Overfire Air

[d]Vendors: B&W = Babcock & Wilcox (Primary Gas-Dual Register Burner); and Todd = Todd Combustion (Todd Dynaswirl LNB).

[e]Short = Short-term test data, i.e., hours.

-- = Data not available.

reduced the NO_x emissions to 0.43 lb/MMBtu (47 percent). The combination of LNB + OFA on Kahe 6 reduced NO_x emissions to 0.28 lb/MMBtu (65 percent) and LNB + OFA + FGR reduced NO_x emissions to 0.19 lb/MMBtu (76 percent). These data show that by combining technologies on this oil-fired boiler, NO_x emissions can be reduced by 47 to 76 percent from uncontrolled levels. For the other oil-fired wall boiler (Contra Costa 6), FGR + OFA reduced the NO_x emissions from 0.55 to 0.19 lb/MMBtu at full-load (65 percent reduction). These data also indicate that combining operational modifications may reduce NO_x emissions as much as or more than combustion hardware changes (i.e., LNB).

For two natural gas-fired boilers (Pittsburgh 6 and Contra Costa 6), FGR + OFA reduced NO_x emissions to 0.16 and 0.24 lb/MMBtu. The Pittsburgh unit had higher uncontrolled NO_x (0.9 lb/MMBtu) than the Contra Costa unit (0.55 lb/MMBtu) and resulted in 82 percent reduction as compared to 57 percent.

For two natural gas-fired boilers (Alamitos 6 and Moss Landing 7), combining FGR + BOOS (similar to FGR + OFA) reduced NO_x emissions to 0.08 to 0.14 lb/MMBtu (92 percent reduction) at full-load. The combination of LNB + FGR on the natural gas boilers reduced NO_x to approximately 0.1 lb/MMBtu on Alamitos 6 and Ormond Beach 2 (89 to 94 percent). And, combining LNB + FGR + BOOS decreased the NO_x emissions to 0.06 to 0.12 lb/MMBtu on Alamitos 6 and Ormond Beach 2 (93 percent).

To summarize, combining combustion controls on natural gas-boilers is effective in reducing NO_x emissions. However, combining combustion controls on oil-firing is not as effective and reductions of up to 75 percent were reported. Whereas, reductions of up to 94 percent on natural gas-fired boilers were reported.

5.3 FLUE GAS TREATMENT CONTROLS

Two commercially available flue gas treatment technologies for reducing NO_x emissions from existing fossil fuel utility boilers are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). Selective noncatalytic reduction involves injecting ammonia or urea into the flue gas to yield nitrogen and water. The ammonia or urea must be injected into specific high-temperature zones in the upper furnace or convective pass for this method to be effective.[92] The other flue gas treatment method, SCR, involves injecting ammonia into the flue gas in the presence of a catalyst. Selective catalytic reduction promotes the reactions by which NO_x is converted to nitrogen and water at lower temperatures than required for SNCR.

5.3.1 Selective Noncatalytic Reduction

5.3.1.1 Process Description. The SNCR process involves injecting ammonia or urea into boiler flue gas at specific temperatures. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water.

As shown in figure 5-32, for the ammonia-based SNCR process, ammonia is injected into the flue gas where the temperature is $950 \pm 30\ ^{o}C$ ($1,750 \pm 90\ ^{o}F$).[93] Even though there are large quantities of O_2 present, NO is a more effective oxidizing agent, so most of the NH_3 reacts with NO by the following mechanism:[94]

$$4NH_3 + 6NO \rightarrow 5N_2 + 6H_2O \qquad (5\text{-}14)$$

Competing reactions that use some of the NH_3 are:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \qquad (5\text{-}15)$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O \qquad (5\text{-}16)$$

For equation 5-14 to predominate, NH_3 must be injected into the optimum temperature zone, and the ammonia must be effectively mixed with the flue gas. When the temperature exceeds the optimum range, equation 5-15 becomes significant, NH_3 is oxidized to NO_x, and the net NO_x reduction decreases.[94] If the temperature of the combustion products falls below the SNCR operating range, the NH_3 does not react and is emitted to

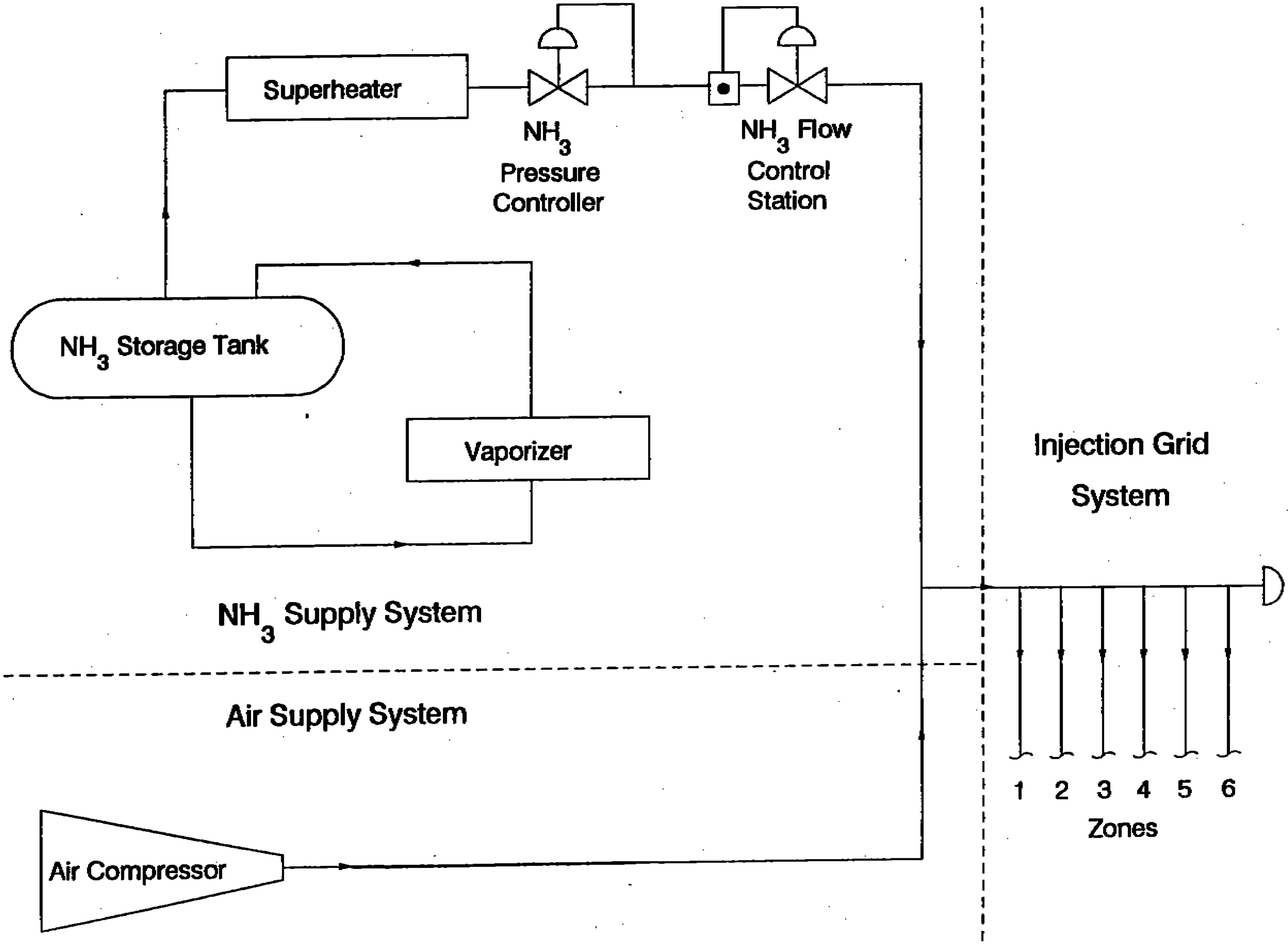


Figure 5-32. Ammonia-based SNCR.[93]

the atmosphere. Ammonia emissions must be minimized because NH_3 is a pollutant and can also react with sulfur oxides in the flue gas to form ammonium salts, which can deposit on downstream equipment such as air heaters. A small amount of hydrogen (not enough to appreciably raise the temperature) can be injected with the NH_3 to lower the temperature range in which SNCR is effective.

As shown in figure 5-33, in the urea-based SNCR process, an aqueous solution of urea ($CO(NH_2)_2$) is injected into the flue gas at one or more locations in the upper furnace or convective pass.[92] The urea reacts with NO_x in the flue gas to form nitrogen, water, and carbon dioxide (CO_2). Aqueous urea has a maximum NO_x reduction activity at approximately 930 to 1,040 ^oC (1,700 to 1,900 ^oF). Proprietary chemical enhancers may be used to broaden the temperature range in which the reaction can occur. Using enhancers and adjusting the concentrations can expand the effectiveness of urea to 820-1,150 ^oC (1,500-2,100 ^oF).[92]

The exact reaction mechanism is not well understood because of the complexity of urea pyrolysis and the subsequent free radical reactions. However, the overall reaction mechanism is:[94]

$$CO(NH_2)_2 + 2NO + 1/2O_2 \rightarrow 2N_2 + CO_2 + 2H_2O \qquad (5\text{-}17)$$

Based on the above chemical reaction, one mole of urea reacts with two moles of NO. However, results from previous research indicate that more than stoichiometric quantities of urea must be injected to achieve the desired level of NO_x removal.[92] Excess urea degrades to nitrogen, carbon dioxide, and unreacted NH_3.

Another version of the urea-based SNCR process uses high energy to inject either aqueous NH_3 or urea solution as shown in figure 5-34.[95] The solution is injected into the flue gas using steam or air as a diluent at one or more specific temperature zones in the convective pass. Additionally,

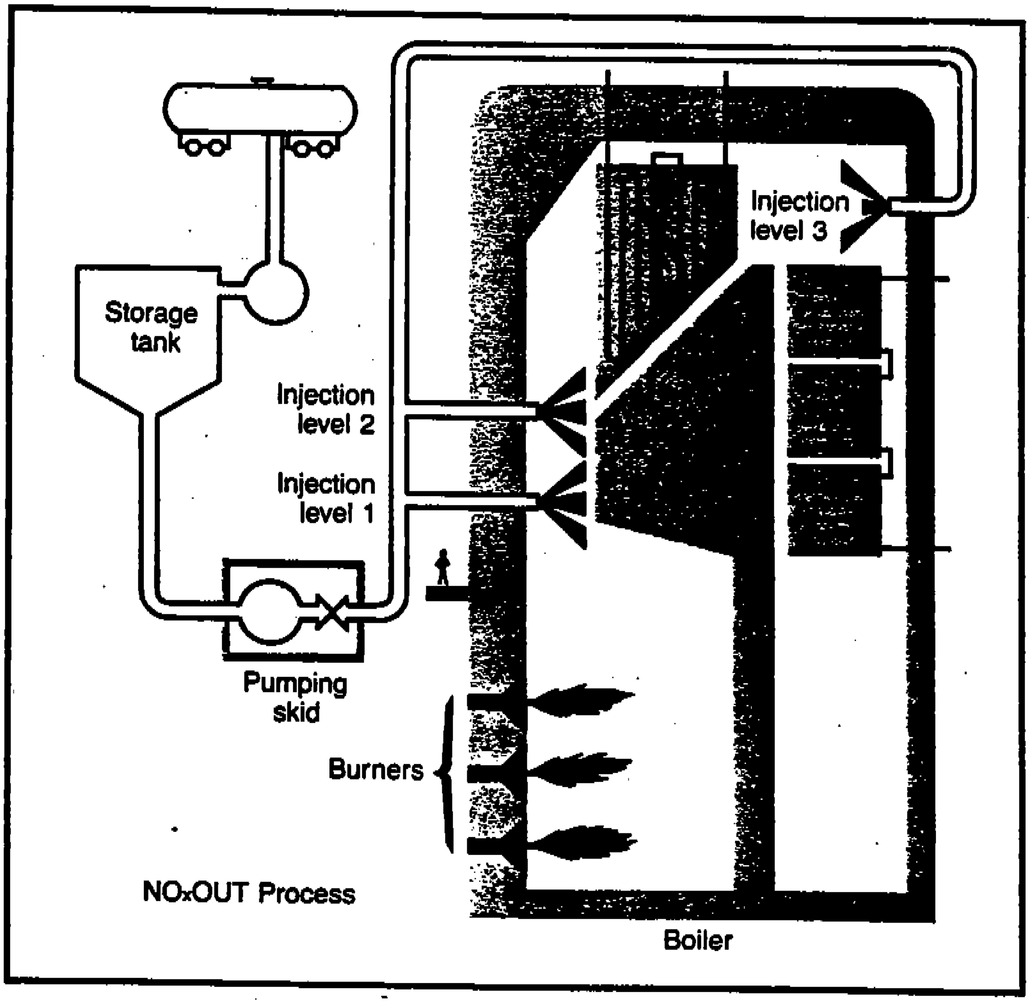


Figure 5-33. Urea-based SNCR.[92]

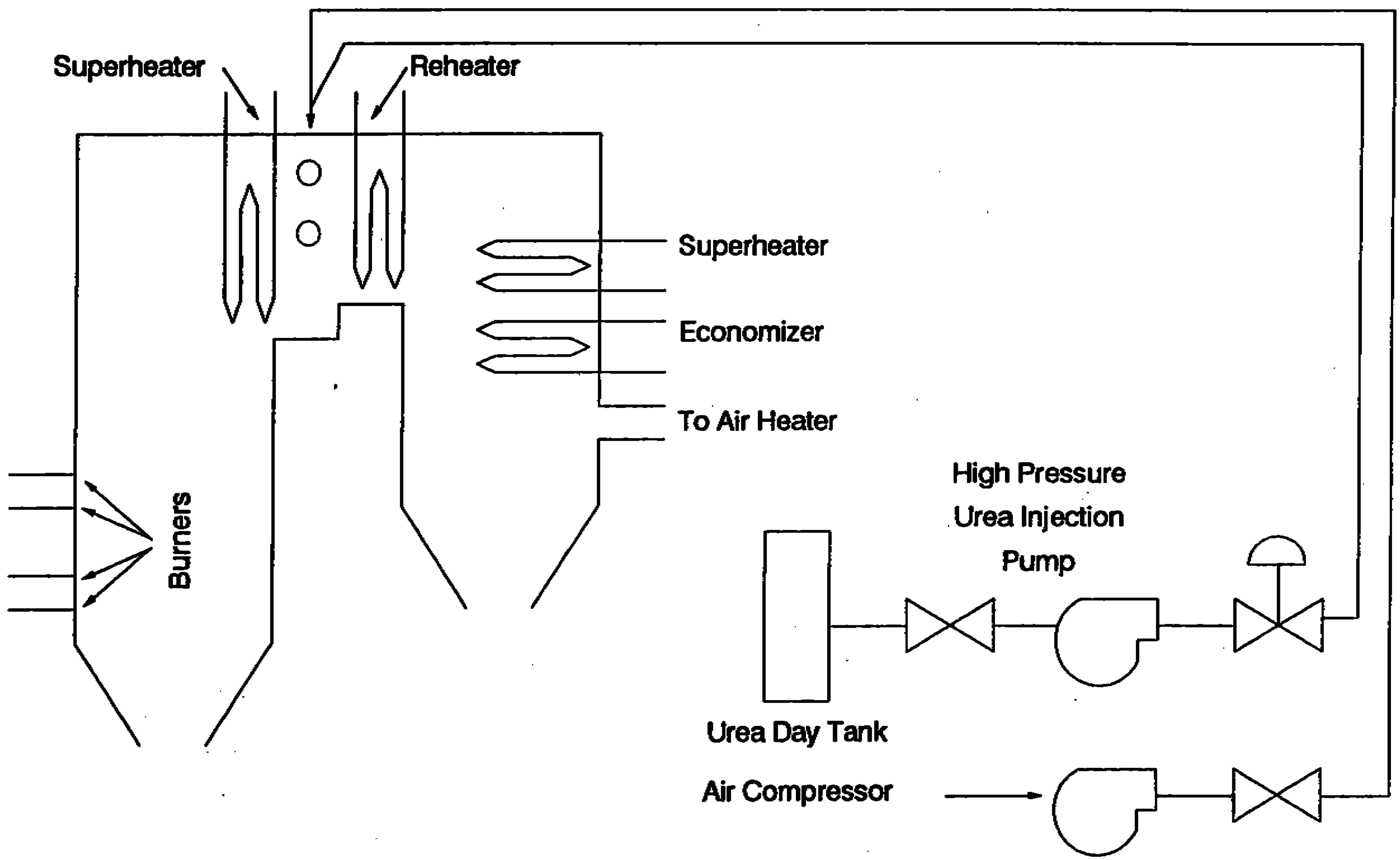


Figure 5-34. High-energy SNCR process.[95]

methanol can be added further in the process to reduce NH_3 slip. This system is based on the same concept as the earlier SNCR systems except that the pressurized urea-water mixtures are injected into the cross-flowing flue gas with high-velocity, air-driven nozzles. High-energy urea injection is especially applicable to units with narrow reagent injection windows because this system provides intense flue gas mixing.[95]

Hardware requirements for SNCR processes include reagent storage tanks, air compressors, reagent injection grids, and an ammonia vaporizer (NH_3-based SNCR). Injection equipment such as a grid system or injection nozzles is needed at one or more locations in the upper furnace or convective pass. A carrier gas, such as steam or compressed air, is used to provide sufficient velocity through the injection nozzles to ensure thorough mixing of the reagent and flue gas. For units that vary loads frequently, multi-level injection is used. A control system consisting of a NO_x monitor and a controller/processor (to receive NO_x and boiler data and to control the amount of reagent injected) is also required.

Most SNCR experience has been on boilers less than 200 MW in size. In larger boilers, the physical distance over which reagent must be dispersed increases and the surface area/volume ratio of the convective pass decreases. Both of these factors are likely to make it more difficult to achieve good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. For larger boilers, more complex reagent injection, mixing, and control systems may be necessary. Potential requirements for such a system could include high momentum injection lances and more engineering and physical/mathematical modeling of the process as part of system design.

5.3.1.2 <u>Factors Affecting Performance</u>

5.3.1.2.1 <u>Coal-fired boilers</u>. Six factors influence the performance of urea- or ammonia-based SNCR systems:

temperature, mixing, residence time, reagent-to-NO_x ratio, and fuel sulfur content. The NO_x reduction kinetic reactions are directly affected by concentrations of NO_x. Reduced concentrations of NO_x lower the reaction kinetics and thus the potential for NO_x reductions.

As shown in figure 5-35, the gas temperature can greatly affect NO_x removal and NH_3 slip.[96] At temperatures below the desired operating range of 930 to 1,090 °C (1,700 to 2,000 °F), the NO_x reduction reactions begin to diminish, and unreacted NH_3 emissions (slip) increase. Above the desired temperature range, NH_3 is oxidized to NO_x, resulting in low NO_x reduction efficiency and low reactant utilization.[96]

The temperature in the upper furnace and convective pass, where temperatures are optimum for SNCR, depends on boiler load, fuel, method of firing (e.g., off-stoichiometric firing), and extent of heat transfer surface fouling or slagging. The flue gas temperature exiting the furnace and entering the convective pass typically may be 1,200 °C ± 110 °C (2,200 °F ± 200 °F) at full load and 1,040 °C ± 70 °C (1,900 °F ± 150 °F) at half load. At a given load, temperatures can increase by as much as 30 to 60 °C (50 to 100 °F) depending on boiler conditions (e.g., extent of slagging on heat transfer surfaces). Due to these variations in the temperatures, it is often necessary to inject the reagent at different locations or levels in the convective pass for different boiler loads.[96]

The second factor affecting SNCR performance is mixing of the reagent with the flue gas. The zone surrounding each reagent injection nozzle will probably be well mixed by the turbulence of the injection. However, it is not possible to mix the reagent thoroughly with the entire flue gas stream because of the short residence time typically available. Stratification of the reagent and flue gas will probably be a greater problem at low boiler loads.[96] Retrofit of furnaces with two or more division walls will be difficult because the

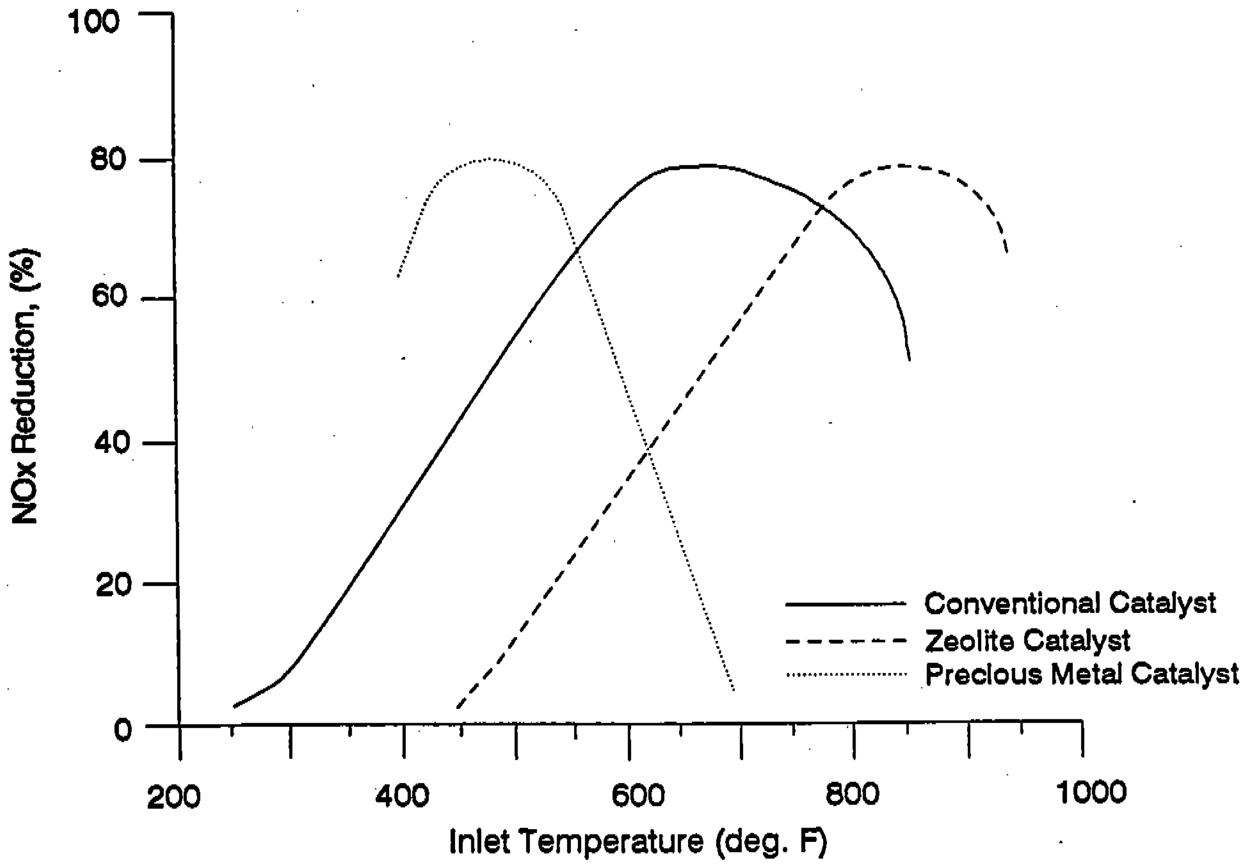


Figure 5-35. General effects of temperature on NO_x removal.[96]

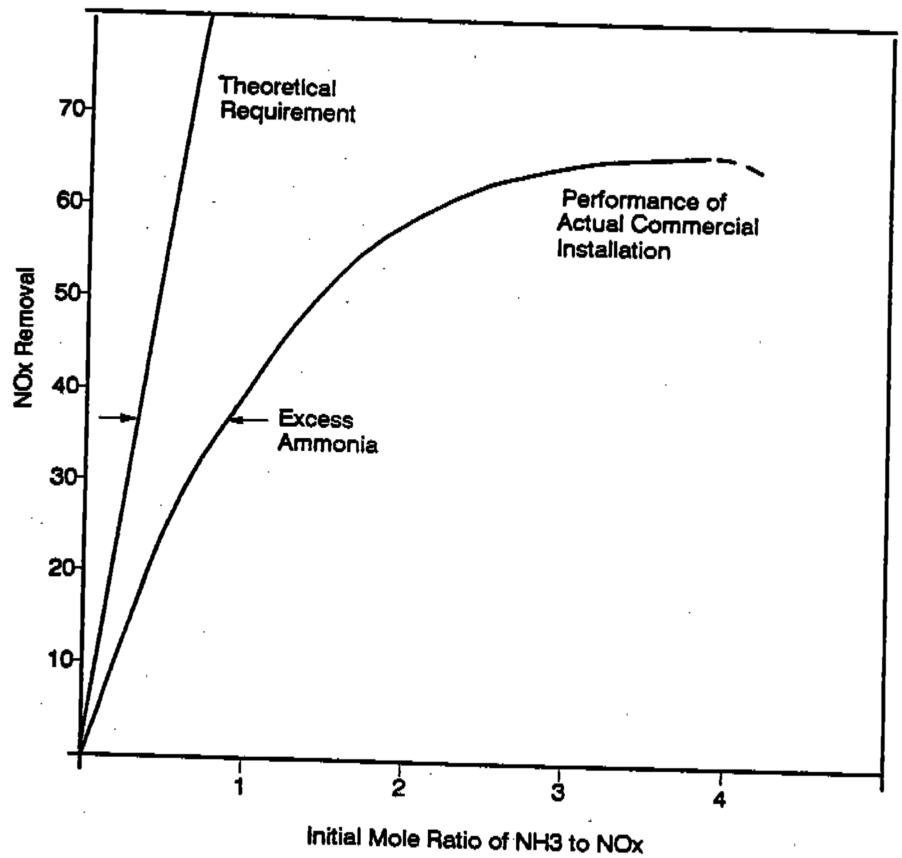
central core(s) of the furnace cannot be treated by injection lances or wall-mounted injectors on the side walls. This may reduce the effectiveness of SNCR.

The third factor affecting SNCR performance is the residence time of the injected reagent within the required temperature window. If residence times are too short, there will be insufficient time for completion of the desired reactions between NO_x and NH_3.

The fourth factor in SNCR performance is the ratio of reagent to NO_x. Figure 5-36 shows that at an ammonia-to-NO_x ratio of 1.0, NO_x reductions of less than 40 percent are achieved.[97] By increasing the NH_3:NO_x ratio to 2.0:1, NO_x reductions of approximately 60 percent can be obtained. Increasing the ratio beyond 3.0:1 has little effect on NO_x reduction. Since NH_3:NO_x ratios higher than the theoretical ratio are required to achieve the desired NO_x reduction, a trade-off exists between NO_x control and the presence of excess NH_3 in the flue gas. Excess NH_3 can react with sulfur compounds in the flue gas, forming ammonium sulfate salt compounds that deposit on downstream equipment. The higher NH_3 feed rates can result in additional annual costs.

The fifth factor in SNCR performance is the sulfur content of the fuel. Sulfur compounds in the fuel can react with NH_3 and form liquid or solid particles that can deposit on downstream equipment. In particular, compounds such as ammonium bisulfate (NH_4HSO_4) and ammonium sulfate [$(NH_4)_2SO_4$] can plug and corrode air heaters when temperatures in the air heater fall below 260 ^oC (500 ^oF). As shown in figure 5-37, given sufficient concentrations of NH_3 and SO_3 in the flue gas, ammonium bisulfate or sulfate can form at temperatures below 260 ^oC (500 ^oF).[98]

5.3.1.2.2 <u>Natural Gas- and Oil-Fired Boilers</u>. The factors affecting the performance of SNCR on coal-fired boilers are applicable to natural gas and oil firing. These factors are: temperature, mixing, residence time, reagent-to-



NOTE: This figure is representative of one specific SNCR application. Actual NO_x removal as a function of molar ratio is boiler-specific.

Figure 5-36. General effect of NH_3:NO_x mole ratio on NO_x removal.

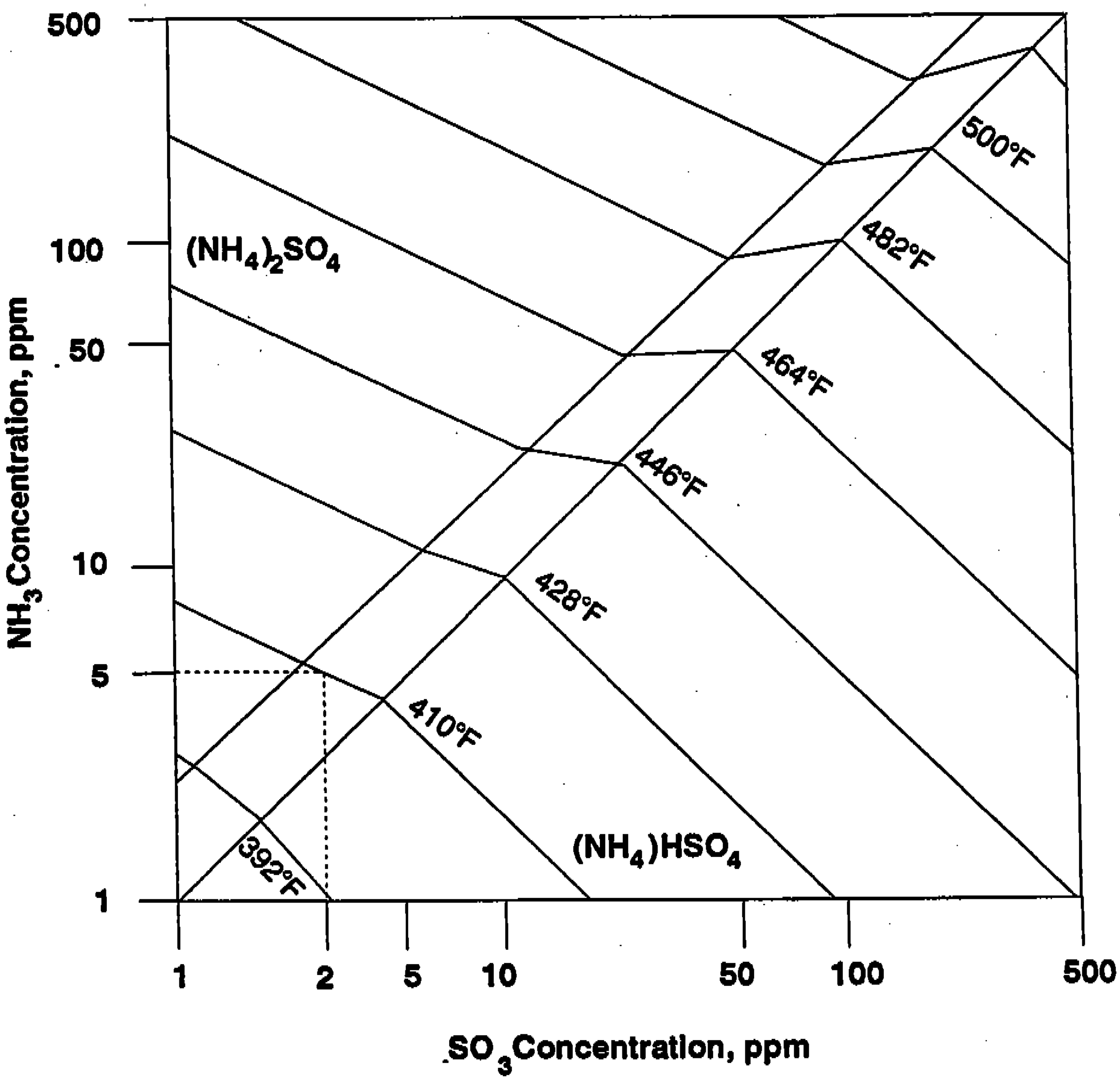


Figure 5-37. Ammonia salt formation as a function of temperature and NH_3 and SO_3 concentration.[98]

NO_x ratio, and fuel sulfur content. Because natural gas and oil do not contain as much sulfur as coal, the fuel sulfur content may not be as much a factor for natural gas- and oil-fired boilers.

5.3.1.3 <u>Performance of SNCR on Utility Boilers</u>. The results of SNCR applied to fossil fuel utility boilers are shown in table 5-14. There are 2 coal-fired, 2 oil-fired, and 10 natural gas-fired SNCR applications represented on the table. One application is ammonia-based SNCR with the remainder being urea-based. Available data on NH_3 slip and N_2O emissions during these tests are presented in chapter 7.

For Valley 4, the NO_x emissions during testing at full load decreased as the molar ratio increased. At a molar ratio of 0.7, the NO_x emissions were 0.76 lb/MMBtu whereas a molar ration of 1.7 resulted in NO_x emissions of 0.50 lb/MMBtu. At reduced loads, the molar ratio has the same effect on NO_x emissions. At 36 percent load, the NO_x was reduced to 0.14 and 0.32 lb/MMBtu with molar ratios of 2.0 and 1.0, respectively. At 34 percent load, the NO_x was reduced to 0.35 and 0.54 lb/MMBtu with molar ratios of 2.0 and 1.0, respectively. The higher NO_x emissions at the 34 percent load are attributed to a different burner pattern being used.

For Arapahoe 4, the NO_x was reduced approximately 30 percent at full-load prior to the retrofit of LNB + OFA. After retrofitting LNB + OFA, SNCR reduced NO_x by 30-40 percent with NH_3 slip less than 20 ppm. At lower loads, SNCR reduced NO_x by 40-50 percent; however, the NH_3 slip increased to as high as 100 ppm. This was attributed to cooled flue gas temperatures at low loads; however, the system is still being optimized and tested.

Long-term data from one subpart Da stoker boiler shows controlled NO_x emissions of approximately 0.3 lb/MMBtu with NH_3 slip of less than 25 ppm. Baseline NO_x levels from this facility was not reported; however, data from another subpart Da stoker facility shows baseline levels of 0.4-0.6 lb/MMBtu.

TABLE 5-14. PERFORMANCE OF SNCR ON CONVENTIONAL U. S. UTILITY BOILERS (Continued)

Utility	Unit (Standard)[a]	Rated Capacity (MW)	Molar N/NO Ratio	Control Type[b] (Vendor)[c]	Length of Test[d]	Capacity Tested (%)	Uncontrolled NO_x Emissions (lb/MMBtu)[e]	Controlled NO_x Emissions (lb/MMBtu)	Reduction in NO_x Emissions (%)	NH_3 Slip (ppm)	Reference
ROOF-FIRED BOILERS, BITUMINOUS COAL											
Public Service Co. of CO	Arapahoe 4 (Pre)	100	1.5	Urea (Noell)	Short	100	1.10[f]	0.68[g]	38[g]	12	64
			1.0			100	1.10[f]	0.68[g]	33[g]	8	
			0.75			100	1.10[f]	0.77[g]	30[g]	5	
			0.5			100	1.10[f]	0.88[g]	20[g]	3	
			0.25			100	1.10[f]	0.99[g]	10[g]	3	
			1.5	Urea (Noell)	Short	110	0.35[h]	0.19	45[i]	18	64
			1.0			110	0.35[h]	0.21	38[i]	8	
			0.75			110	0.35[h]	0.24	30[i]	5	
			1.5	Urea (Noell)	Short	100	0.35[h]	0.16	55[i]	30	64
			1.0			100	0.35[h]	0.18	50[i]	15	
			0.75			100	0.35[h]	0.19	45[i]	10	
			1.5	Urea (Noell)	Short	80	0.30[h]	0.14	55[i]	100	64
			1.0			80	0.30[h]	0.16	45[i]	45	
			0.75			80	0.30[h]	0.18	40[i]	25	
			1.0	Urea (Noell)	Short	60	0.40[h]	0.27	32[i]	8	64
			0.75			60	0.40[h]	0.28	30[i]	50	
STOKER BOILERS, COAL-FIRED											
Cogentrix of Richmond	Cogentrix 1-4 (Da)	--	--	--	Long	--	--	0.28-0.30	--	0-25	101

TABLE 5-14. PERFORMANCE OF SNCR ON CONVENTIONAL U. S. UTILITY BOILERS (Continued)

Utility	Unit (Standard)[a]	Rated Capacity (MW)	Molar N/NO Ratio	Control Type[b] (Vendor)[c]	Length of Test[d]	Capacity Tested (%)	Uncontrolled NO_x Emissions (lb/MMBtu)[e]	Controlled NO_x Emissions (lb/MMBtu)	Reduction in NO_x Emissions (%)	NH_3 Slip (ppm)	Reference
TANGENTIALLY-FIRED BOILERS, FUEL OIL											
Long Island Lighting Co.	Port Jefferson 3 (Pre)	185	0.5	Urea (Nalco)	Short	100	0.32	0.23	27	5-10	102,103
			1.0		Short	100	0.32	0.17	48		
			1.5		Short	100	0.32	0.14	56		
			0.5		Short	65	--	--	45		
			1.0		Short	65	--	--	40		
			1.6		Short	65	--	--	25		
			1.0		Short	33	0.32	0.21	36		
			1.5		Short	33	0.32	0.16	48		
			2.0		Short	33	0.32	0.15	55		
			--	Urea (Nalco)	Long	100	0.32	0.14	55	5-10	102,103
			--		Long	65	--	--	45		
			--		Long	33	0.32	0.14	55		
San Diego Gas and Electric	Encina 2 (Pre)	110	1.0	Urea	Short	85	--	--	40	10-50	104
TANGENTIALLY-FIRED BOILERS, NATURAL GAS											
Southern Cal. Edison Co.	Etiwanda 3 (Pre)	333	--	Urea	Short	96	0.12	0.07	42	--	105
					Short	50	0.06	0.04	33		
					Short	25	0.05	0.03	40		
Southern Cal. Edison Co.	Etiwanda 4 (Pre)	333	--	Urea	Short	96	0.08	0.06	25	--	105
					Short	50	0.05	0.04	20		
					Short	20	0.05	0.03	40		
Southern Cal. Edison Co.	Alamitos 3 (Pre)	333	--	Urea	Short	95	0.09	0.08	11	--	105
					Short	50	0.05	0.04	20		
					Short	21	0.03	0.03	0		

TABLE 5-14. PERFORMANCE OF SNCR ON CONVENTIONAL U. S. UTILITY BOILERS (Continued)

Utility	Unit (Standard)[a]	Rated Capacity (MW)	Molar N/NO Ratio	Control Type[b] (Vendor)[c]	Length of Test[d]	Capacity Tested (%)	Uncontrolled NO_x Emissions (lb/MMBtu)[e]	Controlled NO_x Emissions (lb/MMBtu)	Reduction in NO_x Emissions (%)	NH_3 Slip (ppm)	Reference
TANGENTIALLY-FIRED BOILERS, NATURAL GAS (CONTINUED)											
Southern Cal Edison Co.	Alamitos 4 (Pre)	333	--	Urea	Short Short Short	76 45 21	0.09 0.05 0.05	0.07 0.04 0.04	12 7 14	9 7 6	106
Southern Cal. Edison Co.	El Segundo 3 (Pre)	342	--	Urea	Short Short Short	98 40 20	0.10 0.05 0.05	0.06 0.04 0.04	36 23 28	7 12 17	107
Southern Cal. Edison Co.	El Segundo 4 (Pre)	342	--	Urea	Short Short Short	80 50 23	0.08 0.06 0.07	0.06 0.04 0.05	25 33 28	--	105
WALL-FIRED BOILERS, NATURAL GAS											
Southern Cal. Edison Co.	El Segundo 1 (Pre)	156	--	Urea (AUS)	Short Short Short	111 45 19	0.11 0.1 0.04	0.08 0.06 0.03	26 41 40	15 13 18	107
Southern Cal. Edison Co.	El Segundo 2 (Pre)	156	--	Urea	Short Short Short	85 63 37	0.1 0.09 0.08	0.07 0.05 0.05	30 50 38	--	105
Pacific Gas & Electric	Morro Bay 3[j] (Pre)	345	0.8 1.0 1.2 2.4	Urea (Noell)	Short Short Short Short	100 100 100 100	-- -- -- --	-- -- -- --	25 27 29 27	110	108
			1.0 1.5 2.0	Urea (Noell)	Short Short Short	83 83 83	-- -- --	-- -- --	23 26 27	80	108

TABLE 5-14. PERFORMANCE OF SNCR ON CONVENTIONAL U. S. UTILITY BOILERS (Concluded)

Utility	Unit (Standard)[a]	Rated Capacity (MW)	Molar N/NO Ratio	Control Type[b] (Vendor)[c]	Length of Test[d]	Capacity Tested (%)	Uncontrolled NO_x Emissions (lb/MMBtu)[e]	Controlled NO_x Emissions (lb/MMBtu)	Reduction in NO_x Emissions (%)	NH_3 Slip (ppm)	Reference
WALL-FIRED BOILERS, NATURAL GAS (Continued)											
Pacific Gas & Electric	Morro Bay 3[j] (Pre)	345	0.6 1.0 1.2 1.8	Ammonia (Noell)	Short Short Short Short	100 100 100 100	-- -- -- --	-- -- -- --	27 35 39 45	110	108
			1.8 1.0 1.5 2.0	Ammonia (Noell)	Short Short Short	83 83 83	-- -- --	-- -- --	30 35 41	50	108

[a]Standard: Pre = Pre-NSPS

[b]Control Type: Urea or ammonia (NH_3) injection

[c]Vendors: AUS = AUS Combustion Systems, Inc.; Nalco = Nalco Fuel Tech; and Noell = Noell, Inc.

[d]Short = Short-term test data, i.e., hours.

[e]For Valley 4, 100% capacity = A & B Mill, 35% = A Mill only, 34% = B Mill only.

[f]Uncontrolled NO_x before retrofit of LNB + OFA + SNCR.

[g]Percent reduction with SNCR only, before retrofit of LNB + OFA.

[h]Retrofit with LNB + OFA.

[i]Retrofit with LNB + OFA + SNCR; therefore, percent reduction is for SNCR.

[j]Test installation across one-third of boiler width.

-- = Data not available.

For the Port Jefferson oil-fired boiler, the NO_x emissions were 0.14 to 0.17 lb/MMBtu at full-load and 0.15 to 0.21 lb/MMBtu at minimum load depending on the molar ratio. Higher molar ratios of 1.5 and 2.0 resulted in NO_x removals of up to 56 percent at full and reduced load. The NH_3 slip at an NSR of 1.0 was 20 to 40 parts per million (ppm). Further experimentation to reduce the NH_3 slip at this site is planned.

For the tangentially-fired natural gas boilers with urea-based SNCR, the NO_x emissions at full-load range from 0.06 to 0.08 lb/MMBtu. At lower loads, the NO_x emissions range from 0.03 lb/MMBtu to 0.05 lb/MMBtu. The NO_x reductions for these boilers ranged from 0 to 42 percent. While the results varied from station-to-station for the same boiler type, sister units at the same station generally achieved a similar reduction. Ammonia slip for these boilers was 6 to 17 ppm.

The results were similar for the wall-fired boilers firing natural gas. The NO_x was reduced on El Segundo 1 and 2 to less than 0.1 lb/MMBtu across the load range with an NH_3 slip of less than 75 ppm. At Morro Bay 3, both a urea-based and an NH_3-based SNCR system were tested. Both of these systems reduced the NO_x by 30 to 40 percent across the load range, depending on the molar ratio. However, the ammonia slip was 10 to 20 ppm lower for the ammonia-based SNCR system than the urea-based SNCR. The relatively high NH_3 slip levels are thought to be due to the relatively short residence times in the convection section cavities. The NH_3 slip is reported in chapter 7.

The effect of increasing the molar N to NO ratio on percent NO_x reduction is shown in figures 5-38 and 5-39 for coal-fired and for natural gas- or oil-fired boilers, respectively. As shown in these figures, percent NO_x reduction increases with increasing molar N/NO ratio. However, as molar ratio is increased the amount of slip will also increase. Further, above a molar ratio of approximately

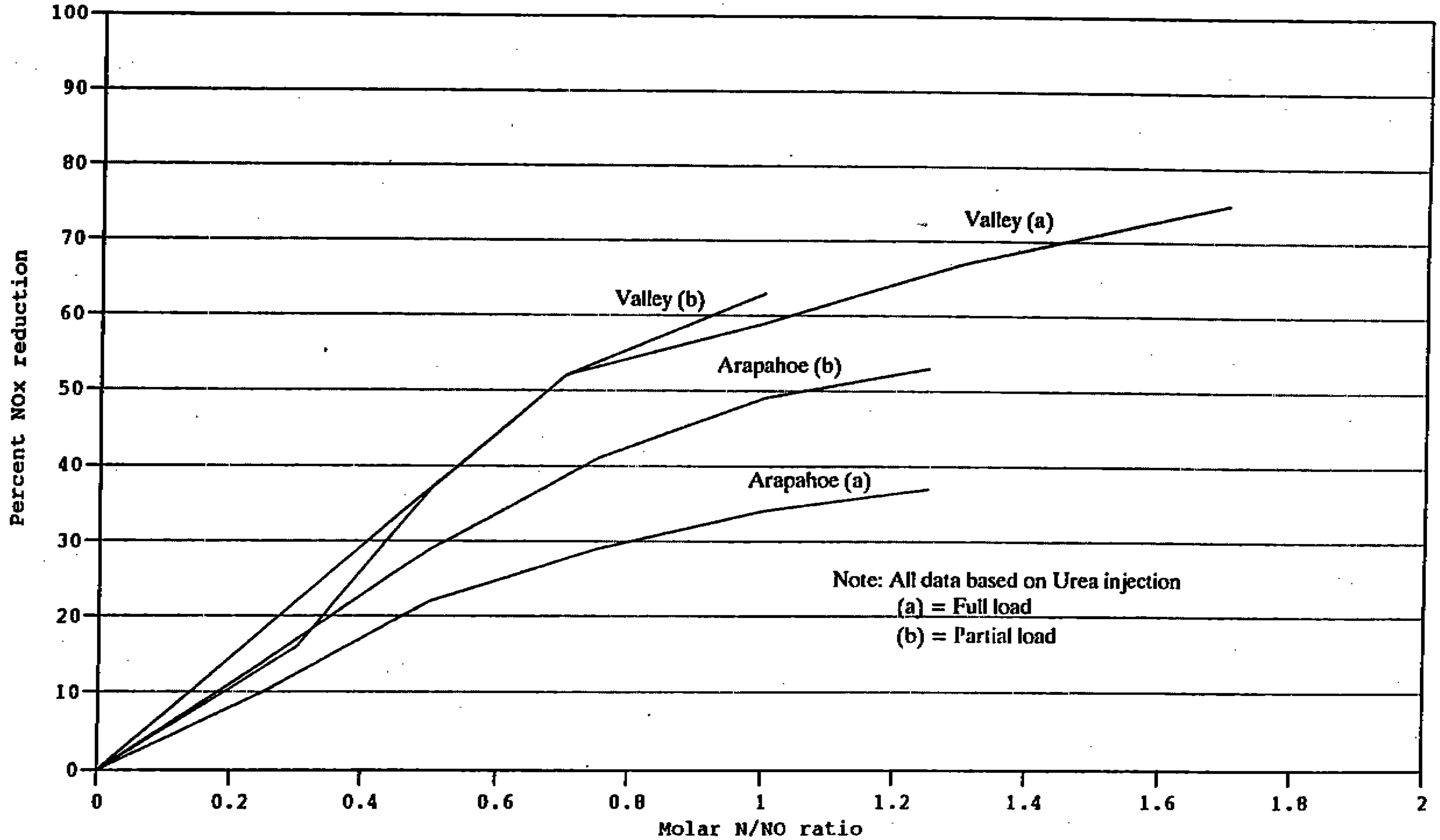


Figure 5-38. NO_x reduction vs. Molar N/NO ratio for conventional U. S. coal-fired boilers with SNCR.

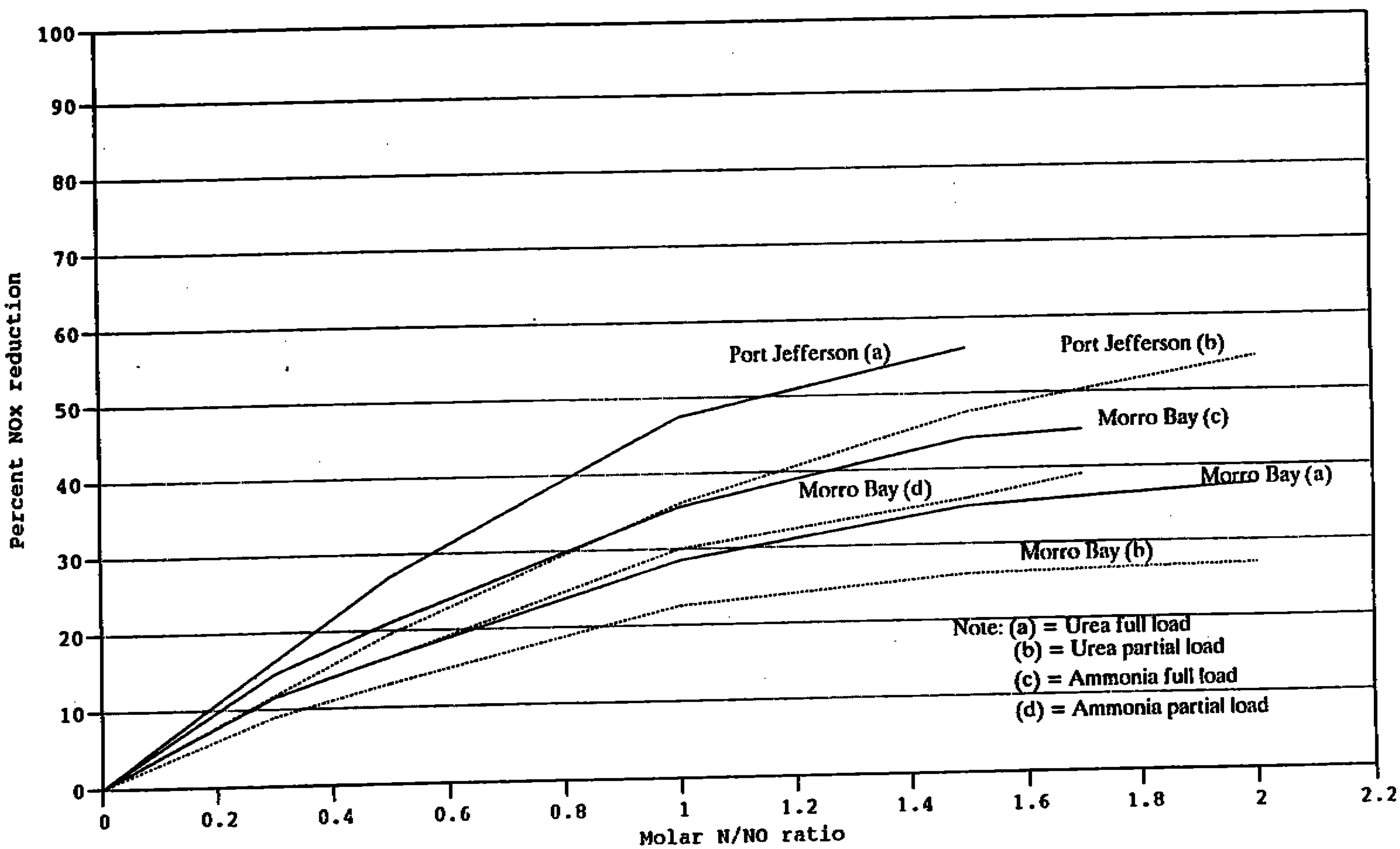


Figure 5-39. NO_x reduction vs. Molar N/NO ratio for conventional U. S. natural gas- and oil-fired boilers with SNCR.

1.0 to 1.5, only slight increases in NO_X reduction are generally seen. Thus, applications of SNCR must be optimized for effective reagent use.

5.3.1.4 Performance of SNCR on Fluidized Bed Boilers. Short-term results of SNCR on seven fluidized bed boilers are given in table 5-15. Two of the boilers are bubbling bed and five are circulating bed. All of these boilers utilize ammonia-based SNCR systems. The NO_X emissions from the Stockton A and B bubbling fluidized bed boilers were 0.03 lb/MMBtu at full-load. The NO_X emissions from the circulating fluidized bed boilers ranged from 0.03 to 0.1 lb/MMBtu at full-load conditions. The average NO_X emissions from these five boilers were 0.08 lb/MMBtu.

5.3.2 Selective Catalytic Reduction

5.3.2.1 Process Description. Selective catalytic reduction involves injecting ammonia into boiler flue gases in the presence of a catalyst to reduce NO_X to N_2 and water. The catalyst lowers the activation energy required to drive the NO_X reduction to completion, and therefore decreases the temperature at which the reaction occurs. The overall SCR reactions are:[113]

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \quad (5\text{-}18)$$

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O \quad (5\text{-}19)$$

There are also undesirable reactions that can occur in an SCR system, including the oxidation of NH_3 and SO_2 and the formation of sulfate salts. Potential oxidation reactions are:[114]

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \quad (5\text{-}20)$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O \quad (5\text{-}21)$$

$$2NH_3 + 2O_2 \rightarrow N_2O + 3H_2O \quad (5\text{-}22)$$

$$2SO_2 + O_2 \rightarrow 2SO_3 \quad (5\text{-}23)$$

TABLE 5-15. PERFORMANCE OF NH_3-BASED SNCR ON U. S. FLUIDIZED BED COMBUSTION BOILERS

Utility	Unit	Years online	Rated capacity (MW)	Coal type[a]	Capacity tested (MMBtu/hr)	Length of test (hrs)	NO_x emissions (lb/MMBtu)	Reference
BUBBLING FLUIDIZED BED								
POSDEF Power Co., L.P.	Stockton A	1989	25	Unk.	280	2	0.03	109
POSDEF Power Co., L.P.	Stockton B	1989	25	Unk.	280	2	0.03	109
CIRCULATING FLUIDIZED BED								
Ultrapower Constellation Operating Services	Rio Bravo Jasmin	1989	37	Bit	389	2	0.08	110
Ultrapower Constellation Operating Services	Rio Bravo POSO	1989	37	Bit	389	2	0.08	110
Energy Systems	Stockton Cogen	1988	56	Unk.	610	4	0.03	111
Applied Energy Services	Barbers Point A	1992	203	Unk.	896	2	0.10	112
Applied Energy Services	Barbers Point B	1992	203	Unk.	896	2	0.10	112

[a]Coal Type: Bit = Bituminous
Unk = Unknown

The reaction rates of both desired and undesired reactions increase with increasing temperature. The optimal temperature range depends upon the type of catalyst and an example of this effect is shown in figure 5-40.[115]

Figure 5-41 shows several SCR configurations that have been applied to power plants in Europe or Japan.[116] The most common configurations are diagrams 1a and 1b, also referred to as "high dust" and "low dust" configurations, respectively. Diagrams 1c and 1d represent applications of spray drying with SCR. Diagrams 1a through 1d are called "hot-side" SCR because the reactor is located before the air heater. Diagram 1e is called "cold-side" SCR because the reactor is located downstream of the air heaters, particulate control, and flue gas desulfurization equipment.[117]

A new type of SCR system involves replacing conventional elements in a Ljungstrom air heater with elements coated with catalyst material. As shown in figure 5-42, the flue gas passes through the air heater where it is cooled, as in a standard Ljungstrom air heater.[118] The catalyst-coated air heater elements serve as the heat transfer surface as well as the NO_x catalyst. The NH_3 required for the SCR process is injected in the duct upstream of the air heater. Because this type of SCR has a limited amount of space in which catalyst can be installed, the NO_x removal is also limited. However, replacing the air heater elements with catalyst material would require no major modifications to the existing boiler and may be applicable to boilers with little available space for add-on controls. While this technique has been used in Germany, there is only one installation in the United States on a natural gas- and oil-fired boiler in California.[119]

The hardware for a hot-side or cold-side SCR system includes the catalyst material; the ammonia system--including a vaporizer, storage tank, blower or compressor, and various valves, indicators, and controls; the ammonia injection grid; the SCR reactor housing (containing layers of catalyst);

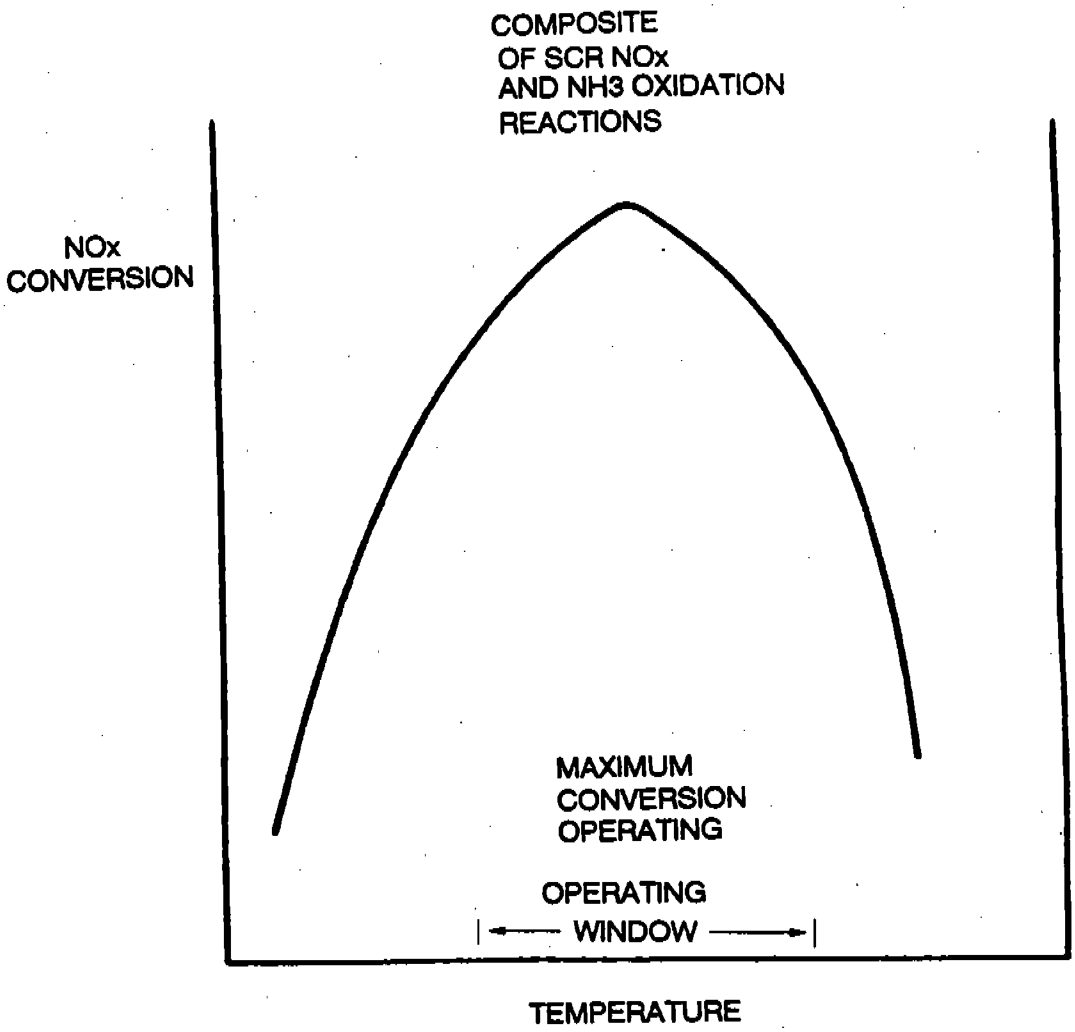


Figure 5-40. Relative effect of temperature on NO_x reduction.[115]

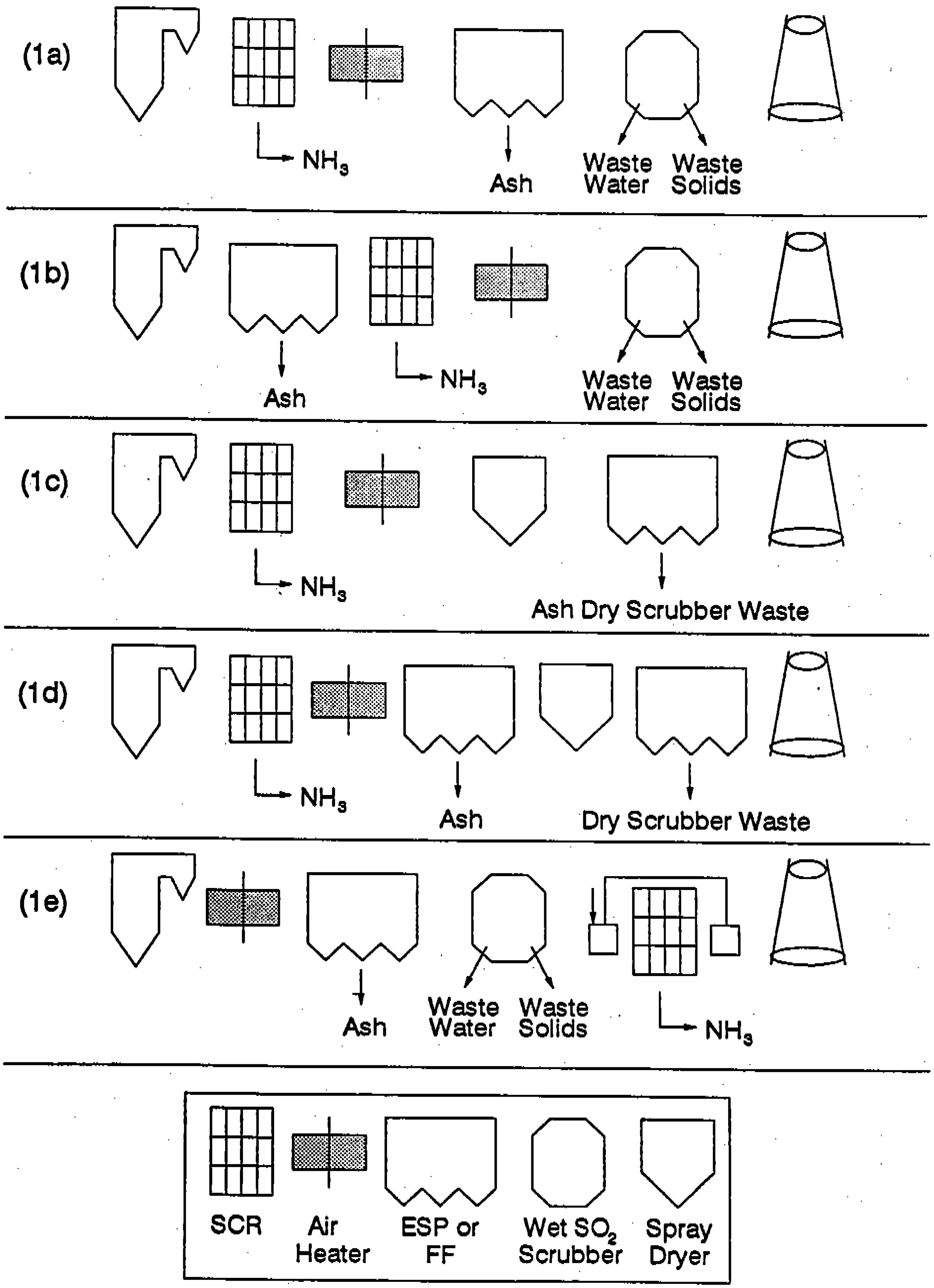


Figure 5-41. Possible configurations for SCR.[116]

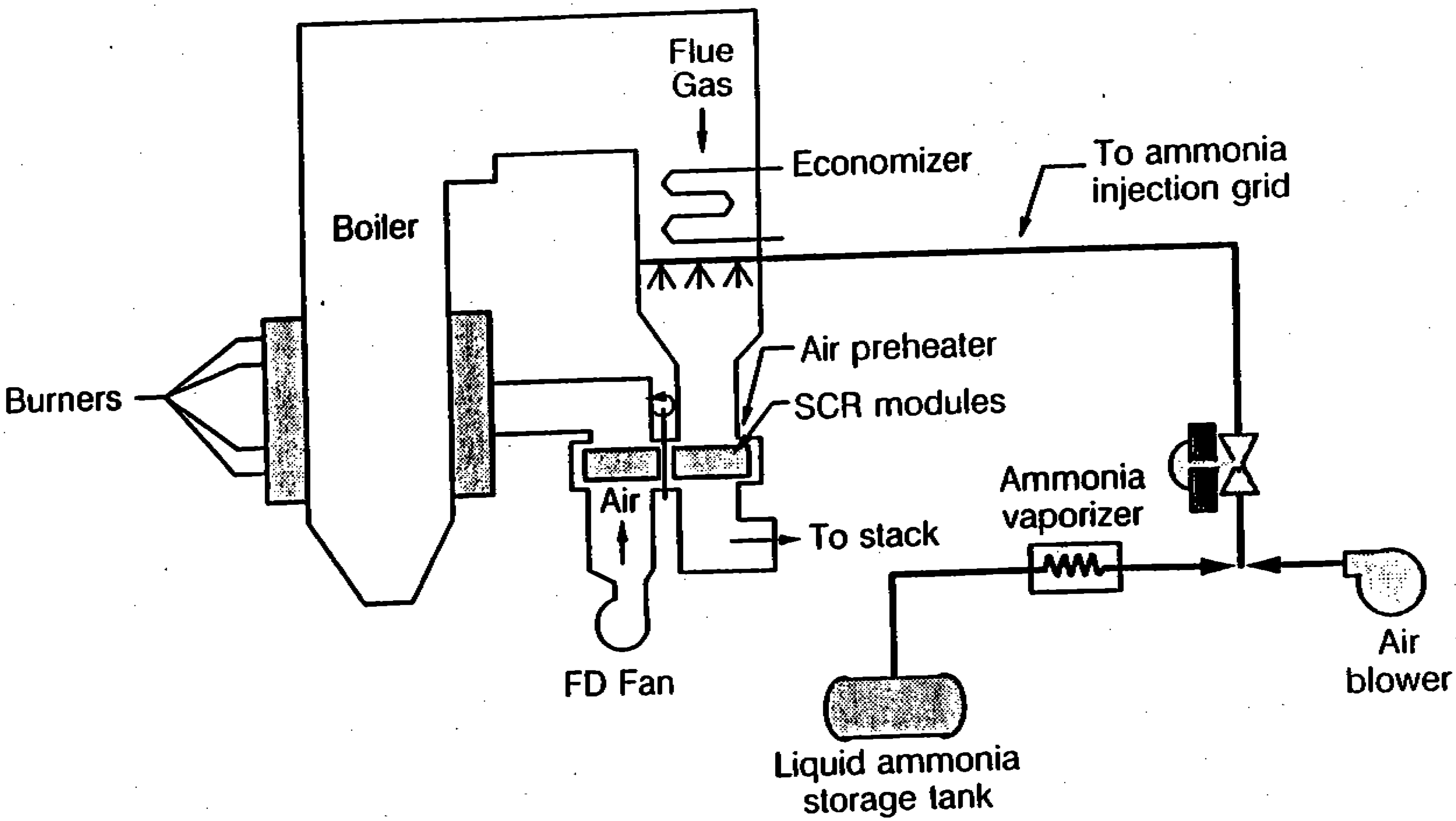


Figure 5-42. Ljungstrom air heater with catalyst coated elements.[118]

transition ductwork; and a continuous emission monitoring system. Anhydrous or dilute aqueous ammonia can be used; however, aqueous ammonia is safer to store and handle. The control system can be either feed-forward control (the inlet NO_x concentration and a preset NH_3/NO_x ratio are used), feed-back control (the outlet NO_x concentration is used to tune the ammonia feed rate), or a combination of the two.

The catalyst must reduce NO_x emissions without producing other pollutants or adversely affecting equipment downstream of the reactor. To accomplish this, the catalyst must have high NO_x removal activity per catalyst unit size, tolerance to variations in temperature due to boiler load swings, minimal tendency to oxidize NH_3 to NO and SO_2 to SO_3, durability to prevent poisoning and deactivation, and resist erosion by fly ash.

The SCR catalyst is typically composed of the active material, catalyst support material, and the substrate. The active compound promotes the NH_3/NO_x reaction and may be composed of a precious metal (e.g., Pt, Pd), a base metal oxide, or a zeolite. The entire catalyst cannot be made of these materials because they are expensive and structurally weak. The catalyst support (usually a metal oxide) provides a large surface area for the active material, thus enhancing the contact of the flue gas with the active material. The mechanical form that holds the active compound and catalyst support material is called the substrate. The individual catalyst honeycombs or plates are combined into modules, and the modules are applied in layers. Figure 5-43 shows a typical configuration for a catalyst reactor.[120] Figure 5-44 shows examples of relative optimum temperature ranges for precious metal, base metal, and zeolite catalysts.[115]

Some manufacturers offer homogeneous extruded monolithic catalysts that consist of either base metal oxide or zeolite formulations. The specific formulations contain ingredients that have mechanical strength and are stable. These catalysts

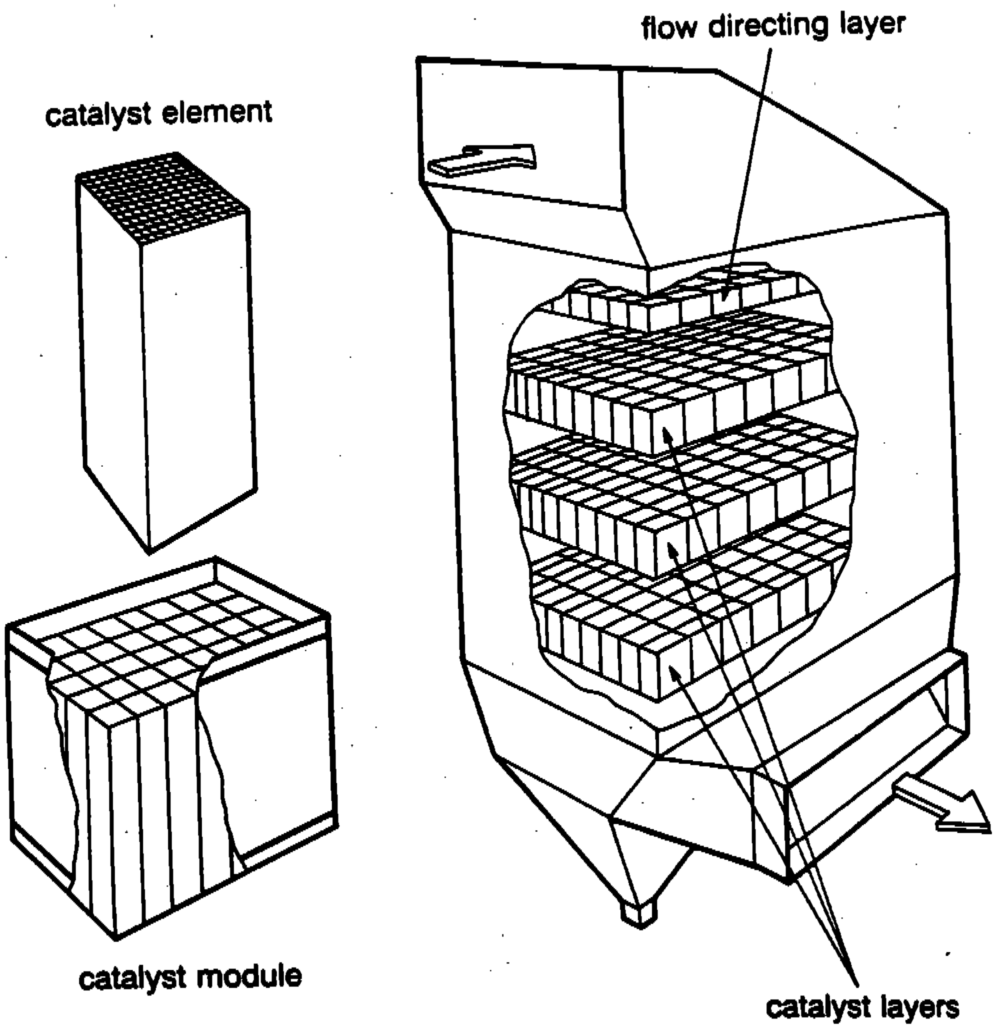


Figure 5-43. Typical configuration for a catalyst reactor.[120]

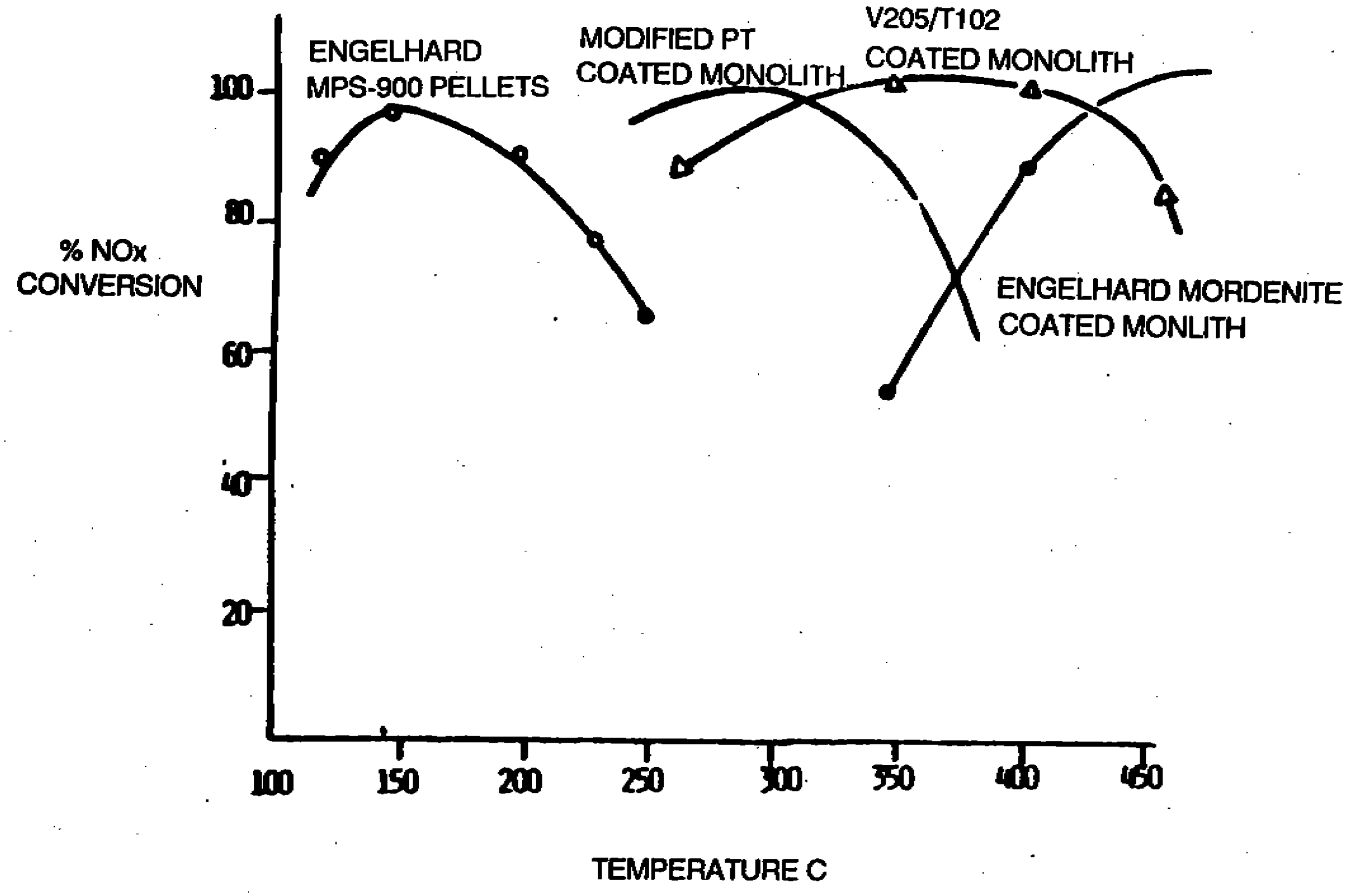


Figure 5-44. Example of optimum temperature range for different types of catalysts.[115]

are comparable in price to composite catalyst and have been installed in Europe and Japan.[121]

The precious metal catalysts are typically platinum (Pt) or palladium (Pd) based. They are primarily used in clean fuel applications and at lower temperatures than the base metal oxides or zeolite catalysts. The NO_x reduction efficiency of precious metal catalysts is reduced above 400 °C (750 °F) because the NH_3 oxidation reaction is favored.[115]

The most common commercially available base metal oxide catalysts are vanadium/titanium based, with vanadium pentoxide (V_2O_5) used as the active material and titanium dioxide (TiO_2) or a titanium oxide-silicon dioxide (SiO_2) as the support material.[122] Vanadium oxides are among the best catalysts for SCR of nitric oxide with ammonia because of their high activity at low temperatures (<400 °C [<750 °F]) and because of their high resistance to poisoning by sulfur oxides.[123]

The zeolite catalysts are crystalline aluminosilicate compounds. These catalysts are characterized by interconnected systems of pores 2 to 10 times the size of NO, NH_3, SO_2, and O_2 molecules. They absorb only the compounds with molecular sizes comparable to their pore size. The zeolite catalyst is reported to be stable over a wider temperature window than other types of catalyst.

The SCR catalyst is usually offered in extruded honeycomb or plate configurations as shown in figure 5-45.[124] Honeycomb catalysts are manufactured by extruding the catalyst-containing material through a die of specific channel and wall thickness. The pitch, or number of open channels, for coal-fired applications is larger than the pitch for oil or natural gas applications due to the increased amount of particulate matter with coal-firing. Plate catalysts are manufactured by pressing a catalyst paste onto a perforated plate or by dipping the plate into a slurry of catalyst resulting in a thin layer of catalyst material being applied to a metal screen or plate.

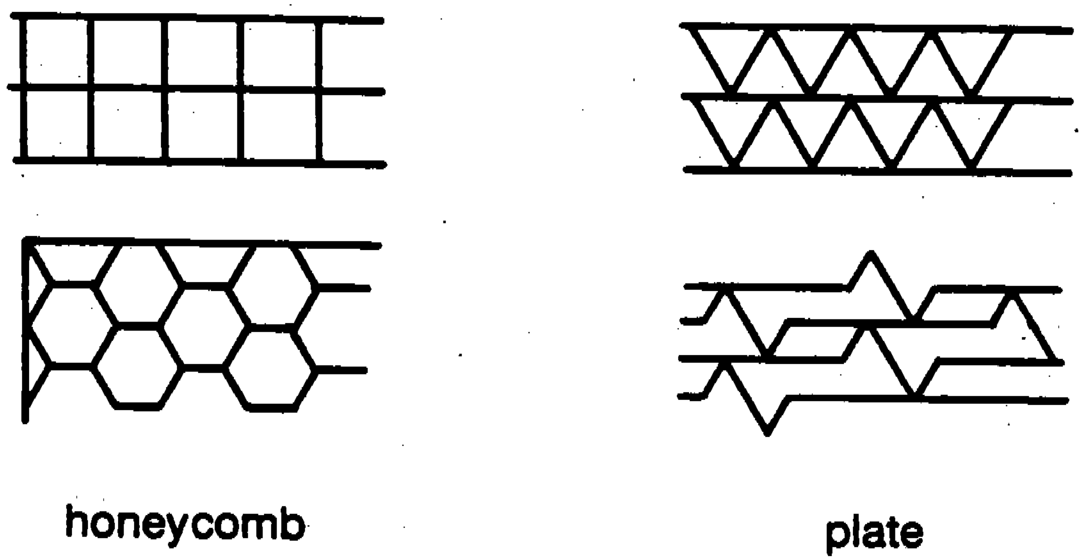


Figure 5-45. Configuration of parallel flow catalyst.[124]

5.3.2.2 Factors Affecting Performance

5.3.2.2.1 Coal-fired boilers. The performance of an SCR system is influenced by six factors: flue gas temperature, fuel sulfur content, NH_3/NO_x ratio, NO_x concentration at the SCR inlet, space velocity, and catalyst condition.

Temperature greatly affects the performance of SCR systems, and, as discussed earlier, each type of SCR catalyst has an optimum operating temperature range. Below this range, NO_x reduction does not occur, or occurs too slowly, which results in NH_3 slip. Above the optimum temperature, the NH_3 is oxidized to NO_x, which decreases the NO_x reduction efficiency. The optimum temperature will depend on the type of catalyst material being used.

The second factor affecting the performance of SCR is the sulfur content of the fuel. Approximately 1 to 4 percent of the sulfur in the fuel is converted to SO_3. The SO_3 can then react with ammonia to form ammonium sulfate salts, which deposit and foul downstream equipment. As can be seen in figure 5-46, the conversion of SO_2 to SO_3 is temperature dependent, with higher conversion rates at the higher temperatures.[125] The temperature-sensitive nature of SO_2 to SO_3 conversion is especially important for boilers operating at temperatures greater than 370 °C (700 °F) at the economizer outlet. Potential reaction equations for ammonium sulfate salts are:[126]

$$NH_3 \text{ (gas)} + SO_3 \text{ (gas)} + H_2O \text{ (gas)} \rightarrow NH_4HSO_4 \text{ (liquid)} \quad (5\text{-}24)$$

$$NH_4HSO_4 \text{ (liquid)} + NH_3 \text{ (gas)} \rightarrow (NH_4)_2SO_4 \text{ (solid)} \quad (5\text{-}25)$$

$$2\ NH_3 \text{ (gas)} + SO_3 \text{ (gas)} + H_2O \text{ (gas)} \rightarrow (NH_4)_2SO_4 \text{ (solid)} \quad (5\text{-}26)$$

With the use of medium- to high-sulfur coals, the concentration of SO_3 will likely be higher than experienced in most SCR applications to date. This increase in SO_3 concentration has the potential to affect ammonium sulfate salt formation. However, there is insufficient SCR

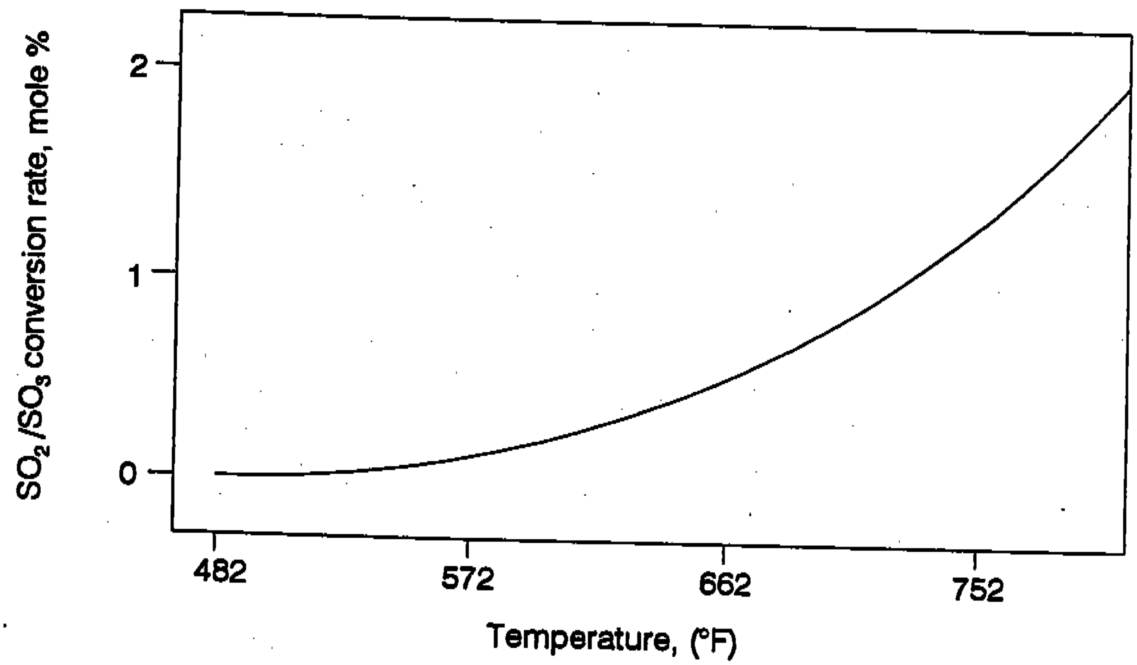


Figure 5-46. Effect of temperature on conversion of SO_2 to SO_3.[125]

application experience with medium- to high-sulfur coals to know the nature of the effects. Applications of SCR with medium- to high-sulfur coals may need to incorporate ways to minimize the impacts of ammonium sulfate salt formation and deposition.

The third factor affecting SCR performance is the ratio of NH_3 to NO_x. For NO_x reduction efficiencies up to approximately 80 percent, the NH_3-NO_x reaction follows approximately 1:1 stoichiometry. To achieve greater NO_x removal, it is necessary to inject excess NH_3, which results in higher levels of NH_3 slip.

The fourth factor affecting SCR performance is the concentration of NO_x at the SCR inlet. The NO_x reduction is relatively unchanged with SCR for inlet NO_x concentrations of 150 to 600 ppm.[127] However, at inlet concentrations below 150 ppm, the reduction efficiencies decrease with decreasing NO_x concentrations.[128]

The fifth factor affecting SCR performance is the gas flow rate and pressure drop across the catalyst. Gas flow through the reactor is expressed in terms of space velocity and area velocity. Space velocity (hr^{-1}) is defined as the inverse of residence time. It is determined by the ratio of the amount of gas treated per hour to the catalyst bulk volume. As space velocity increases, the contact time between the gas and the catalyst decreases. As the contact time decreases, so does NO_x reduction. Area velocity (ft/hr) is related to the catalyst pitch and is defined as the ratio of the volume of gas treated per hour to the apparent surface area of the catalyst. At lower area velocities, the NO_x in the flue gas has more time to react with NH_3 on the active sites on the catalyst; at higher area velocities, the flue gas has less time to react.[129]

The sixth factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NO_x removal decreases. Catalyst can be deactivated from wear resulting from attrition, cracking, or breaking over time, or from fouling by solid particle deposition in the catalyst pores and on the surface. Similarly, catalyst can be deactivated or "poisoned" when certain compounds (such as arsenic, lead, and alkali oxides) react with the active sites on the catalyst. Poisoning typically occurs over the long term, whereas fouling can be sudden. When the maximum temperature for the catalyst material is exceeded, catalysts can be thermally stressed or sintered, and subsequently deactivated. As the catalyst degrades by these processes, the NH_3/NO_x ratio must be increased to maintain the desired level of NO_x reduction. This can result in increased levels of NH_3 slip. However, the greatest impact of degradation is on catalyst life. Because the catalyst is a major component in the cost of SCR, reducing the life of the catalyst has a serious impact on the cost.

The top layer of catalyst is typically a "dummy" layer of catalyst used to straighten the gas flow and reduce erosion of subsequent catalyst layers. A metal grid can also be used as a straightening layer. The dummy layer is made of inert material that is less expensive than active catalyst material.[130] Active catalyst material can be replaced as degradation occurs in several different ways in order to maintain NO_x removal efficiency. First, all the catalyst may be replaced at one time. Second, extra catalyst may be added to the reactor, provided extra space has been designed into the reactor housing for this purpose. Third, part of the catalyst may be periodically replaced, which would extend the useful life of the remaining catalyst.

5.3.2.2.2 Oil and natural gas-fired boilers. The factors affecting the performance of SCR on coal-fired boilers are generally applicable to natural gas- and oil-firing. However, the effect may not be as severe on the natural gas- and oil-fired applications.

The six factors affecting SCR performance on coal-fired boilers were: flue gas temperature, fuel sulfur content, NH_3/NO_x ratio, NO_x concentration at the SCR inlet, space velocity, and catalyst condition. Of these, the fuel sulfur content will not be as much a factor in natural gas and oil firing applications because these fuels do not contain as much sulfur as coal. Therefore, there will not be as much SO_3 in the flue gas to react with excess ammonia and deposit in downstream equipment.

Another parameter which will not have as much impact in natural gas- or oil-fired boilers is the condition of the catalyst material. The SCR catalyst material can still be damaged by sintering or poisoned by certain compounds. However, since natural gas- and oil-fired boilers do not have as much fly ash as coal-fired boilers, the pores in the catalyst will not plug as easily and the surface of the catalyst would not be scoured or eroded due to the fly ash particles.

5.3.2.3 Performance of Selective Catalytic Reduction. Table 5-16 presents the results from pilot-scale SCR installations at two coal-fired boilers and one oil-fired boiler. The SCR pilot plants are equal to approximately 1 to 2 MW and process a slip-stream of flue gas from the boiler. Each pilot plant contained two different catalysts that were evaluated simultaneously. As of 1993, these pilot plants had been operating 2-3 years.

For the coal-fired SCR demonstration projects, the results indicate that 75-80 percent NO_x reduction has been achieved with ammonia slip of less than 20 ppm. The lower NO_x reduction and higher NH_3 slip for the oil-fired demonstration at the Oswego site were measured at higher-than-design space velocities. Note that these results are pilot facilities in which operating and process parameters can be carefully controlled.

To date, there are no full-scale SCR applications on oil- or coal-firing. However, as shown in table 5-16, Southern

TABLE 5-16. PERFORMANCE OF SCR ON U. S. UTILITY BOILERS

Utility	Unit	Fuel Type	SCR Type[a]	NH_3 slip (ppm)	NH_3 to-NO_x ratio	Reduction in NO_x emissions[b] (%)	Reference
PILOT-SCALE SYSTEMS							
NY State Elec. & Gas	Kintigh	Coal	Cold	<1 <1	0.8 0.8	80[c] 80[d]	131
Tennessee Valley Authority	Shawnee	Coal	Hot	1-7[e] 2-20[f]	0.8 0.8	75-80[e] 75-80[f]	132
Niagara Mohawk	Oswego	Oil	Hot	Up to 20[g] Up to 50[h]	0.8 0.8	75-80[g] 60-80[h]	133
FULL-SCALE SYSTEMS							
Southern California Edison	Huntington Beach 2	Gas	Hot	10-40	--	90	134

[a]Type: Cold = Cold-side, post-FGD SCR, after air preheater; and Hot = Hot-side, high-dust SCR, before air preheater

[b]Results are given for two different catalysts.

[c]Space velocity = 6,990 hr^{-1}; catalyst exposure time = 7,800 hours

[d]Space velocity = 8,940 hr^{-1}; catalyst exposure time = 2,400 hours.

[e]Space velocity = 3,240 hr^{-1}; catalyst exposure time = 3,600 to 14,000 hours.

[f]Space velocity = 2,200 hr^{-1}; catalyst exposure time = 1,500 to 7,700 hours.

[g]Space velocity = 4,350 to 17,400 hr^{-1};

[h]Space velocity = 6,900 to 27,400 hr^{-1};

-- = Data not available.

California Edison has a commercial size installation of SCR on their gas-fired Huntington Beach Unit 2 boiler. The NO_x reduction reported was approximately 90 percent with the highest level of NH_3 slip at 40 ppm.

The effect of catalyst exposure time and space velocity on catalyst performance was also examined for each of the pilot-scale demonstrations. Figures 5-47a and 5-47b show NO_x removal and NH_3 slip as a function of NH_3/NO_x ratio for two catalysts in a cold-side, post-FGD SCR demonstration at the Kintigh site.[130] The results show no change in the activity of either the extruded catalyst after 7,800 hours of operation or the replacement composite catalyst after 2,400 hours of operation. Each catalyst controlled NO_x emissions by 80 percent at an NH_3/NO_x ratio of 0.8 with a corresponding NH_3 slip of < 1 ppm.[131]

Figures 5-48a and 5-48b show performance results for two catalysts in the high-dust SCR demonstration at the Shawnee site.[132] The figures show a decrease in catalyst activity and an increase in residual NH_3 with increasing hours of operation for both catalysts. This deterioration in catalyst activity is more pronounced for the zeolite catalyst as shown in figure 5-48b.[132]

Figures 5-49a and 5-49b show the performance results for the two catalysts evaluated in the SCR application on the oil-fired boiler at the Oswego plant.[133] In each figure, the curves show the effect of space velocity on NO_x reduction as a function of NH_3/NO_x ratio. The effect of space velocity on NH_3 slip is also shown in the figures. The results show the expected decrease in NO_x reduction and increase in NH_3 slip at the higher space velocity for both catalysts. The effect is more pronounced on the V/Ti catalyst.[133]

5.3.3 <u>Selective Noncatalytic Reduction and Combustion Controls</u>

5.3.3.1 <u>Process Description</u>. Combustion controls such as LNBs and OFA may be used in combination with SNCR to reduce

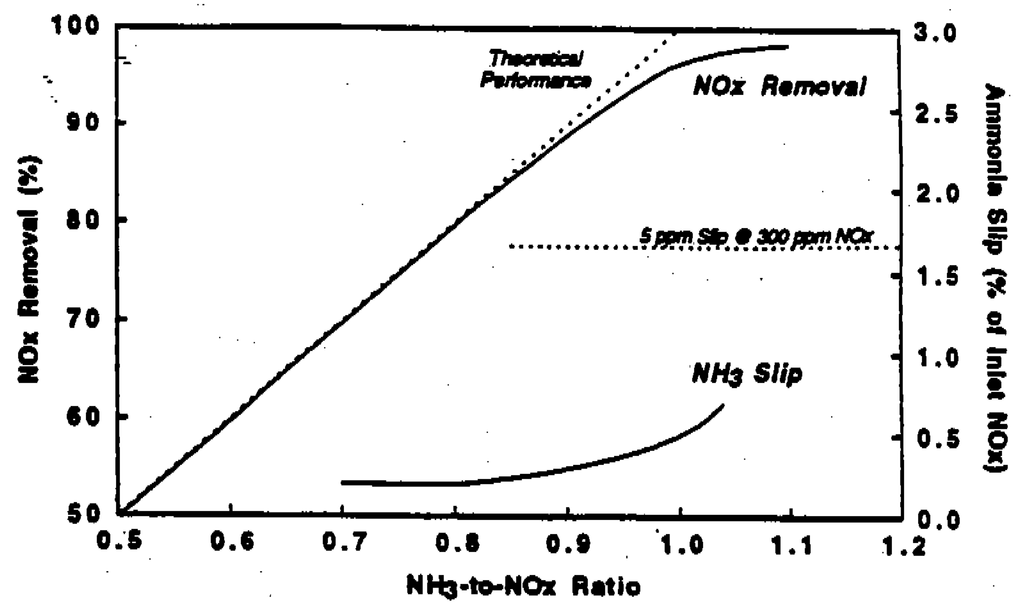


Figure 5-47a. Extruded catalyst NO_x conversion and residual NH_3 versus NH_3-to-NO_x Ratio.[131]

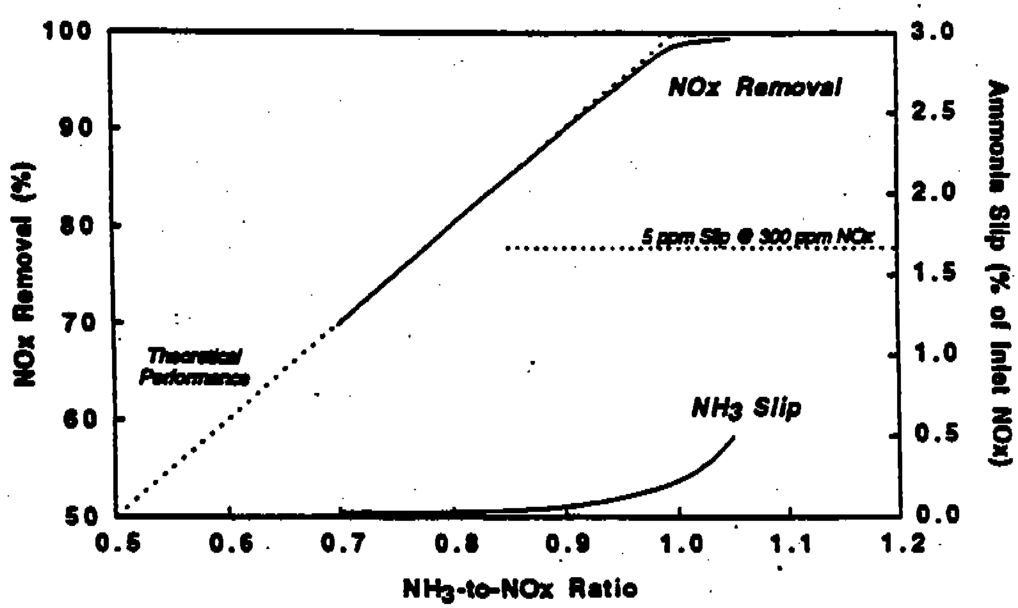


Figure 5-47b. Replacement composite catalyst NO_x conversion and residual NH_3 versus NH_3-to-NO_x Ratio.[131]

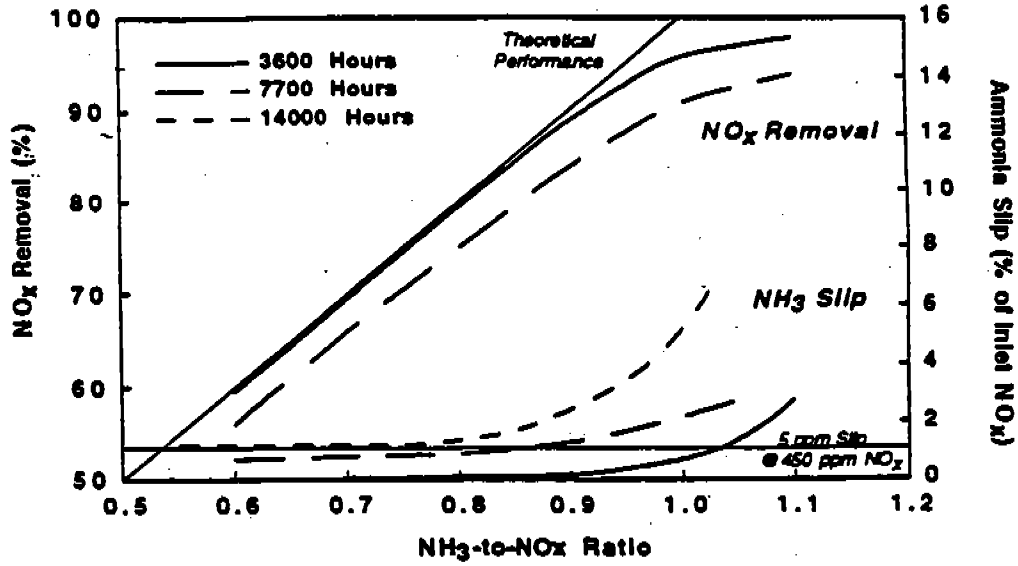


Figure 5-48a. V/Ti catalyst ammonia slip and NO_X removal versus ammonia-to-NO_X ratio.[132]

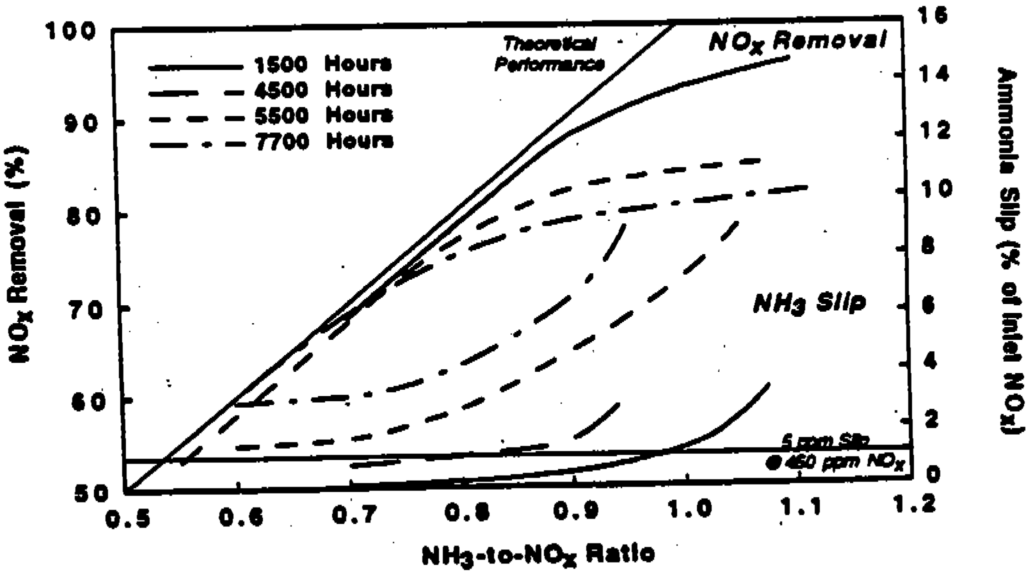


Figure 5-48b. Zeolite catalyst ammonia slip and NO_X removal versus ammonia-to-NO_X ratio.[132]

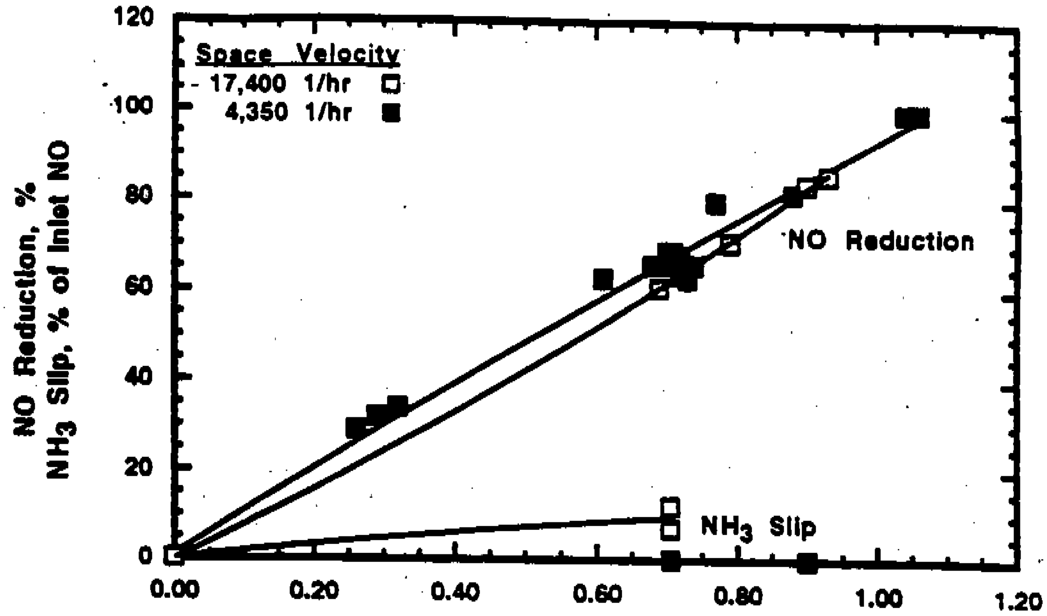


Figure 5-49a. T_1O_2 corrugated plate catalyst NO_x conversion and residual NH_3 versus NH_3-to-NO_x ratio.[133]

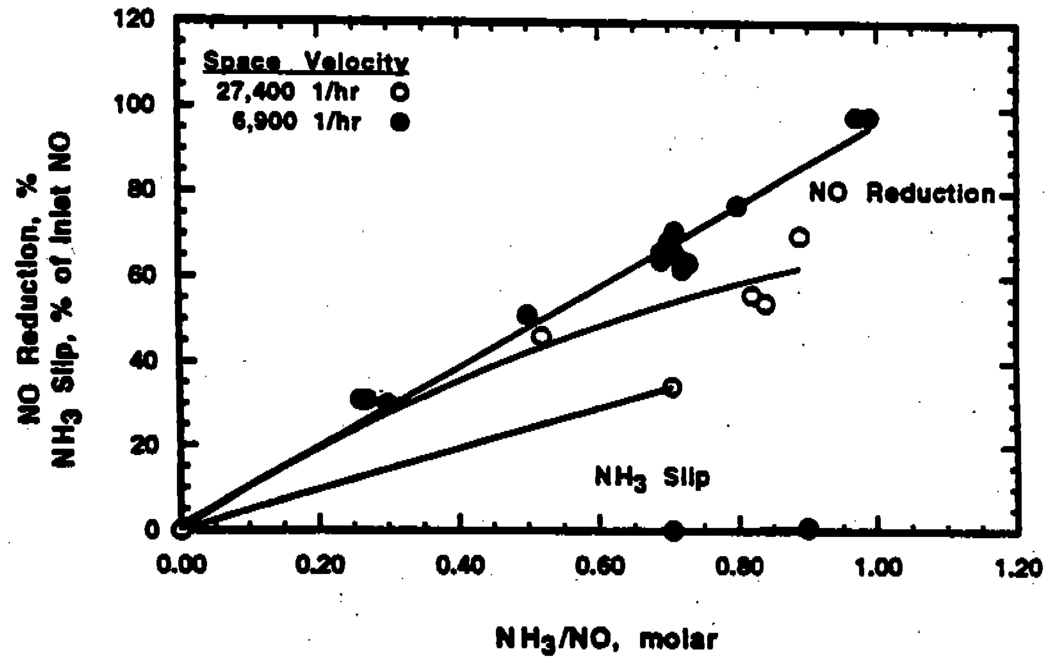


Figure 5-49b. Vanadium titanium extruded catalyst NO_x conversion and residual NH_3 versus NH_3-to-NO_x ratio.[133]

NO_x emissions on fossil fuel-fired utility boilers to achieve high levels of NO_x reduction. It may also be possible to employ operational modifications such as LEA, BOOS, and FGR to provide additional reductions in NO_x prior to the SNCR system.

The process descriptions for combustion controls for coal-fired boilers are presented in section 5.1 and combustion control descriptions for natural gas- and oil-fired boilers are presented in sections 5.2. Selective noncatalytic reduction is described in section 5.3.1.

5.3.3.2 Factors Affecting Performance. The same basic factors affecting the performance of individual combustion controls or SNCR will apply to these controls used in combination. However, since SNCR requires specific operating conditions such as gas temperature and residence time, the range of operating conditions for the combustion controls may be severely reduced if the combustion controls and SNCR system are designed incorrectly. When combining LNB + OFA + SNCR, some systems may be designed to achieve more NO_x reduction with the LNB + OFA and use SNCR to "trim" NO_x to desired levels. There are a very limited number of boilers employing a combination of these controls; therefore, all the factors affecting performance have not yet been identified.

The factors affecting the individual combustion controls for coal-, natural gas- and oil-fired applications are given in sections 5.1 and 5.2. The factors affecting SNCR are presented in section 5.3.2.

5.3.3.3 Performance of Combustion Controls and Selective Noncatalytic Reduction. There is one application of LNB + OFA + SNCR on a coal-fired boiler at Public Service Company of Colorado's Arapahoe Station Unit 4. This is a 100 MW roof-fired boiler. Short-term data from this unit is given in Table 5-17. The predicted NO_x reduction for LNB + OFA + SNCR was 70 percent; however, reported reductions have been 70-85 percent.

As was discussed in section 5.1.4.3.1, the LNB + OFA educed NO_x emissions across the load range by 60-70 percent.

TABLE 5-17. PERFORMANCE OF LNB + OFA + SNCR ON CONVENTIONAL U.S. UTILITY BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	Control type[b] (vendor)[c]	Length of test[d]	Molar N/NO ratio	Capacity tested	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)		Reference
ROOF-FIRED BOILER, BITUMINOUS COAL											
Public Service Co. of CO	Arapahoe 4	100	DRB-XCL + OFA + Urea (B&W, Noell)	Short	1.5	110	1.10	0.19	83	18	64
					1.0	110	1.10	0.21	81	8	
					0.75	110	1.10	0.24	78	5	
					1.5	100	1.10	0.16	85	30	64
					1.0	100	1.10	0.18	84	15	
					0.75	100	1.10	0.19	83	10	
					1.5	80	1.07	0.14	87	100	64
					1.0	80	1.07	0.16	85	45	
					0.75	80	1.07	0.18	79	25	
					1.0	60	1.00	0.27	73	8	64
					0.75	60	1.00	0.28	72	50	

[a]Standard: Pre-NSPS

[b]Control Type: DRB-XCL = Babcock & Wilcox; Dual Resister XCL Burner + Urea injection.

[c]Vendor: B&W = Babcock & Wilcox.

[d]Short = Short-term test data, i.e., hours.

The addition of SNCR reduced NO_x an additional 30-40 percent across the load range making a total reduction of approximately 70-85 percent.

The NH_3 slip was lowest (5-20 ppm) at 110 MW where the flue gas temperature are the highest. As the load and thus flue gas temperature are lowered, the NH_3 slip increases to as high as 100 ppm.

5.3.4 Selective Catalytic Reduction and Combustion Controls

5.3.4.1 Process Description. Combustion controls such as OFA + LNB can be used in combination with SCR to reduce NO_x emissions on fossil fuel-fired utility boilers to achieve the highest level of NO_x reduction. It may also be possible to use operational modifications such as LEA and BOOS, and FGR to reduce NO_x prior to the SCR reactor.

The process descriptions for combustion controls for coal-fired boilers are given in section 5.1 and the process descriptions for combustion controls for natural gas- and oil-fired boilers are presented in section 5.2. Selective catalytic reduction is described in section 5.3.2.

5.3.4.2 Factors Affecting Performance of Combustion Controls and Selective Catalytic Reduction. The same basic factors affecting the performance of individual combustion controls or SCR will apply to these controls used in combination. However, since SCR requires very rigid operating conditions such as flue gas temperature and gas flow rate, the range of operating conditions for the combustion controls may be severely reduced. There are very few boilers employing a combination of these controls; therefore, all the factors affecting performance have not yet been identified.

The factors affecting the individual combustion controls for coal-fired applications and natural gas- and oil-fired applications are given in sections 5.1 and 5.2. The factors affecting SCR are presented in section 5.3.2.

5.3.4.3 Performance of Combustion Controls and Selective Catalytic Reduction. There are no known retrofits of SCR on utility boilers that also have combustion controls.

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6.0 NO_x TECHNOLOGY CONTROL COSTS

This chapter presents the estimated cost and cost effectiveness of nitrogen oxide (NO_x) control technologies on fossil fuel-fired utility boilers. The section includes estimated total capital cost, annualized busbar cost (hereafter referred to as busbar cost), and cost effectiveness for 30 generic model plants, as well as information on the sensitivity of busbar cost and cost effectiveness to variations in key technical and economic assumptions. Sections 6.1 and 6.2 discuss costing methodology and the model plants, respectively. Sections 6.3 and 6.4 present the cost results for combustion modifications applied to coal-fired boilers and to natural gas- and oil-fired boilers, respectively. Section 6.5 presents the cost results for flue gas treatment and combination controls.

6.1 COSTING METHODOLOGY

This section describes the procedures used to estimate the capital and operating costs for new and retrofit NO_x control technologies, and how these costs were converted to busbar and cost effectiveness estimates. Cost procedures follow the general methodology contained in the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG)[1] and the Office of Air Quality (OAQPS) Costing Manual.[2] The general framework for handling capital and annual costs is shown in table 6-1. All costs are presented on 1991 dollars. However, cost indices for 1992 dollars are only 0.85 percent lower than 1991 dollars; therefore the values in this chapter are indicative of the 1991-1992 timeframe. The costing

TABLE 6-1. CAPITAL AND OPERATING COST COMPONENTS

Total capital cost	Direct cost	Basic system cost	Basic equipment Initial chemicals/catalyst Installation Start-up/optimization testing
		Retrofit cost	Scope adders Work area congestion
	Indirect cost		General facilities Engineering Royalty Fees Project contingency Process contingency
Total O&M Cost	Fixed O&M cost		Operating labor Maintenance labor Supervisory labor Maintenance materials
	Variable O&M cost		Energy penalty Chemicals/catalyst Electricity Water Waste disposal

procedures used to estimate the annualized cost of each NO_x control technology are presented in sections 6.3 through 6.5 immediately prior to the presentation of cost results for each technology.

6.1.1 Total Capital Cost

Total capital cost includes direct and indirect costs. Direct costs are divided into two categories: basic system cost and retrofit cost. This section describes the procedures for estimating basic system cost, retrofit cost, and indirect cost.

6.1.1.1 Basic System Cost. Basic system cost includes purchase and installation of system hardware directly associated with the control technology. This cost reflects the cost of the basic system components for a new application, but does not include any site-specific upgrades or modifications to existing equipment required to implement the control technology at an existing plant (e.g., new ignitors, new burner management system, and waterwall or windbox modifications). In addition, any initial chemical or catalyst costs and start-up/optimization tests are included in basic system cost. Costs associated with purchase and installation of continuous emission monitoring (CEM) equipment required for determining compliance with State and Federal emission limits are not included in the analysis.

The data used to estimate basic system cost for each technology were obtained from utility questionnaires, vendor information, published literature, and other sources. These cost data were then compiled in a data base, examined for general trends in capital cost versus boiler size (i.e., megawatt [MW]), and statistically analyzed using linear regression to fit a functional form of:

$$BSC = a * MW^b \qquad (6\text{-}1)$$

where:

BSC = Basic system cost ($/kW)

a = Constant derived from regression analysis

MW = Boiler size (MW)

b = Constant derived from regression analysis

The basic system cost for the model plants and sensitivity analyses were then derived for each NO_X control technology using equation 6-1 and the calculated values of "a" and "b."

6.1.1.2 <u>Retrofit Cost</u>. Installation of NO_X controls on an existing boiler is generally more costly than installation on a new unit. This increased cost is referred to as the retrofit cost.

Retrofit costs are partially due to upgrades and modifications to the boiler that are required for the NO_X control system to operate as designed. These modifications and upgrades are referred to as scope adders. Table 6-2 lists possible scope adders for the retrofit of combustion control systems (e.g., low NO_X burner [LNB], LNB + advanced overfire air [AOFA], reburn). A possible scope adder for selective noncatalytic reduction (SNCR) includes boiler control modifications. A possible scope adder for selective catalytic reduction (SCR) retrofit is the air heater replacement. Another factor that contributes to the retrofit cost is the restricted access and work space congestion caused by existing equipment and facilities. A boiler with relatively few obstructions is less costly to retrofit than a boiler with substantial access limitations and congestion in the work area.

For combustion control systems, scope adders contribute more to the retrofit cost than do access and congestion factors. Typically, burners and overfire air ports can be installed from inside the boiler, so exiting equipment does not interfere. For SCR, site access and congestion can contribute significantly to the retrofit cost. The retrofit cost is generally low for SNCR since few scope adders are necessary when adding an SNCR system, and site access and congestion are less critical than in SCR applications.

To estimate the total direct cost (basic system cost + retrofit cost), the basic system cost is multiplied by a

TABLE 6-2. POSSIBLE SCOPE ADDERS FOR RETROFIT OF COMBUSTION CONTROLS

Scope adders
Ignitors (Modify)
Ignitors (Replace)
Waterwall Modifications
Flame Scanners
Pulverizer Modifications
Boiler Control Modifications
Burner Management
Coal Piping Modifications
Windbox Modifications
Structural Modifications
Asbestos Removal
Insulation
Electrical System Modifications
Fan Modifications
Demolition

retrofit factor. The retrofit factor accounts for the retrofit cost as a percentage of the basic system cost. For example, a retrofit factor of 1.3 indicates that the retrofit cost is 30 percent of the basic system cost. Retrofit factors were developed for each NO_x control technology based on cost data for planned or actual installations of individual NO_x control technologies to existing utility boilers. The cost data were also used to estimate low, medium, and high retrofit factors for the model boiler analysis. A low retrofit factor of 1.0 could indicate a new unit or an existing unit requiring minimal, if any, upgrade or modification, and the work area is easily accessible. A medium retrofit factor reflects moderate equipment upgrades or modifications and/or some congestion in the work area. A high retrofit factor indicates that extensive scope adders are required and/or substantial access limitations and congestion of the work area.

6.1.1.3 <u>Indirect Costs</u>. Indirect costs include general facilities, engineering expenses, royalty fees, and contingencies. General facilities include offices, laboratories, storage areas, or other facilities required for installation or operation of the control system. Examples of general facilities are expansion of the boiler control room to house new computer cabinets for the boiler control system, or expansion of an analytical laboratory. Engineering expenses include the utility's internal engineering efforts and those of the utility's architect/engineering (A&E) contractor. Engineering costs incurred by the technology vendor are included in the equipment cost and are considered direct costs.

There are two contingency costs: project contingency and process contingency. Project contingency is assigned based on the level of detail in the cost estimate. It is intended to cover miscellaneous equipment and materials not included in the direct cost estimate. Project contingencies range from 5 to 50 percent of the direct costs, depending on the level of detail included in the direct cost estimate. Generally, the more detailed the cost estimate, the less the project contingency required. Process contingency is based on the maturity of the technology and the number of previous installations. Process contingency covers unforeseen expenses incurred because of inexperience with newer technologies. Process contingencies range from 0 to 40+ percent of the direct costs. Generally, the older and more mature the technology, the less process contingency required.

To estimate the total capital cost (total direct cost + indirect costs), the total direct cost is multiplied by a indirect cost factor. The indirect cost factor accounts for the indirect costs as a percentage of the total direct cost. For example, an indirect cost factor of 1.3 indicates that the indirect costs are 30 percent of the total direct cost. Indirect cost factors were developed for each NO_X technology. These indirect cost factors are based on cost data from planned and actual installations of individual NO_X control technologies to different boilers.

6.1.2 <u>Operating and Maintenance Costs</u>

Operating and maintenance (O&M) costs include fixed and variable O&M components. Fixed O&M costs include operating, maintenance, and supervisory labor, and maintenance materials. Fixed O&M are assumed to be independent of capacity factor. Variable O&M costs include any energy penalty resulting from efficiency losses associated with a given technology, and chemical, electrical, water, and waste disposal costs. Variable O&M costs are dependent on capacity factor.

Cost rates for labor and materials included in the cost estimates are shown in table 6-3. The prices listed for coal, residual oil, distillate oil, and natural gas are the estimated national average prices for the year 2000, using the reference case analysis of the Department of Energy's (DOE's) 1992 Annual Energy Outlook.[3] The prices listed for ammonia and urea are average values obtained from vendors. Prices for labor, solid waste, electricity, water, and high pressure

TABLE 6-3. FIXED AND VARIABLE O&M UNIT COSTS

Item	Cost	Unit	Reference
Operating labor	20.00	$/man-hr	1
Maintenance labor	20.00	$/man-hr	1
Coal	1.74	$/MMBtu	3
Residual oil	4.62	$/MMBtu	3
Distillate oil	5.73	$/MMBtu	3
Natural gas	3.27	$/MMBtu	3
Ammonia	145.00	$/ton	4, 5, 6, 7
Urea	200.00[a]	$/ton of 50% urea solution by wt.	8, 9, 10, 11
Solid waste	9.50	$/ton	1
Electricity	0.05	$/kWh	1
Water	0.60	$/1000 gal	1
High pressure steam	3.50	$/1000 lb	1

[a]Note that the cost for urea is listed for a 50 percent urea solution. $200/ton of 50 percent solution is roughly equivalent to $400/ton urea on a dry basis.

steam, are listed in 1989 dollars. These quantities do not have a major influence on total O&M costs, and therefore, more recent values were not used.

6.1.3 Calculation of Busbar Cost and Cost Effectiveness

Busbar cost is the sum of annualized capital costs and total O&M costs divided by the annual electrical output of the boiler. Busbar cost is commonly expressed in mills/kWh (1 mill = $0.001) and is a direct indicator of the cost of the control technology to the utility and its customers. To convert total capital cost to an annualized capital charge, the total capital cost is multiplied by an annual capital recovery factor (CRF). The CRF is based on the economic life over which the capital investment is amortized and the cost of capital (i.e., interest rate), and is calculated using the following equation:

$$CRF = i(1+i)^n/[(1+i)^n-1] \tag{6-2}$$

where:

i = interest rate [assumed to be 0.10 (i.e., 10 percent) throughout this study]

n = the economic life of the equipment

Cost-effectiveness values indicate the total cost of a control technology per unit of NO_x removed and are calculated by dividing the total annualized capital charge and O&M expense by the annual reduction in tons of NO_x emitted from the boiler.

Example calculations of these values are provided in appendix A.1.

6.2 MODEL PLANT DEVELOPMENT

To estimate the capital cost, busbar cost, and cost effectiveness of NO_x control technologies, a series of model plants were developed. These model plants reflect the projected range of size, duty cycle, retrofit difficulty, economic life, uncontrolled NO_x emissions, and controlled NO_x emissions for each major boiler type and NO_x control technology. In addition, cost estimates were developed to illustrate the sensitivity of busbar costs and cost effectiveness to variations in each of the above parameters. Key design and operating specifications for the model plant boilers are presented in section 6.2.1. The NO_x control technologies applied to each model plant type are presented in section 6.2.2. The procedures used to estimate the sensitivity of busbar cost and cost effectiveness to key design and operating assumptions are described in section 6.2.3.

6.2.1 Model Boiler Design and Operating Specifications

Thirty model plants were selected to represent the population of existing and projected utility boilers. These model plants represent six groups of boilers: coal-fired wall, tangential, cyclone, and fluidized bed combustion (FBC) boilers; and natural gas- and oil-fired wall and tangential boilers. Within each of these groups, five model boilers were selected to estimate the range of total capital costs ($/kW), busbar cost (mills/kWh), and cost effectiveness ($/ton of NO_x removed) for individual NO_x control technologies. These five model boilers represent the typical range of plant size and duty cycle that exist for a given boiler type. For every group except the FBC boilers, the models include a large (600 MW) baseload unit, medium-size (300 MW) cycling and baseload units, and small (100 MW) peaking and baseload units. Because of the limitations on the size of FBC boilers, the FBC model plants are smaller than the other categories model plants and also have different duty cycles. The FBC model plants include a large (200 MW) baseload boiler, medium-size (100 MW) cycling and baseload units, and small (50 MW) cycling and baseload units.

For defining the model plants, the economic life of the control technology was assumed to be 20 years. Key design and operating characteristics for each of the 30 model plants are listed in table 6-4.

6.2.2 NO_x Control Alternatives

Eight NO_x control alternatives were selected for analysis:

TABLE 6-4. DESIGN AND OPERATING CHARACTERISTICS OF MODEL BOILERS

Fuel type	Furnace type	Boiler capacity, MW	Capacity factor, %	Heat rate, Btu/kWh	Uncontrolled NO_x, lb/MMBtu
Coal	Wall	100	10	12,500	0.9
Coal	Wall	100	65	10,000	0.9
Coal	Wall	300	30	11,000	0.9
Coal	Wall	300	65	10,000	0.9
Coal	Wall	600	65	10,000	0.9
Coal	Tangential	100	10	12,500	0.7
Coal	Tangential	100	65	10,000	0.7
Coal	Tangential	300	30	11,000	0.7
Coal	Tangential	300	65	10,000	0.7
Coal	Tangential	600	65	10,000	0.7
Coal	Cyclone	100	10	12,500	1.5
Coal	Cyclone	100	65	10,000	1.5
Coal	Cyclone	300	30	11,000	1.5
Coal	Cyclone	300	65	10,000	1.5
Coal	Cyclone	600	65	10,000	1.5
Coal	FBC	50	30	11,000	0.19
Coal	FBC	50	65	10,000	0.19
Coal	FBC	100	30	11,000	0.19

TABLE 6-4. DESIGN AND OPERATING CHARACTERISTICS OF MODEL BOILERS (Concluded)

Fuel type	Furnace type	Boiler capacity, MW	Capacity factor, %	Heat rate, Btu/kWh	Uncontrolled NO_x, lb/MMBtu
Coal	FBC	100	65	10,000	0.19
Coal	FBC	200	65	10,000	0.19
Gas/Oil	Wall	100	10	12,500	0.5
Gas/Oil	Wall	100	65	10,000	0.5
Gas/Oil	Wall	300	30	11,000	0.5
Gas/Oil	Wall	300	65	10,000	0.5
Gas/Oil	Wall	600	65	10,000	0.5
Gas/Oil	Tangential	100	10	12,500	0.3
Gas/Oil	Tangential	300	30	11,000	0.3
Gas/Oil	Tangential	100	65	10,000	0.3
Gas/Oil	Tangential	300	65	10,000	0.3
Gas/Oil	Tangential	600	65	10,000	0.3

- four combustion control alternatives (operational modifications, LNB, LNB + AOFA, and reburn);
- two flue gas treatment alternatives (SNCR and SCR); and
- two combinations of combustion and flue gas treatment (LNB + SNCR and LNB + AOFA + SCR).

Operational modifications (described in section 5.1) include low excess air (LEA), burners-out-of-service (BOOS), and biased burner firing (BF). To estimate the costs of operational modifications, LEA + BOOS was selected as an example of this option.

Tangentially-fired boilers with either close-coupled overfire air (CCOFA) or no overfire air (OFA) ports were classified in the LNB category (e.g., low NO_x concentric firing system [LNCFS] I, discussed in section 5.1.4). Tangentially-fired boilers with separated OFA systems were classified in the LNB + AOFA category (e.g., LNCFS III, discussed in section 5.1.4). As defined in section 5.1, wall-fired units may have OFA or AOFA systems. However, because retrofit data were available only for the LNB + AOFA systems and because of its higher NO_x reduction potential, analysis is limited to LNB + AOFA.

The matrix of control alternatives applied to each of the four groups of model boilers is shown in table 6-5. Performance levels used for each model boiler and control alternative are discussed in conjunction with the cost results in sections 6.3 through 6.5.

6.2.3 Sensitivity Analysis

In addition to the model plant analysis, a sensitivity analysis is conducted for each NO_x control technology to examine the effect of varying selected plant design and operating characteristics on the technology's busbar cost and cost effectiveness. For each NO_x control technology, a reference boiler is selected to illustrate the results of the sensitivity analysis. These results are presented in two graphs for each technology/reference boiler combination.

TABLE 6-5. NO_x CONTROL ALTERNATIVES EVALUATED

NO_x control alternative	Coal-fired boilers				Natural gas- and oil-fired	
	Wall	Tangential	Cyclone	FBC	Wall	Tangential
Operational controls					X	X
LNB[a]	X	X			X	X
LNB+AOFA	X	X			X	X
Reburn	X	X	X		X	X
SNCR	X	X	X	X	X	X
SCR	X	X	X		X	X
LNB+SNCR	X	X			X	X
LNB+AOFA+SCR	X	X			X	X

[a]For tangentially-fired boilers, LNB includes close-coupled OFA.

As an example, the results of the sensitivity analysis for a coal-fired tangential boiler retrofit with LNB are shown in figures 6-1 and 6-2. The two figures show the effects of seven independent parameters (retrofit factor, boiler size, capacity factor, economic life, uncontrolled NO_x levels, NO_x reduction efficiency, and average annual heat rate) on cost effectiveness and busbar cost. Key performance and cost parameters for this reference boiler are a 1.3 retrofit factor, a 40-percent capacity factor, a 20-year economic life, a 0.7 lb/MMBtu controlled NO_x emission rate, a 45-percent reduction in NO_x due to the LNB retrofit, and an 11,000 Btu/kWh average annual heat rate.

Figure 6-1 examines the effect of varying four of the seven parameters (retrofit factor, boiler size, capacity factor, and economic life). The central point on the graph reflects the cost effectiveness ($238 per ton) and busbar cost (0.41 mills/kWh) for LNB applied to the reference boiler. Each of the four curves emanating from the central point illustrates the effect of changes in the individual parameter on cost effectiveness and busbar cost, while holding the other six parameters constant (this number includes the other three parameters shown on figure 6-1 and the three parameters illustrated in figure 6-2). Thus, each curve isolates the effect of the selected independent parameter on cost effectiveness and busbar cost. For example, a smaller boiler size, such as 200 MW, results in an estimated increase in the cost effectiveness value from $238 to $314 per ton and an increase in busbar cost from 0.41 mills/kWh to 0.54 mills/kWh.

Figure 6-2 illustrates the sensitivity of cost effectiveness to the remaining three parameters (uncontrolled

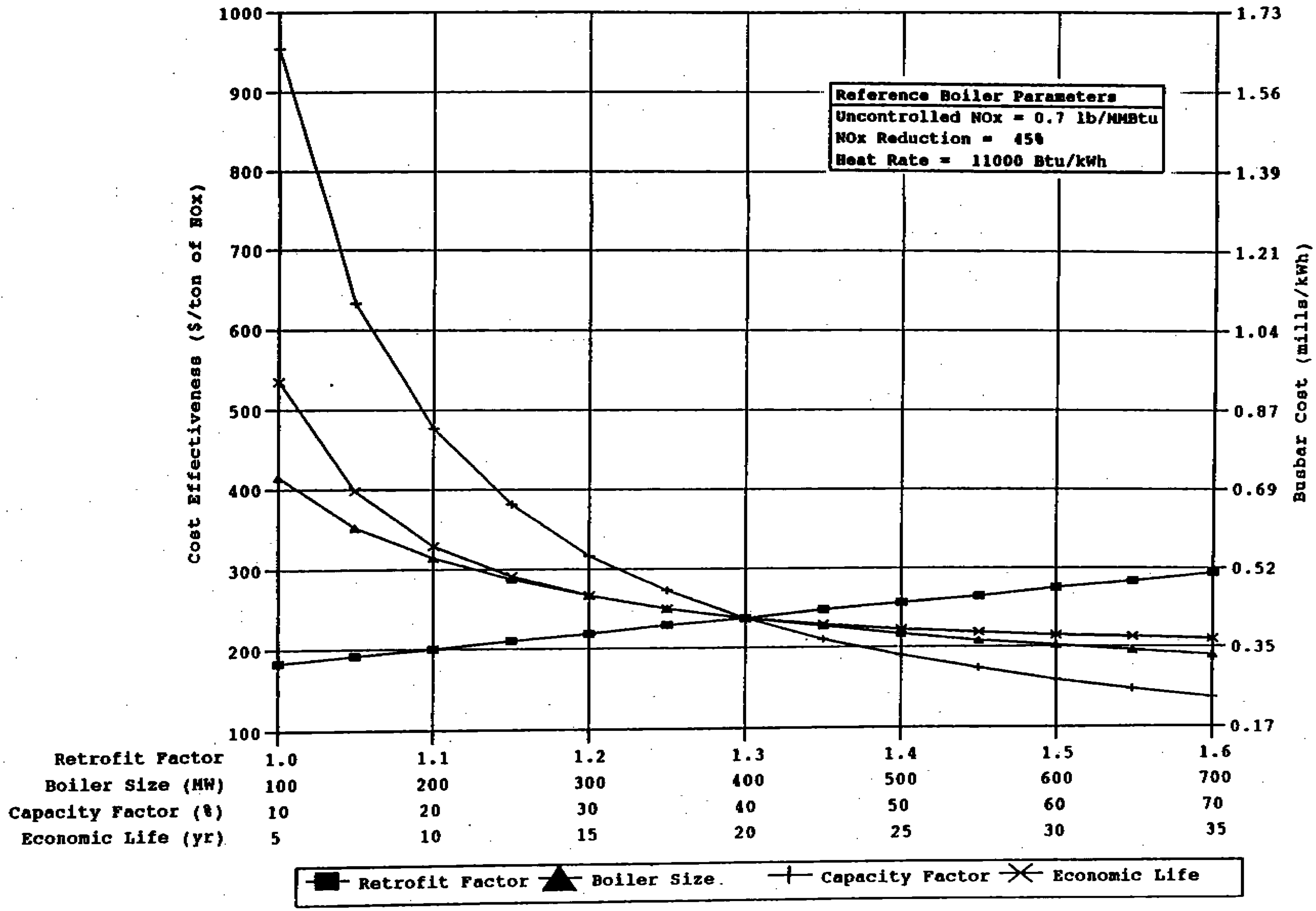

Figure 6-1. Impact of plant characteristics on LNB cost effectiveness and busbar cost for coal-fired tangential boilers.

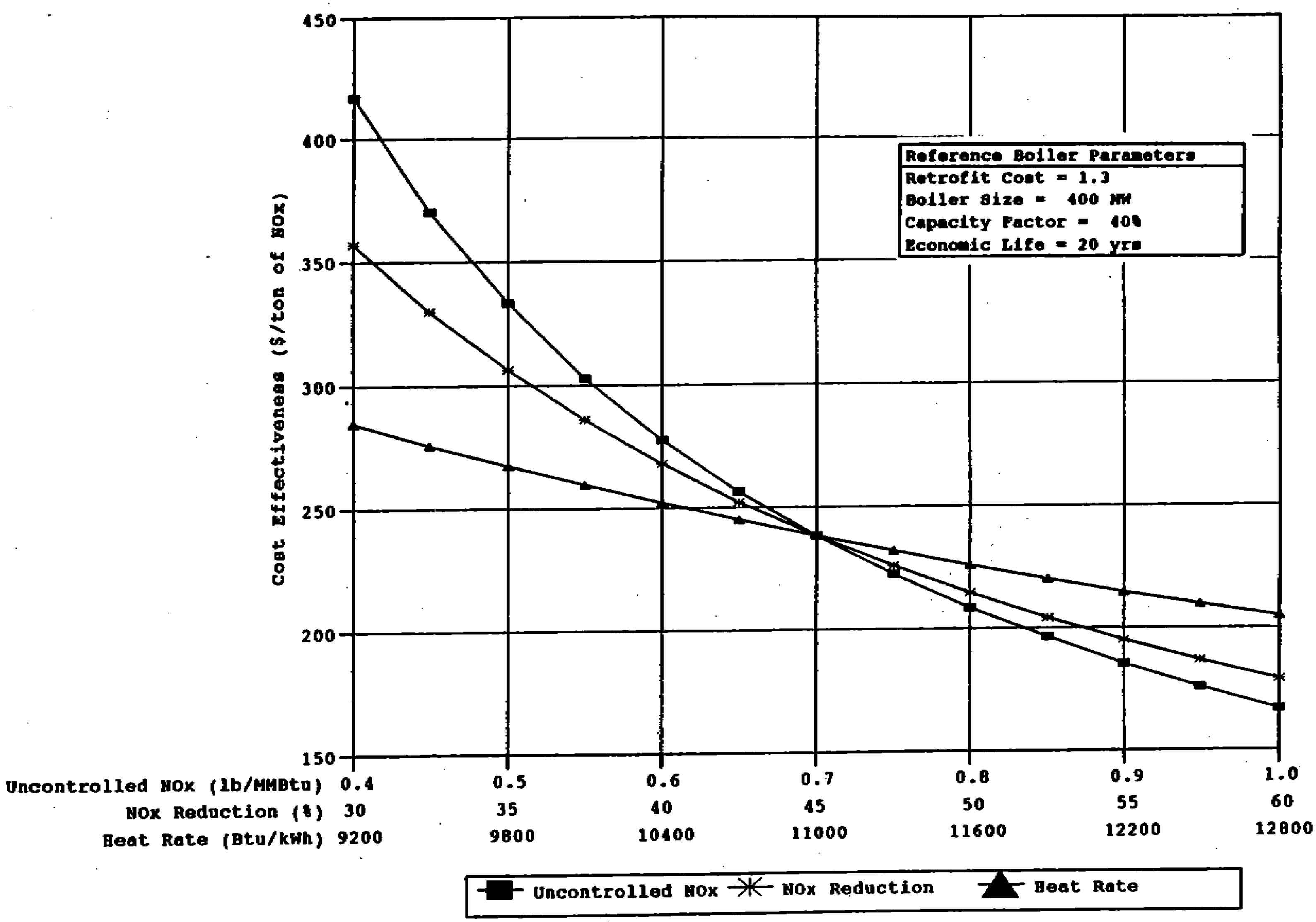

Figure 6-2. Impact of NO_x emission characteristics and heat rate on LNB cost effectiveness for coal-fired tangential boilers.

NO_x levels, NO_x reduction efficiency, and heat rate).[a] As with figure 6-1, the central point on the graph reflects the cost effectiveness and busbar cost for LNB applied to the reference boiler. Each of the three curves emanating from the central point illustrates the effect of changes in the individual parameter on cost effectiveness, while holding the other six parameters constant. Use of the curves to estimate the sensitivity of cost effectiveness to changes in an independent parameter is the same as with figure 6-1.

The independent plant design and operating parameters used in the sensitivity analyses for other control technologies will vary from those listed in the example above.

6.3 COMBUSTION MODIFICATIONS FOR COAL-FIRED BOILERS

This section presents the total capital cost, busbar cost, and cost effectiveness estimates for LNB, LNB + AOFA, and reburn applied to coal-fired boilers. Cost estimates for AOFA by itself are included with the discussion of LNB + AOFA.

6.3.1 Low NO_x Burners

Cost estimates for LNB technology are presented in this section for coal-fired wall and tangential boilers.

6.3.1.1 Costing Procedures. Costing procedures for LNB applied to wall-fired boilers were based on data obtained from 10 units, ranging in size from 130 to 800 MW. These data included seven cost estimates and three actual installation costs. These data are summarized in appendix A-2.

No cost data were available for LNB applied to tangentially-fired units (LNCFS I). Therefore, vendor information on the relative cost of LNB and close-coupled OFA (LNCFS I) and LNB + close-coupled and separated OFA (LNCFS III) was used to develop the LNCFS I cost algorithm for

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[a]Because of the inter-relationships between cost effectiveness and busbar cost, it is not possible to simultaneously graph the effect on both values of changes to uncontrolled NO_x levels, NO_x reduction efficiency, and heat rate. If busbar cost estimates are needed, refer to the cost procedures provided in appendix A.

tangentially-fired units. This information indicates that LNB costs for tangential units are approximately 55 percent of the cost of LNB + AOFA.[12] Based on this information, the LNCFS III cost algorithm for tangentially-fired boilers (refer to section 6.3.2) was adjusted for LNCFS I so that LNCFS I costs are about 40 percent lower than LNCFS III. A scaling factor of 0.60 (b=-0.40) was assumed for LNCFS I. Details on these calculations are provided in appendix A.3.

The basic system cost coefficients used in equation 6-1 for wall-fired LNB systems were calculated to be a=220 and b=-0.44, based on the available cost data discussed above. For tangentially-fired LNB systems, the cost coefficients were calculated to be a=80 and b=-0.40, based on adjustments of the LNCFS III cost algorithm.

Retrofit costs for wall-fired LNB systems averaged 15 percent of the basic system cost (retrofit factor of 1.15) based on the available installation data. For tangentially-fired LNB systems, a retrofit factor of 1.15 was also assumed. For the model plant analysis, low, medium, and high retrofit factors of 1.0, 1.3, and 1.6 were used.

For both wall-fired and tangentially-fired LNB systems, indirect costs were estimated at 30 percent of basic system and retrofit costs. Fixed and variable O&M costs were assumed to be negligible.

6.3.1.2 Model Plants Results. The capital cost, busbar cost, and cost effectiveness for the ten wall- and tangentially-fired model boilers are presented in table 6-6. An economic life of 20 years and a NO_x reduction efficiency of 45 percent were assumed for all of the model boilers. For the 600 MW baseload wall-fired boiler, the estimated cost effectiveness ranges from $175 to $279 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $2,000 to $3,200 per ton.

Cost per ton of NO_x removed with LNB on tangential boilers is lower than LNB on wall-fired boilers because of

TABLE 6-6. COSTS FOR LNB APPLIED TO COAL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Retrofit factor	1.0	1.3	1.6	1.0	1.3	1.6	1.0	1.3	1.6
Wall-fired boilers[a]									
100 MW, Peaking[b]	38	49	60	5.06	6.57	8.06	2,000	2,600	3,200
100 MW, Baseload[c]	38	49	60	0.78	1.01	1.24	380	499	615
300 MW, Cycling[d]	23	30	37	1.04	1.35	1.66	467	606	746
300 MW, Baseload	23	30	37	0.48	0.62	0.77	237	308	379
600 MW, Baseload	17	22	27	0.35	0.46	0.57	175	227	279
Tangentially-fired boilers[e]									
100 MW, Peaking	16	21	26	2.21	2.87	3.54	1,120	1,460	1,800
100 MW, Baseload	16	21	26	0.34	0.44	0.54	216	281	345
300 MW, Cycling	11	14	17	0.47	0.62	0.76	274	356	438
300 MW, Baseload	11	14	17	0.22	0.28	0.35	139	181	223
600 MW, Baseload	8	10	13	0.17	0.22	0.27	105	137	169

[a]Uncontrolled NO_x levels of 0.90 lb/MMBtu and an LNB NO_x reduction of 45 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.70 lb/MMBtu and an LNB NO_x reduction of 45 percent were used for tangentially-fired boilers.

lower capital cost associated with LNCFS I. The cost effectiveness for the 600 MW tangentially-fired boiler ranges from $105 to $169 per ton. For the 100 MW peaking tangentially-fired boiler, cost effectiveness ranges from $1,120 to $1,800 per ton.

6.3.1.3 Sensitivity Analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-3. Figure 6-4 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in figure 6-4, because equal percent changes in uncontrolled NO_x and NO_x reductions result in equivalent changes in cost effectiveness, these two curves overlap. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $400 per ton of NO_x removed and 0.90 mills/kWh.

Of the plant characteristics, the variation of capacity factor from 10 to 70 percent has the greatest impact on cost effectiveness and busbar cost. The cost effectiveness value and busbar cost are inversely related to capacity factor, and thus, as capacity factor decreases, the cost effectiveness value and busbar cost increase. This is especially noticeable at low capacity factors where a decrease of 75 percent in the reference plant's capacity factor (from 40 percent to 10 percent) results in an increase in the cost effectiveness value and busbar cost of nearly 300 percent.

Variations in economic life and boiler size follow a trend similar to capacity factor, but do not cause as great a change in cost effectiveness and busbar cost. For example, a decrease of 75 percent in economic life (from 20 to 5 years) results in an increase in the plant's cost effectiveness value and busbar cost of nearly 125 percent. Similarly, a decrease of 75 percent in boiler size (from 400 to 100 MW) results in

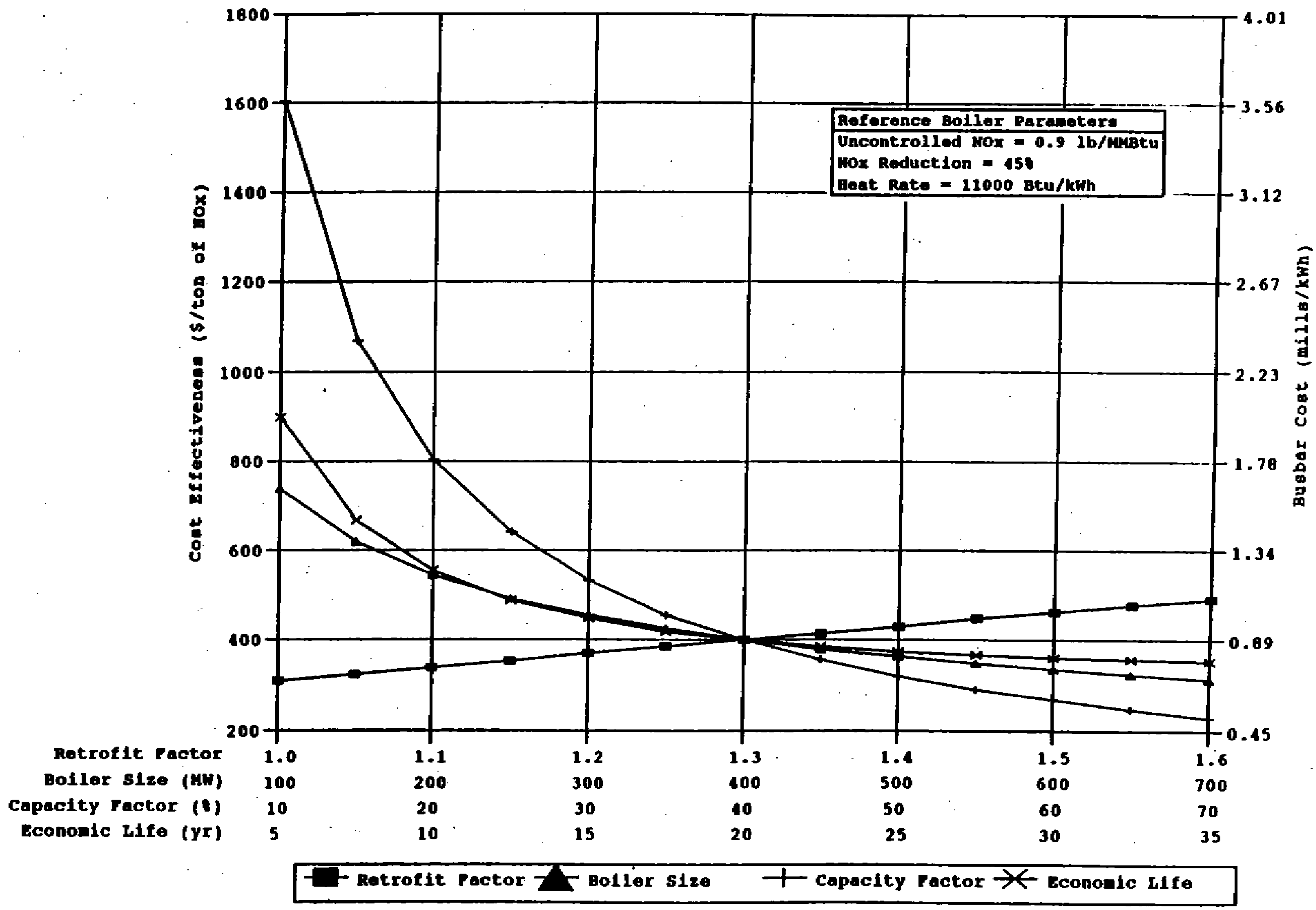

Figure 6-3. Impact of plant characteristics on LNB cost effectiveness and busbar cost for coal-fired wall boilers.

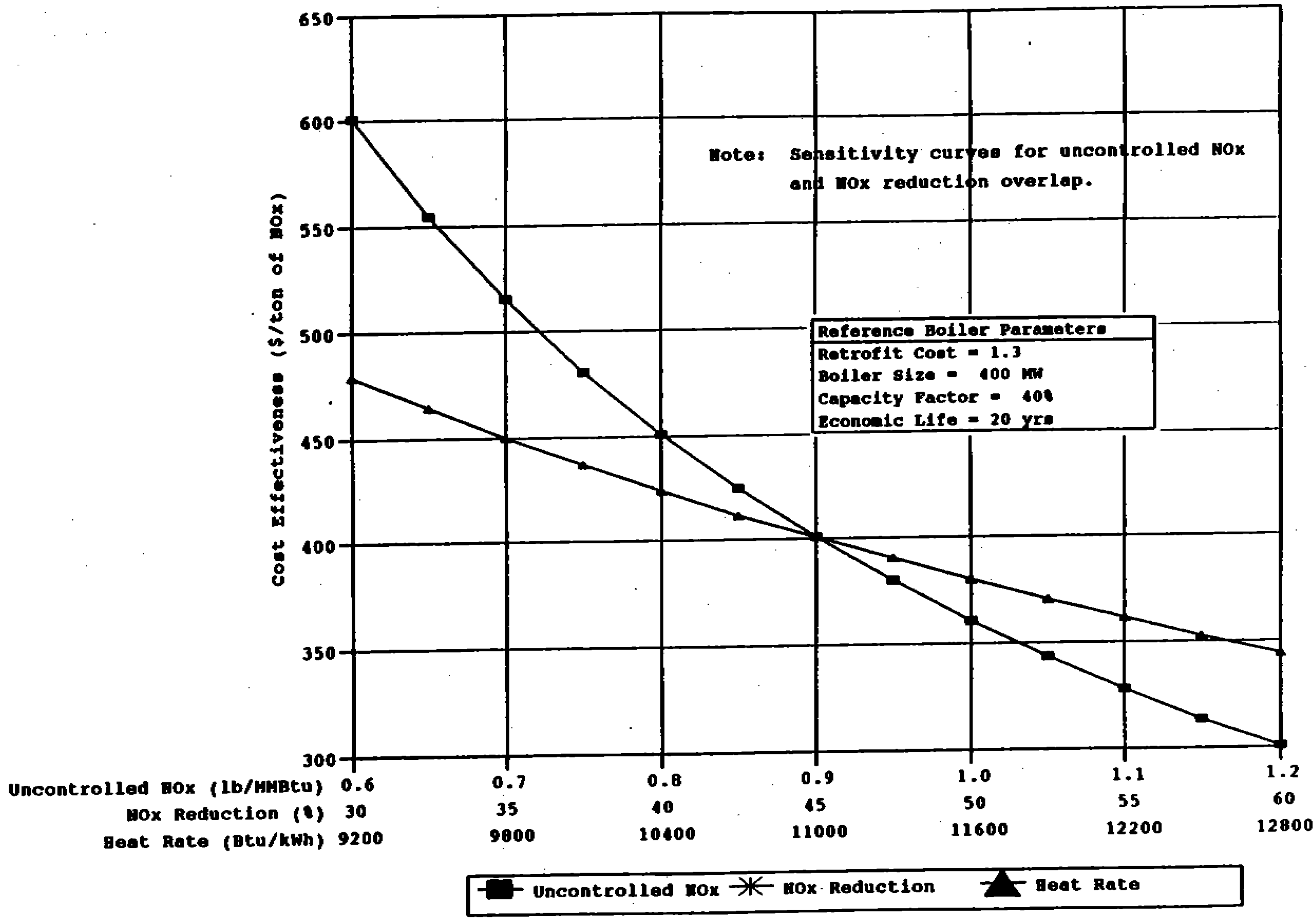

Figure 6-4. Impact of NO_x emission characteristics and heat rate on LNB cost effectiveness for coal-fired wall boilers.

an increase in the plant's cost effectiveness value and busbar cost of nearly 80 percent.

Variation in the retrofit factor from 1.0 to 1.6 causes the smallest relative percent change in cost effectiveness and busbar cost. Increases of 0.1 in the retrofit factor cause a linear increase of approximately 8 percent in the cost effectiveness value and busbar cost.

Uncontrolled NO_x, NO_x reduction, and heat rate all exhibit an inverse relationship with the cost effectiveness value. As mentioned above, equal percentage changes in uncontrolled NO_x and NO_x reduction result in equivalent changes in cost effectiveness. A decrease of 30 percent in either of the parameters results in a 50 percent increase in the cost effectiveness value. Heat rate also exhibits an inverse relationship with the cost effectiveness value, however, since the potential relative change in heat rate is less than the potential variation in the NO_x characteristics, the impact on cost effectiveness is not as great.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-5. Figure 6-6 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $240 per ton of NO_x removed and 0.41 mills/kWh. The cost effectiveness value and busbar cost for LNB applied to tangentially-fired boilers are lower than for LNB on wall-fired boilers because of lower capital costs associated with tangentially-fired boilers. The sensitivity curves follow the same general trends as with LNB applied to wall-fired boilers. In contrast to the curves for LNB applied to wall-fired boilers, uncontrolled NO_x and NO_x reduction do not overlap for tangentially-fired boilers due to the difference in relative percent changes in the two parameters.

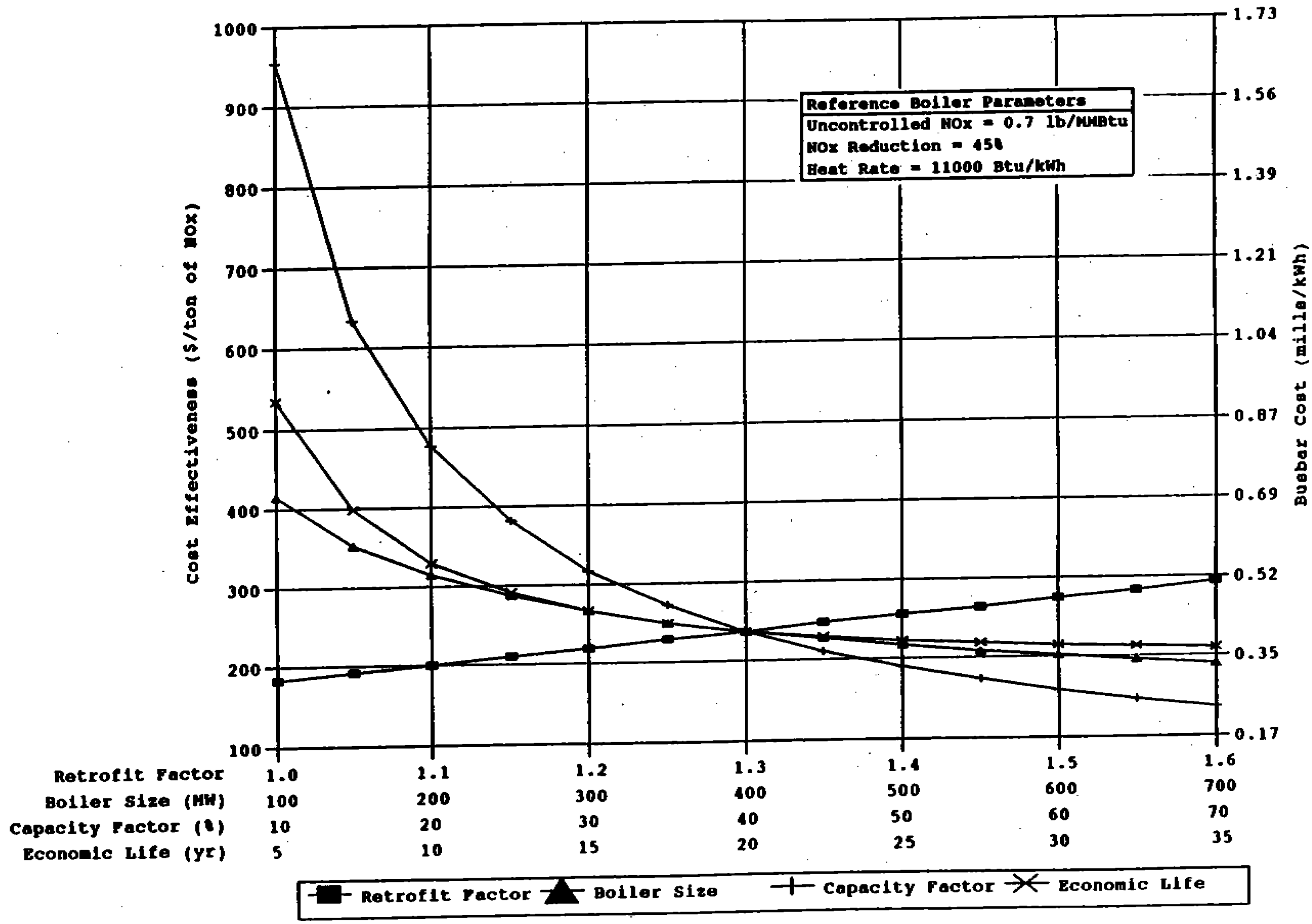

Figure 6-5. Impact of plant characteristics on LNB cost effectiveness and busbar cost for coal-fired tangential boilers.

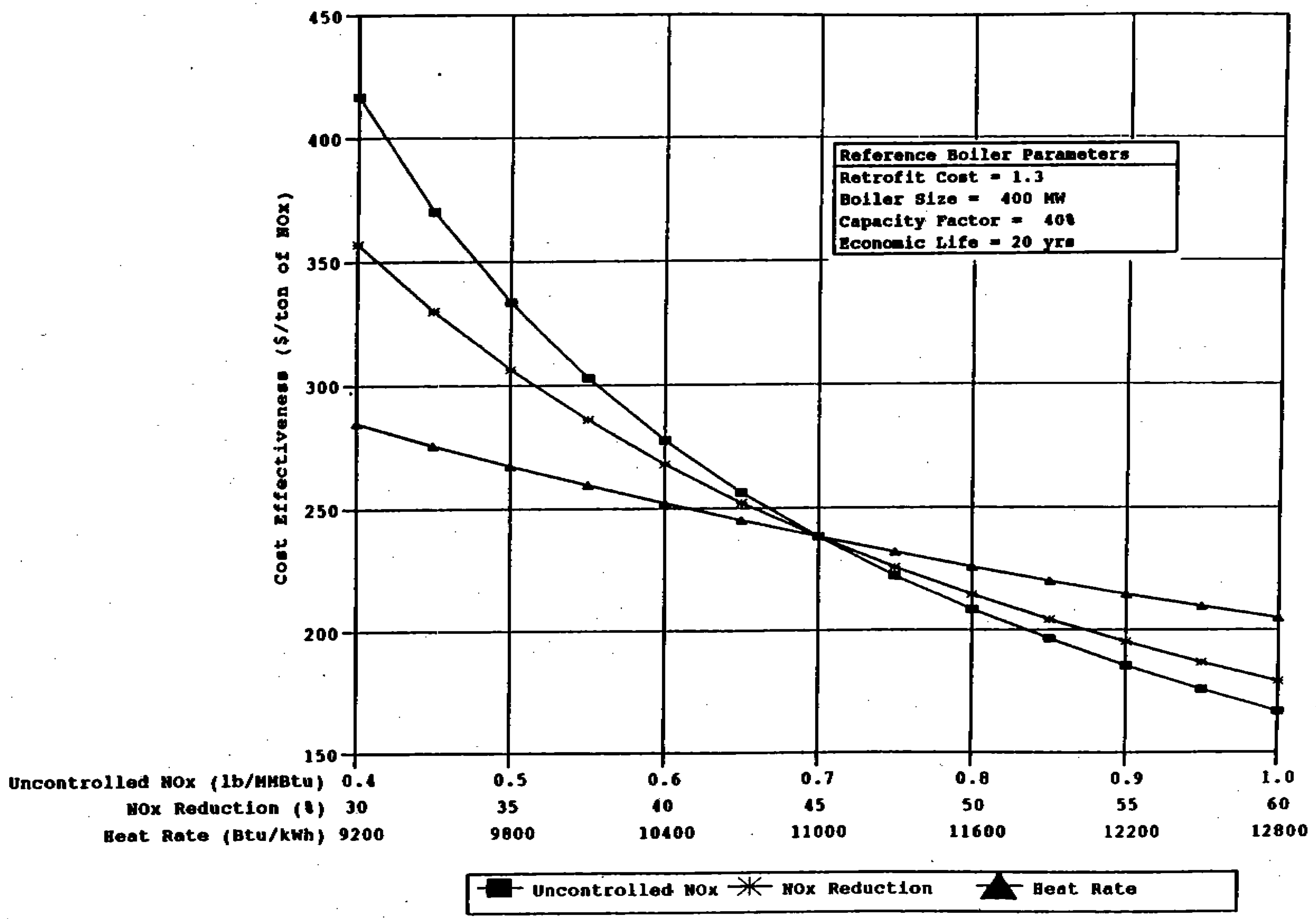

Figure 6-6. Impact of NO_x emission characteristics and heat rate on LNB cost effectiveness for coal-fired tangential boilers.

6.3.2 Low NO_x Burners with Advanced Overfire Air

Cost estimates for LNB + AOFA technology are presented for coal-fired wall and tangential boilers. Estimated NO_x reductions and capital costs for AOFA by itself are 40 to 50 percent of the levels expected from LNB + AOFA. As a result, busbar costs for AOFA by itself are estimated at 40 to 50 percent of the cost estimates in this section for LNB + AOFA and cost effectiveness values are estimated to approximately equal those for LNB + AOFA.

6.3.2.1 Costing Procedures. There were limited cost data available on LNB + AOFA applied to wall-fired boilers. Therefore, as explained in appendix A.4, the basic system cost algorithm for LNB + AOFA was developed based on a relative price differential between LNB and LNB + AOFA. Based on the data available, the LNB basic system cost algorithm was adjusted so that LNB + AOFA costs are approximately 75 percent higher than LNB alone. The scaling factor was derived from the LNB + AOFA cost estimates.

Costing procedures for LNB + AOFA applied to tangentially-fired boilers (LNCFS III) were based on cost estimates obtained from 14 units, ranging in size from 124 to 905 MW. These data are summarized in appendix A.5.

The basic system cost coefficients used in equation 6-1 for wall-fired LNB + AOFA systems were calculated to be a=552, b=-0.50, based on the adjustments of the LNB cost algorithm. For tangentially-fired LNB + AOFA systems, the cost coefficients were calculated to be a=247 and b=-0.49, based on the available cost data discussed above.

Retrofit costs for tangentially-fired LNB + AOFA systems ranged from 14 to 65 percent of the basic system cost, with a mean of 30 percent. This corresponds to a mean retrofit factor of 1.30. This retrofit factor was assumed to apply to wall-fired LNB + AOFA systems as well. For the model plant analysis, low, medium, and high retrofit factors of 1.0, 1.3, and 1.6 were used.

Indirect costs ranged from 20 to 45 percent of total direct costs for tangentially-fired LNB + AOFA systems. Based on this, an indirect cost factor of 1.30 was assumed for the cost procedures for both tangentially-fired and wall-fired systems. Fixed and variable O&M costs were assumed to be negligible.

6.3.2.2 Model Plants Results. The capital cost, busbar cost, and cost effectiveness for the ten wall- and tangentially-fired model boilers are presented in table 6-7. An economic life of 20 years and a NO_x reduction efficiency of 50 percent were assumed for all of these boilers. For the 600 MW baseload wall-fired boiler, the estimated cost effectiveness ranged from $269 to $430 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $3,420 to $5,470 per ton.

Cost per ton of NO_x removed with LNB + AOFA is lower for the tangentially-fired units due to the lower capital cost of LNCFS III. Cost effectiveness for the tangentially-fired units ranged from $165 to $264 per ton for the 600 MW baseload unit and $2,060 to $3,300 per ton for the 100 MW peaking unit.

6.3.2.3 Sensitivity Analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-7. Figure 6-8 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $630 per ton of NO_x removed and 1.6 mills/kWh. The sensitivity curves follow the same general trends as with LNB applied to coal-fired wall boilers (refer to section 6.3.1.3).

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) on cost

TABLE 6-7. COSTS FOR LNB + AOFA APPLIED TO COAL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Retrofit factors	1.0	1.3	1.6	1.0	1.3	1.6	1.0	1.3	1.6
Wall-fired boilers[a]									
100 MW, Peaking[b]	72	93	115	9.62	12.5	15.4	3,420	4,450	5,470
100 MW, Baseload[c]	72	93	115	1.48	1.92	2.37	658	855	1,050
300 MW, Cycling[d]	41	54	66	1.85	2.41	2.96	748	973	1,200
300 MW, Baseload	41	54	66	0.85	1.11	1.37	380	494	608
600 MW, Baseload	29	38	47	0.60	0.79	0.97	269	349	430
Tangentially-fired boilers[e]									
100 MW, Peaking	34	44	54	4.51	5.86	7.21	2,060	2,680	3,300
100 MW, Baseload	34	44	54	0.69	0.90	1.11	396	515	634
300 MW, Cycling	20	26	31	0.88	1.14	1.40	456	592	729
300 MW Baseload	20	26	31	0.40	0.53	0.65	231	301	370
600 MW, Baseload	14	18	22	0.29	0.37	0.46	165	214	264

[a]Uncontrolled NO_x levels of 0.90 lb/MMBtu and an LNB + AOFA NO_x reduction of 50 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.70 lb/MMBtu and an LNB + AOFA NO_x reduction of 50 percent were used for tangentially-fired boilers.

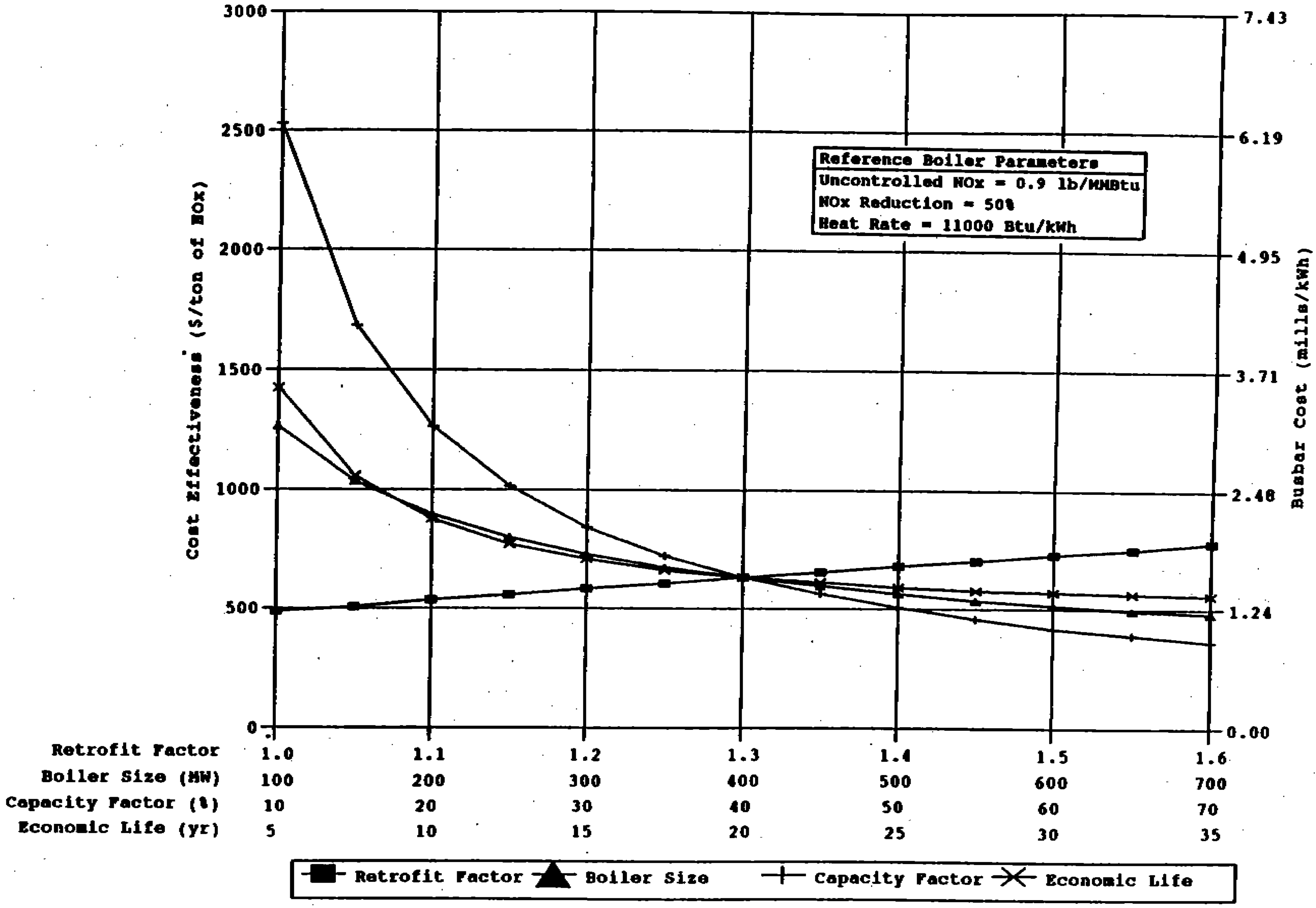

Figure 6-7. Impact of plant characteristics on LNB + AOFA cost effectiveness and busbar cost for coal-fired wall boilers.

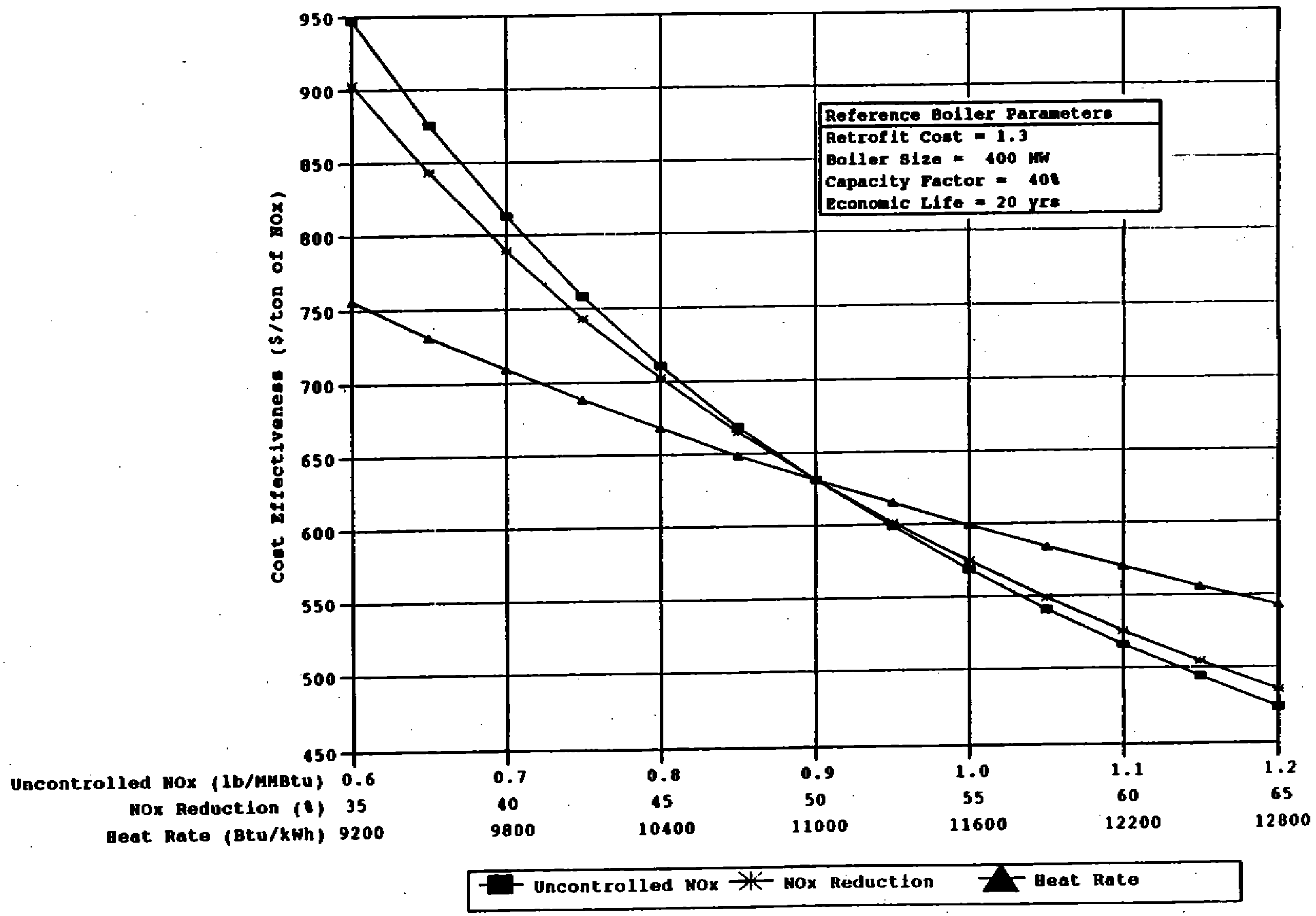

Figure 6-8. Impact of NO_x emission characteristics and heat rate on LNB + AOFA cost effectiveness for coal-fired wall boilers.

effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-9. Figure 6-10 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost-effectiveness and busbar cost are approximately $390 per ton of NO_x removed and 0.74 mills/kWh. The cost effectiveness values and busbar costs for LNB + AOFA applied to tangentially-fired boilers are lower than for LNB + AOFA on wall-fired boilers because of lower capital costs associated with tangentially-fired boilers. The sensitivity curves follow the same general trends as with LNB applied to coal-fired wall boilers (refer to section 6.3.1.3).

6.3.3 Natural Gas Reburn

Cost estimates for natural gas reburn (NGR) are presented for coal-fired wall, tangential, and cyclone boilers in this section.

6.3.3.1 Costing Procedures. Limited cost data on NGR for coal-fired boilers were obtained from vendor and utility questionnaire responses. Cost data on reburn were submitted for one 75 MW plant in response to the questionnaire, and a vendor provided installation costs for a 33 MW and 172 MW unit. These data are summarized in appendix A.6. A regression on the data showed a high degree of scatter and no obvious costing trend. Therefore, the reburn costs were based upon the 172 MW unit, whose size is more representative of most utility boilers.

The economy of scale was assumed to be 0.6 for the reburn basic cost algorithm. Using this assumption, the cost coefficients in equation 6-1 for reburn are a=229 and b=-0.40. The cost of installing a natural gas pipeline was not included in the analysis because it is highly dependent on site specific parameters such as the unit's proximity to a gas line and the difficulty of installation.

The vendor questionnaire indicated that the retrofit of natural gas reburn would cost 10 to 20 percent more than a

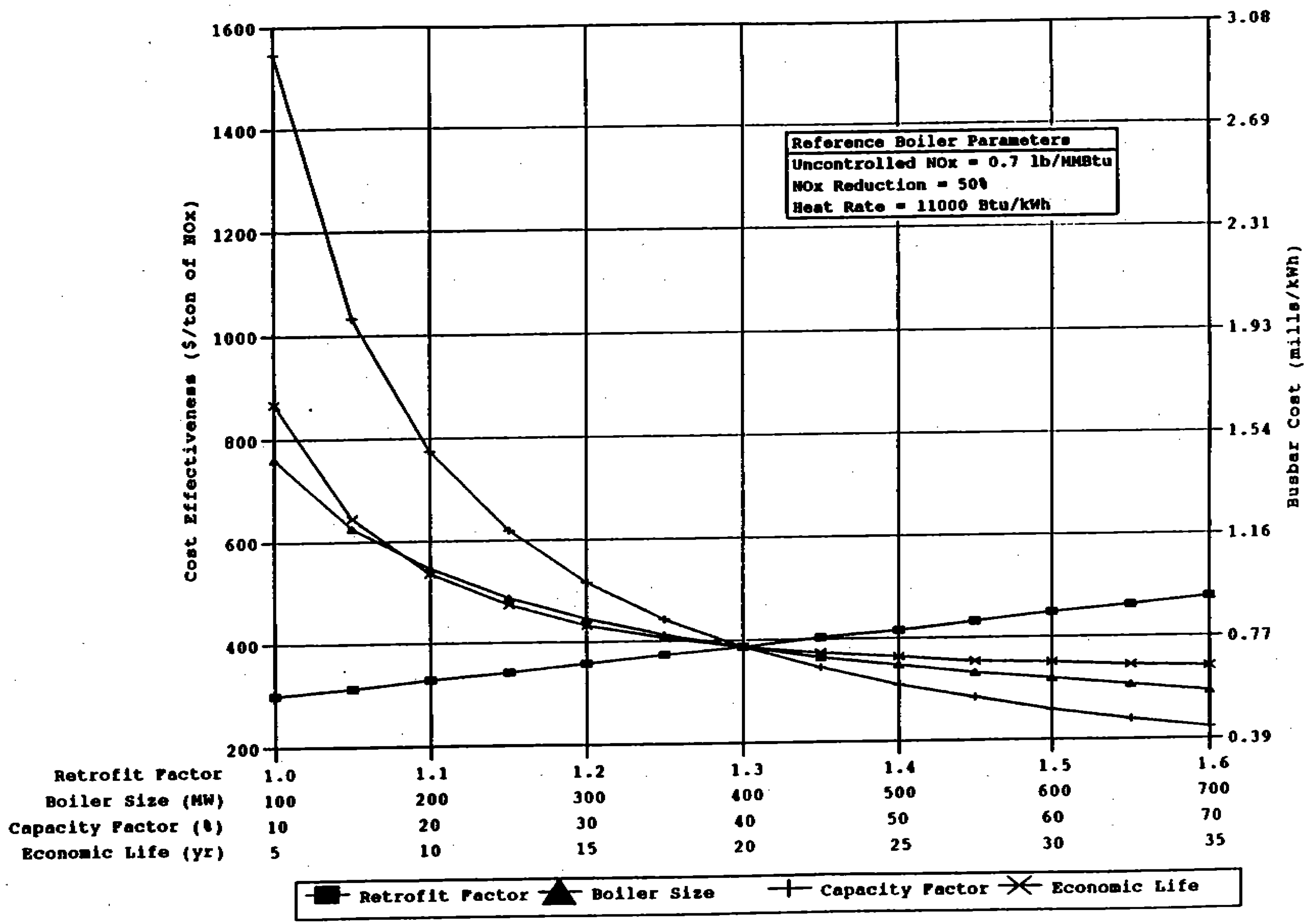

Figure 6-9. Impact of plant characteristics on LNB + AOFA cost effectiveness and busbar cost for coal-fired tangential boilers.

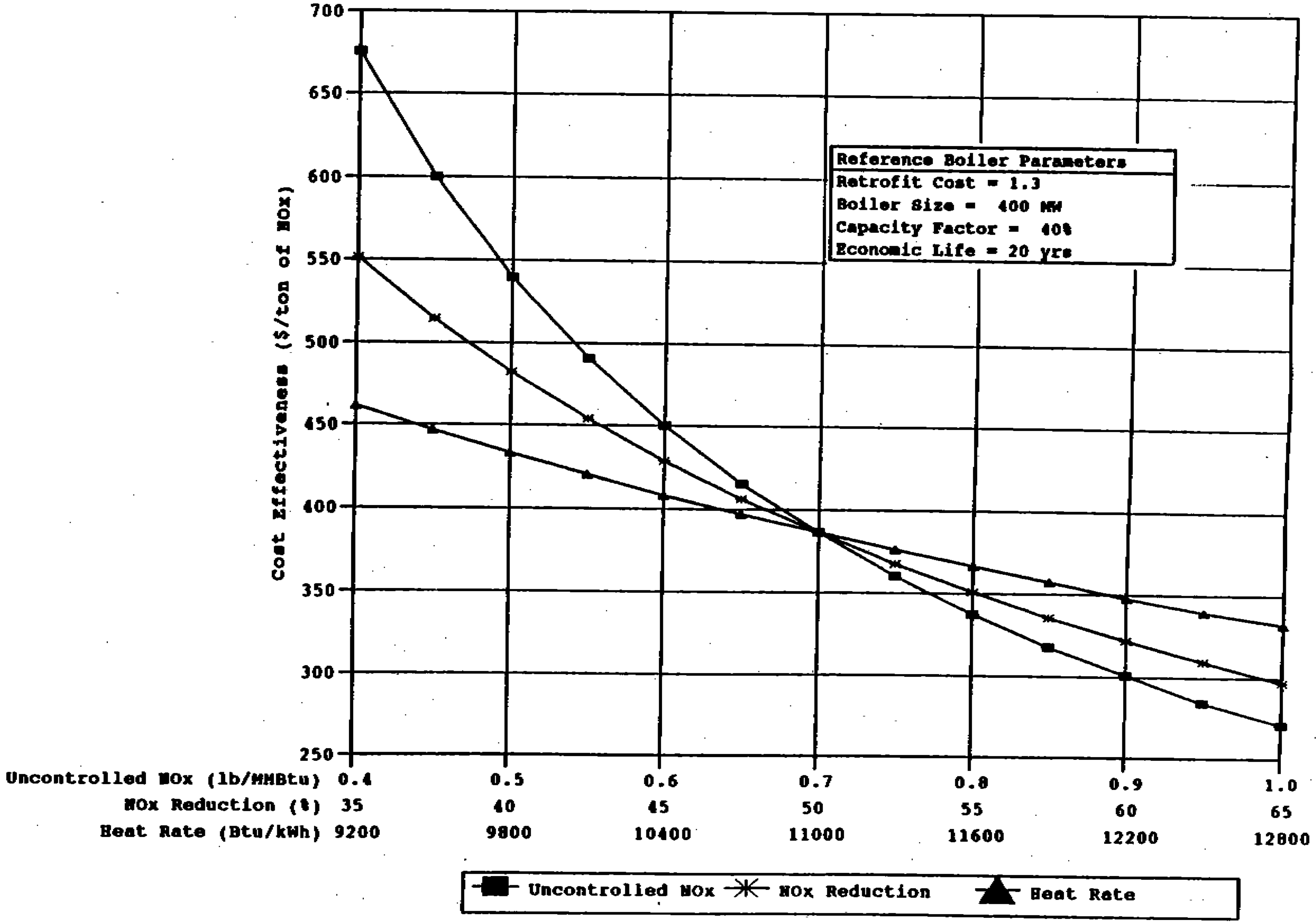

Figure 6-10. Impact of NO_x emission characteristics and heat rate on LNB + AOFA cost effectiveness for coal-fired tangential boilers.

reburn system applied to a new boiler. From this, the retrofit factor was assumed to be 1.15. However, for the sensitivity analysis, the retrofit factor was varied from 1.0 to 1.6 to account for different retrofit difficulties on specific boilers.

The indirect costs were estimated to be 40 percent of the total direct cost, corresponding to an indirect cost factor of 1.40.

Annual O&M costs were the total of the additional fuel costs caused by the higher price of natural gas versus coal and utility savings on sulfur dioxide (SO_2) credits, caused by lower SO_2 emission levels when using natural gas reburn on a coal-fired boiler. The analysis was conducted assuming 18 percent of the total heat input was from natural gas. The SO_2 credit was assumed to be $200 per ton of SO_2, equal to $0.24/MMBtu based on a coal-sulfur content of 1.5 percent.

Refer to appendix A.6 for a summary of the costing data and procedures.

6.3.3.2 Model Plants Results. The capital cost, busbar cost, and cost effectiveness for the 15 wall-, tangentially-, and cyclone-fired model boilers are presented in table 6-8. An economic life of 20 years and a NO_x reduction efficiency of 55 percent were assumed for all of these boilers. The fuel price differential was varied from $0.50 to $2.50/MMBtu. For the 600 MW baseload wall-fired boiler, the estimated cost effectiveness ranges from $480 to $2,080 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $3,010 to $4,600 per ton.

Cost per ton of NO_x removed with reburn is higher for the tangentially-fired units due to the lower baseline NO_x emissions. Cost effectiveness for the tangentially-fired units ranges from $615 per ton to $2,680 per ton for the 600 MW baseload unit and $3,870 per ton to $5,930 per ton for the 100 MW peaking unit.

TABLE 6-8. COSTS FOR NGR APPLIED TO COAL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Fuel price differential ($/MMBtu)	0.50	1.50	2.50	0.5	1.50	2.50	0.50	1.50	2.50
Wall-fired Boilers[a]									
100 MW, Peaking[b]	58.0	58.0	58.0	8.44	10.7	12.9	3,010	3,800	4,600
100 MW, Baseload[c]	58.0	58.0	58.0	1.69	3.49	5.29	753	1,560	2,360
300 MW, Cycling[d]	38.0	38.0	38.0	2.22	4.20	6.18	898	1,700	2,500
300 MW, Baseload	38.0	38.0	38.0	1.26	3.06	4.86	562	1,360	2,170
600 MW, Baseload	29.0	29.0	29.0	1.07	2.87	4.67	478	1,280	2,080
Tangentially-fired boilers[e]									
100 MW, Peaking	58.0	58.0	58.0	8.44	10.7	12.9	3,870	4,900	5,930
100 MW, Baseload	58.0	58.0	58.0	1.69	3.49	5.29	968	2,000	3,030
300 MW, Cycling	38.0	38.0	38.0	2.22	4.20	6.18	1,150	2,190	3,220
300 MW Baseload	38.0	38.0	38.0	1.26	3.06	4.86	722	1,750	2,790
600 MW, Baseload	29.0	29.0	29.0	1.07	2.87	4.67	615	1,650	2,680
Cyclone-fired boilers[f]									
100 MW, Peaking	58.0	58.0	58.0	8.46	10.7	13.0	1,810	2,290	2,770
100 MW, Baseload	58.0	58.0	58.0	1.71	3.51	5.31	456	938	1,420
300 MW, Cycling	38.0	38.0	38.0	2.23	4.21	6.19	543	1,020	1,510
300 MW, Baseload	38.0	38.0	38.0	1.28	3.08	4.88	342	823	1,300
600 MW, Baseload	29.0	29.0	29.0	1.09	2.89	4.69	291	773	1,250

[a]Uncontrolled NO_x levels of 0.90 lb/MMBtu and an NGR NO_x reduction of 55 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.70 lb/MMBtu and an NGR NO_x reduction of 55 percent were used for tangentially-fired boilers.
[f]Uncontrolled NO_x levels of 1.5 lb/MMBtu and an NGR NO_x reduction of 55 percent were used for cyclone-fired boilers.

Cost per ton of NO_x removed is lower for cyclone-fired boilers than for wall-fired boilers because of higher baseline NO_x for cyclone-fired boilers. For the 600 MW baseload cyclone boiler, cost effectiveness ranges from $290 to $1,250 per ton and for the 100 MW peaking boiler, cost effectiveness ranges from $1,810 to $2,720 per ton.

6.3.3.3 Sensitivity Analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and fuel price differential on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-11. Figure 6-12 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown, the reference boiler's cost effectiveness and busbar cost are approximately $1,400 per ton of NO_x removed and 3.8 mills/kWh.

Of the parameters shown in figure 6-11, the variation of capacity factor from 10 to 70 percent and variation of fuel price differential from $0.50 to $2.50/MMBtu have the greatest impact on cost effectiveness and busbar cost. The cost effectiveness value and busbar cost are inversely related to capacity factor, and thus, as capacity factor decreases, the cost effectiveness value and busbar cost increase. This is especially noticeable at low capacity factors where a decrease of 75 percent in the reference plant's capacity factor (from 40 percent to 10 percent) results in an increase in the cost effectiveness value and busbar cost of approximately 100 percent.

The cost effectiveness value and busbar cost are linearly related to fuel price differential. An increase or decrease of $1.00/MMBtu in the fuel price differential compared to the reference plant cause a corresponding change in cost effectiveness and busbar cost of approximately 50 percent.

Variations in economic life and boiler size follow a trend similar to capacity factor, but do not cause as great a change in cost effectiveness and busbar cost. For example, a

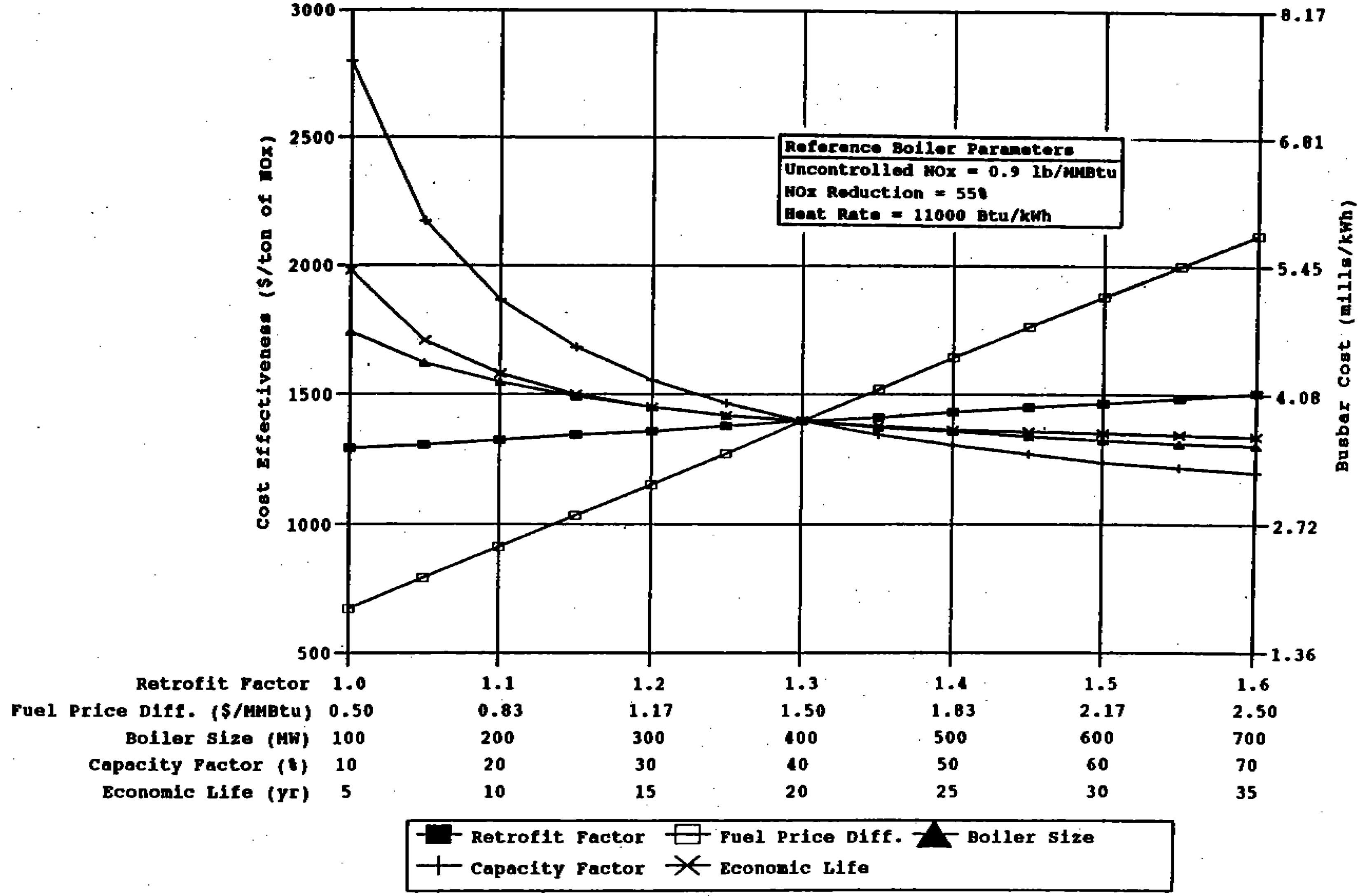

Figure 6-11. Impact of plant characteristics on NGR cost effectiveness and busbar cost for coal-fired wall boilers.

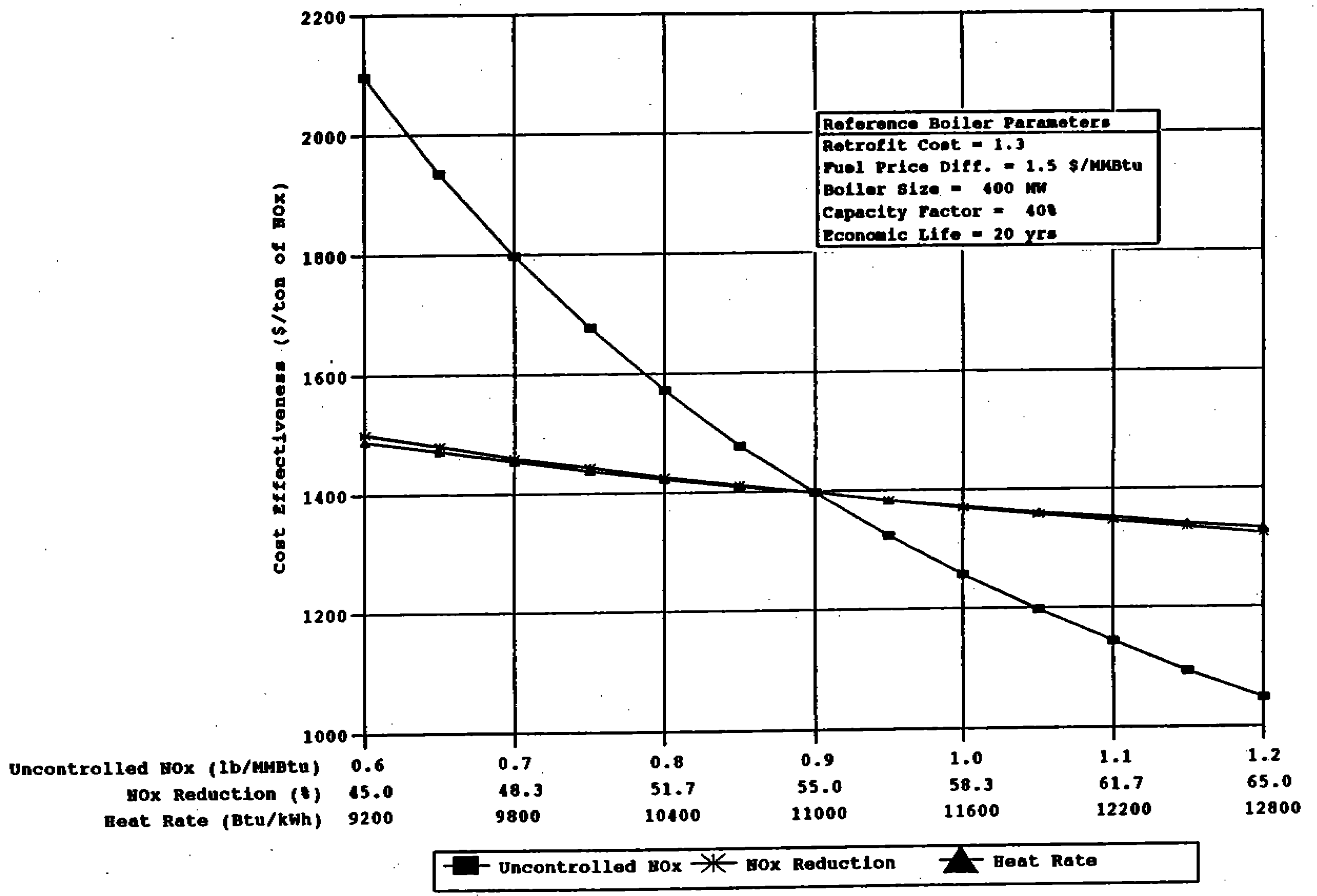

Figure 6-12. Impact of NO_x emission characteristics and heat rate on NGR cost effectiveness for coal-fired wall boilers.

decrease of 75 percent in economic life (from 20 to 5 years) results in an increase in the plant's cost effectiveness value and busbar cost of nearly 45 percent. Similarly, a decrease of 75 percent in the boiler size (from 400 to 100 MW) results in an increase in the plant's cost effectiveness value and busbar cost of nearly 25 percent.

Variation in the retrofit factor from 1.0 to 1.6 causes the smallest relative percent change in cost effectiveness and busbar cost. Increases of 0.1 in the retrofit factor cause a linear increase of approximately 6 percent in the cost effectiveness value and busbar cost.

Of the parameters shown in figure 6-12, the variation of uncontrolled NO_x from 0.6 to 1.2 lb/MMBtu has the greatest impact on cost effectiveness. Uncontrolled NO_x levels exhibit an inverse relationship with the cost effectiveness value. A 30-percent decrease in the reference plant's uncontrolled NO_x level (0.9 to 0.6 lb/MMBtu) results in an increase in the cost effectiveness value of 50 percent. Variations in the NO_x reduction from 45 to 65 percent and heat rate from 9,200 to 12,800 Btu/kWh have less than a 6-percent change in cost effectiveness.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and fuel price differential on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-13. Figure 6-14 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown, the reference boiler's cost effectiveness and busbar cost are approximately \$1,800 per ton of NO_x removed and 3.8 mills/kWh. The cost effectiveness value for natural gas reburn applied to tangentially-fired boilers is generally higher than for natural gas reburn on wall-fired boilers, because of the lower uncontrolled NO_x levels of tangentially-fired boilers. The sensitivity curves follow the same general trends as with natural as reburn applied to wall-fired boilers.

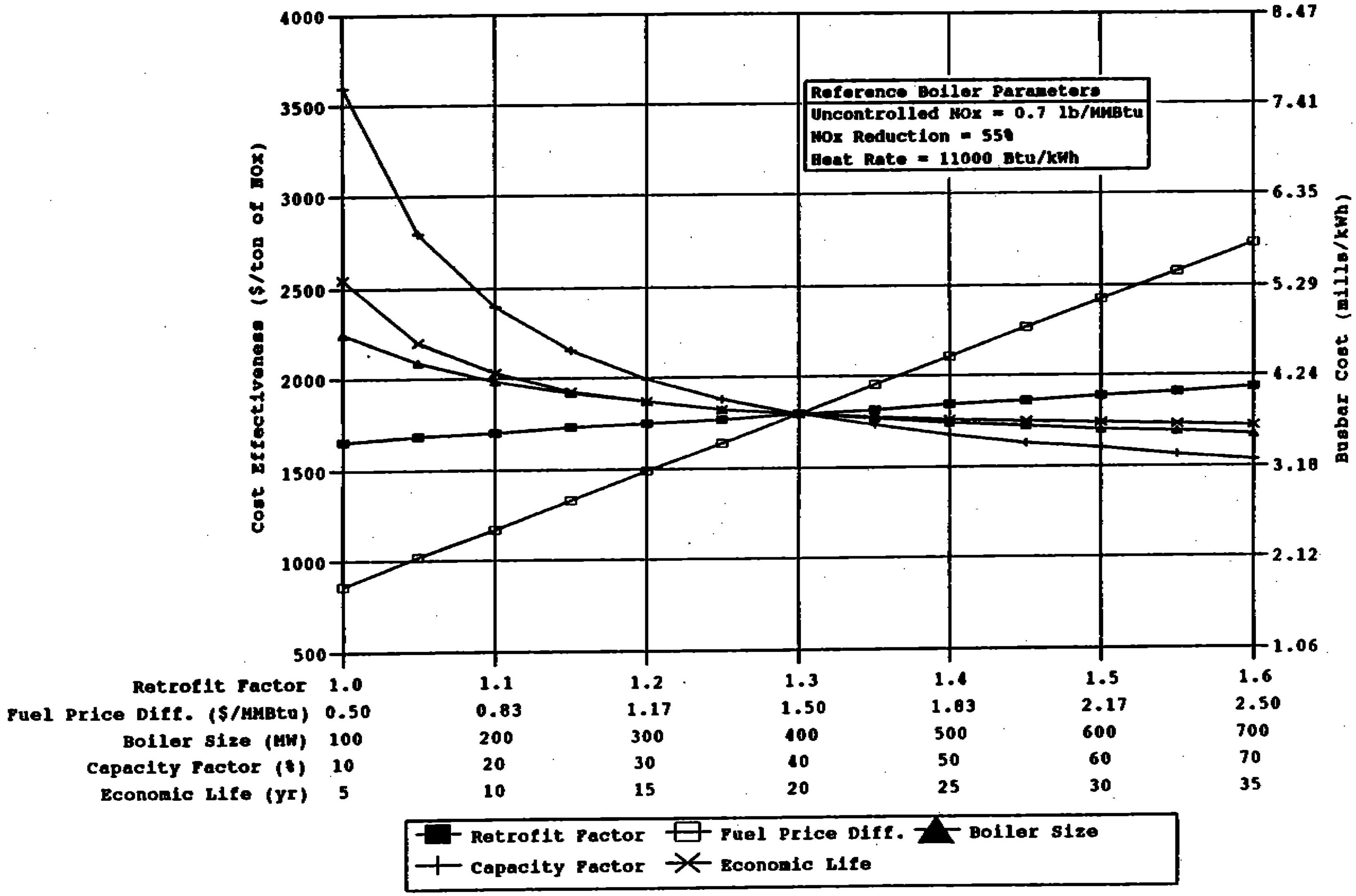

Figure 6-13. Impact of plant characteristics on NGR cost effectiveness and busbar cost for coal-fired tangential boilers.

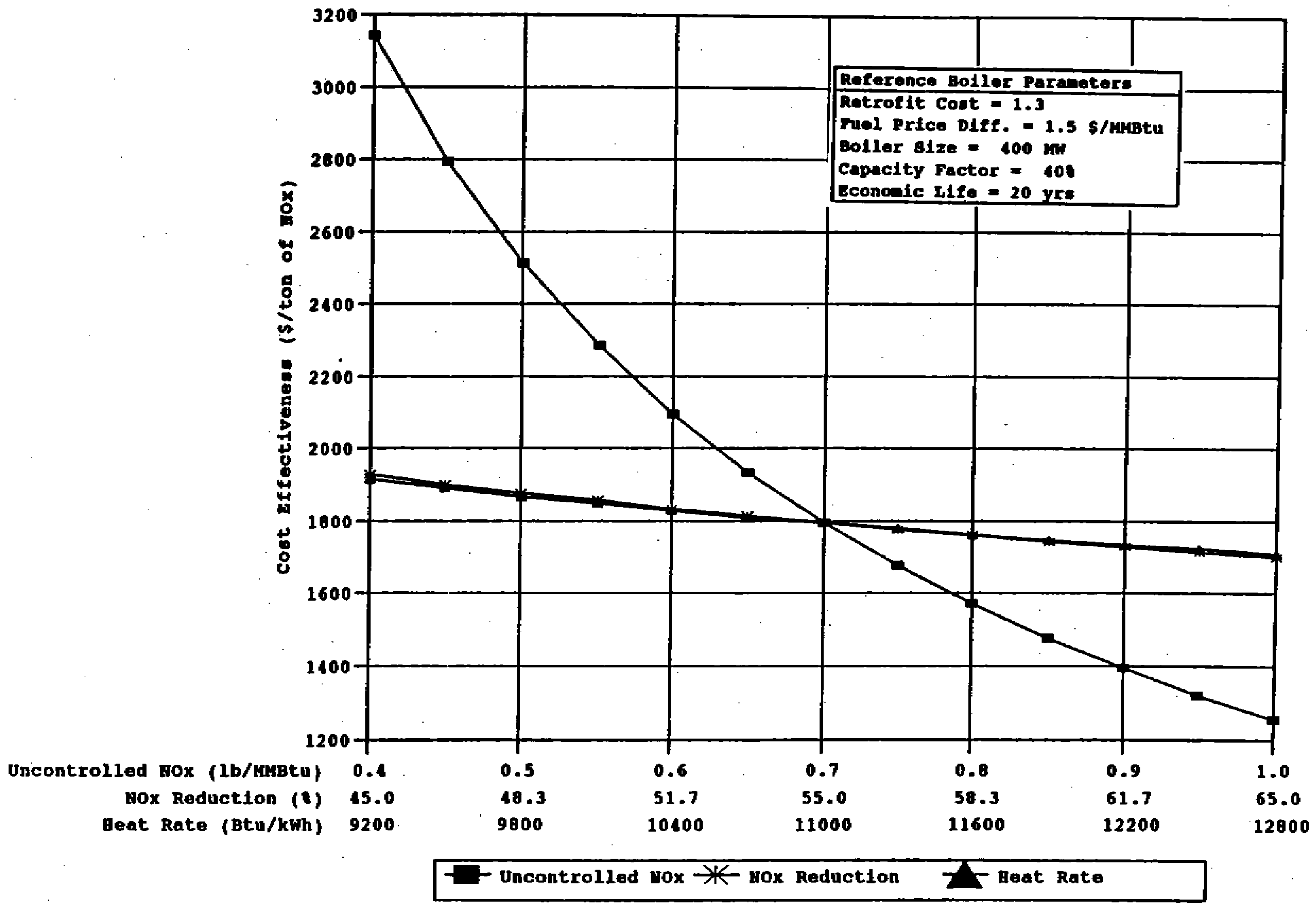

Figure 6-14. Impact of NO_x emission characteristics and heat rate on NGR cost effectiveness for coal-fired tangential boilers.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and fuel price differential on cost effectiveness and busbar cost for cyclone-fired boilers is shown in figure 6-15. Figure 6-16 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown, the reference boiler's cost effectiveness and busbar cost are approximately $840 per ton of NO_x removed and 3.8 mills/kWh. The cost effectiveness value for natural gas reburn applied to cyclone-fired boilers is lower than for natural gas reburn on wall-fired boilers because of higher uncontrolled NO_x levels of cyclone-fired boilers. The sensitivity curves follow the same general trends as with natural gas reburn applied to wall-fired boilers.

6.4 COMBUSTION MODIFICATIONS FOR NATURAL GAS- AND OIL-FIRED BOILERS

This section presents the capital cost, busbar cost, and cost effectiveness estimates for operational modifications (with LEA + BOOS used as an example), LNB, LNB + AOFA, and reburn applied to natural gas- and oil-fired boilers. Cost estimates for AOFA by itself are included with the discussion of LNB + AOFA.

6.4.1 Operational Modifications

6.4.1.1 Costing Procedures. Cost estimates for LEA + BOOS as an example of operational modifications were prepared for natural gas- and oil-fired wall and tangential boilers.

The only capital costs required for implementing LEA + BOOS are costs for emissions and boiler efficiency testing to determine the optimal fuel and air settings. The cost of a 4-week testing and tuning period was estimated at $75,000. There are no retrofit costs associated with LEA + BOOS. Indirect costs were estimated at 25 percent of the direct costs.

Burners-out-of-service alone can decrease boiler efficiency by up to 1 percent, which ultimately increases

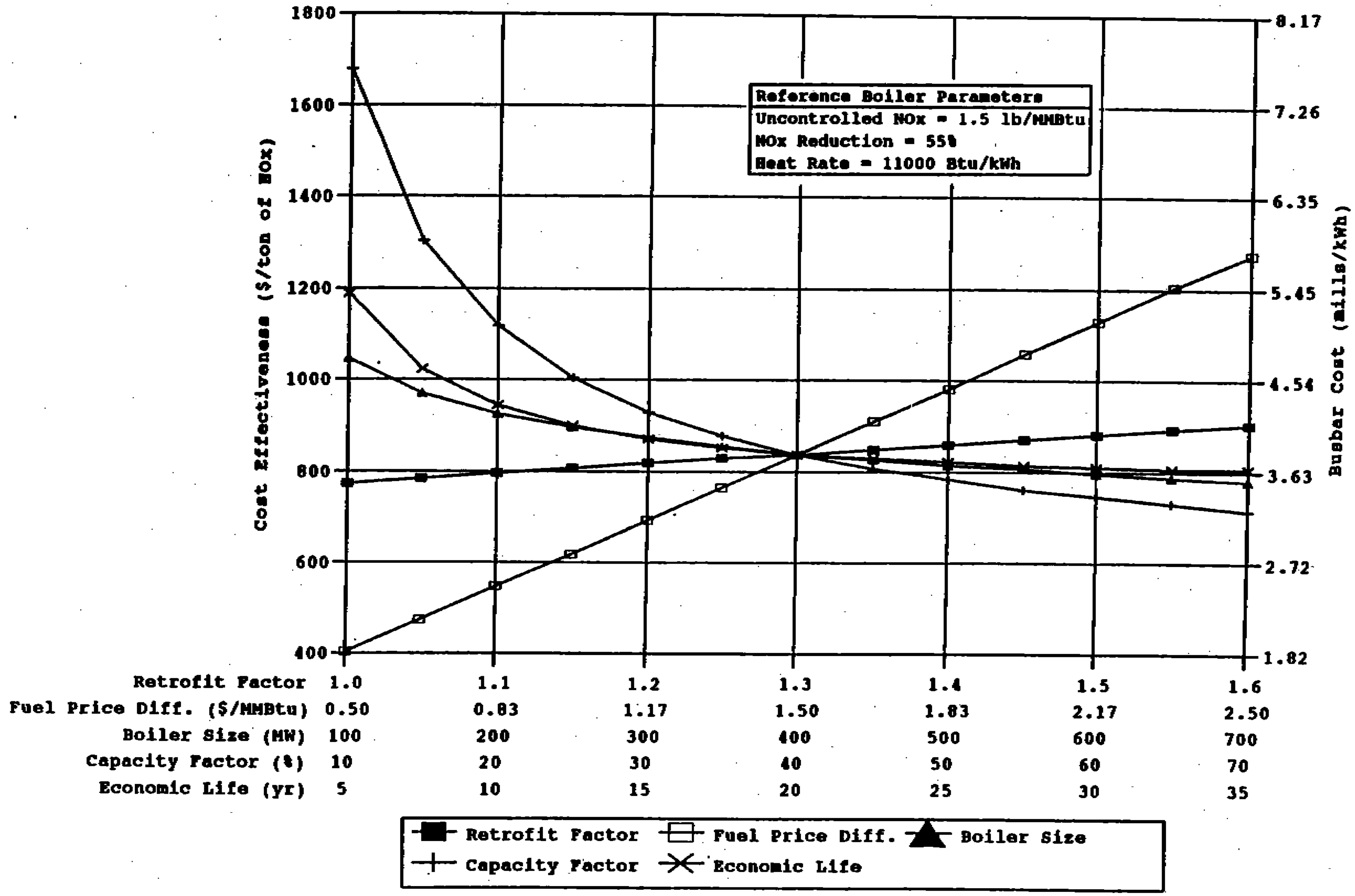

Figure 6-15. Impact of plant characteristics on NGR cost effectiveness and busbar cost for coal-fired cyclone boilers.

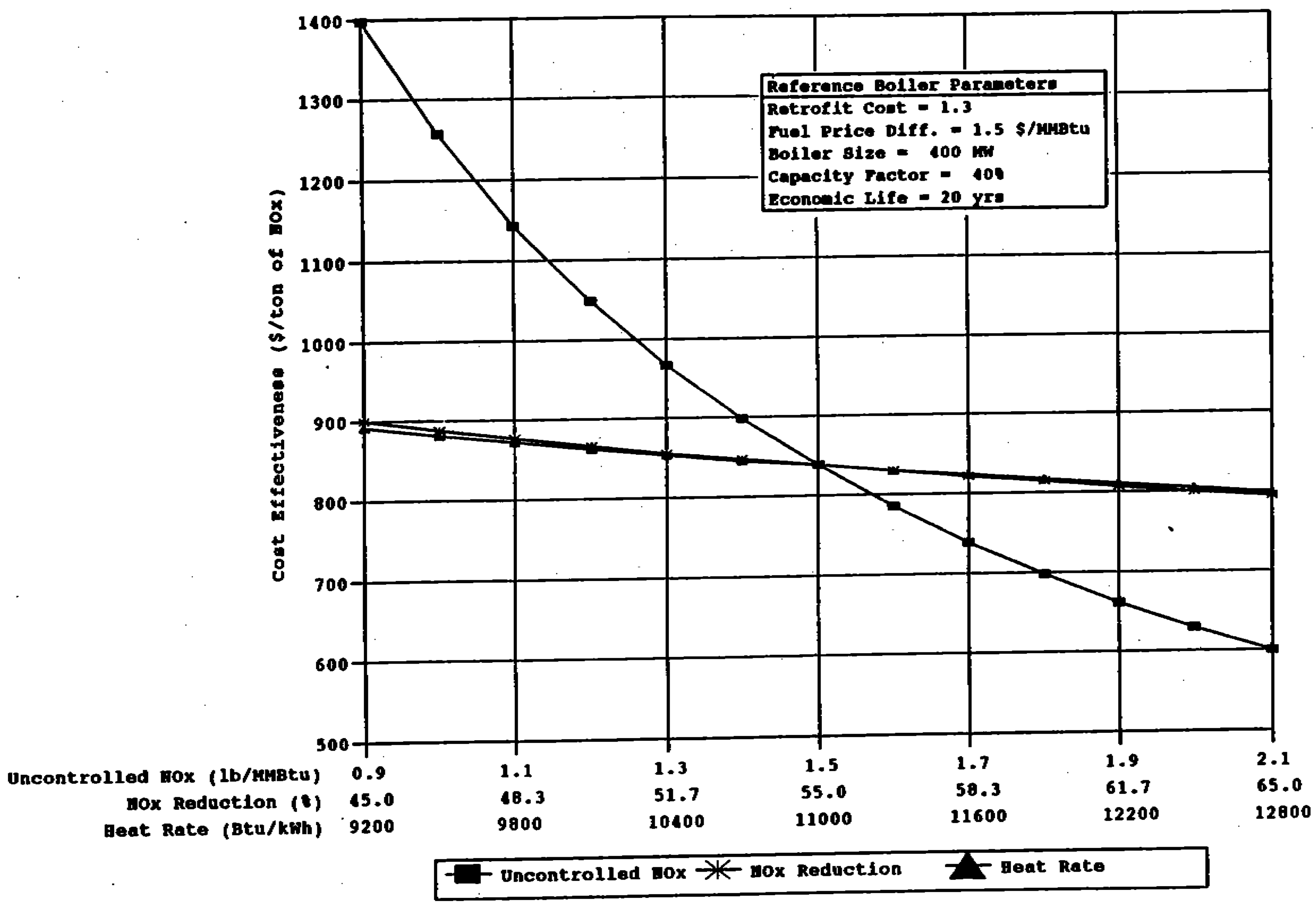

Figure 6-16. Impact of NO_x emission characteristics and heat rate on NGR cost effectiveness for coal-fired cyclone boilers.

annual fuel costs. An average efficiency loss of 0.3 percent has been reported.[13]

For the model plant analysis, LEA + BOOS was assumed to cause a 0.1, 0.3, and 0.5 percent loss in boiler efficiency. Other O&M costs were assumed to be negligible.

6.4.1.2 Model Plants Results. The capital cost, busbar cost, and cost effectiveness for the ten wall- and tangentially-fired model boilers are presented in table 6-9. For all of these boilers, an economic life of 20 years and a NO_x reduction efficiency of 40 percent were assumed. For the 600 MW baseload wall-fired boiler, the estimated cost effectiveness ranges from $43 to $202 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $140 to $299 per ton.

Cost per ton of NO_x removed for tangential units is higher than for wall-fired units due to lower uncontrolled NO_x levels and, therefore, fewer tons of NO_x removed. The cost effectiveness values for the tangentially-fired units ranges from $71 to $336 per ton for the 600 MW boiler and $234 to $498 for the 100 MW peaking boiler.

6.4.1.3 Sensitivity Analysis. The effect of plant characteristics (boiler size, capacity factor, and economic life) and boiler efficiency on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-17. Figure 6-18 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in figure 6-18, because equal percent changes in boiler size and capacity factor result in equivalent changes in cost effectiveness, these two curves overlap. As shown in both figures, the reference boiler's cost effectiveness and busbar cost are approximately $130 per ton of NO_x removed and 0.14 mills/kWh.

Of the parameters shown in figure 6-17, the variation of efficiency loss from 0.0 to 0.6 percent has the greatest impact on cost effectiveness and busbar cost. The cost

TABLE 6-9. COSTS FOR LEA + BOOS APPLIED TO NATURAL GAS- AND OIL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Efficiency loss (%)	0.1	0.3	0.5	0.1	0.3	0.5	0.1	0.3	0.5
Wall-fired boilers[a]									
100 MW, Peaking[b]	0.94	0.94	0.94	0.18	0.27	0.37	140	219	299
100 MW, Baseload[c]	0.94	0.94	0.94	0.06	0.14	0.22	59	138	218
300 MW, Cycling[d]	0.31	0.31	0.31	0.06	0.14	0.23	52	132	211
300 MW, Baseload	0.31	0.31	0.31	0.05	0.13	0.20	46	125	205
600 MW, Baseload	0.16	0.16	0.16	0.04	0.12	0.20	43	122	202
Tangentially-fired boilers[e]									
100 MW, Peaking	0.94	0.94	0.94	0.18	0.27	0.37	234	366	498
100 MW, Baseload	0.94	0.94	0.94	0.06	0.14	0.22	98	230	363
300 MW, Cycling	0.31	0.31	0.31	0.06	0.14	0.23	87	219	352
300 MW Baseload	0.31	0.31	0.31	0.05	0.13	0.20	77	209	342
600 MW, Baseload	0.16	0.16	0.16	0.04	0.12	0.20	71	203	336

[a]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an LEA + BOOS NO_x reduction of 40 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an LEA + BOOS NO_x reduction of 40 percent were used for tangentially-fired boilers.

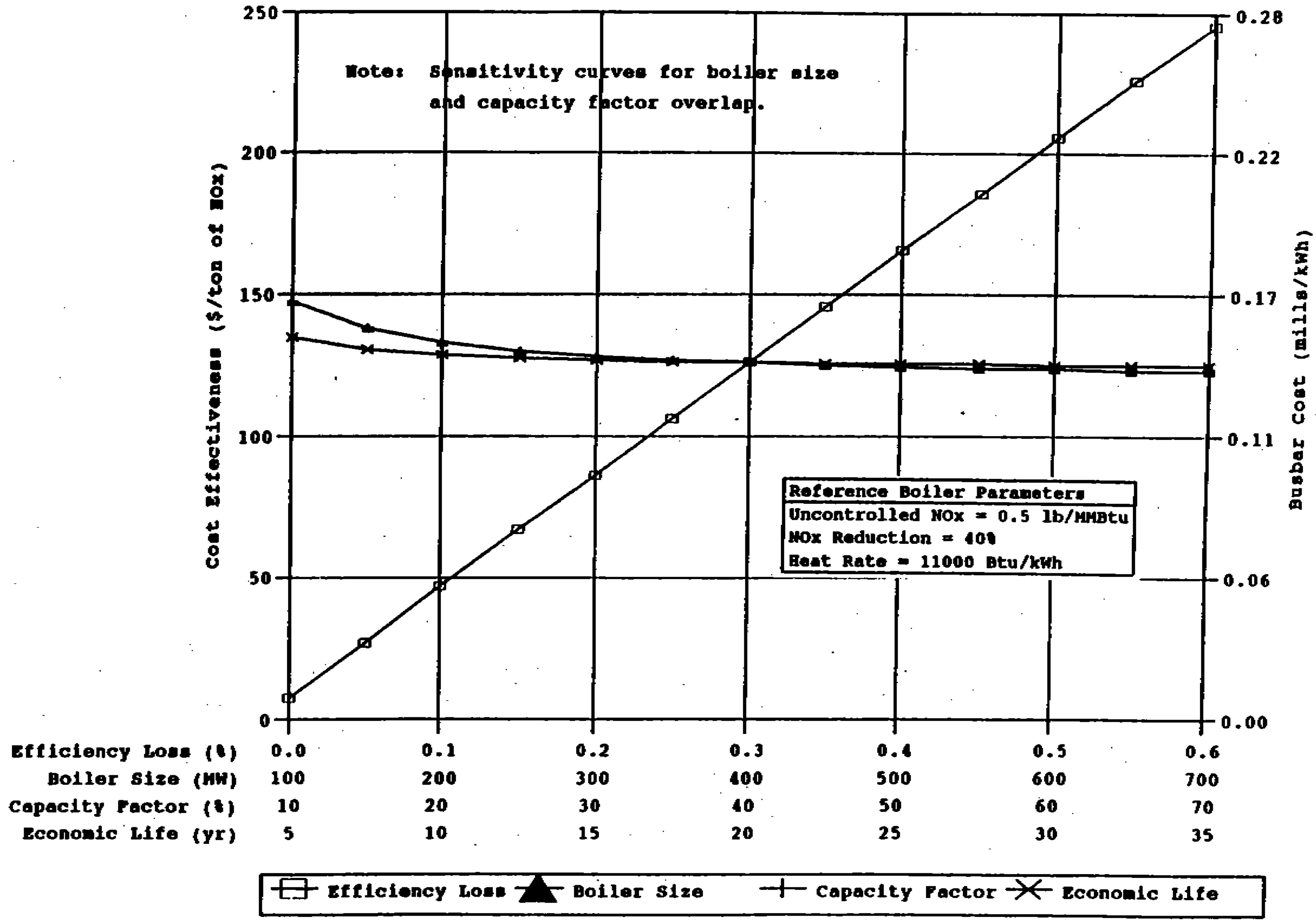

Figure 6-17. Impact of plant characteristics on LEA + BOOS cost effectiveness and busbar cost for natural gas- and oil-fired wall boilers.

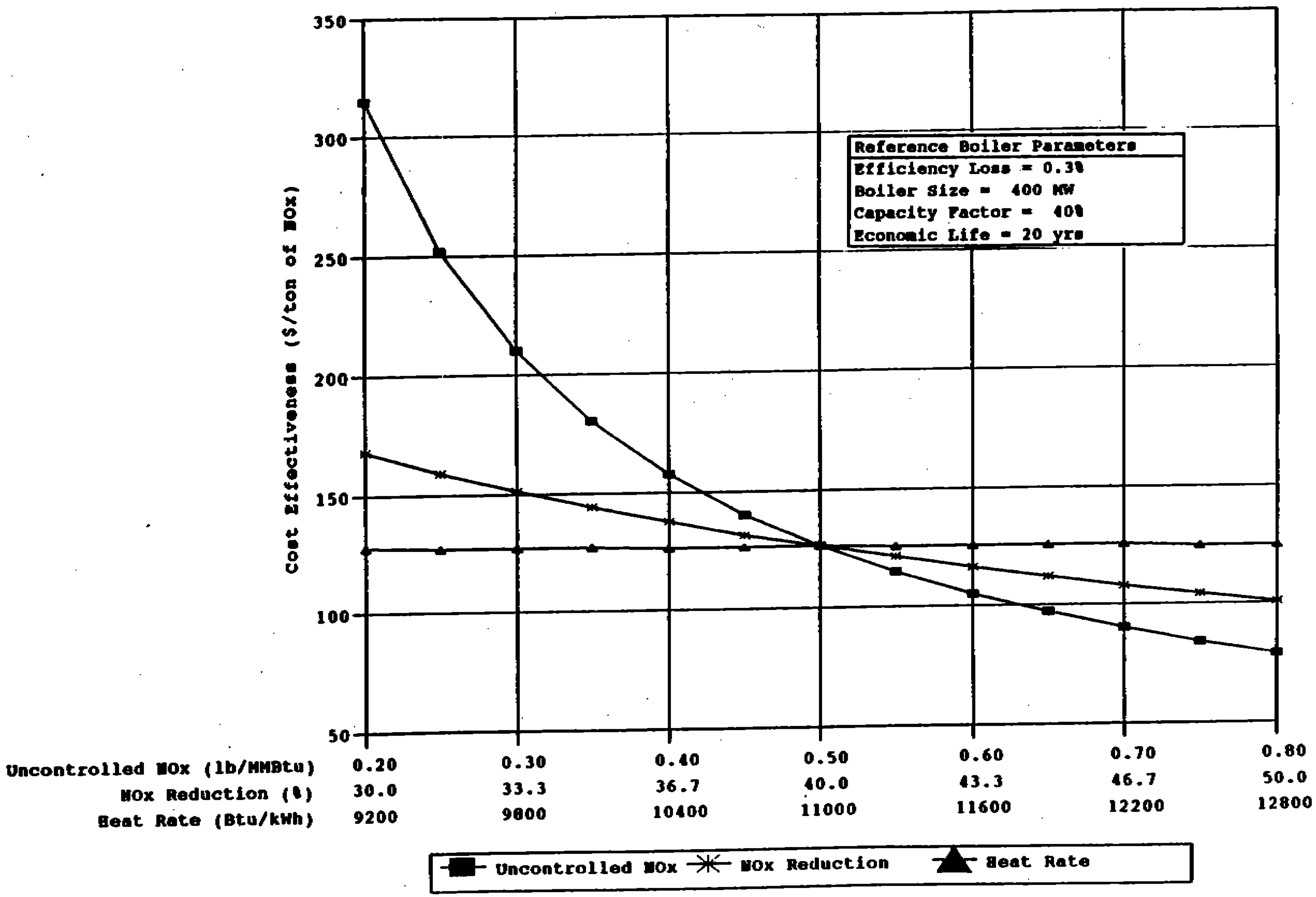

Figure 6-18. Impact of NO_x emission characteristics and heat rate on LEA + BOOS cost effectiveness for natural gas- and oil-fired wall boilers.

effectiveness value and busbar cost are linearly related to fuel price differential. A 0.1 percent boiler efficiency loss results in an increase in the cost effectiveness value and busbar cost of 30 percent.

Variations in boiler size, capacity factor, and economic life follow similar trends, and have less impact on cost effectiveness and busbar cost than fuel price differential. For example, a decrease of 75 percent in boiler size and capacity factor result in an increase in the plant's cost effectiveness value and busbar cost of approximately 20 percent. A decrease of 75 percent in economic life result in an increase of the plant's cost effectiveness value and busbar cost of less than 10 percent.

Of the parameters shown in figure 6-18, the variation of uncontrolled NO_x from 0.2 to 0.8 lb/MMBtu has the greatest impact on cost effectiveness. Uncontrolled NO_x roughly exhibits a inverse relationship with the cost effectiveness value. A 60 percent decrease in the reference plant's uncontrolled NO_x level (0.5 to 0.2 lb/MMBtu) results in an increase in the cost value effectiveness of 60 percent.

Variations in the NO_x reduction follow a trend similar to uncontrolled NO_x, but do not cause as great a change in cost effectiveness. For example, a decrease of 25 percent in NO_x reduction (from 40 to 30 percent) results in an increase in the plant's cost effectiveness value and busbar cost of nearly 30 percent. Variation in heat rate has very little effect upon cost effectiveness.

The effect of plant characteristics (boiler size, capacity factor, and economic life) and boiler efficiency loss on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-19. Figure 6-20 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in figure 6-20, because equal percent changes in boiler size and capacity factor result in equivalent changes in cost effectiveness, these two

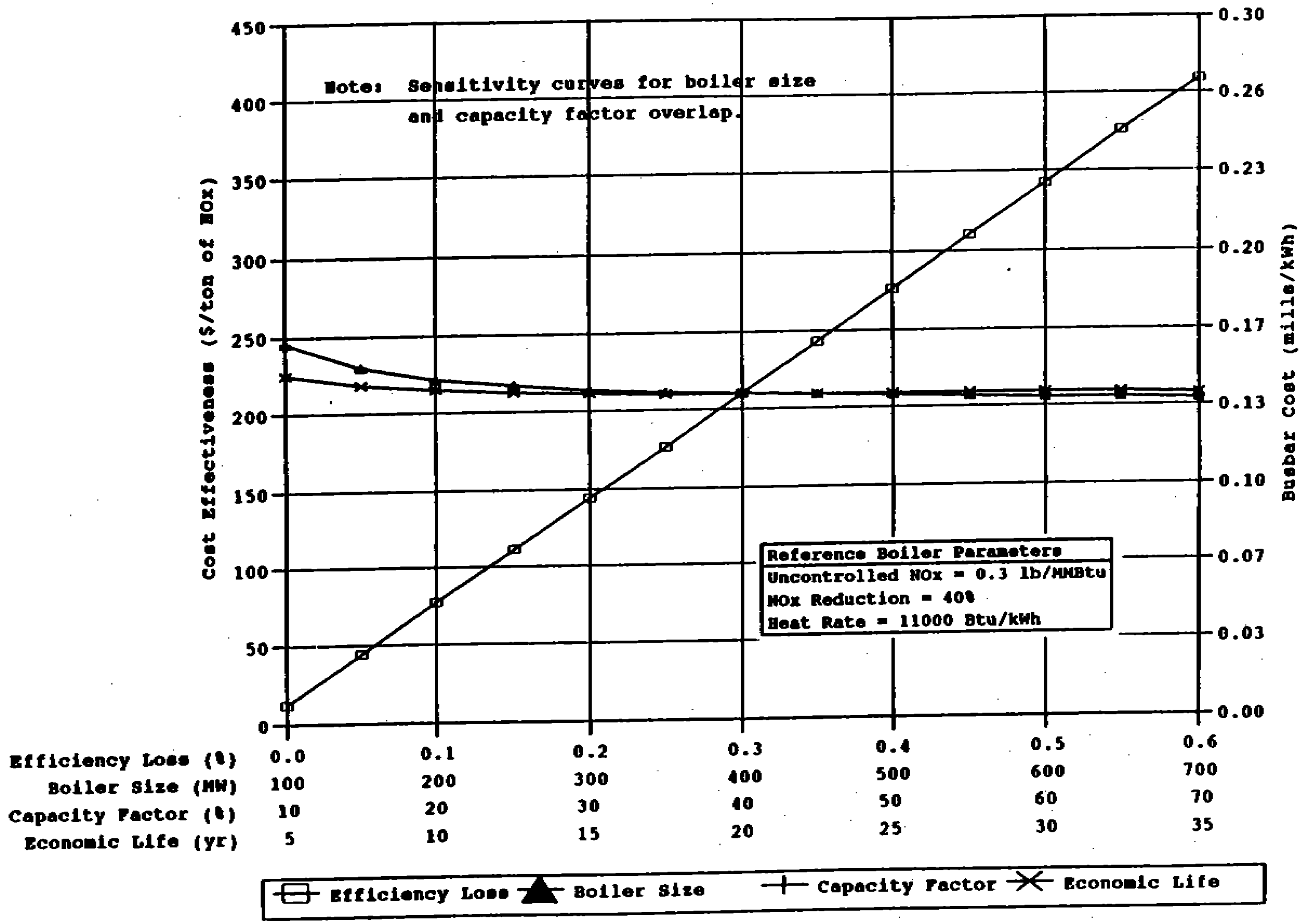

Figure 6-19. Impact of plant characteristics on LEA + BOOS cost effectiveness and busbar cost for natural gas- and oil-fired tangential boilers.

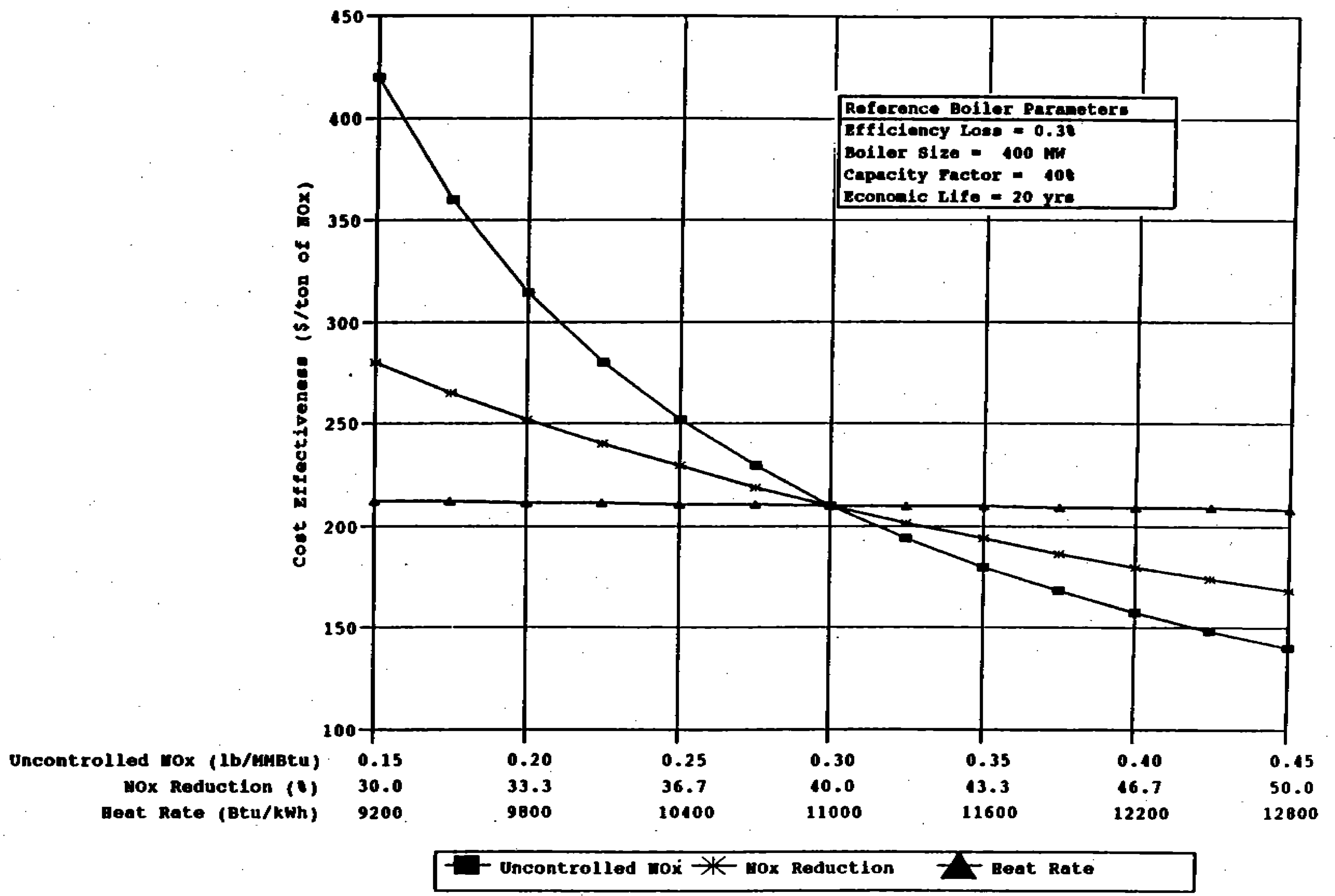

Figure 6-20. Impact of NO_x emission characteristics and heat rate on LEA + BOOS cost effectiveness for natural gas- and oil-fired boilers.

curves overlap. As shown in both figures, the reference boiler's cost effectiveness and busbar cost are approximately \$200 per ton of NO_x removed and 0.14 mills/kWh. The cost effectiveness values for LEA + BOOS applied to tangentially-fired boilers is higher for LEA + BOOS than on wall-fired boilers because of the low uncontrolled NO_x levels of tangentially-fired boilers. The sensitivity curves follow the same general trends as with LEA + BOOS applied to wall-fired boilers.

6.4.2 Low NO_x Burners

Cost estimates for LNB technology are presented for natural gas- and oil-fired wall and tangential boilers in this section. Estimated NO_x reductions and capital costs for AOFA by itself are 40 to 50 percent of the levels expected from LNB + AOFA. As a result, busbar cost for AOFA by itself are estimated at 40 to 50 percent of the cost estimates in this section for LNB + AOFA and cost effectiveness values are estimated to approximately equal those for LNB + AOFA.

6.4.2.1 Costing Procedures. Cost data from the utility questionnaire for LNB applied to natural gas- and oil-fired wall boilers were limited to an installed cost for one oil-fired wall unit. The data from this unit were combined with literature estimates of installed costs for two natural gas- and oil-fired boilers.[13] These three data points were then compared to installed costs for coal-fired wall LNB systems assuming a retrofit factor of 1.15. As discussed in appendix A.8, these data suggest that installed costs for natural gas- and oil-fired boilers are equal to the costs for coal-fired boilers. As a result, the LNB basic system cost algorithm for coal-fired wall boilers was used to estimate the costs for natural gas- and oil-fired LNB systems. Thus, the basic system cost coefficients in equation 6-1 were a=220 and b=-0.44 for wall-fired LNB systems.

For LNB applied to natural gas- and oil-fired tangential boilers, no cost data were available. Because of similarities between LNB technology applied to all fossil fuels, the costs for LNB on natural gas- and oil-fired tangential boilers were assumed to be equal to costs associated with LNB applied to coal-fired tangential boilers. Thus, the basic system cost coefficients in equation 6-1 were a=80 and b=-0.40 for tangentially-fired LNB systems. Because specific data on scope adders for gas- and oil-fired units were not available, the retrofit factors for coal-fired boilers of 1.0, 1.3, and 1.6 were used for the model plant analysis. Indirect costs were estimated at 30 percent of basic system and retrofit costs. Fixed and variable O&M costs were assumed to be negligible.

6.4.2.2 Model Plants Results. The capital cost, busbar cost, and cost effectiveness for the ten wall- and tangentially-fired model boilers are presented in table 6-10. An economic life of 20 years and a NO_x reduction efficiency of 45 percent were assumed for all of these boilers. For the 600 MW baseload wall-fired boiler, the estimated cost effectiveness ranges from $314 to $503 per ton of NO_x removed. For the 100-MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $3,600 to $5,750 per ton.

Cost per ton of NO_x removed with LNB on tangentially-fired boilers is lower than LNB on wall-fired boilers because of the lower capital cost with LNCFS I. For the 600 MW baseload tangentially-fired boiler, the cost-effectiveness ranges from $246 to $394 per ton. For the 100 MW peaking tangentially-fired boiler, cost effectiveness ranges from $2,620 to $4,190 per ton.

6.4.2.3 Sensitivity Analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-21. Figure 6-22 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in these figures, the reference boiler's cost effectiveness and busbar

TABLE 6-10. COSTS FOR LNB APPLIED TO NATURAL GAS- AND OIL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Retrofit factors	1.0	1.3	1.6	1.0	1.3	1.6	1.0	1.3	1.6
Wall-fired boilers[a]									
100 MW, Peaking[b]	38	49	60	5.06	6.57	8.09	3,600	4,670	5,750
100 MW, Baseload[c]	38	49	60	0.78	1.01	1.24	691	899	1,110
300 MW, Cycling[d]	23	30	37	1.04	1.35	1.66	840	1,090	1,340
300 MW, Baseload	23	30	37	0.48	0.62	0.77	426	554	682
600 MW, Baseload	17	22	27	0.35	0.46	0.57	314	409	503
Tangentially-fired boilers[e]									
100 MW, Peaking	16	21	26	2.21	2.87	3.54	2,620	3,400	4,190
100 MW, Baseload	16	21	26	0.34	0.44	0.54	504	655	806
300 MW, Cycling	11	14	17	0.47	0.62	0.76	639	831	1,020
300 MW Baseload	11	14	17	0.22	0.28	0.35	325	422	519
600 MW, Baseload	8	10	13	0.17	0.22	0.27	246	320	394

[a]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an LNB NO_x reduction of 45 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an LNB NO_x reduction of 45 percent were used for tangentially-fired boilers.

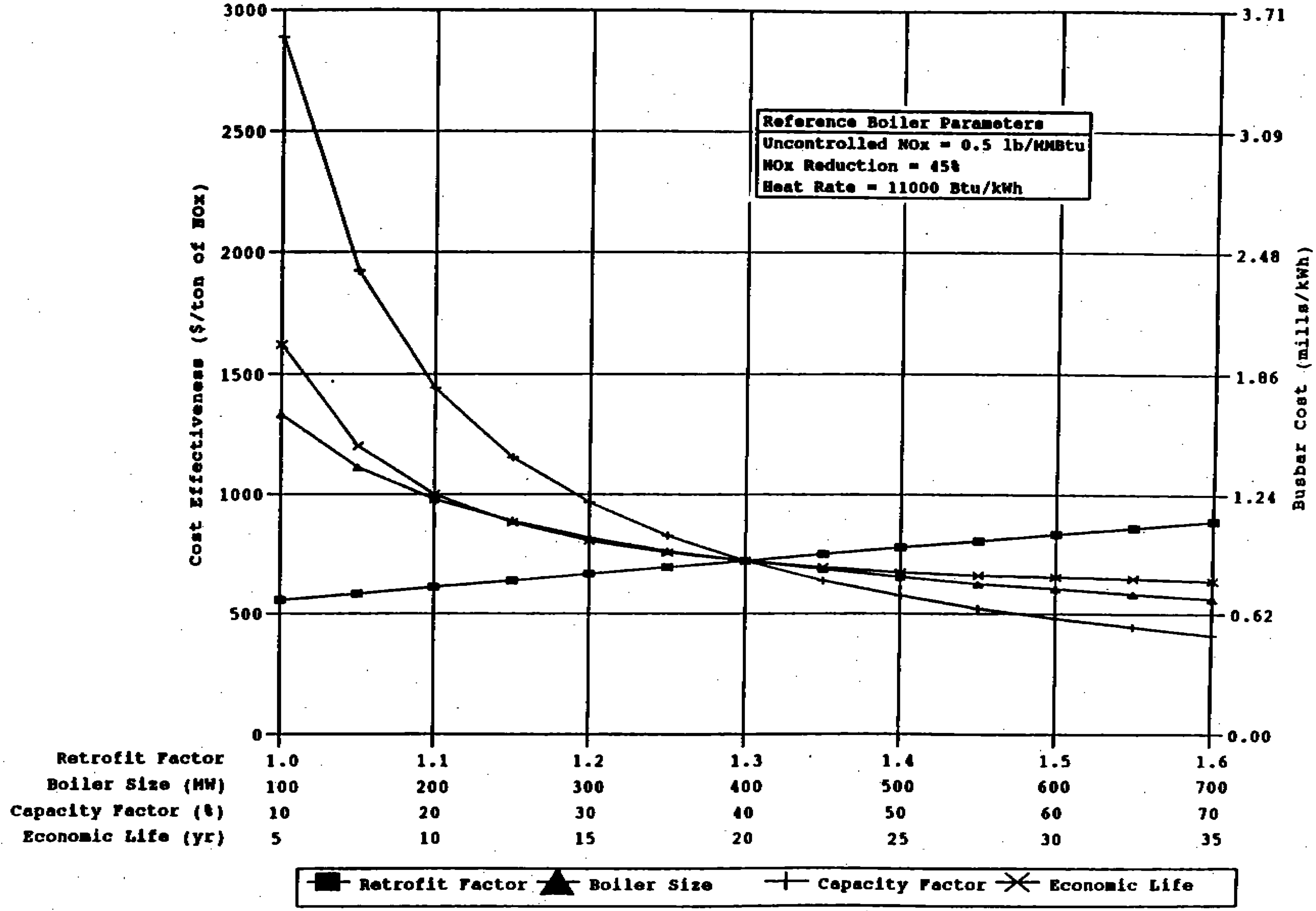

Figure 6-21. Impact of plant characteristics on LNB cost effectiveness and busbar cost for natural gas- and oil-fired wall boilers.

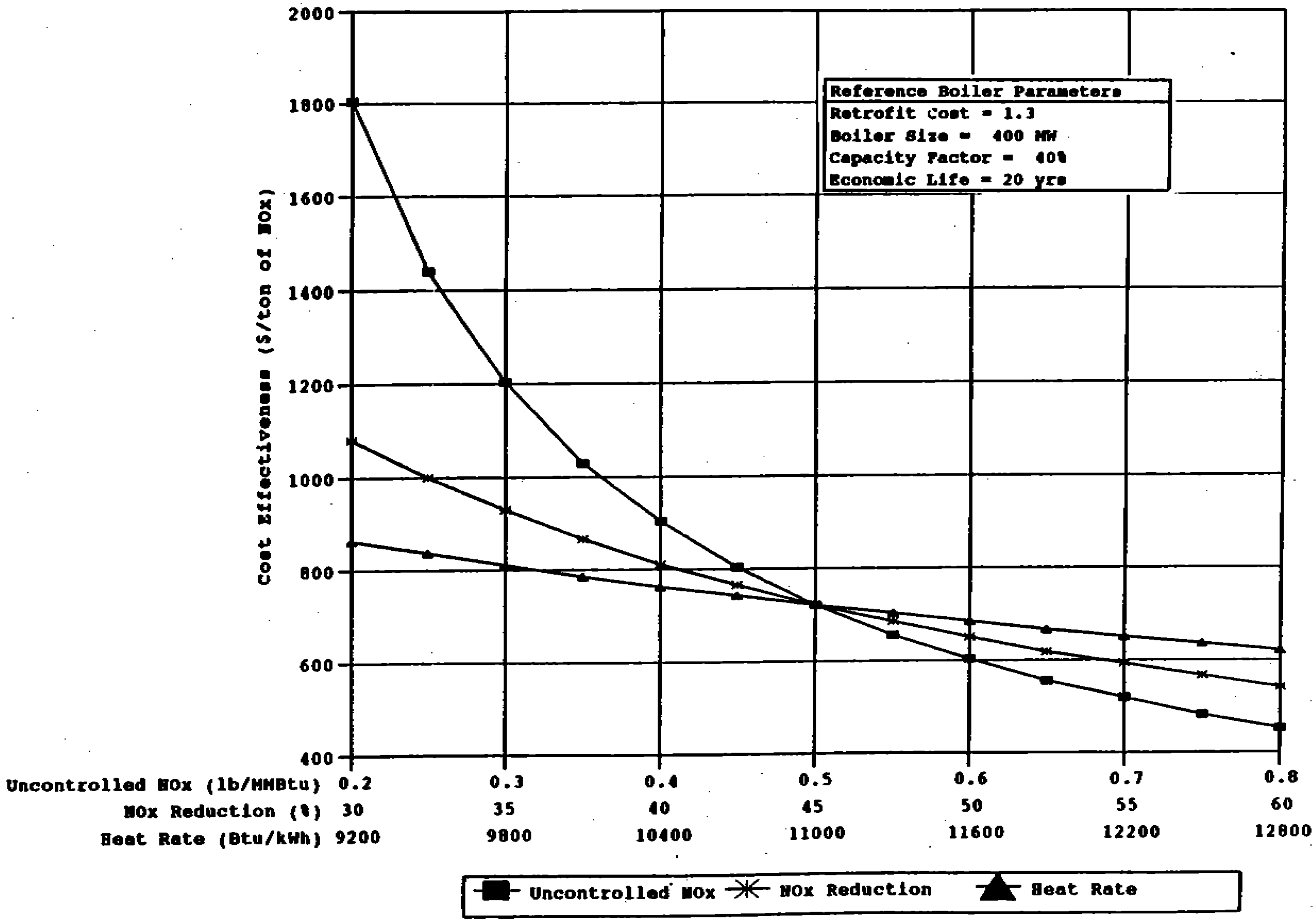

Figure 6-22. Impact of NO_x emission characteristics and heat rate on LNB cost effectiveness for natural gas- and oil-fired wall boilers.

cost are approximately $720 per ton of NO_x removed and 0.89 mills/kWh. The sensitivity curves follow the same general trends as with LNB applied to coal-fired wall boilers (refer to section 6.3.1.3).

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-23. Figure 6-24 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $560 per ton of NO_x removed and 0.41 mills/kWh. The cost effectiveness values and busbar costs for LNB applied to tangentially-fired boilers are lower than for LNB on wall-fired boilers because of lower capital costs associated with tangentially-fired boilers. The sensitivity curves follow the same general trends as with LNB applied to coal-fired wall boilers (refer to section 6.3.1.3).

6.4.3 <u>Low NO_x Burners with Advanced Overfire Air</u>

Cost estimates for LNB + AOFA technology were prepared for natural gas- and oil-fired wall and tangential boilers.

6.4.3.1 Costing Procedures. No cost data were available on LNB + AOFA technology applied to natural gas- and oil-fired wall and tangential units. However, because of the similarity between LNB technology applied to all fossil fuels, costs for LNB + AOFA on natural gas- and oil-fired boilers were assumed to be equal to the costs for LNB + AOFA technology on coal-fired boilers. Thus, the basic system cost coefficients in equation 6-1 were a=552 and b=-0.40 for wall-fired LNB + AOFA systems and a=247 and b=-0.49 for tangentially-fired LNB + AOFA systems. Due to the lack of actual cost data, the specific scope adders for natural gas- and oil-fired boilers could not be estimated. As a result, the same scope adder costs for coal-fired units were assumed to be applicable to natural gas- and oil-fired boilers. Therefore, the retrofit

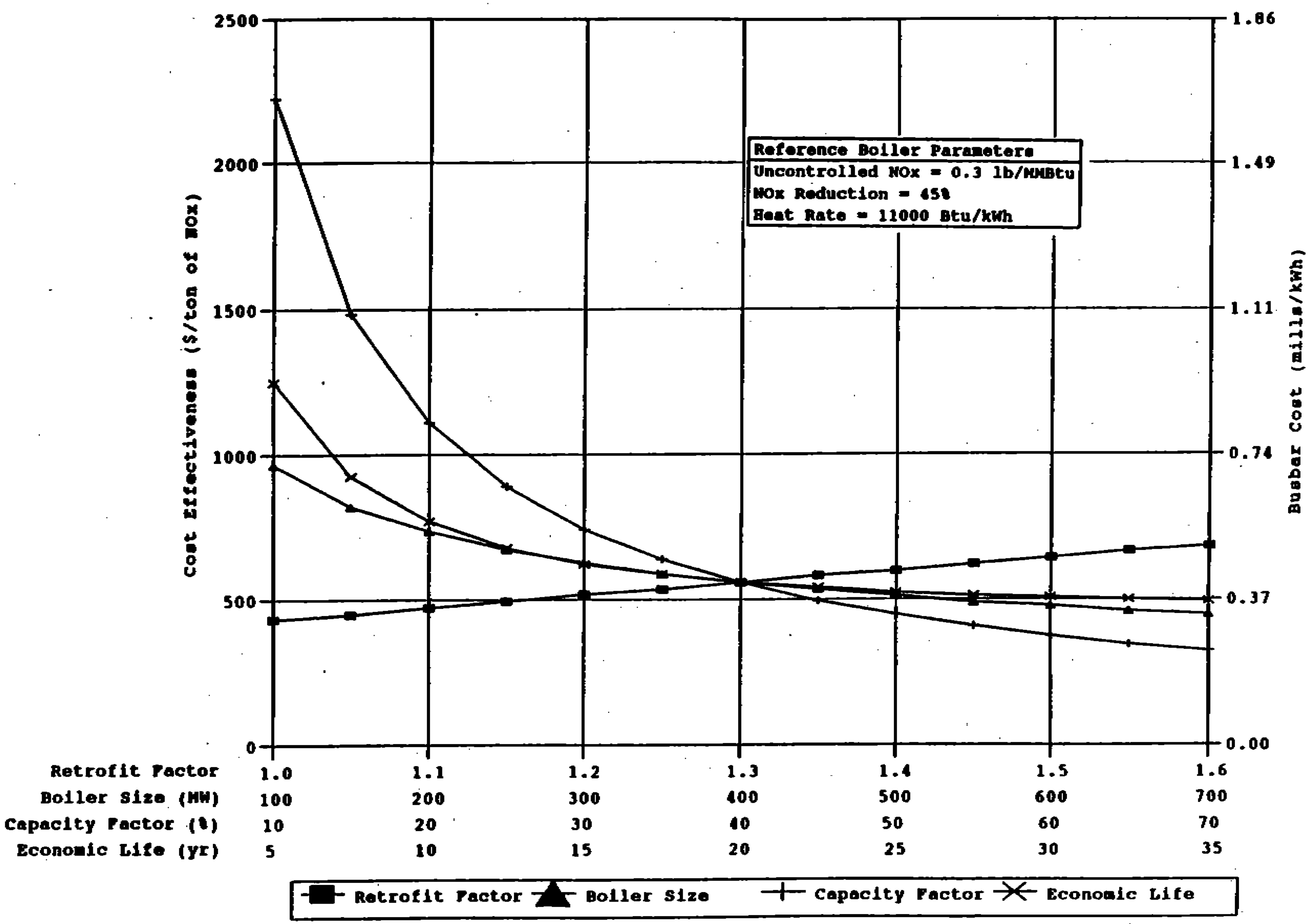

Figure 6-23. Impact of plant characteristics on LNB cost effectiveness and busbar cost for natural gas- and oil-fired tangential boilers.

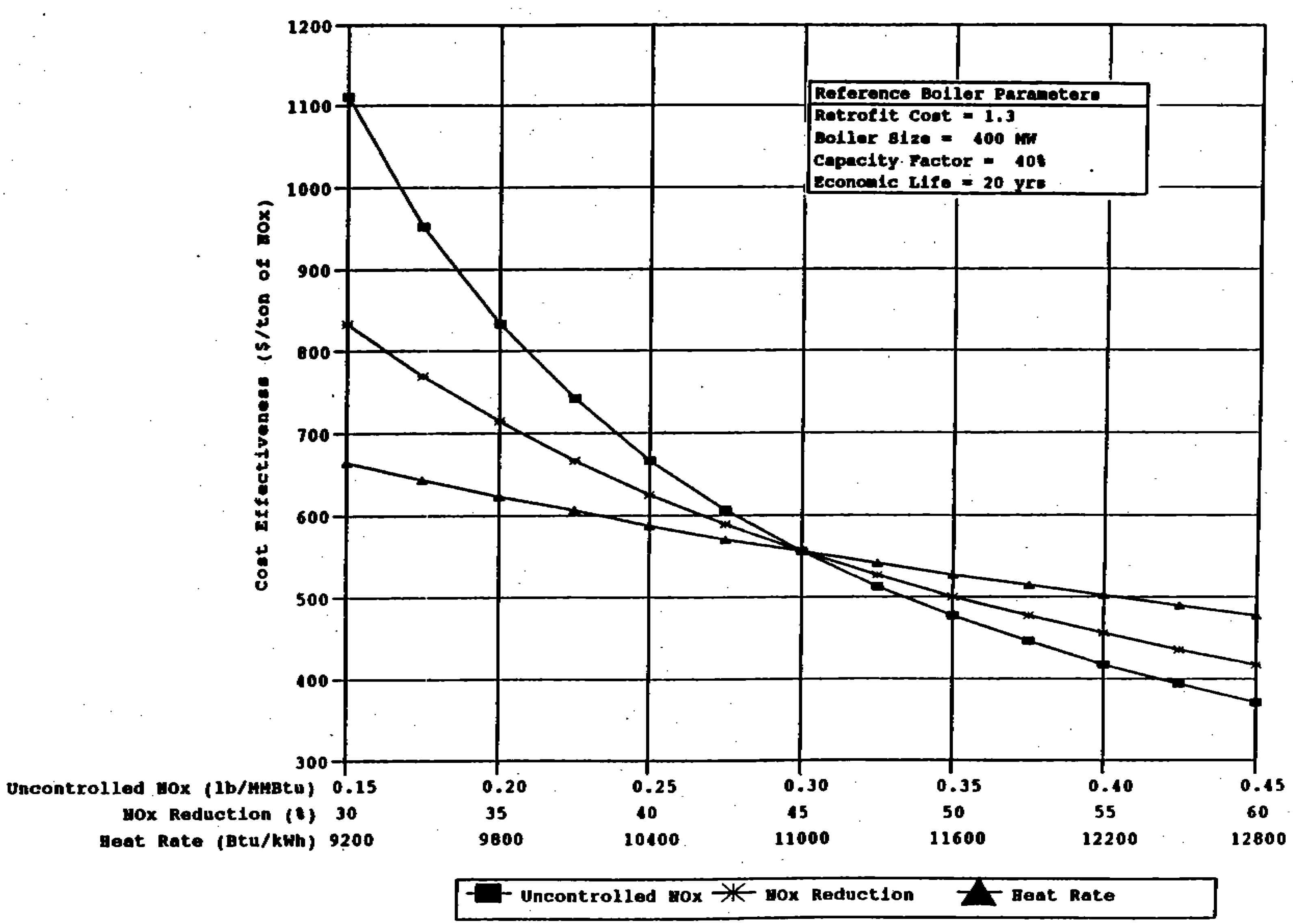

Figure 6-24. Impact of NO_x emission characteristics and heat rate on LNB cost effectiveness for natural gas- and oil-fired tangential boilers.

factors are 1.0, 1.3, and 1.6. Indirect costs were estimated at 30 percent of basic system and retrofit costs. Fixed and variable O&M costs were assumed to be negligible.

6.4.3.2 Model Plants Results. The capital cost, busbar cost, and cost effectiveness for the ten wall- and tangentially-fired model boilers are presented in table 6-11. An economic life of 20 years and a NO_x reduction efficiency of 50 percent were assumed for all of these boilers. For the 600 MW baseload wall-fired boiler, the estimated cost-effectiveness ranges from $483 to $774 per ton of NO_x removed. For the 100-MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $6,160 to $9,850 per ton.

Cost per ton of NO_x removed with LNB + AOFA is lower for tangentially-fired units due to the lower capital cost of LNCFS III. For the 600-MW baseload tangentially-fired boiler, the cost effectiveness ranges from $384 to $615 per ton. For the 100 MW peaking tangentially-fired boiler, cost effectiveness ranges from $4,810 to $7,690 per ton.

6.4.3.3 Sensitivity Analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-25. Figure 6-26 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $1,200 per ton of NO_x removed and 1.6 mills/kWh. The sensitivity curves follow the same general trends as with LNB applied to coal-fired wall boilers (refer to section 6.3.1.3).

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-27. Figure 6-28 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat

TABLE 6-11. COSTS FOR LNB + AOFA BURNERS APPLIED TO NATURAL GAS- AND OIL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Retrofit factors	1.0	1.3	1.6	1.0	1.3	1.6	1.0	1.3	1.6
Wall-fired boilers[a]									
100 MW, Peaking[b]	72	93	115	9.62	12.5	15.4	6,160	8,010	9,850
100 MW, Baseload[c]	72	93	115	1.48	1.92	2.37	1,180	1,540	1,900
300 MW, Cycling[d]	41	54	66	1.85	2.41	2.96	1,350	1,750	2,160
300 MW, Baseload	41	54	66	0.85	1.11	1.37	684	889	1,090
600 MW, Baseload	29	38	47	0.60	0.79	0.97	483	629	774
Tangentially-fired boilers[e]									
100 MW, Peaking	34	44	54	4.51	5.86	7.21	4,810	6,250	7,690
100 MW, Baseload	34	44	54	0.69	0.90	1.11	925	1,200	1,480
300 MW, Cycling	20	26	31	0.88	1.14	1.40	1,060	1,380	1,700
300 MW Baseload	20	26	31	0.40	0.53	0.65	540	702	864
600 MW, Baseload	14	18	22	0.29	0.37	0.46	384	500	615

[a]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an LNB + AOFA NO_x reduction of 50 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an LNB + AOFA NO_x reduction of 50 percent were used for tangentially-fired boilers.

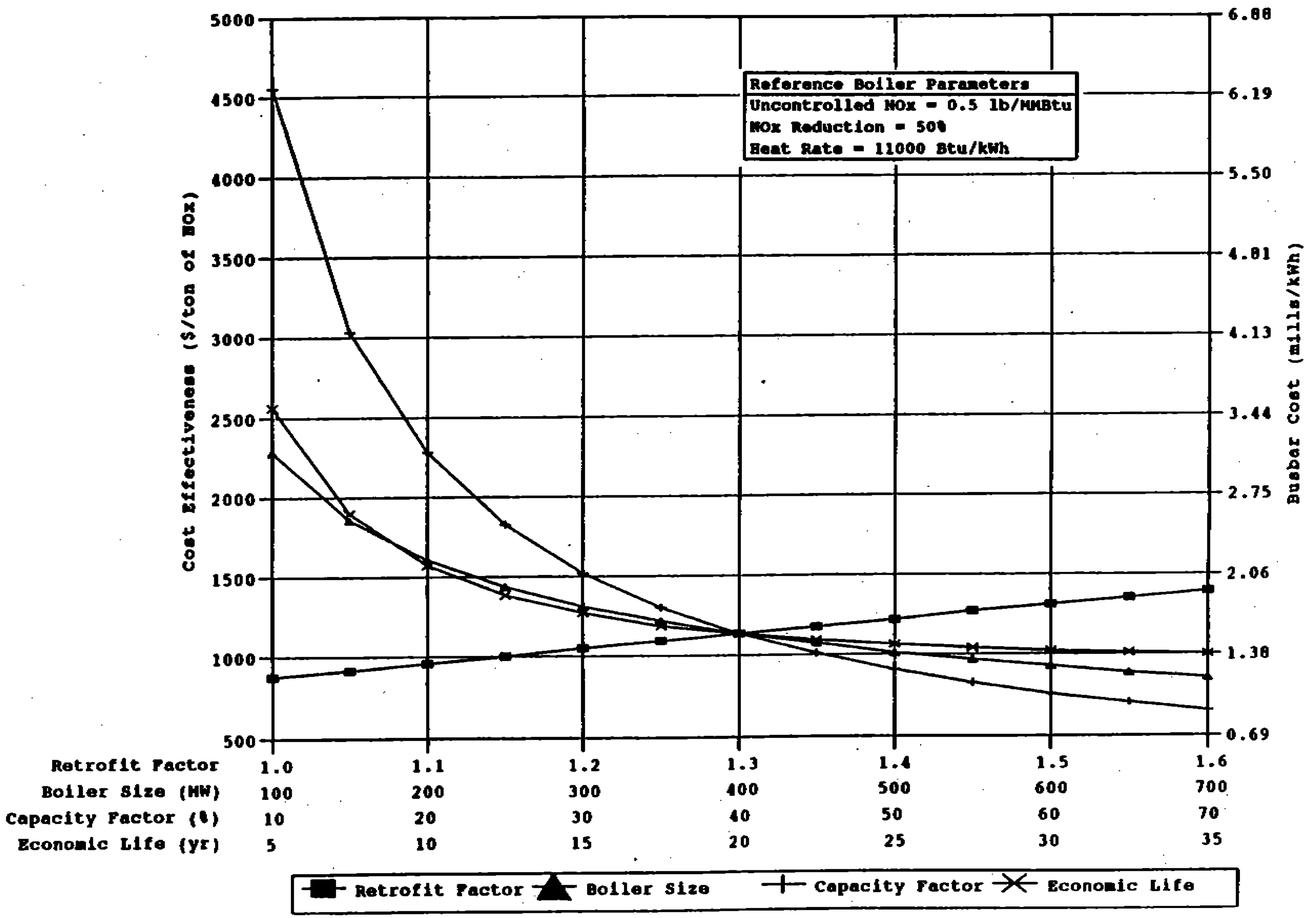

Figure 6-25. Impact of plant characteristics on LNB + AOFA cost effectiveness and busbar cost for natural gas- and oil-fired wall boilers.

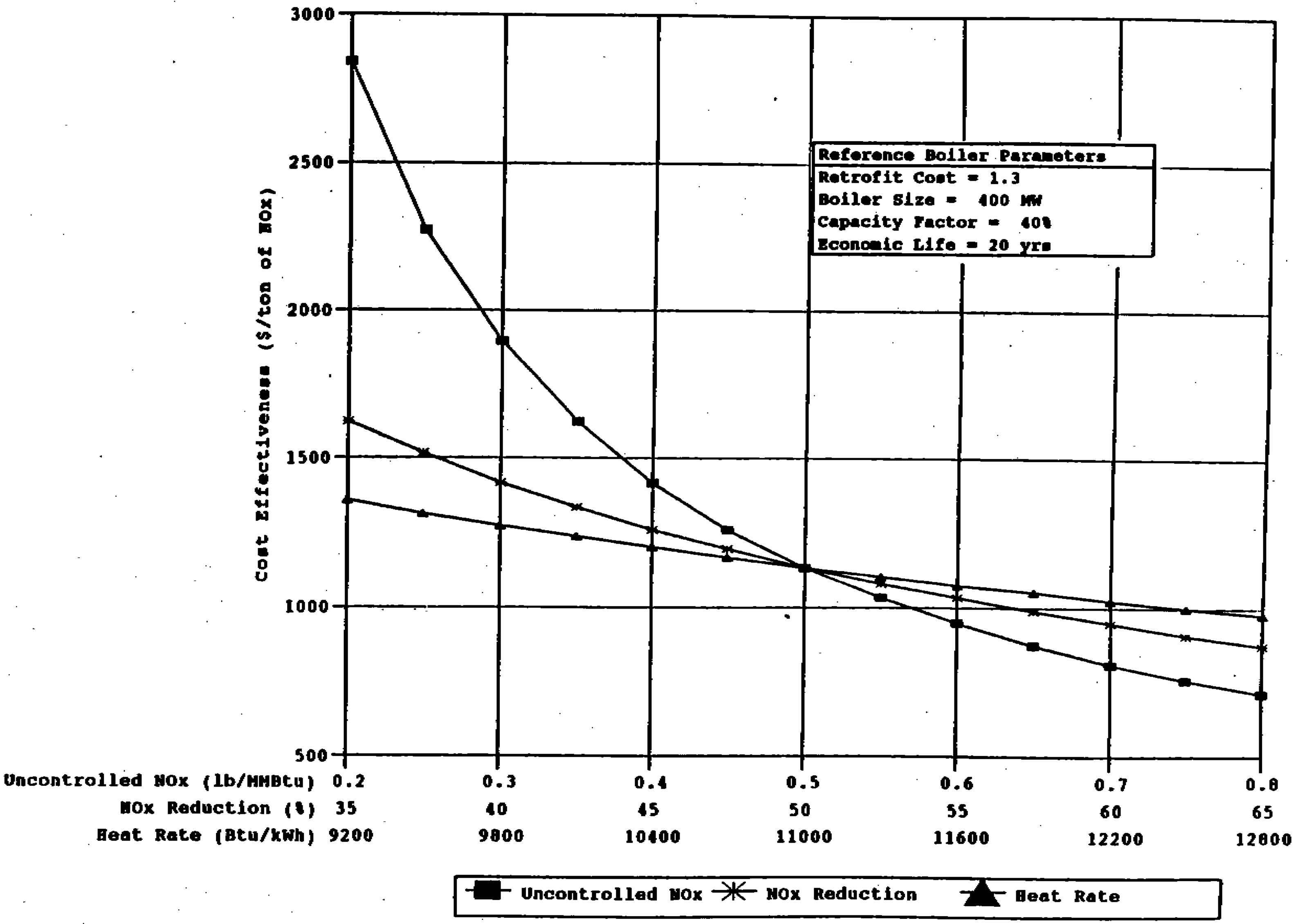

Figure 6-26. Impact of NO_x emission characteristics and heat rate on LNB + AOFA cost effectiveness for natural gas- and oil-fired wall boilers.

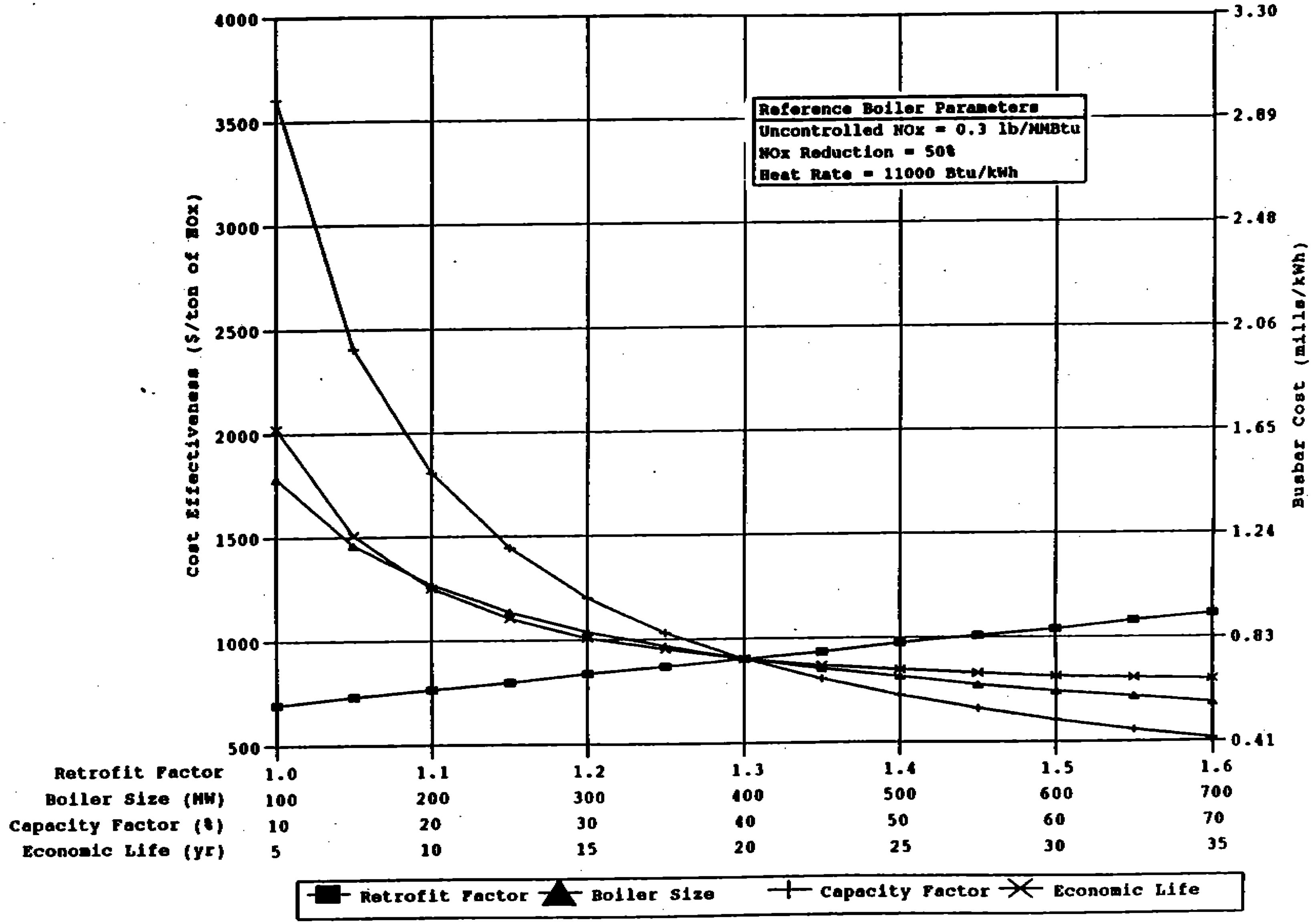

Figure 6-27. Impact of plant characteristics on LNB + AOFA cost effectiveness and busbar cost for natural gas- and oil-fired tangential boilers.

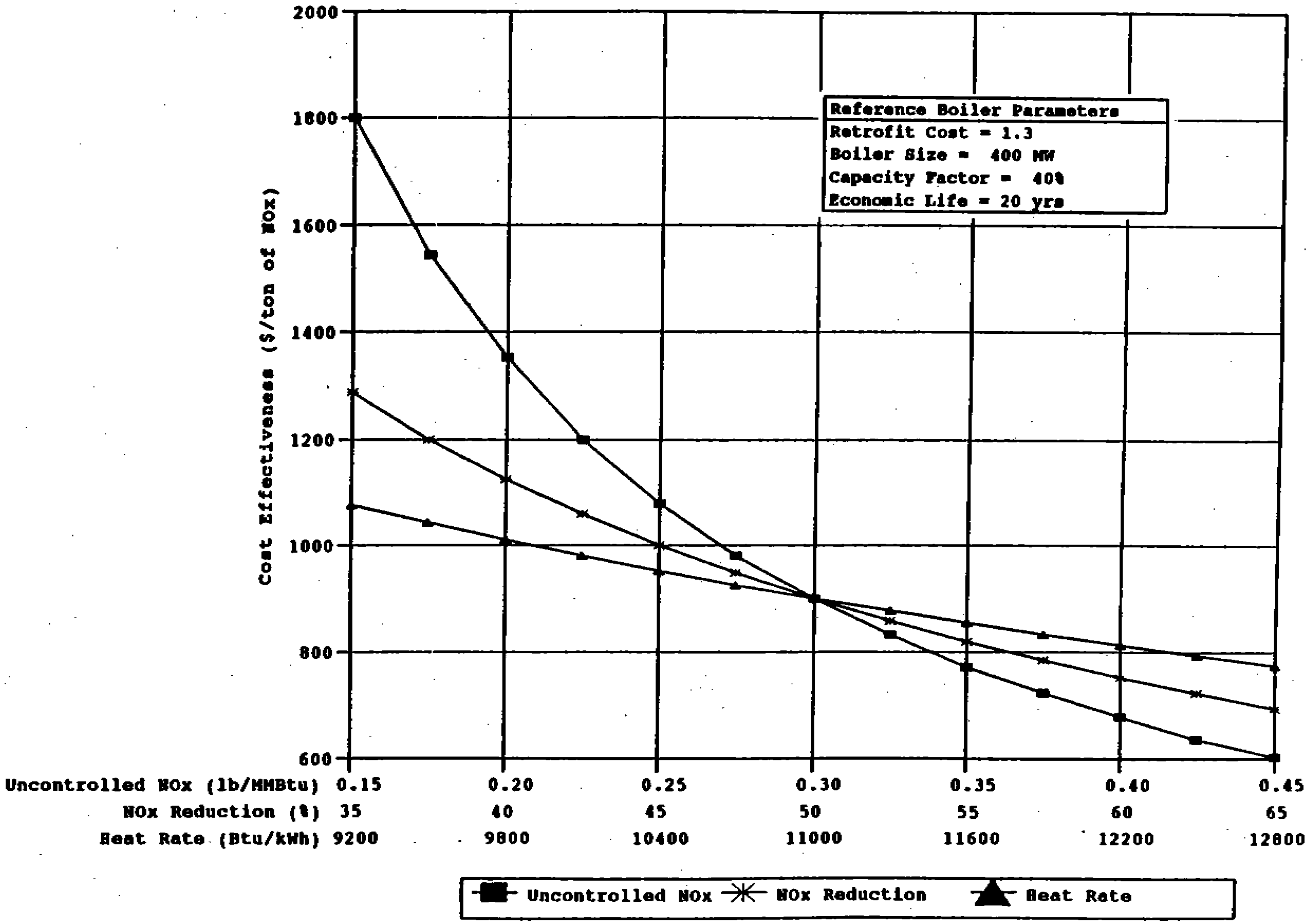

Figure 6-28. Impact of NO_x emission characteristics and heat rate on LNB + AOFA cost effectiveness for natural gas- and oil-fired tangential boilers.

rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $900 per ton of NO_x removed and 0.74 mills/kWh. The cost effectiveness value and busbar cost for LNB + AOFA applied to tangentially-fired boilers are lower than for LNB + AOFA on wall-fired boilers because of lower capital costs associated with tangentially-fired boilers. The sensitivity curves follow the same general trends as with LNB applied to coal-fired wall boilers (refer to section 6.3.1.3).

6.4.4 Natural Gas Reburn

Cost estimates for NGR were prepared for wall and tangential oil-fired boilers.

6.4.4.1 Costing Procedures. No actual cost data were received from utilities or vendors for reburn applied to oil-fired boilers. Because of the general similarity between the application of reburn to both oil- and coal-fired boilers, the capital cost procedures that were used for coal-fired boilers were also used for oil-fired boilers. Therefore, the coefficients in equation 6-1 are a=243 and b=-0.40. The retrofit factor and indirect cost factor were estimated to be 1.15 and 1.40, respectively.

Although the national average price of fuel oil is higher per million Btu than natural gas, there are regions of the country (e.g., New England) where fuel oil is the less expensive fuel. As a result, fuel oil is the primary boiler fuel in these areas. In these situations, natural gas reburn can be used as an economic option to reduce NO_x emissions. For the economic analysis of natural gas reburn on oil-fired boilers, a price differential between these two fuels of $0.50 to $2.50/MMBtu was assumed. To account for the lower sulfur content of natural gas compared to fuel oil, a credit for reduced SO_2 emissions of $200 per ton was used. Based on a fuel oil sulfur content of 1.0 percent, this credit equates to approximately $0.16/MMBtu of natural gas fired.

6.4.4.2 Model Plants Results. The capital cost, busbar cost, and cost effectiveness for the ten wall- and tangentially-fired model boilers are presented in table 6-12. An economic life of 20 years and a NO_x reduction efficiency of 55 percent were assumed for all of these boilers. For the 600 MW baseload wall-fired boiler, the estimated cost effectiveness ranges from $950 to $3,560 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $5,080 to $7,690 per ton.

Cost per ton of NO_x removed with natural gas reburn on tangentially-fired boilers is higher than that of wall-fired boilers because of lower baseline NO_x emissions for tangentially-fired boilers. For the 600 MW baseload tangentially-fired boiler, the cost effectiveness ranges from $1,580 to $5,940 per ton. For the 100 MW peaking tangentially-fired boiler, cost effectiveness ranges from $8,460 to $12,800 per ton.

6.4.4.3 Sensitivity Analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and fuel price differential on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-29. Figure 6-30 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown, the reference boilers cost effectiveness and busbar cost are approximately $2,700 per ton of NO_x removed and 4.0 mills/kWh. The sensitivity curves follow the same general trends as for natural gas reburn applied to coal-fired wall boilers (refer to section 6.3.3.3).

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and fuel price differential on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-31. Figure 6-32 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x

TABLE 6-12. COSTS FOR NGR APPLIED TO OIL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Fuel price differential ($/MMBtu)	0.50	1.50	2.50	0.50	1.50	2.50	0.50	1.50	2.50
Wall-fired boilers[a]									
100 MW, Peaking[b]	58.0	58.0	58.0	8.72	11.0	13.2	5,080	6,390	7,690
100 MW, Baseload[c]	58.0	58.0	58.0	1.92	3.72	5.52	1,390	2,700	4,010
300 MW, Cycling[d]	38.0	38.0	38.0	2.47	4.45	6.43	1,630	2,940	4,250
300 MW, Baseload	38.0	38.0	38.0	1.49	3.29	5.09	1,080	2,390	3,700
600 MW, Baseload	29.0	29.0	29.0	1.30	3.10	4.90	946	2,260	3,560
Tangentially-fired boilers[e]									
100 MW, Peaking	58.0	58.0	58.0	8.72	11.0	13.2	8,460	10,600	12,800
100 MW, Baseload	58.0	58.0	58.0	1.92	3.72	5.52	2,320	4,510	6,690
300 MW, Cycling	38.0	38.0	38.0	2.47	4.45	6.43	2,720	4,900	7,080
300 MW Baseload	38.0	38.0	38.0	1.49	3.29	5.09	1,800	3,990	6,170
600 MW, Baseload	29.0	29.0	29.0	1.30	3.10	4.90	1,580	3,760	5,940

[a]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an NGR NO_x reduction of 55 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an NGR NO_x reduction of 55 percent were used for tangentially-fired boilers.

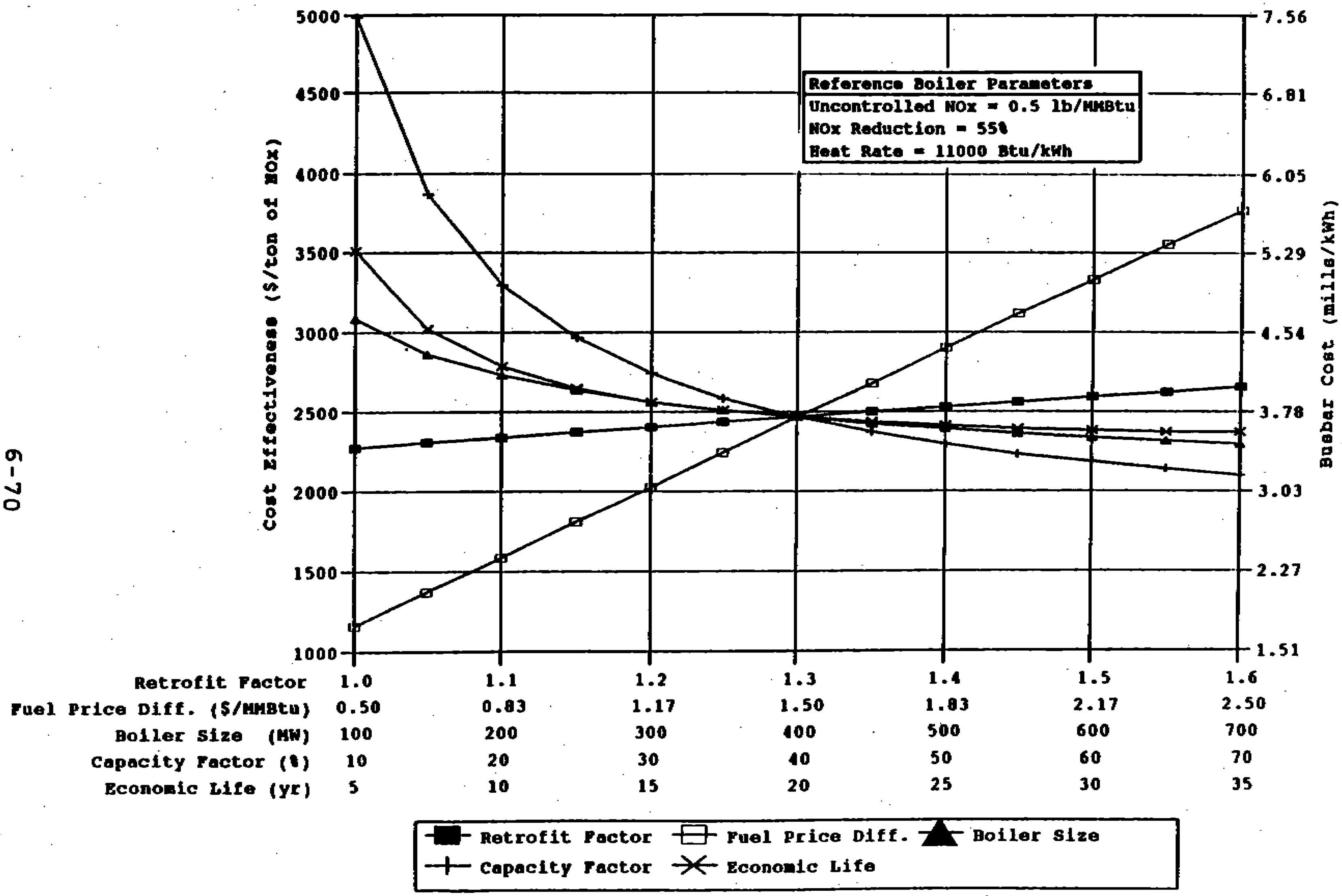

Figure 6-29. Impact of plant characteristics on NGR cost effectiveness and busbar cost for oil-fired wall boilers.

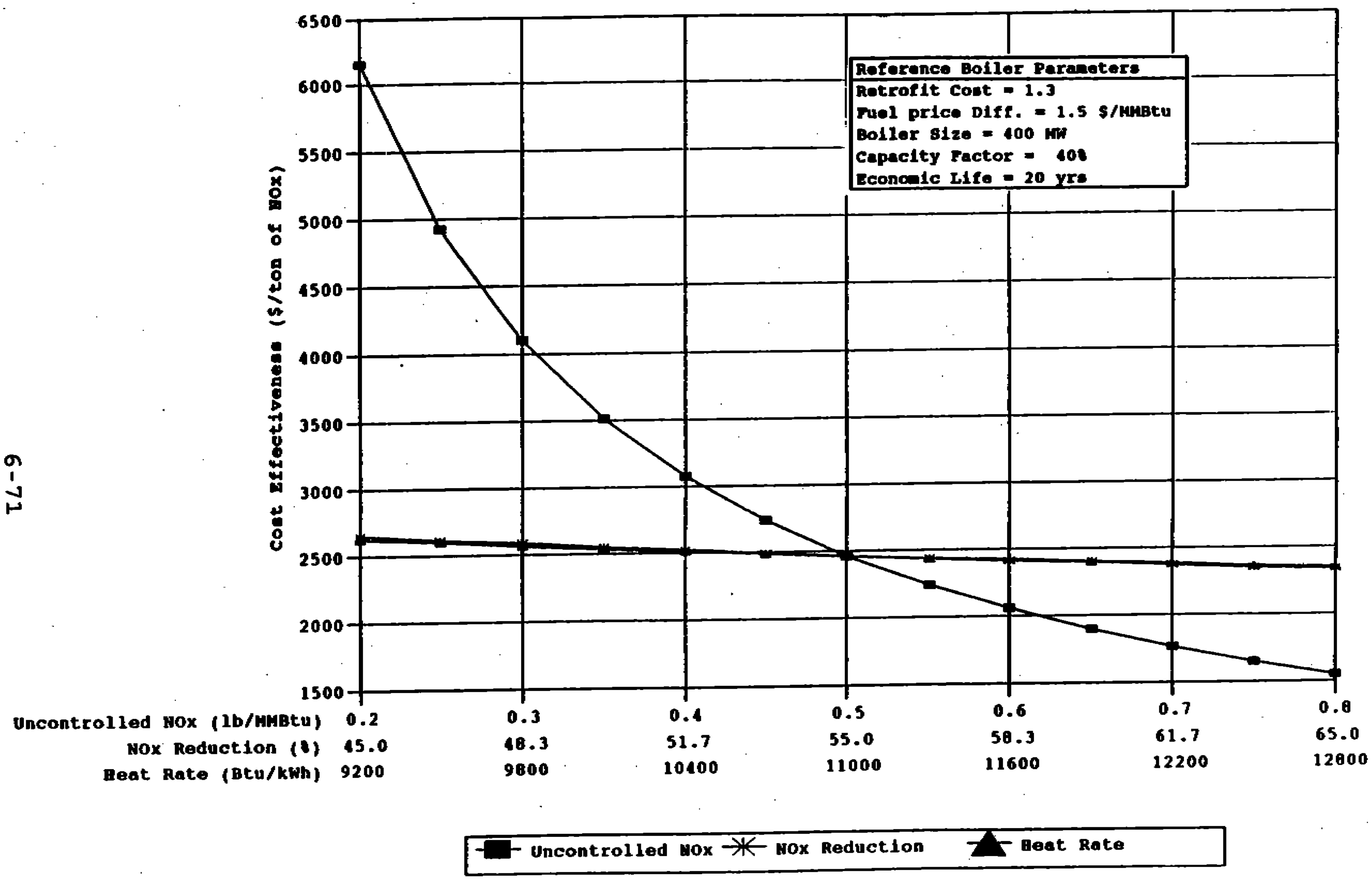

Figure 6-30. Impact of NO_x emission characteristics and heat rate on NGR cost effectiveness for oil-fired wall boilers.

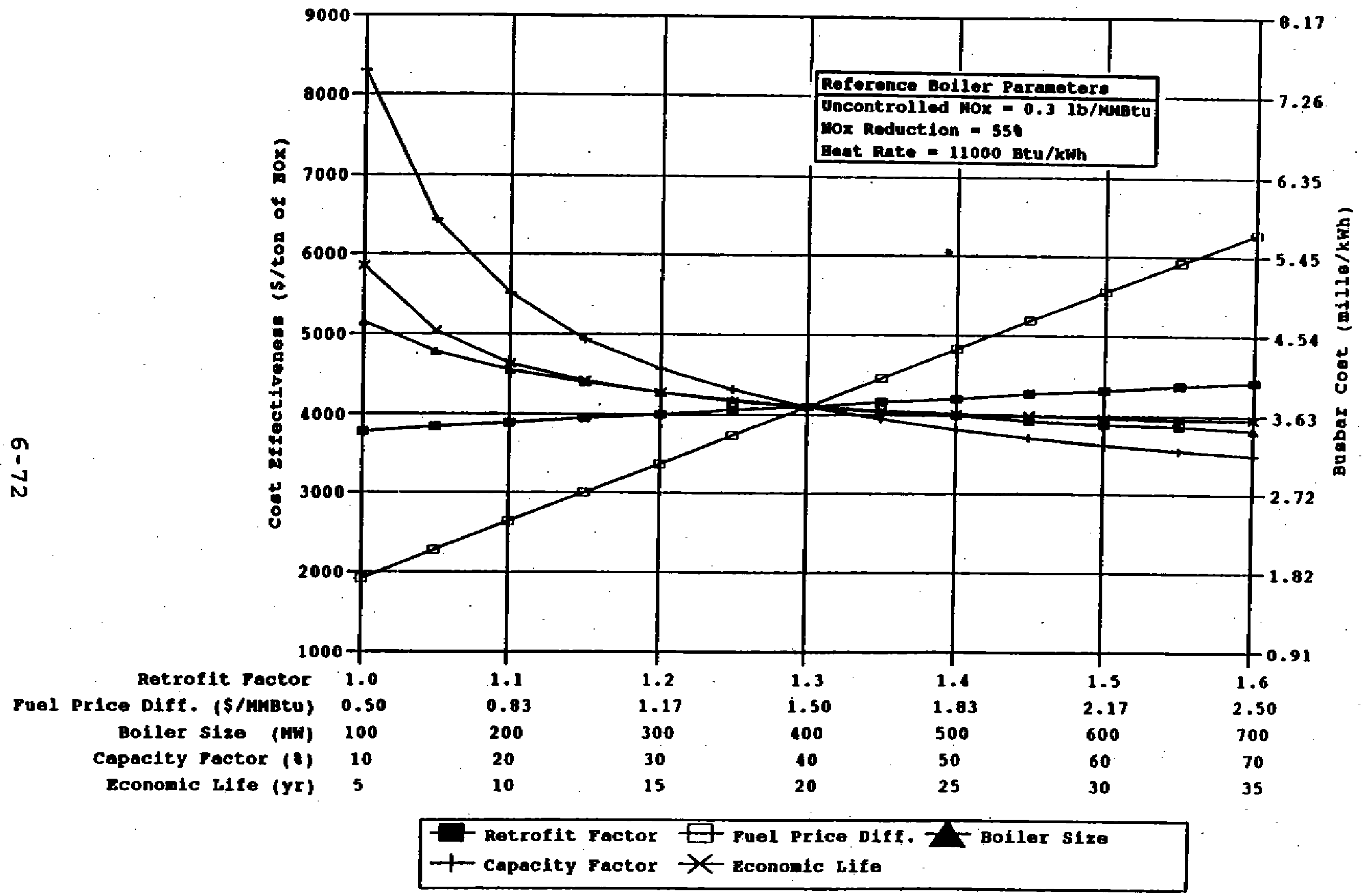

Figure 6-31. Impact of plant characteristics on NGR cost effectiveness and busbar cost for oil-fired tangential boilers.

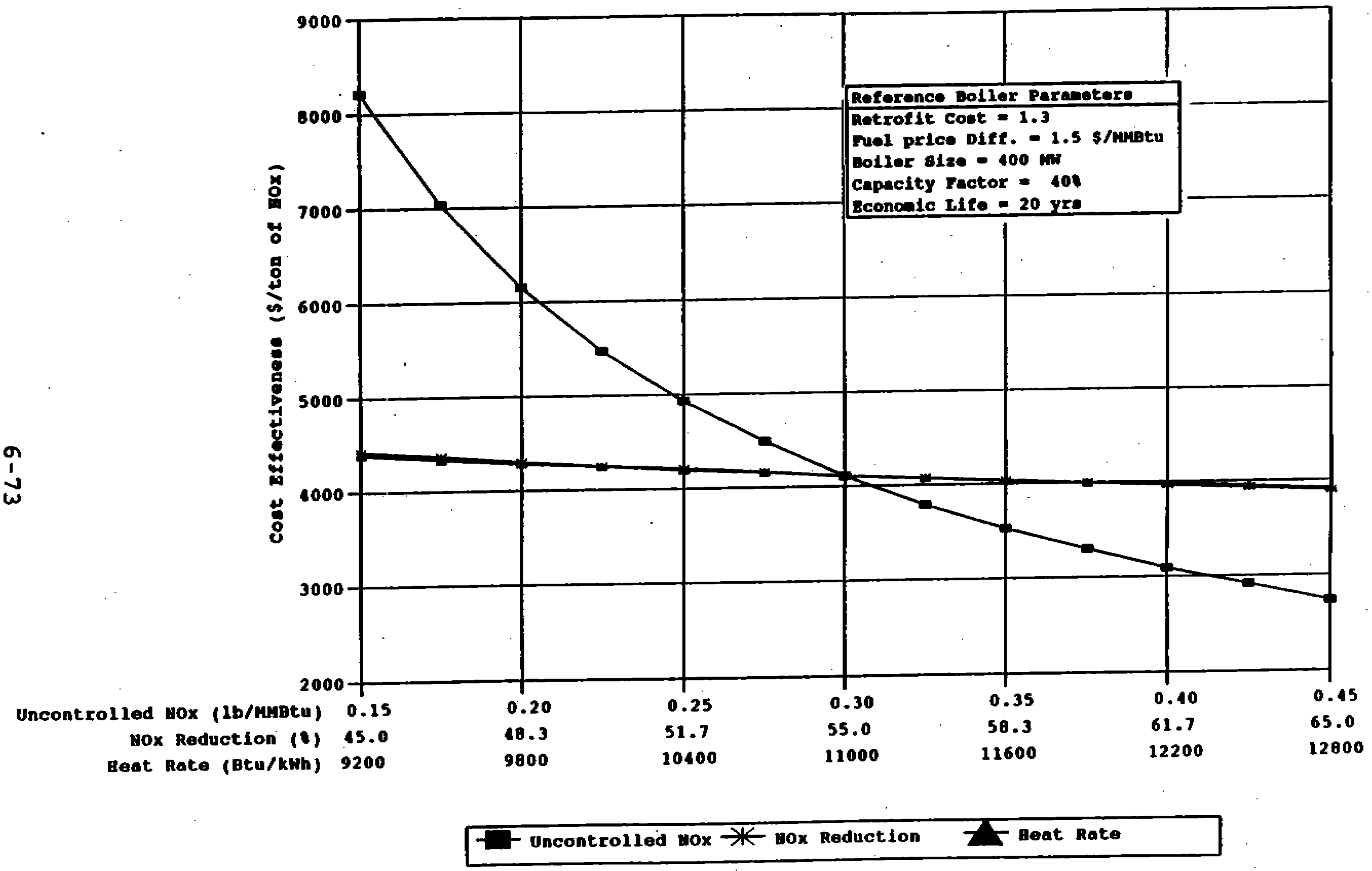

Figure 6-32. Impact of NO_x emission characteristics and heat rate on NGR cost effectiveness for oil-fired tangential boilers.

reduction efficiency) and heat rate. As shown, the reference boiler's cost effectiveness and busbar cost are approximately $4,450 per ton of NO_x removed and 4.0 mills/kWh. The cost effectiveness values for natural gas reburn applied to tangentially-fired boilers is generally higher than for natural gas reburn on wall-fired boilers because of the lower uncontrolled NO_x levels of tangentially-fired boilers The sensitivity curves follow the same general trends as for natural gas reburn applied to coal-fired wall boilers (refer to section 6.3.3.3).

6.5 FLUE GAS TREATMENT CONTROLS

This section presents the capital cost, busbar cost, and cost-effectiveness estimates for flue gas treatment controls on fossil fuel boilers. Costs for SNCR are given in section 6.5.1 and costs for SCR are in section 6.5.2. Costs for combining LNB + SNCR are presented in section 6.5.3 and the cost of LNB + OFA + SCR are given in section 6.5.4.

6.5.1 Selective Noncatalytic Reduction

Cost estimates for SNCR technology are presented in this section for coal-fired wall, tangential, cyclone, and FBC boilers, and for natural gas- and oil-fired wall and tangential boilers. Because the cost estimates for a low-energy, urea-based SNCR system were found to be comparable in cost to a high-energy NH_3-based SNCR system, results are only presented for the low-energy, urea-based SNCR system.

6.5.1.1 Costing Procedures. Vendor cost estimates were used to develop the capital cost algorithms.[14] Each boiler was assumed to have two levels of wall injectors and one level of lance injectors. Since FBC units are typically smaller and have different operating characteristics than wall-, tangential-, or cyclone-fired boilers, these units have a greater likelihood of needing less than three levels of injectors. If two levels of injectors were eliminated on the FBC units, cursory analysis indicates that levelized technology costs could decrease 40 percent.

The injected urea solution was assumed to be 10 percent urea by weight, 90 percent dilution water. The normalized stoichiometric ratio (NSR) was assumed to be 1.0. Simplified algorithms in the form of equation 6-1 were developed from the capital cost estimates. The capital cost coefficients for the three coal-fired boilers were nearly identical, therefore, a=32 and b=-0.24 was used to characterize the costs for all three. Similarly, the cost coefficients for both natural gas- and oil-fired boilers were nearly identical, and coefficients of a=31 and b=-0.25 were used to characterize costs for both.

Vendor cost estimates were also used to estimate fixed O&M costs. The costs for an SNCR system include operating, maintenance, supervisory labor, and maintenance materials. Fixed O&M costs were found to be independent of fuel type. Simplified algorithms in the form of equation A.5 (appendix A.1) were developed from the vendor estimates.[15] The boilers had fixed O&M cost coefficients of a=85,700 and b=-0.21.

Variable O&M costs include the urea solution (chemical costs), energy losses due to mixing air, energy losses due to the vaporization of the urea solution, dilution water, and electricity costs necessary to operate the air compressor and other miscellaneous equipment. The chemical costs were estimated by determining the amount of urea that had to be injected as a function of the baseline NO_X emission levels and the assumed NSR of 1.0. The amount of urea injected was multiplied by solution price to determine the chemical cost. The amount of urea injected was also used to determine the energy loss to the injected solution. This energy loss was multiplied by the fuel cost to determine the costs. Electricity costs were determined as a function of unit size and reagent injection rate. Appendix A.10 presents the equation for calculating urea cost.

A retrofit factor of 1.0 was assumed for the analysis based upon the assumption that the retrofit of SNCR has few scope adders and work area congestion is not a significant factor for retrofitting the technology (refer to section 6.1.1.2). The indirect cost factor was assumed to be 1.3. However, due to the limited SNCR applications on boilers with generating capabilities of over 200 MW, the indirect costs on these units may be a greater percentage of total direct costs then on smaller units.

6.5.1.2 Model Plants Results.

6.5.1.2.1 Coal-fired model plants. The capital cost, busbar cost, and cost effectiveness for the 20 coal-fired wall, tangential, cyclone, and FBC boilers are presented in table 6-13. An economic life of 20 years and a NO_x reduction efficiency of 45 percent were assumed for all of these boilers. The urea price for each boiler was varied from $140 to $260 per ton for a 50-percent urea solution. For the 600 MW baseload wall-fired boiler, the estimated cost effectiveness ranges from $560 to $870 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $2,160 to $2,470 per ton.

Cost per ton of NO_x removed with SNCR on tangential coal-fired boilers is higher than wall-fired boilers because of lower uncontrolled NO_x for tangentially-fired boilers. Cost effectiveness for the 600 MW baseload tangentially-fired boiler ranges from $610 to $910 per ton. For the 100 MW peaking tangentially-fired boiler, cost effectiveness ranges from $2,660 to $2,960 per ton.

Cost per ton of NO_x removed with SNCR on cyclone boilers is lower than wall- and tangentially-fired boilers because of higher uncontrolled NO_x for cyclone boilers. Cost effectiveness for the 600 MW baseload cyclone boiler ranges from $510 to $820 per ton and for the 100 MW peaking cyclone boiler, cost effectiveness ranges from $1,460 to $1,780 per ton.

Cost per ton of NO_x removed with SNCR on an FBC boiler is higher than wall-, tangentially- and cyclone-fired boilers due to the lower uncontrolled NO_x levels on FBC boilers as compared to the other three types of boilers. Cost effectiveness for the 200 MW baseload FBC boiler ranges from \$1,520 to \$1,820 per ton. For the 50 MW cycling FBC boiler, cost effectiveness ranges from \$5,100 to \$5,410 per ton.

6.5.1.2.2 Natural gas- and oil-fired model plants. The capital cost, busbar cost, and cost effectiveness for the 10 natural gas- and oil-fired wall and tangential model boilers are presented in table 6-14. An economic life of 20 years and a NO_x reduction efficiency of 35 percent were assumed for all of these boilers. For the 600 MW baseload wall-fired boiler, the estimated cost effectiveness ranges from \$859 to \$1,240 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from \$4,470 to \$4,850 per ton.

Cost per ton of NO_x removed with SNCR on tangential boilers is higher than wall-fired boilers because of lower baseline NO_x for the tangentially-fired boilers. Cost effectiveness for the 600 MW baseload tangentially-fired boiler ranges from \$1,070 to \$1,430 per ton. For the 100 MW peaking tangentially-fired boiler, cost effectiveness ranges from \$7,090 to \$7,450 per ton.

6.5.1.3 Sensitivity Analysis

6.5.1.3.1 Coal-fired boiler sensitivity analysis. The effect of plant characteristics (boiler size, capacity factor, and economic life) and urea solution on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-33. Figure 6-34 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately \$820 per ton of NO_x removed and 1.8 mills/kWh.

Of the parameters shown in figure 6-33, the variation of capacity factor from 10 to 70 percent has the greatest impact on cost effectiveness and busbar cost. The cost effectiveness value and busbar cost are inversely related to capacity factor, and thus, as capacity factor decreases, the cost

TABLE 6-14. COSTS FOR SNCR APPLIED TO NATURAL GAS- AND OIL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Urea cost, $/ton	140	200	260	140	200	260	140	200	260
Wall-fired boilers[a]									
100 MW, Peaking[b]	13	13	13	4.89	5.10	5.30	4,470	4,660	4,850
100 MW, Baseload[c]	13	13	13	1.15	1.31	1.48	1,310	1,500	1,690
300 MW, Cycling[d]	10	10	10	1.33	1.51	1.69	1,380	1,570	1,760
300 MW, Baseload	10	10	10	0.85	1.02	1.18	976	1,160	1,350
600 MW, Baseload	8	8	8	0.75	0.92	1.08	859	1,050	1,240
Tangentially-fired boilers[e]									
100 MW, Peaking	13	13	13	4.65	4.77	4.89	7,090	7,270	7,450
100 MW, Baseload	13	13	13	0.96	1.05	1.15	1,820	2,000	2,180
300 MW, Cycling	10	10	10	1.12	1.22	1.33	1,940	2,120	2,300
300 MW Baseload	10	10	10	0.66	0.76	0.85	1,260	1,440	1,620
600 MW, Baseload	8	8	8	0.56	0.66	0.75	1,070	1,250	1,430

[a]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an SNCR NO_x reduction of 35 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an SNCR NO_x reduction of 35 percent were used for tangentially-fired boilers.

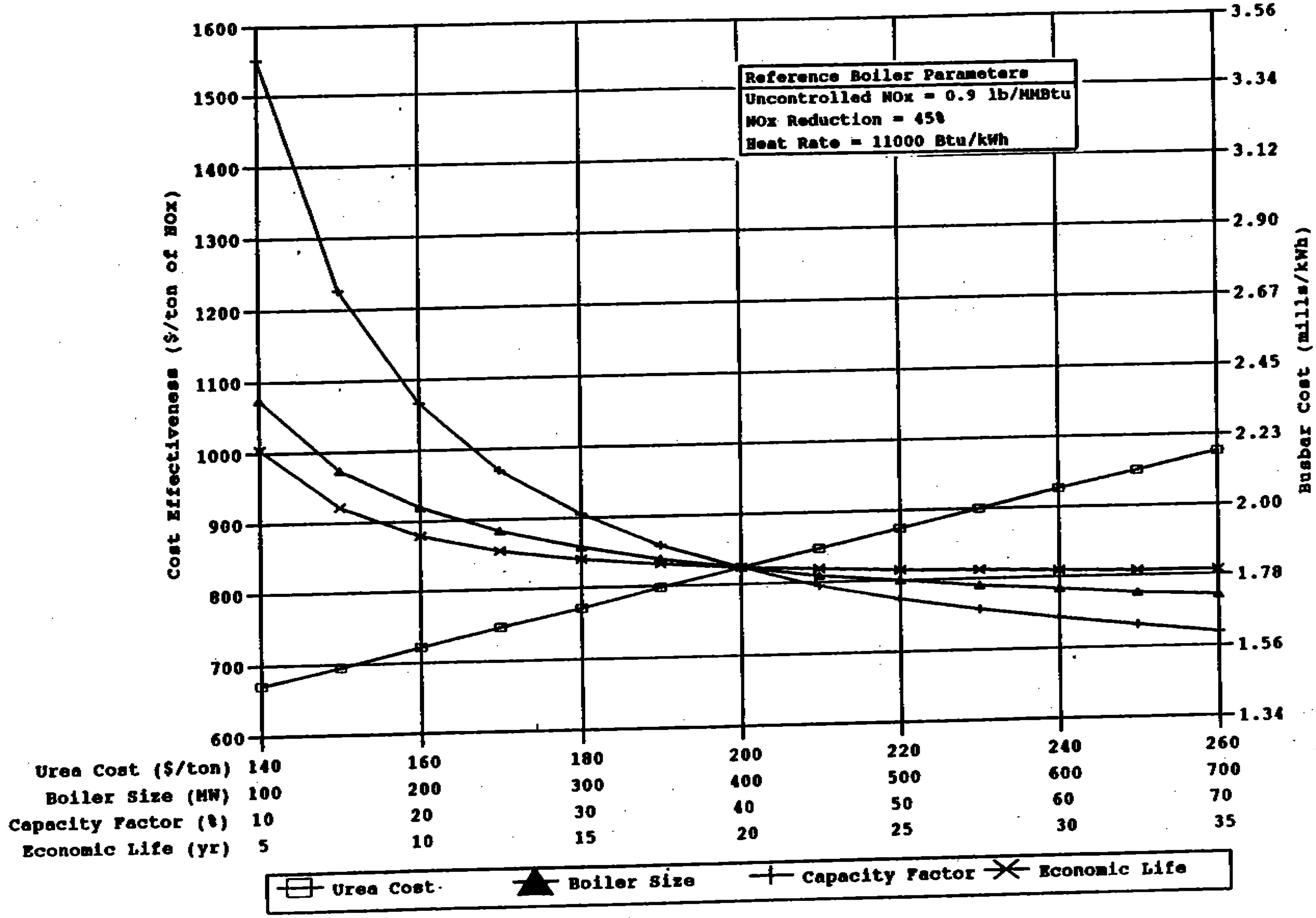

Figure 6-33. Impact of plant characteristics on SNCR cost effectiveness and busbar cost for coal-fired wall boilers.

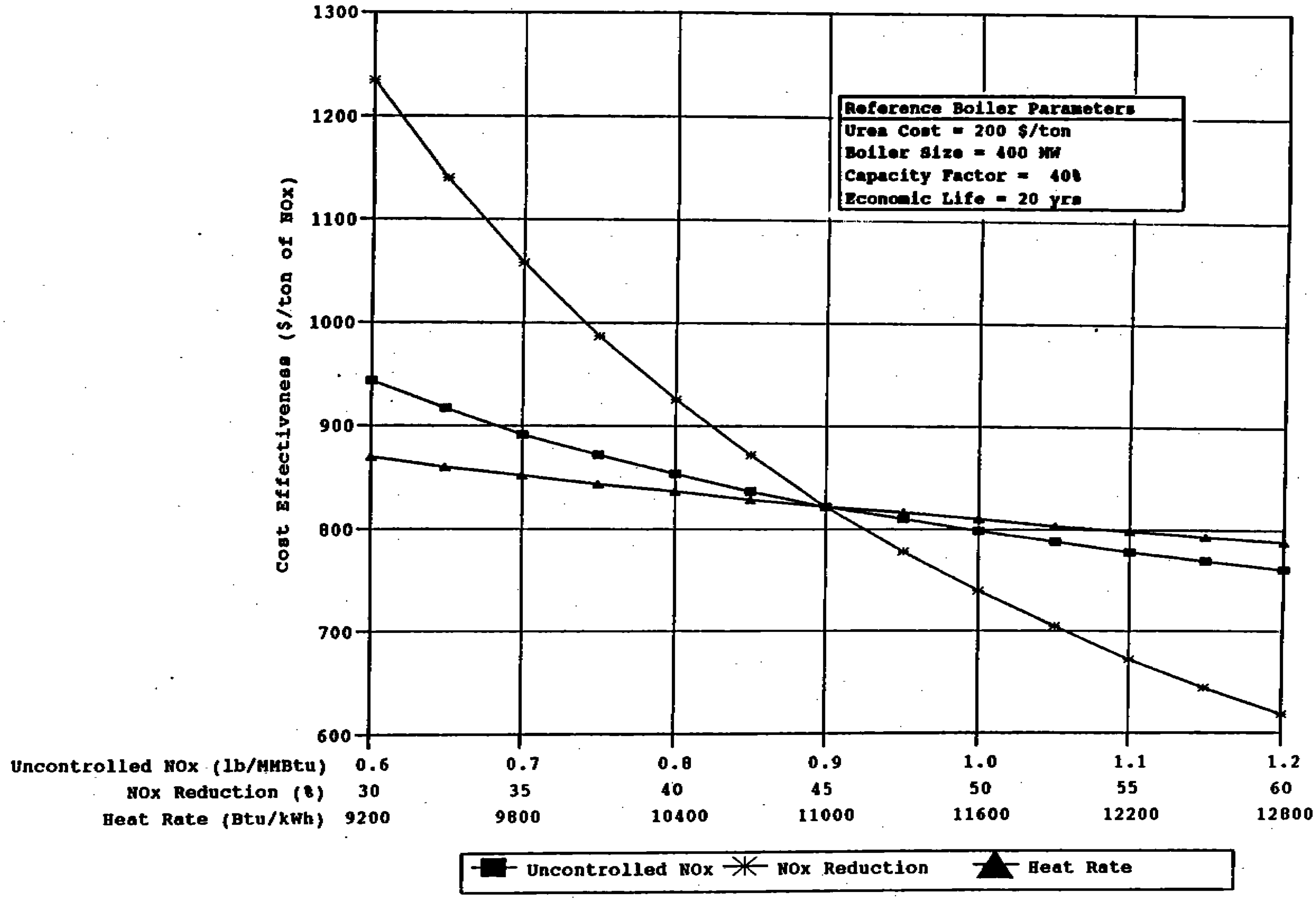

Figure 6-34. Impact of NO_x emission characteristics and heat rate on SNCR cost effectiveness for coal-fired wall boilers.

effectiveness value and busbar cost increase. This is especially noticeable at low capacity factors where a decrease of 75 percent in the reference plant's capacity factor (from 40 percent to 10 percent) results in an increase in the cost effectiveness value and busbar cost of nearly 90 percent.

Variations in economic life and boiler size follow a trend similar to capacity factor, but do not cause as great a change in cost effectiveness and busbar cost. For example, a decrease of 75 percent in economic life (from 20 to 5 years) results in an increase in the plant's cost effectiveness value and busbar cost of approximately 30 percent. Similarly, a decrease of 75 percent in the boiler size (from 400 to 100 MW) results in an increase in the plant's cost effectiveness value and busbar cost of nearly 25 percent.

Cost effectiveness shown in figure 6-34, the variation of NO_x reduction from 30 to 60 percent has the greatest impact on cost effectiveness. Variation in NO_x reduction is inversely related to cost effectiveness and busbar cost. A 50-percent decrease in the reference plant's NO_x reduction (45 to 30 percent) results in an increase in the cost effectiveness value of approximately 50 percent. Variations in the uncontrolled NO_x level and heat rate have less than a 5-percent change in cost effectiveness.

The effect of plant characteristics (boiler size, capacity factor, and economic life) and urea solution price on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-35. Figure 6-36 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $900 per ton of NO_x removed and 1.6 mills/kWh. The cost effectiveness values of SNCR applied to tangentially-fired boilers are slightly higher than for SNCR on wall-fired boilers because of lower uncontrolled NO_x levels of tangentially-fired boilers, although the busbar cost is less

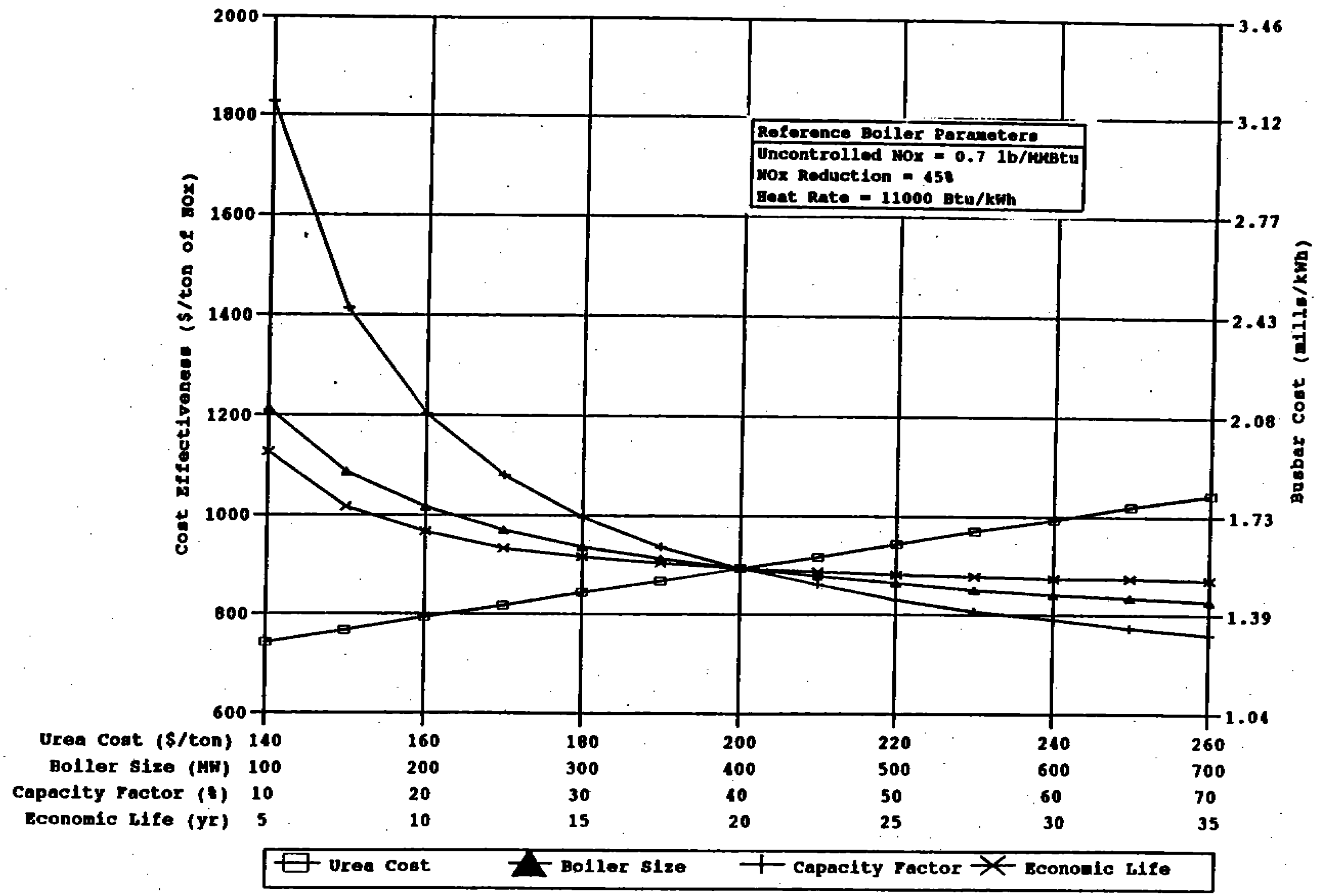

Figure 6-35. Impact of plant characteristics on SNCR cost effectiveness and busbar cost for coal-fired tangential boilers.

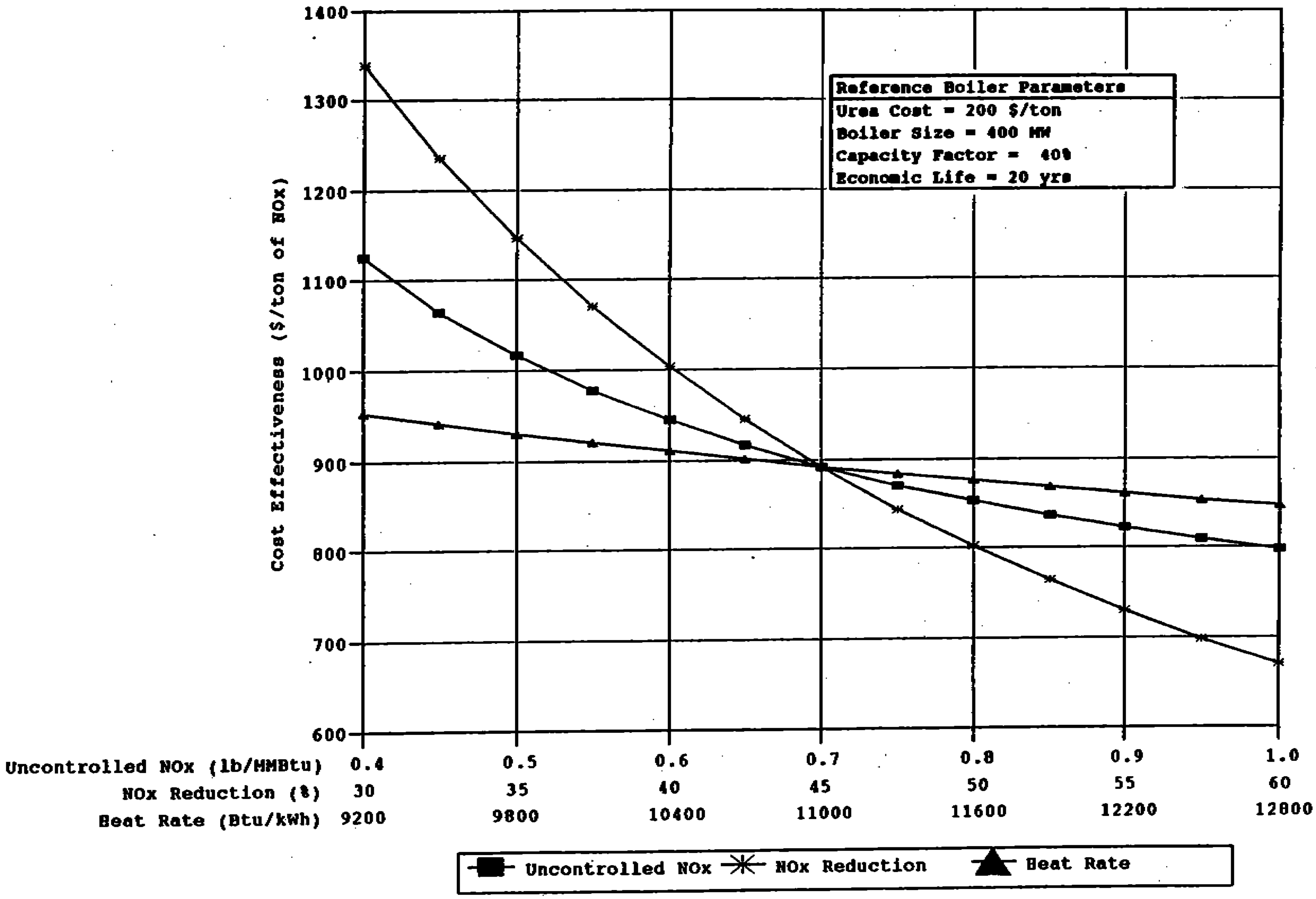

Figure 6-36. Impact of NO_x emission characteristics and heat rate on SNCR cost effectiveness for coal-fired tangential boilers.

because of the smaller amount of urea that must be injected to achieve an equivalent percent NO_x reduction. The sensitivity curves follow the same general trends as with SNCR applied to wall-fired boilers.

The effect of plant characteristics (boiler size, capacity factor, and economic life) and urea solution price on cost effectiveness and busbar cost for cyclone boilers is shown in figure 6-37. Figure 6-38 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $730 per ton of NO_x removed and 2.7 mills/kWh. The cost effectiveness values and busbar cost for SNCR applied to cyclone-fired boilers are lower than for SNCR on wall-fired boilers because of higher uncontrolled NO_x levels of cyclone-fired boilers. The sensitivity curves follow the same general trends as with SNCR applied to wall-fired boilers.

The effect of plant characteristics (boiler size, capacity factor, and economic life) and urea solution price on cost effectiveness and busbar cost for FBC boilers is shown in figure 6-39. Figure 6-40 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $1,700 per ton of NO_x removed and 0.81 mills/kWh. The cost effectiveness values for SNCR applied to FBC boilers is higher than SNCR on wall-fired boilers because of lower uncontrolled NO_x levels of FBC boilers, although the busbar cost is less because of the smaller amount of urea that must be injected to achieve equivalent percent NO_x reductions. The sensitivity curves follow the same general trends as with SNCR applied to wall-fired boilers.

6.5.1.3.2 <u>Natural gas- and oil-fired boiler sensitivity analysis</u>. The effect of plant characteristics (boiler size,

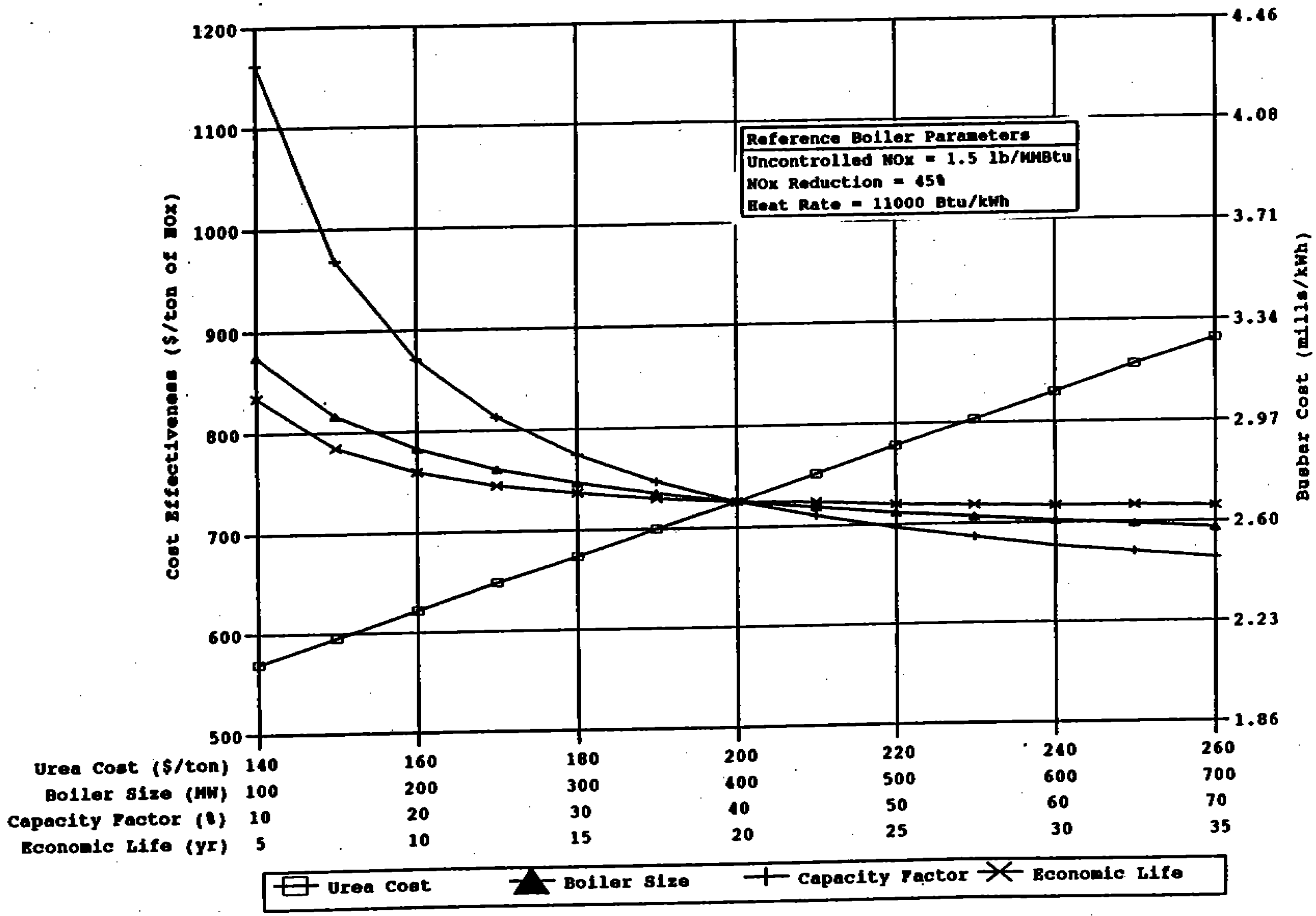

Figure 6-37. Impact of plant characteristics on SNCR cost effectiveness and busbar cost for coal-fired cyclone boilers.

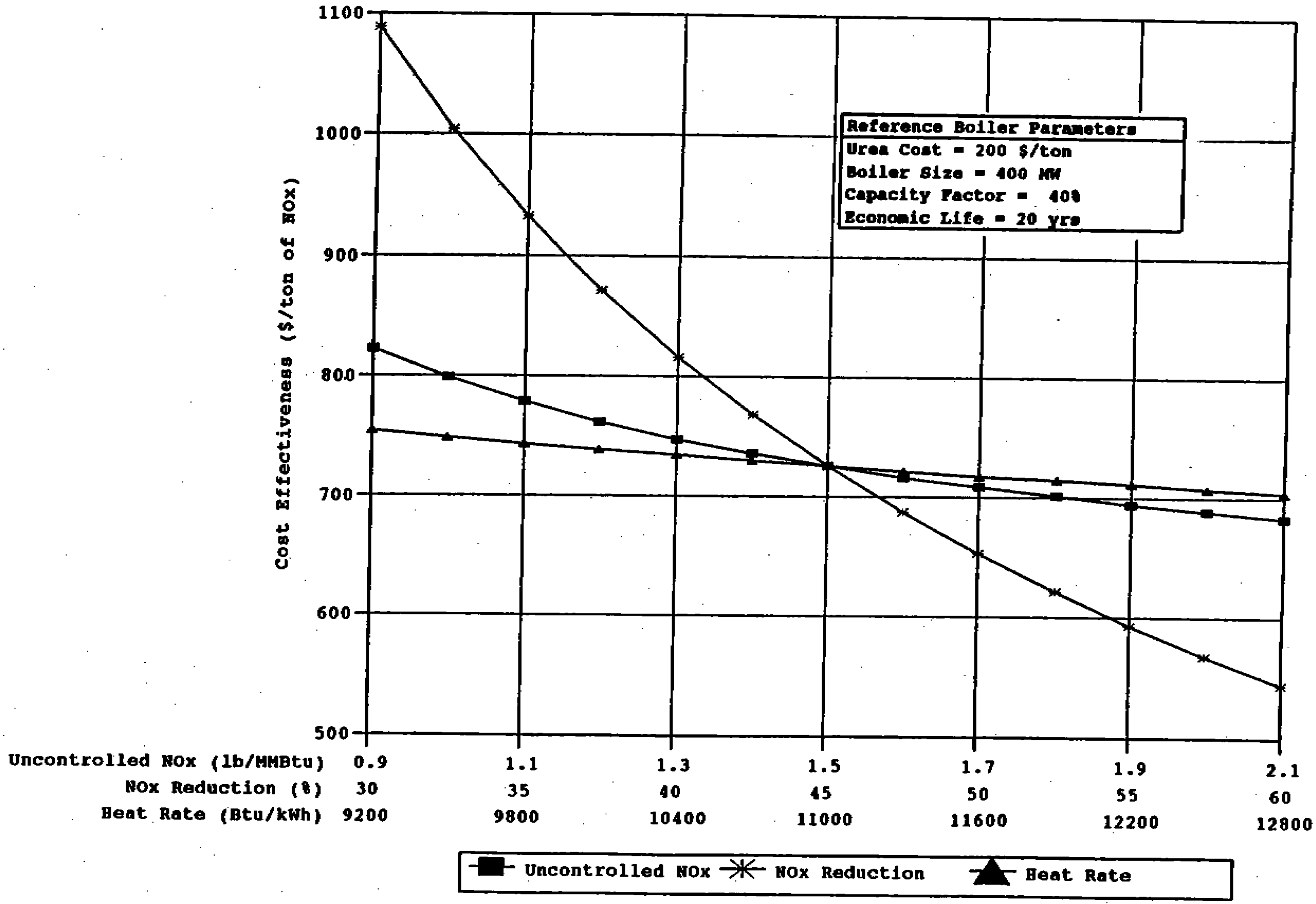

Figure 6-38. Impact of NO_x emission characteristics and heat rate on SNCR cost effectiveness for coal-fired cyclone boilers.

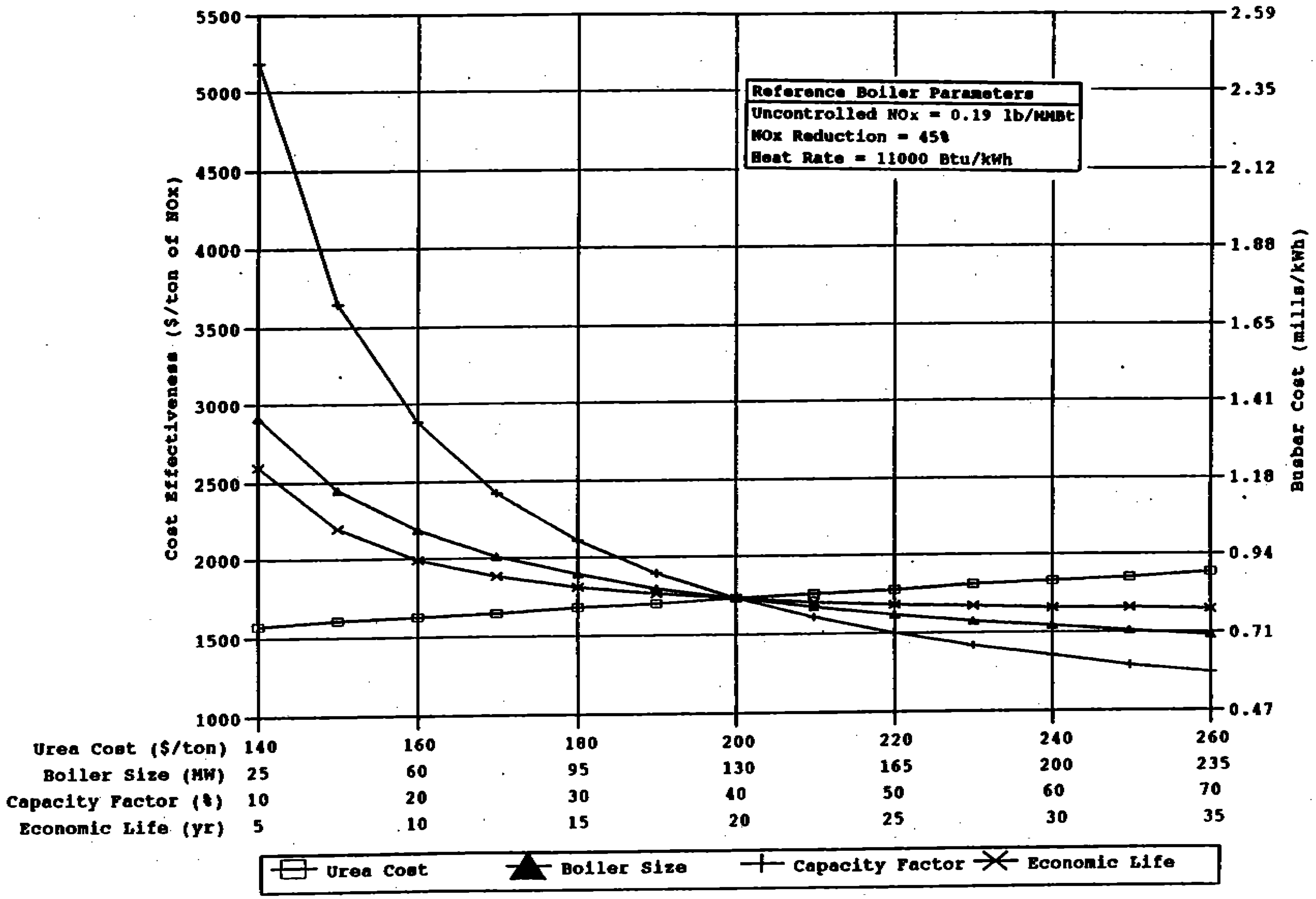

Figure 6-39. Impact of plant characteristics on SNCR cost effectiveness and busbar cost for coal-fired FBC boilers.

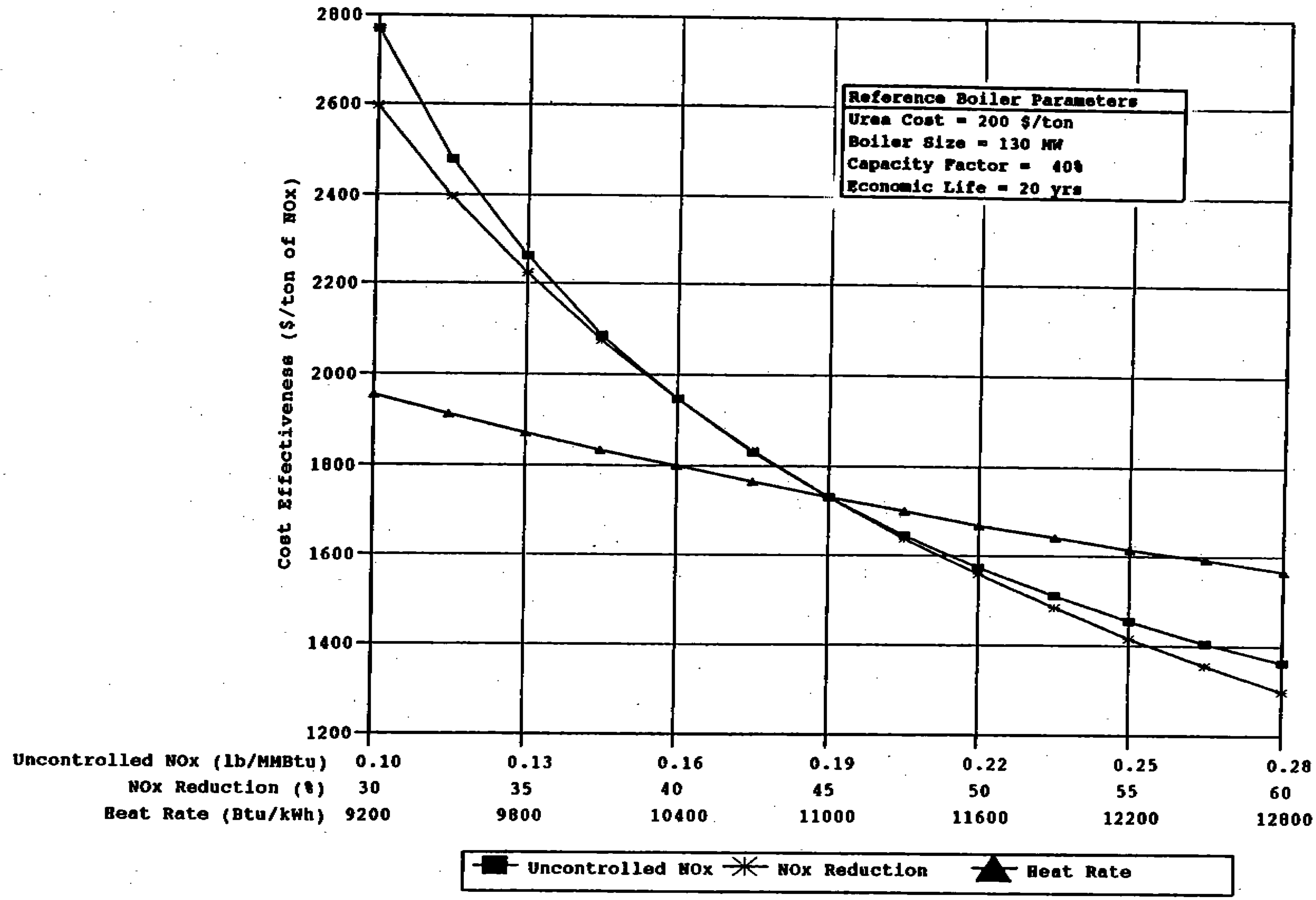

Figure 6-40. Impact of NO_x emission characteristics and heat rate on SNCR cost effectiveness for coal-fired FBC boilers.

capacity factor, and economic life) and urea solution price on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-41. Figure 6-42 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $1,300 per ton of NO_x removed and 1.2 mills/kWh. The cost effectiveness values for SNCR applied to natural gas- and oil-fired wall boilers is higher than for SNCR on coal-fired wall boilers because of lower uncontrolled NO_x levels of natural gas- and oil-fired boilers, although the busbar cost is less because of the smaller amount of urea that must be injected to control NO_x. The sensitivity curves follow the same general trends as with SNCR applied to coal-fired wall boilers.

The effect of plant characteristics (boiler size, capacity factor, and economic life) and urea solution price on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-43. Figure 6-44 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $1,600 per ton of NO_x removed and 0.95 mills/kWh. The cost effectiveness values for SNCR applied to tangentially-fired boilers are higher than SNCR on wall fired boilers because of lower uncontrolled NO_x levels of tangentially-fired boilers, although the busbar cost is less because of smaller amount of urea that must be injected to control NO_x. The sensitivity curves follow the same general trends as with SNCR applied to coal-fired wall boilers.

6.5.2 SCR

Cost estimates for SCR technology are presented in this section for coal-fired and natural gas- and oil-fired wall and tangential boilers. In addition, estimates are presented for SCR applied to cyclone-fired coal boilers.

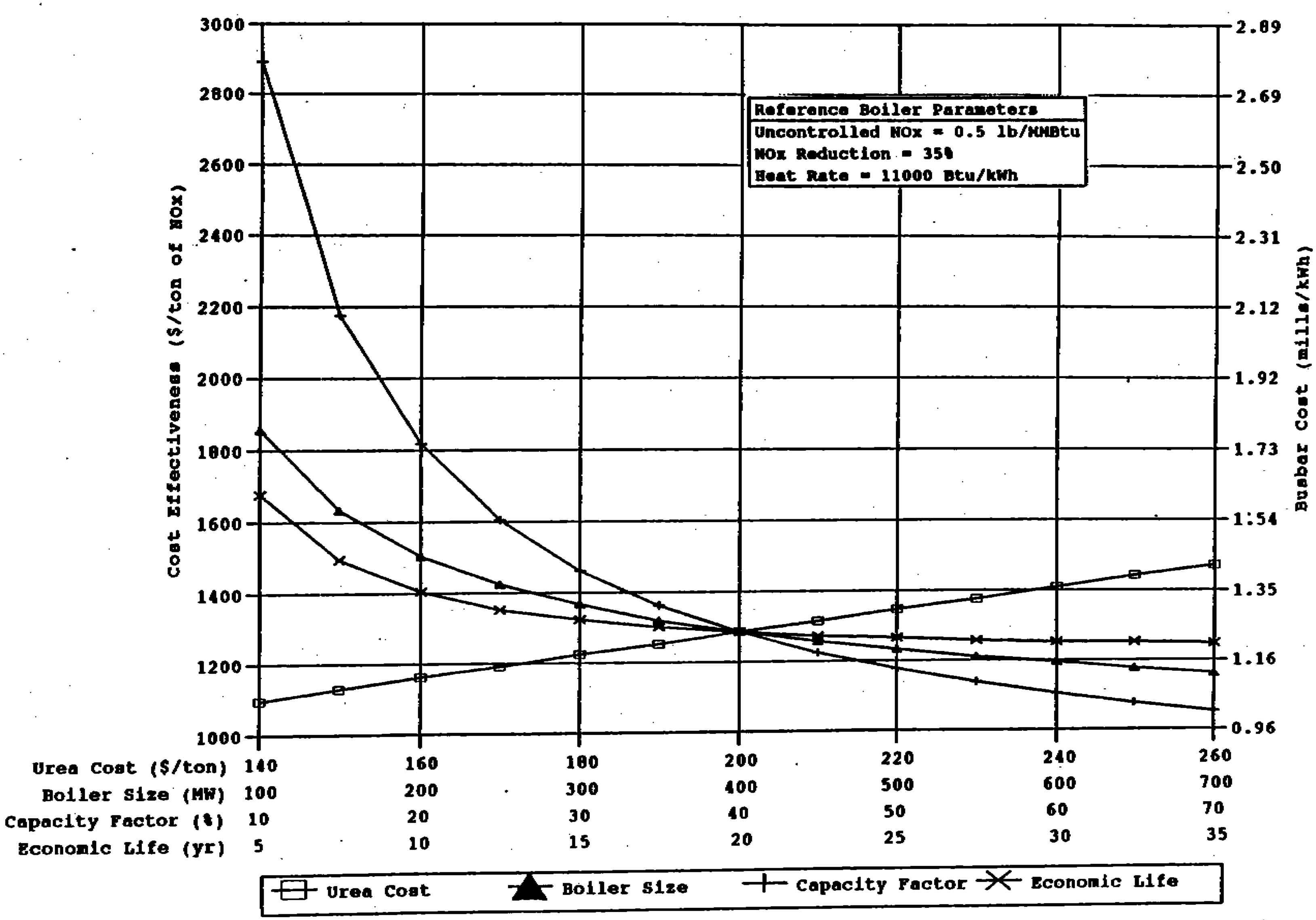

Figure 6-41. Impact of plant characteristics on SNCR cost effectiveness and busbar cost for natural gas- and oil-fired wall boilers.

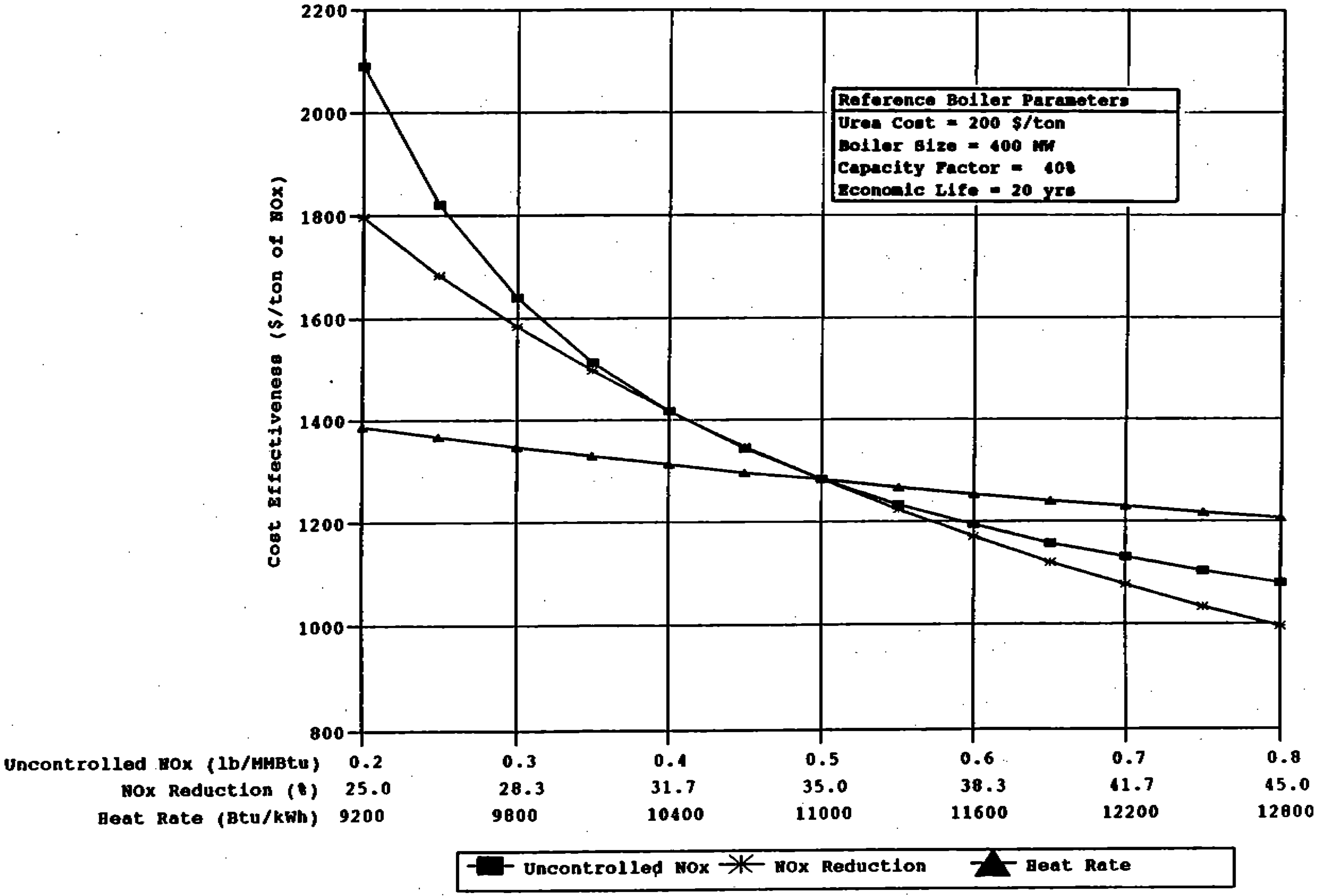

Figure 6-42. Impact of NO_x emission characteristics and heat rate on SNCR cost effectiveness for natural gas- and oil-fired wall boilers.

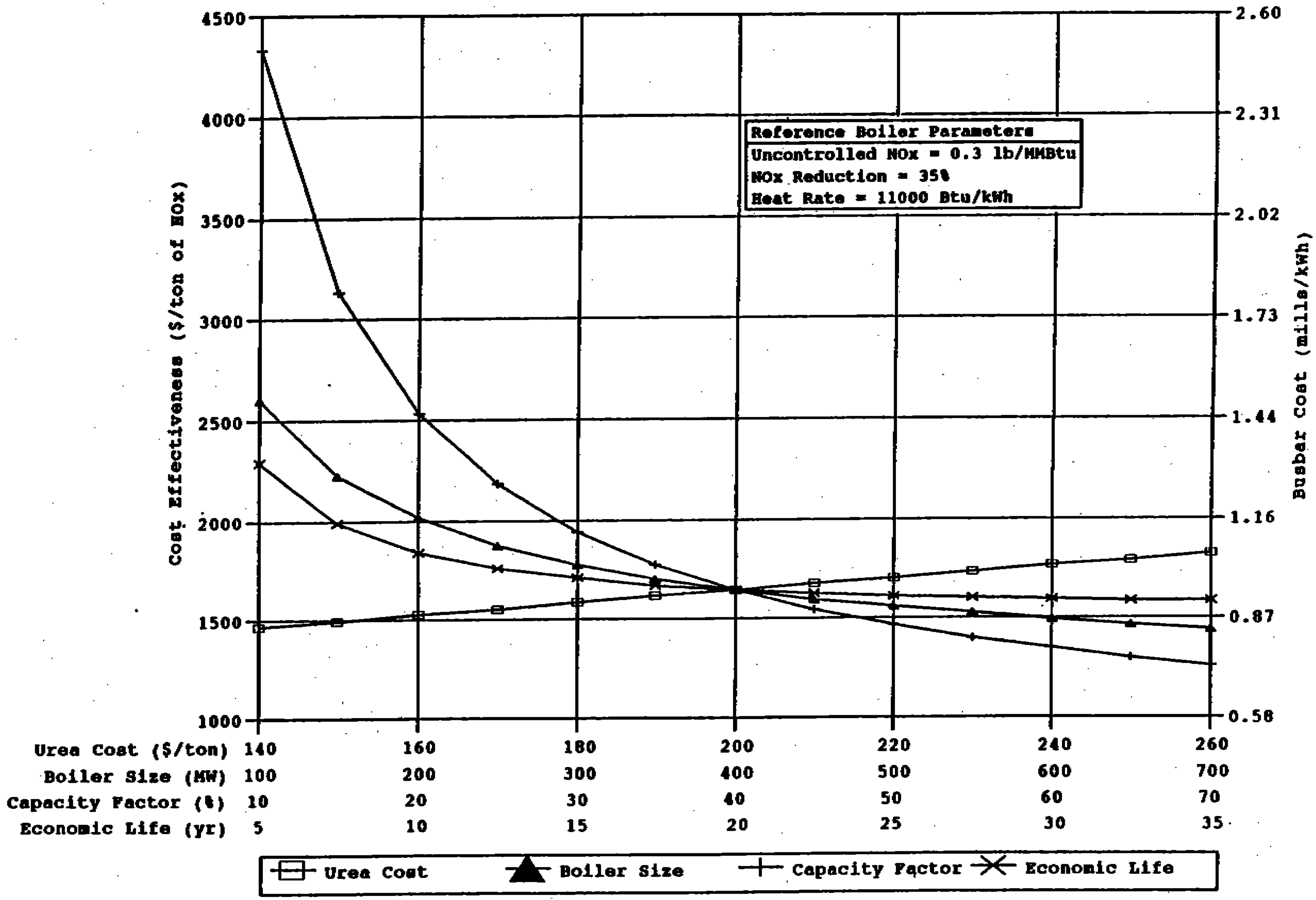

Figure 6-43. Impact of plant characteristics on SNCR cost effectiveness and busbar cost for natural gas- and oil-fired tangential boilers.

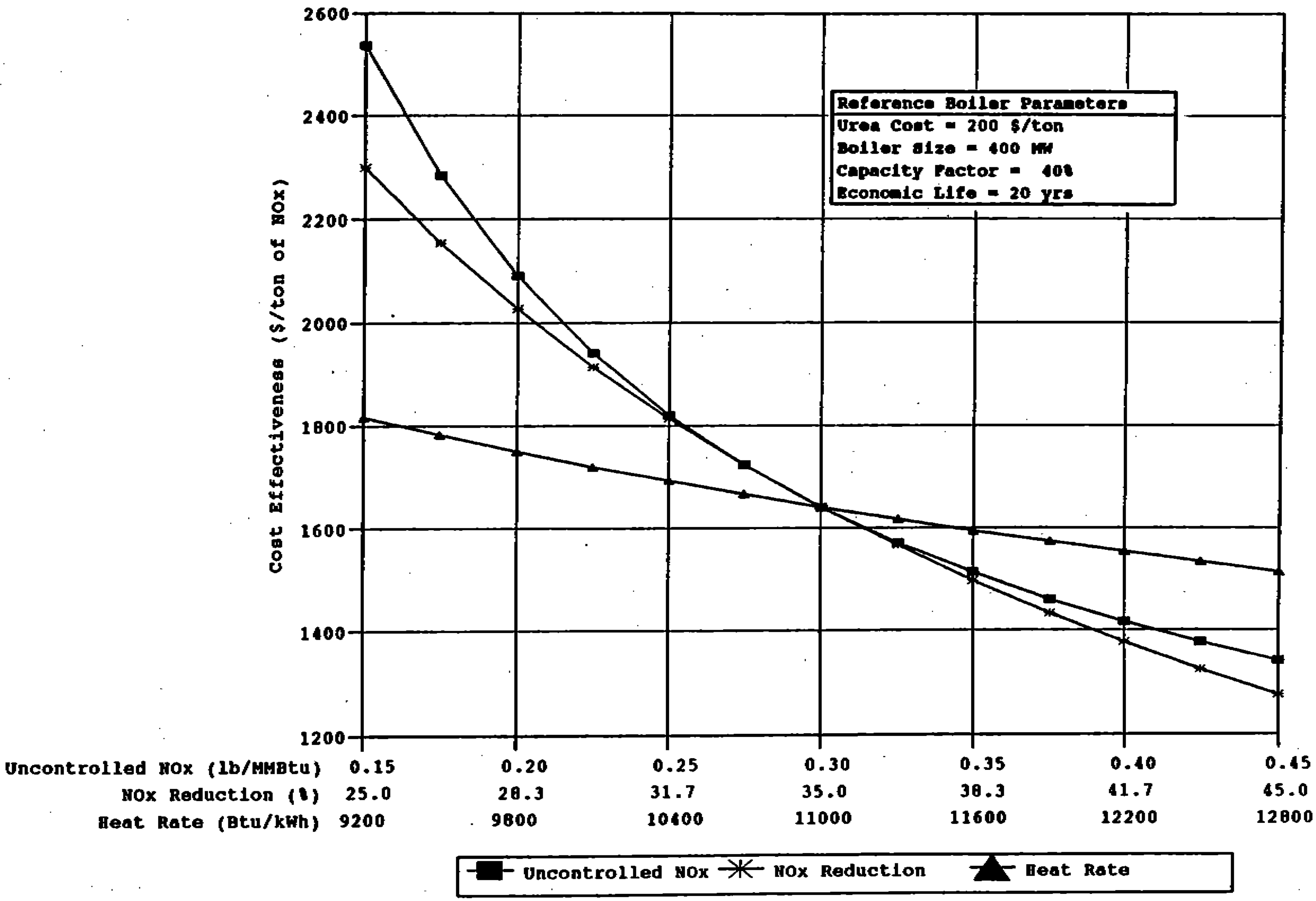

Figure 6-44. Impact of NO_x emission characteristics and heat rate on SNCR cost effectiveness for natural gas- and oil-fired tangential boilers.

6.5.2.1. Costing Procedures. Based on outputs from Integrated Air Pollution Control System (IAPCS)[16], simplified algorithms in the form of equation 6-1 were developed to estimate capital costs. The SCR basic system cost coefficients for each of the five boiler types are:

Fuel	Boiler type	a	b
Coal	Wall	174	-0.30
	Tangential	165	-0.30
	Cyclone	196	-0.31
Oil/Gas	Wall	165	-0.324
	Tangential	156	-0.329

Catalyst price, which has a significant impact on capital costs, was estimated to be $400/ft^3 for coal-, natural gas-, and oil-fired boilers. Catalyst life was assumed to be 3 years for coal-fired boilers and 6 years for natural gas- and oil-fired boilers. Catalyst volumes for coal-fired boilers were assumed to be double the volume of oil-fired boilers and approximately six times larger than the volume of natural gas-fired boilers.

Fixed operating and maintenance costs for an SCR system include operating, maintenance, supervisory labor and maintenance materials and overhead. Variable O&M costs are ammonia, catalyst replacement, electricity, water, steam, and catalyst disposal. The IAPCS model was used to estimate fixed and variable O&M costs, and details on these calculations are provided in appendix A.11.

The following factors affect the retrofit difficulty and costs of an SCR system:

- Congestion in the construction area from existing buildings and equipment.
- Underground electrical cables and pipes.
- The length of ductwork required to connect the SCR reactor vessels to the existing ductwork.

Due to the lack of actual installation cost data, an EPA analysis of SCR costs were used to estimate retrofit factors.[17]

This reference estimates retrofit factors of 1.02 (low), 1.34 (moderate), and 1.52 (high), based on data obtained from hot-side SCR retrofits on German utility boilers. For the model plant analysis, a moderate retrofit factor of 1.34 was used. Indirect costs were assumed to be 45 percent of the process capital. For the application of SCR to boilers burning medium- to high-sulfur coals, indirect costs may be greater than 45 percent of the process capital, due to factors discussed in chapter 5.

6.5.2.2 Model Plants Results

6.5.2.2.1 Coal-fired model plants. The capital cost, busbar cost, and cost effectiveness for the 15 coal-fired wall, tangential, and cyclone boilers are presented in table 6-15. An economic life of 20 years and a NO_x reduction efficiency of 80 percent and a space velocity of 2,500/hr were assumed for all of these boilers. For the 600 MW baseload wall-fired boiler, the estimated cost effectiveness ranges from $1,270 to $1,670 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $7,540 to $9,650 per ton.

Cost per ton of NO_x removed with SCR on tangentially-fired boilers is higher than wall-fired boilers because of lower uncontrolled NO_x levels for tangentially-fired boilers. Cost effectiveness for the 600 MW baseload tangentially-fired boiler ranges from $1,580 to $2,100 per ton. For the 100 MW peaking tangentially-fired boiler, cost effectiveness ranges from $9,470 to $12,200 per ton.

Cost per ton of NO_x removed with SCR on cyclone-fired boilers is lower than wall-fired boilers because of higher uncontrolled NO_x levels for cyclone-fired boilers. Cost effectiveness for the 600 MW baseload cyclone-fired boiler ranges from $810 to $1,050 per ton and for the 100 MW cyclone boiler, cost effectiveness ranges from $4,670 to $5,940 per ton.

6.5.2.2.2 Natural gas and oil-fired model plants. The capital cost, busbar cost, and cost effectiveness for the

TABLE 6-15. COSTS FOR SCR APPLIED TO COAL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Catalyst life (yr)	2	3	4	2	3	4	2	3	4
Wall-fired boilers[a]									
100 MW, Peaking[b]	110	110	110	43.4	37.1	33.9	9,650	8,250	7,540
100 MW, Baseload[c]	110	110	110	7.16	6.19	5.70	1,990	1,720	1,580
300 MW, Cycling[d]	86.0	86.0	86.0	13.1	11.0	9.91	3,300	2,770	2,500
300 MW, Baseload	86.0	86.0	86.0	6.34	5.36	4.88	1,760	1,490	1,360
600 MW, Baseload	75.0	75.0	75.0	6.02	5.04	4.56	1,670	1,400	1,270
Tangentially-fired boilers[e]									
100 MW, Peaking	106	106	106	42.6	36.3	33.1	12,200	10,400	9,470
100 MW, Baseload	106	106	106	6.97	6.00	5.51	2,490	2,140	1,970
300 MW, Cycling	83.0	83.0	83.0	12.8	10.7	9.66	4,160	3,480	3,140
300 MW Baseload	83.0	83.0	83.0	6.18	5.21	4.72	2,210	1,860	1,690
600 MW, Baseload	72.0	72.0	72.0	5.88	4.90	4.42	2,100	1,750	1,580
Cyclone-Fired boilers[f]									
100 MW, Peaking	117	117	117	44.5	38.3	35.0	5,940	5,090	4,670
100 MW, Baseload	117	117	117	7.53	6.56	6.07	1,260	1,090	1,010
300 MW, Cycling	90.0	90.0	90.0	13.5	11.4	10.3	2,040	1,720	1,560
300 MW, Baseload	90.0	90.0	90.0	6.65	5.68	5.19	1,110	947	866
600 MW, Baseload	78.0	78.0	78.0	6.31	5.34	4.85	1,050	890	809

[a]Uncontrolled NO_x levels of 0.90 lb/MMBtu and an SCR NO_x reduction of 80 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.70 lb/MMBtu and an SCR NO_x reduction of 80 percent were used for tangentially-fired boilers.
[f]Uncontrolled NO_x levels of 1.5 lb/MMBtu and an SCR NO_x reduction of 80 percent were used for cyclone-fired boilers.

10 natural gas- and oil-fired wall and tangential model boilers are presented in tables 6-16 and 6-17, respectively. An economic life of 20 years and a NO_x reduction efficiency of 85 percent were assumed for all of these boilers. Space velocities of 14,000/hr and 5,000/hr were assumed for natural gas-fired boilers and oil-fired boilers, respectively. Cost per ton of NO_x removed with SCR on natural gad-fired boilers is lower than oil-fired boilers because of smaller catalyst volumes for natural gas-fired boilers.

For the 600 MW baseload wall-fired boilers, the estimated cost effectiveness ranges from $970 to $1,070 per ton of NO_x removed for the natural gas-fired boilers and $1,130 to $1,410 per ton of NO_x removed for the oil-fired boilers. For the 100 MW peaking natural gas- and oil-fired wall boilers, the estimated cost effectiveness ranges from $6,700 to $7,200 per ton and $7,550 to $8,990 per ton, respectively.

Cost per ton of NO_x removed with SCR on tangentially-fired boilers is higher than wall-fired boilers because of lower uncontrolled NO_x levels for tangentially-fired boilers. Cost effectiveness for the 600 MW baseload tangentially-fired boiler ranges from $1,530 to $1,690 per ton for the natural gas-fired boilers and $1,800 to $2,260 per ton of NO_x removed for the oil-fired boilers. For the 100 MW peaking natural gas- and oil-fired tangential boilers, cost effectiveness ranges from $10,800 to $11,700 per ton and $12,200 to $14,600 per ton, respectively.

6.5.2.3 Sensitivity Analysis

6.5.2.3.1 Coal-fired boiler sensitivity analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and catalyst life on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-45. Figure 6-46 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost

TABLE 6-16. COSTS FOR SCR APPLIED TO NATURAL GAS-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Catalyst life (yr)	3	6	9	3	6	9	3	6	9
Wall-fired boilers[a]									
100 MW, Peaking[b]	74.0	74.0	74.0	19.1	18.1	17.8	7,200	6,830	6,700
100 MW, Baseload[c]	74.0	74.0	74.0	3.30	3.15	3.10	1,550	1,480	1,460
300 MW, Cycling[d]	53.0	53.0	53.0	5.03	4.70	4.59	2,150	2,010	1,960
300 MW, Baseload	53.0	53.0	53.0	2.55	2.40	2.35	1,200	1,130	1,100
600 MW, Baseload	43.0	43.0	43.0	2.26	2.11	2.06	1,070	994	970
Tangentially-fired boilers[e]									
100 MW, Peaking	72.0	72.0	72.0	18.6	17.6	17.3	11,700	11,000	10,800
100 MW, Baseload	72.0	72.0	72.0	3.15	2.99	2.94	2,470	2,350	2,310
300 MW, Cycling	52.0	52.0	52.0	4.86	4.53	4.42	3,470	3,230	3,150
300 MW Baseload	52.0	52.0	52.0	2.43	2.27	2.22	1,900	1,780	1,740
600 MW, Baseload	42.0	42.0	42.0	2.15	2.00	1.95	1,690	1,570	1,530

[a]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an SCR NO_x reduction of 85 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an SCR NO_x reduction of 85 percent were used for tangentially-fired boilers.

TABLE 6-17. COSTS FOR SCR APPLIED TO OIL-FIRED BOILERS

Plant identification	Total capital cost, $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Catalyst life (yr)	3	6	9	3	6	9	3	6	9
Wall-fired boilers[a]									
100 MW, Peaking[b]	82.0	82.0	82.0	23.9	21.0	20.1	8,990	7,910	7,550
100 MW, Baseload[c]	82.0	82.0	82.0	4.03	3.59	3.44	1,900	1,690	1,620
300 MW, Cycling[d]	60.0	60.0	60.0	6.61	5.66	5.34	2,830	2,420	2,280
300 MW, Baseload	60.0	60.0	60.0	3.28	2.84	2.69	1,540	1,340	1,270
600 MW, Baseload	50.0	50.0	50.0	3.00	2.55	2.41	1,410	1,200	1,130
Tangentially-fired boilers[e]									
100 MW, Peaking	79.0	79.0	79.0	23.3	20.5	19.5	14,700	12,800	12,200
100 MW, Baseload	79.0	79.0	79.0	3.88	3.44	3.29	3,040	2,700	2,580
300 MW, Cycling	59.0	59.0	59.0	6.44	5.49	5.17	4,600	3,910	3,690
300 MW Baseload	59.0	59.0	59.0	3.16	2.72	2.57	2,480	2,130	2,010
600 MW, Baseload	49.0	49.0	49.0	2.88	2.44	2.30	2,260	1,920	1,800

[a]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an SCR NO_x reduction of 85 percent were used for wall-fired boilers.
[b]Peaking = 10 percent capacity factor.
[c]Baseload = 65 percent capacity factor.
[d]Cycling = 30 percent capacity factor.
[e]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an SCR NO_x reduction of 85 percent were used for tangentially-fired boilers.

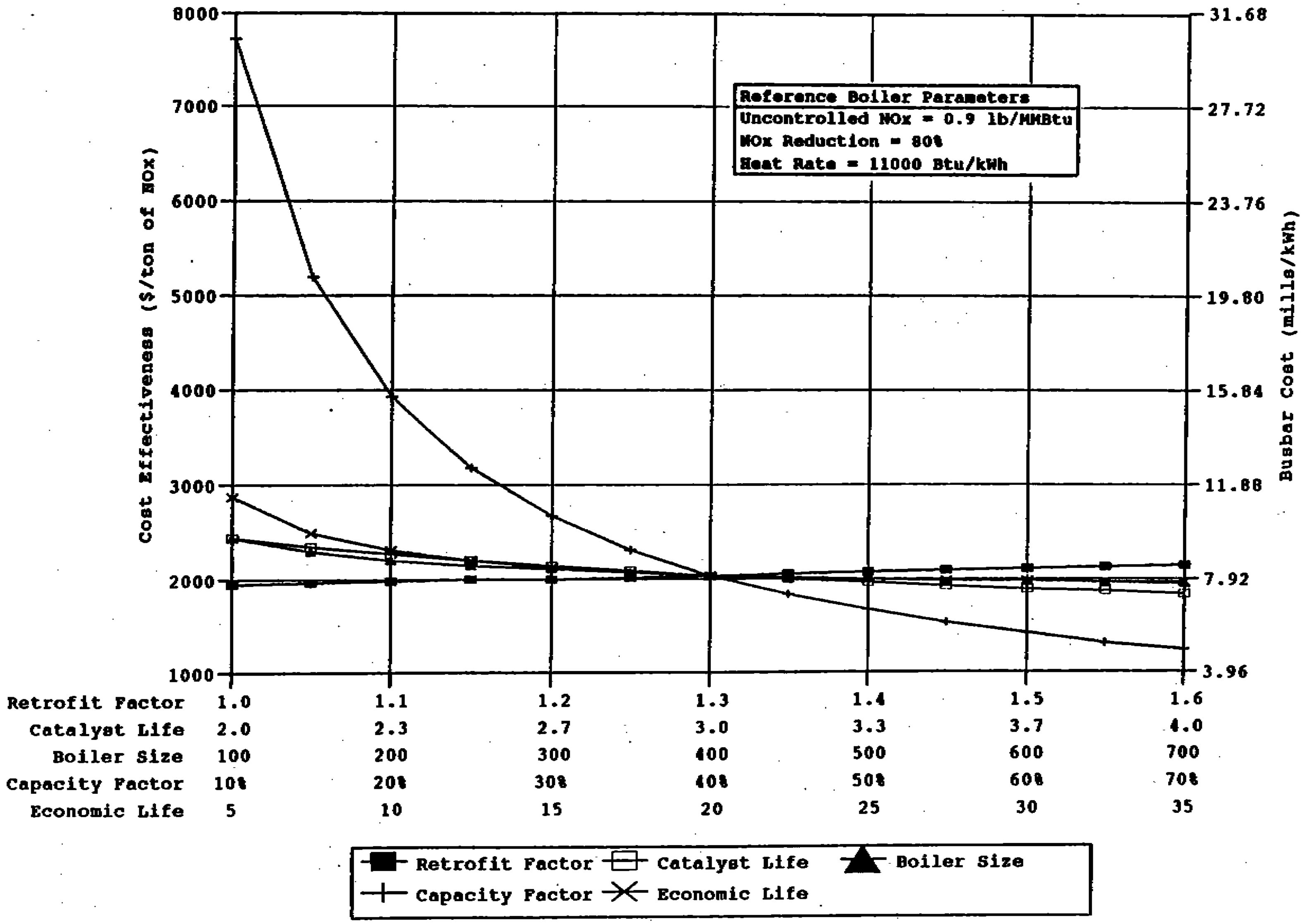

Figure 6-45. Impact of plant characteristics on SCR cost effectiveness and busbar cost for coal-fired wall boilers.

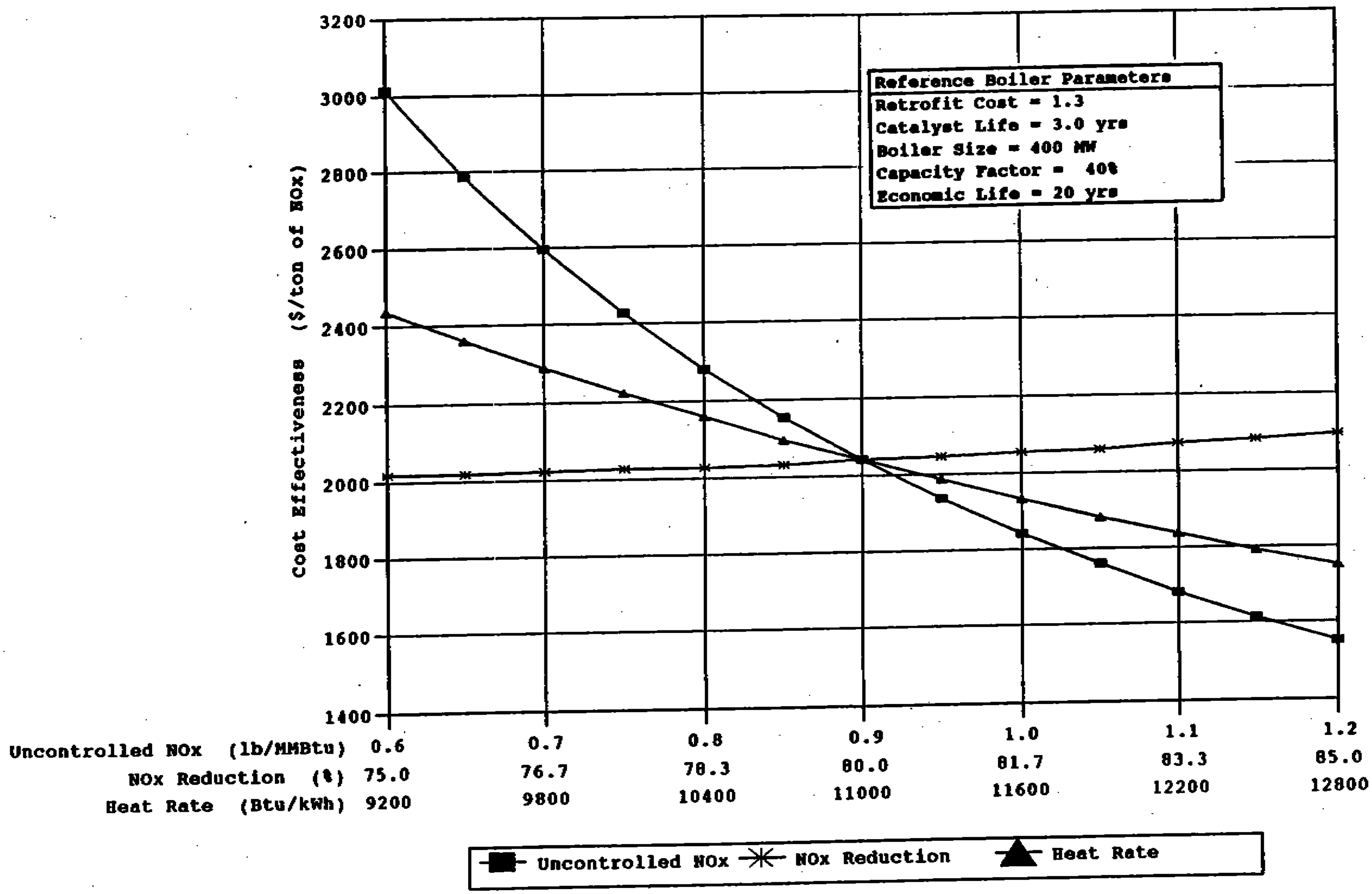

Figure 6-46. Impact of NO_x emission characteristics and heat rate on SCR cost effectiveness for coal-fired wall boilers.

effectiveness and busbar cost are approximately $2,000 per ton of NO_x removed and 8.1 mills/kWh.

Of the parameters shown in figure 6-45, the variation of capacity factor from 10 to 70 percent has the greatest impact on cost effectiveness and busbar cost. The cost effectiveness value and busbar cost exhibit a nearly inverse relationship with capacity factor, and thus, as capacity factor decreases, the cost effectiveness value and busbar cost increase. This is especially noticeable at low capacity factors where a decrease of 75 percent in the reference plant's capacity factor (from 40 to 10 percent) results in an increase in the cost effectiveness value and busbar cost of over 250 percent.

Variations in catalyst life, economic life, and boiler size follow a trend similar to capacity factor, but do not cause as great a change in cost effectiveness and busbar cost. For example, a decrease of 33 percent of the catalyst life (from 3 years to 2 years) increases the cost effectiveness approximately 25 percent. Similarly, a decrease of 75 percent in economic life (from 20 to 5 years) results in an increase in the plant's cost effectiveness value and busbar cost of approximately 50 percent, and a decrease of 75 percent in the boiler size (from 400 to 100 MW) results in an increase in the plant's cost effectiveness value and busbar cost of nearly 25 percent.

The cost effectiveness value and busbar cost are linearly related to retrofit factor. An increase or decrease of 0.3 from the reference plant's retrofit factor of 1.3 causes a corresponding change in the cost effectiveness value and busbar cost of less than 5 percent.

Of the parameters shown in figure 6-46, the variation of uncontrolled NO_x from 0.6 to 1.2 lb/MMBtu has the greatest impact on cost effectiveness. Variation in NO_x reduction exhibits an inverse relationship to cost effectiveness. A 33 percent decrease in the reference plants uncontrolled NO_x (from 0.9 to 0.6 lb/MMBtu) results in an increase in the cost effectiveness value of approximately 50 percent.

Variation in the heat rate from 9,200 to 12,800 Btu/kWh follows a trend similar to the variation in uncontrolled NO_X. A 16-percent decrease in heat rate (11,000 to 9,200 Btu/kWh) results in an increase of cost effectiveness of approximately 20 percent. Potential variations in the NO_X reduction efficiency of the system result in less than a 5-percent change in cost effectiveness.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and catalyst life on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-47. Figure 6-48 presents the sensitivity of cost effectiveness to NO_X emission characteristics (uncontrolled NO_X level and NO_X reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $2,600 per ton of NO_X removed and 7.9 mills/kWh. The cost effectiveness values and busbar cost for SCR applied to tangentially-fired boilers are higher than for SCR on wall-fired boilers because of lower uncontrolled NO_X levels for tangentially-fired boilers, although the busbar cost is slightly lower for tangentially-fired boilers because of the lower capital and O&M costs. The sensitivity curves follow the same general trends as with SCR applied to wall-fired boilers.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and catalyst life on cost effectiveness and busbar cost for cyclone-fired boilers is shown in figure 6-49. Figure 6-50 presents the sensitivity of cost effectiveness to NO_X emission characteristics (uncontrolled NO_X level and NO_X reduction efficiency) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $1,300 per ton of NO_X removed and 8.5 mills/kWh. The cost effectiveness values and busbar cost for SCR applied to cyclone-fired boilers are lower than for wall-fired boilers because of higher uncontrolled NO_X levels for cyclone-fired

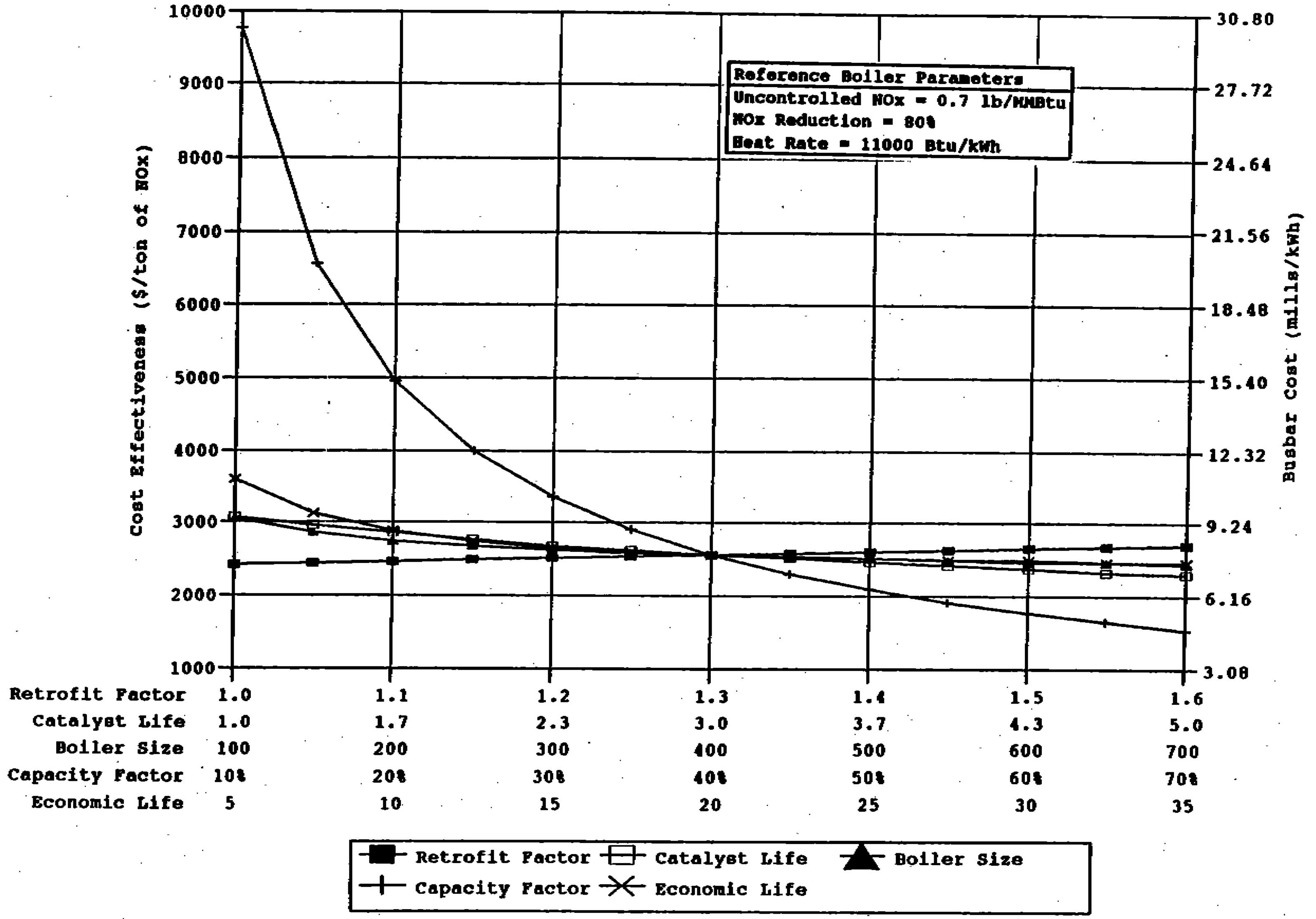

Figure 6-47. Impact of plant characteristics on SCR cost effectiveness and busbar cost for coal-fired tangential boilers.

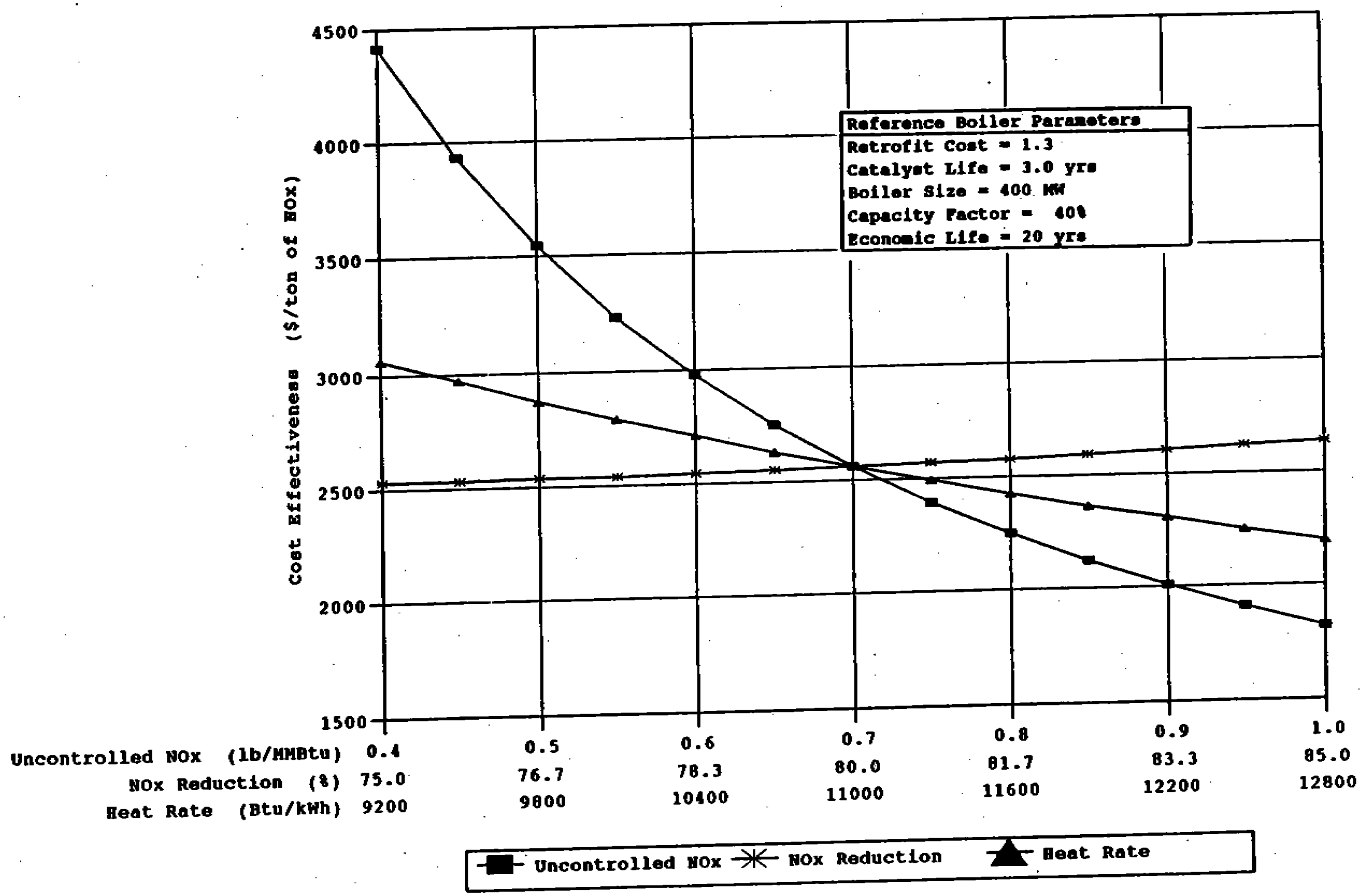

Figure 6-48. Impact of NO_X emission characteristics and heat rate on SCR cost effectiveness for coal-fired tangential boilers.

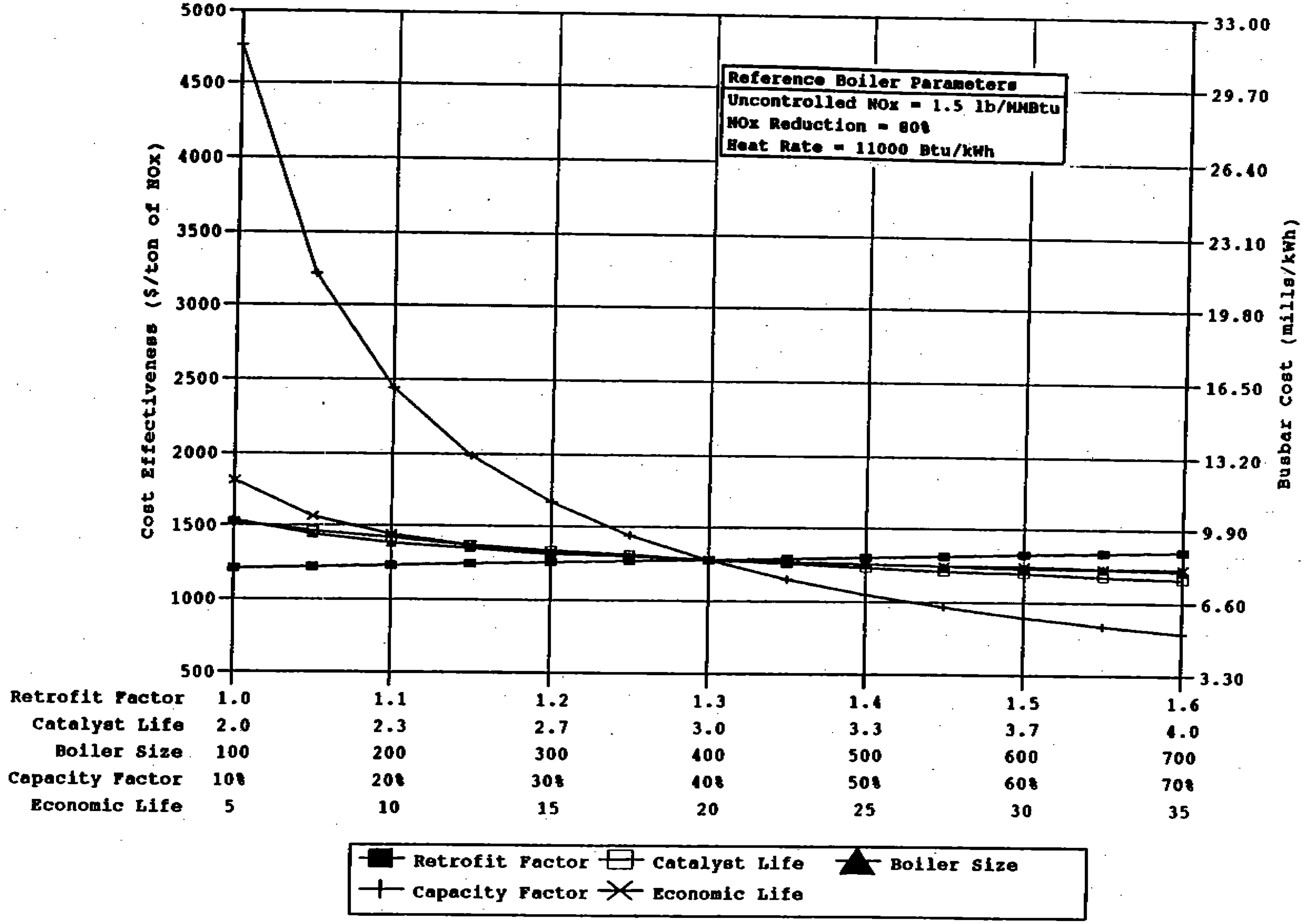

Figure 6-49. Impact of plant characteristics on SCR cost effectiveness and busbar cost for coal-fired cyclone boilers.

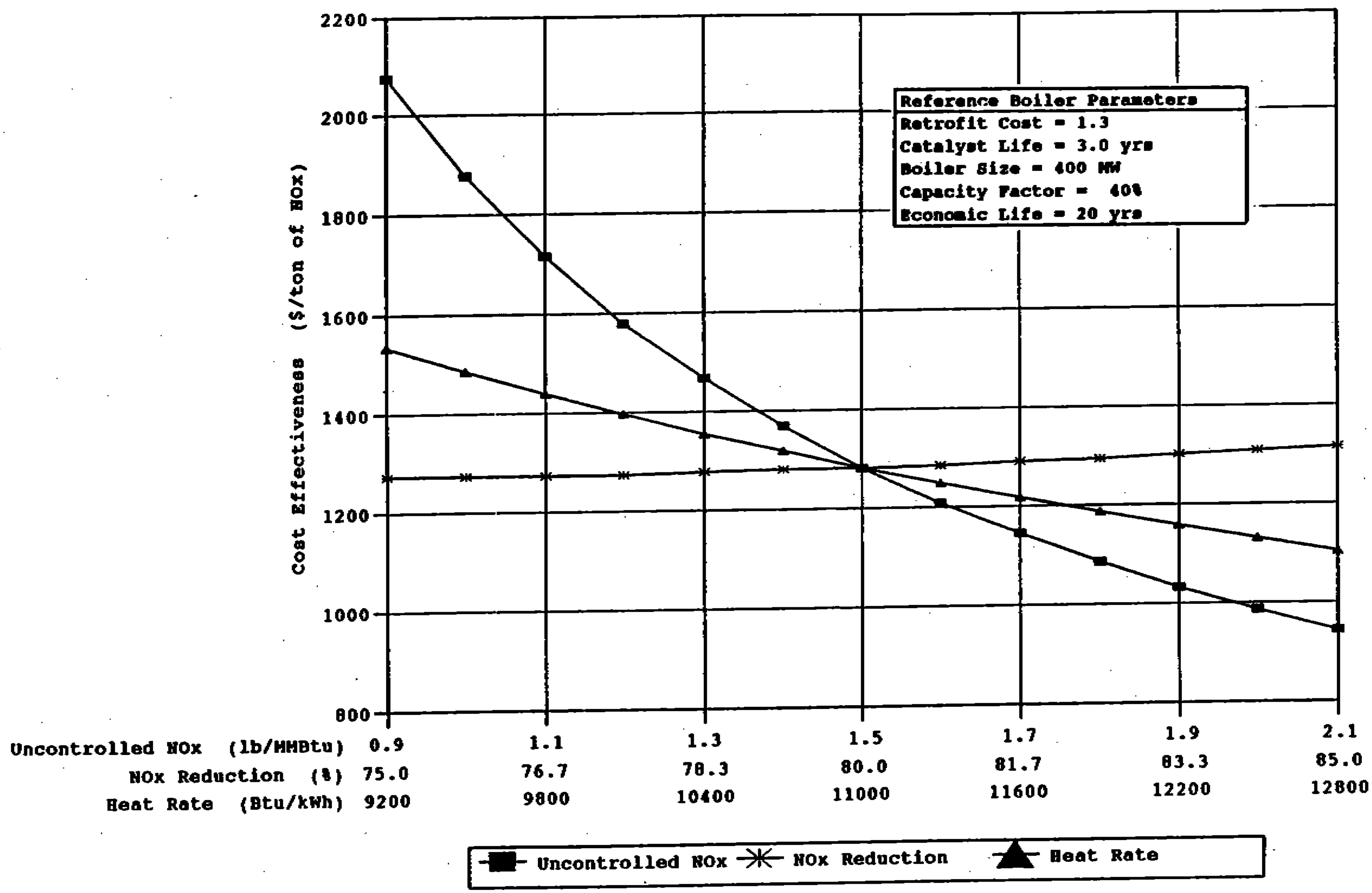

Figure 6-50. Impact of NO_x emission characteristics and heat rate on SCR cost effectiveness for coal-fired cyclone boilers.

boilers, although the busbar cost is slightly higher for cyclone-fired boilers of the higher capital and O&M costs. The sensitivity curves follow the same general trends as with SCR applied to wall-fired boilers.

6.5.2.3.2 Natural gas- and oil-fired boiler sensitivity analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and catalyst life on cost effectiveness and busbar cost for wall-fired boilers is shown in figures 6-51 and 6-52. Figures 6-53 and 6-54 present the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the natural gas-fired reference boiler's cost effectiveness and busbar cost are approximately $1,450 per ton of NO_x removed and 3.4 mills/kWh and the oil-fired reference boilers cost effectiveness and busbar cost are approximately $1,750 per ton on NO_x removed and 4.1 mills/kWh. The cost effectiveness value and busbar cost for SCR applied to natural gas-fired boilers are lower than for oil-fired boilers because of the smaller catalysts volumes on natural gas-boilers. Similarly, cost effectiveness and busbar cost for SCR applied to natural gas- and oil-fired wall boilers are lower than for the coal-fired wall boilers because of the smaller catalyst volumes and expected longer catalyst life on natural gas- and oil-fired boilers. The sensitivity curves follow the same general trends as with SCR applied to coal-fired wall boilers.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and catalyst life on cost effectiveness and busbar cost for natural gas- and oil-fired tangential boilers is shown in figures 6-55 and 6-56. Figures 6-57 and 6-58 present the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency) and heat rate. As shown in the figures, the natural gas-fired reference boiler's cost effectiveness and busbar cost are approximately $2,300 per ton of NO_x removed and 3.2 mills/kWh and the oil-

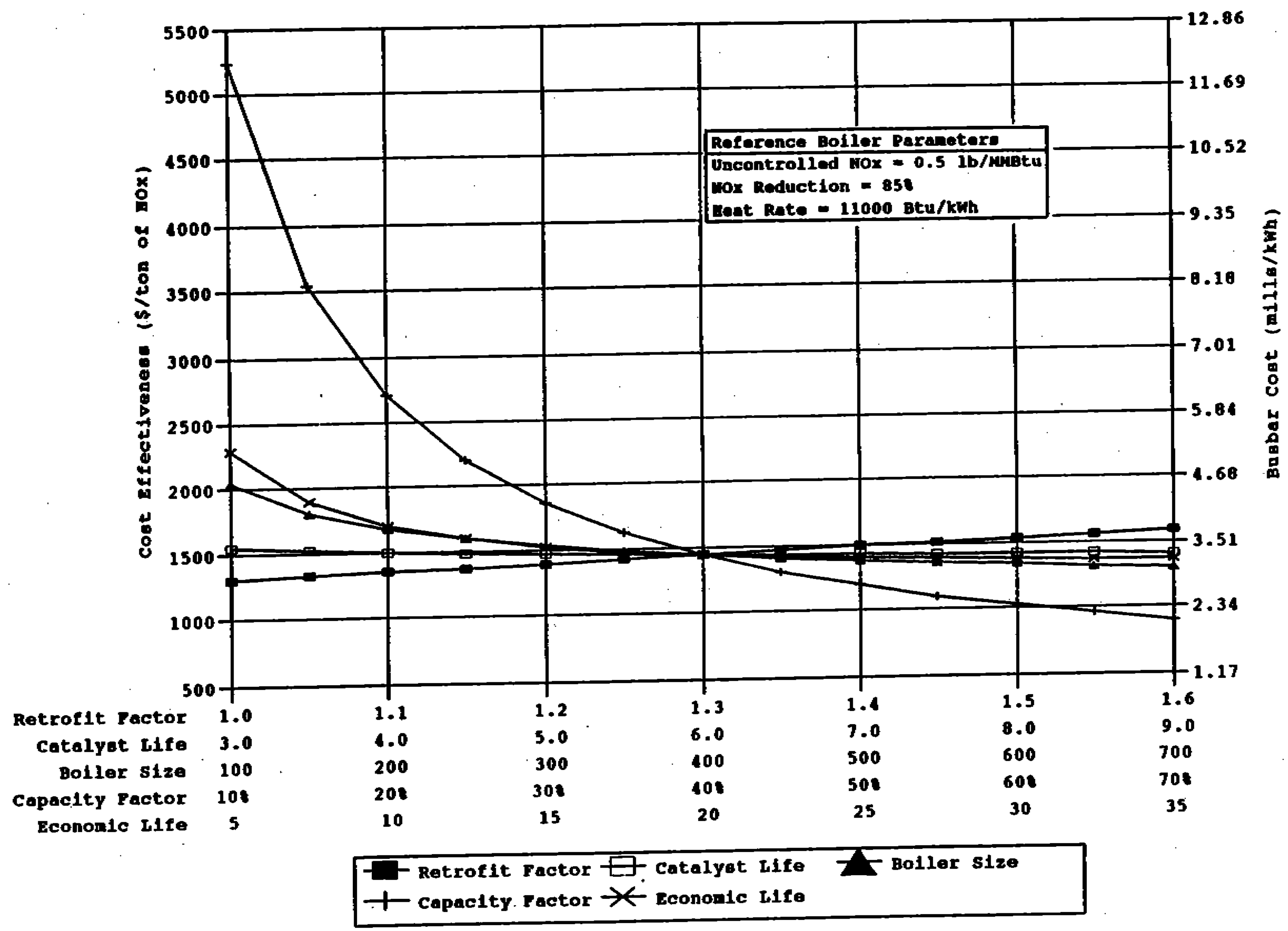

Figure 6-51. Impact of plant characteristics on SCR cost effectiveness and busbar cost for natural gas-fired wall boilers.

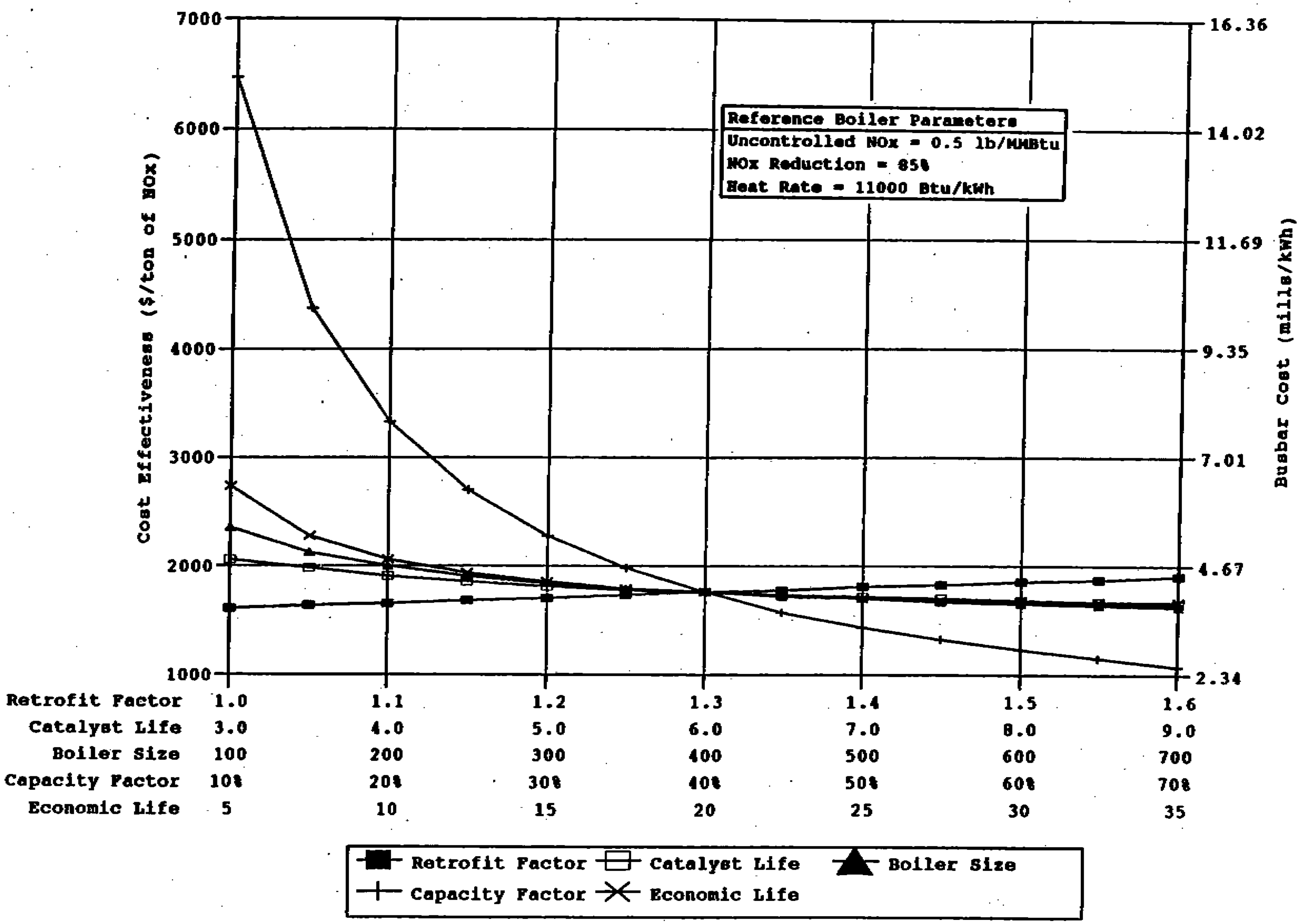

Figure 6-52. Impact of plant characteristics on SCR cost effectiveness and busbar cost for oil-fired wall boilers.

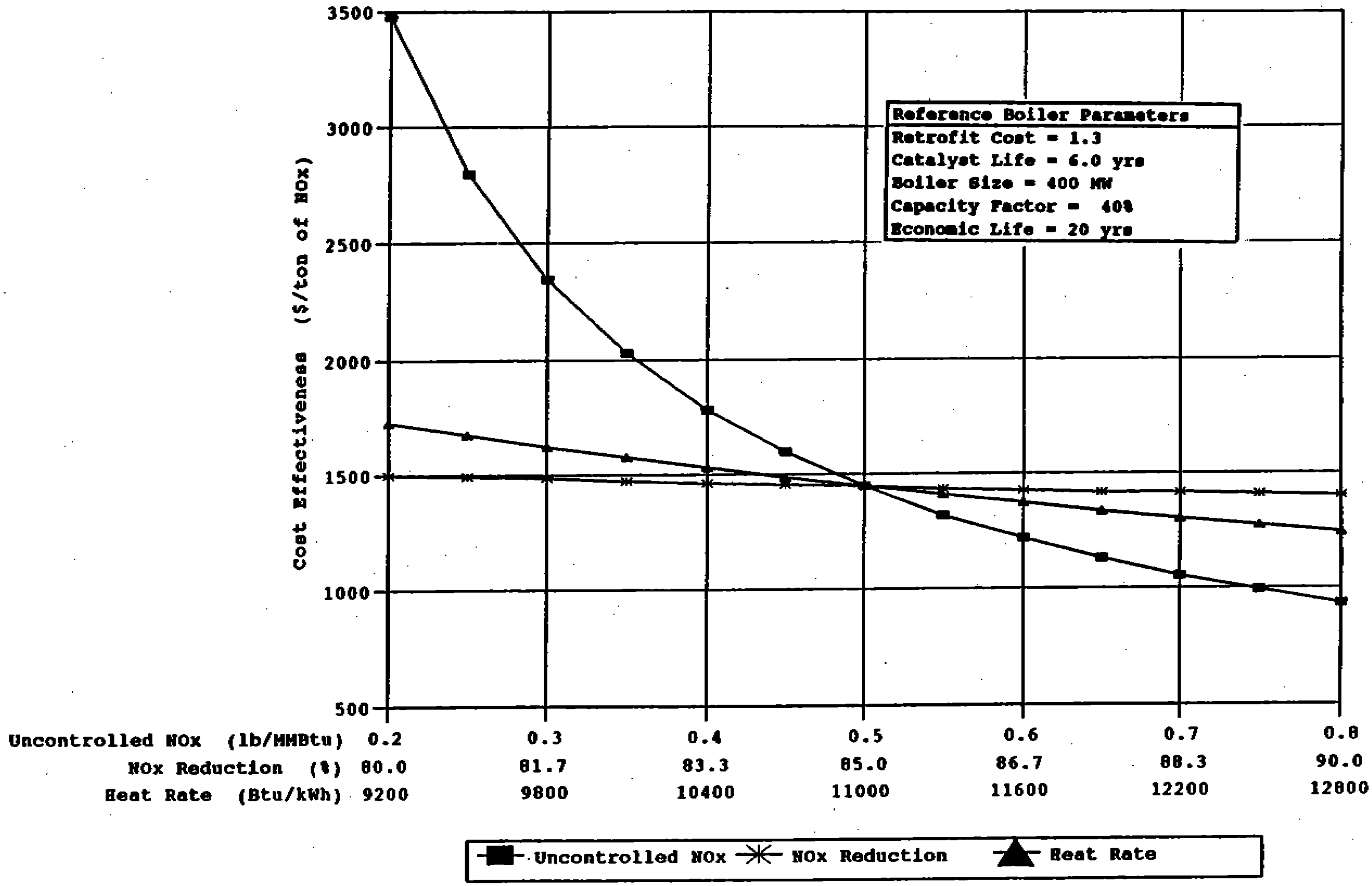

Figure 6-53. Impact of NO_X emission characteristics and heat rate on SCR cost effectiveness for natural gas-fired wall boilers.

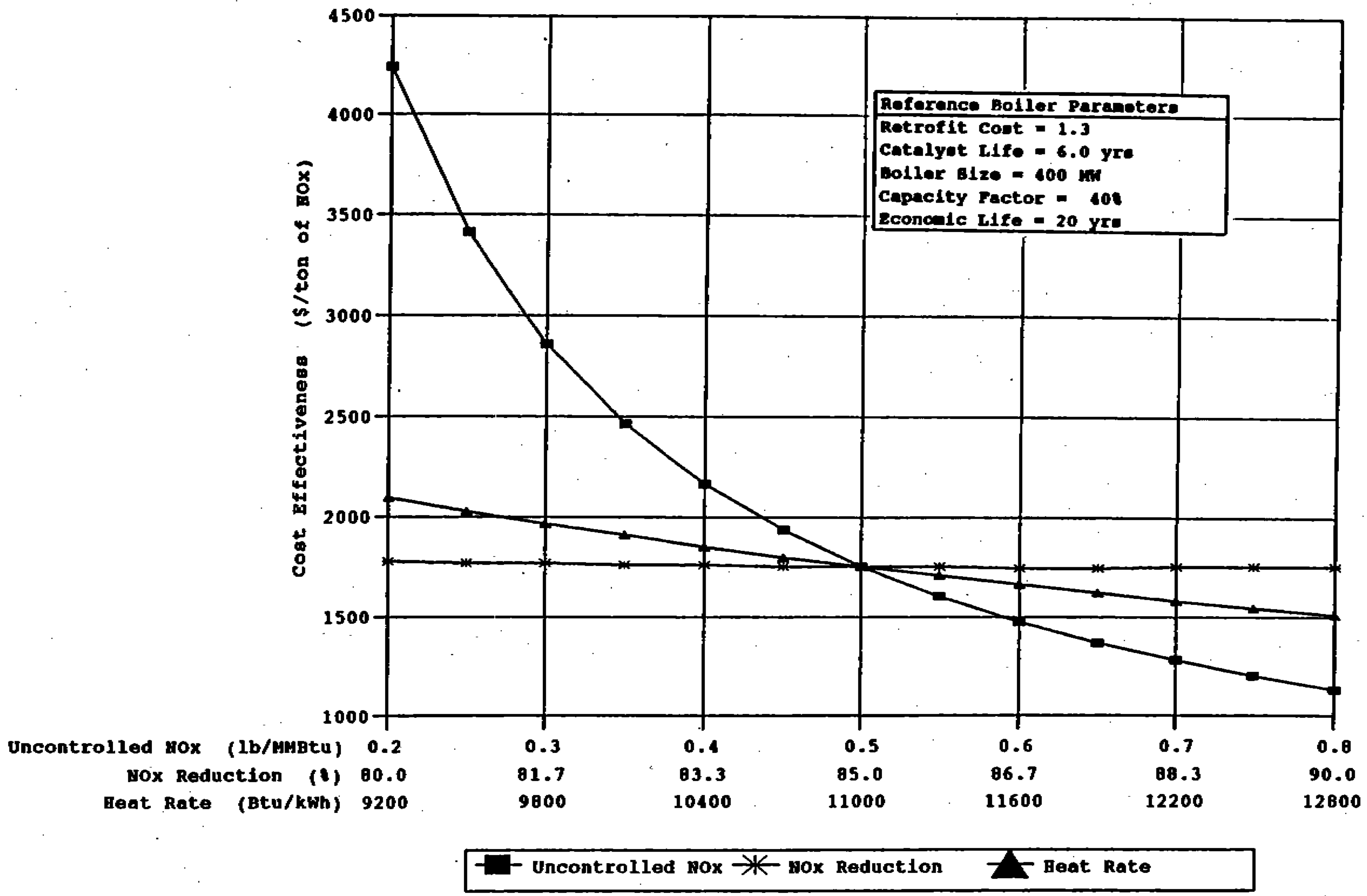

Figure 6-54. Impact of NO_x emission characteristics and heat rate on SCR cost effectiveness for oil-fired wall boilers.

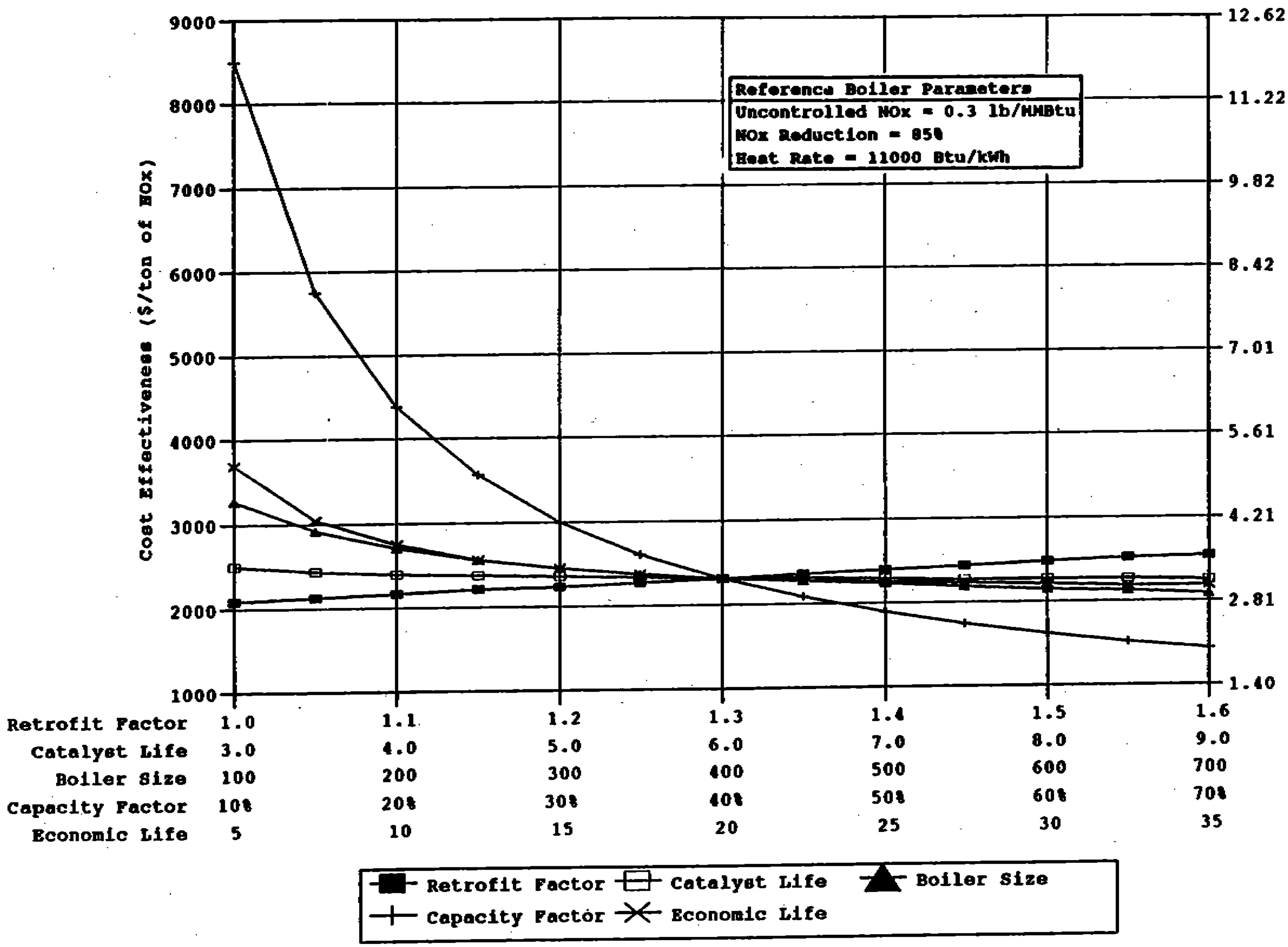

Figure 6-55. Impact of plant characteristics on SCR cost effectiveness and busbar cost for natural gas-fired tangential boilers.

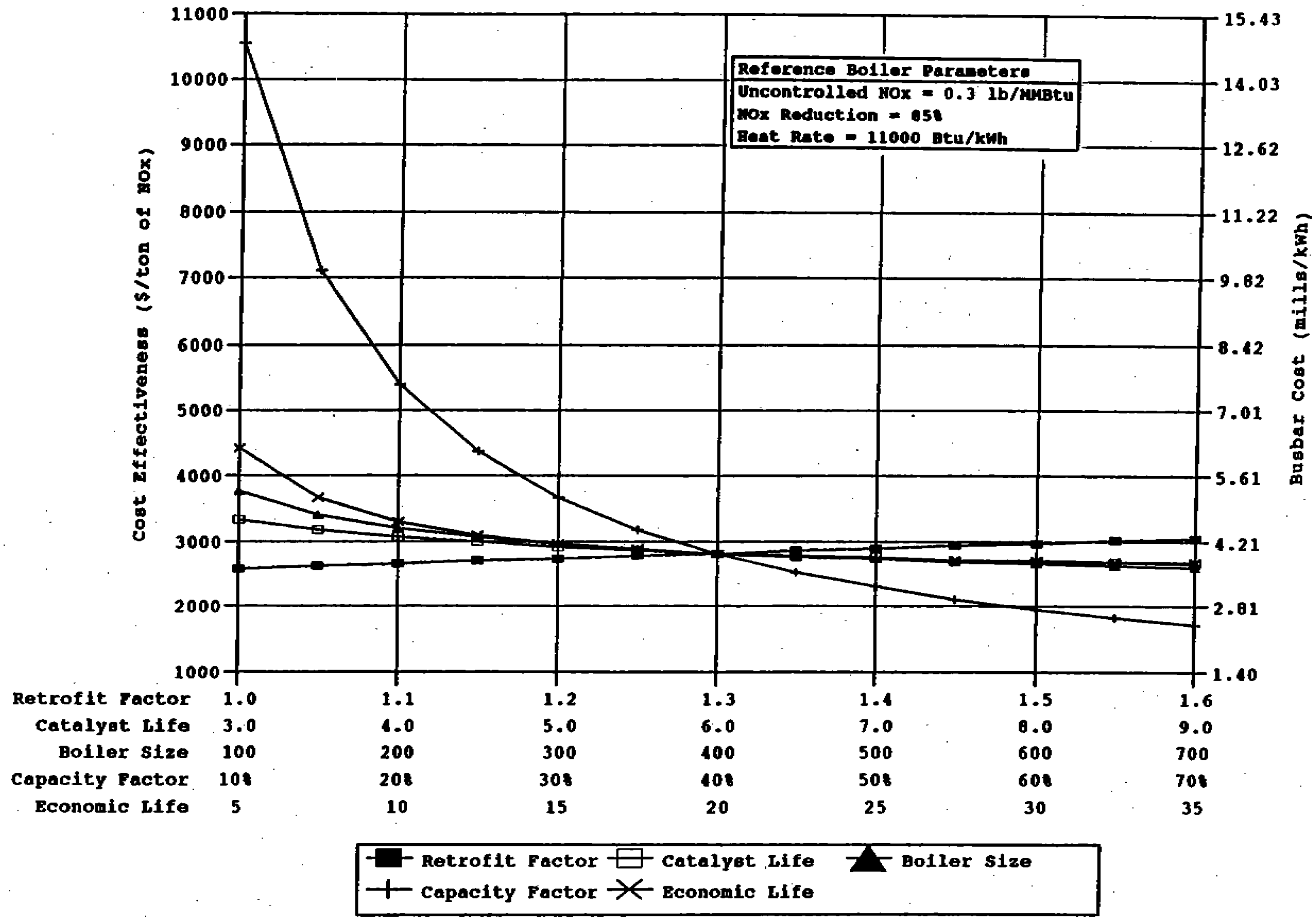

Figure 6-56. Impact of plant characteristics on SCR cost effectiveness and busbar cost for oil-fired tangential boilers.

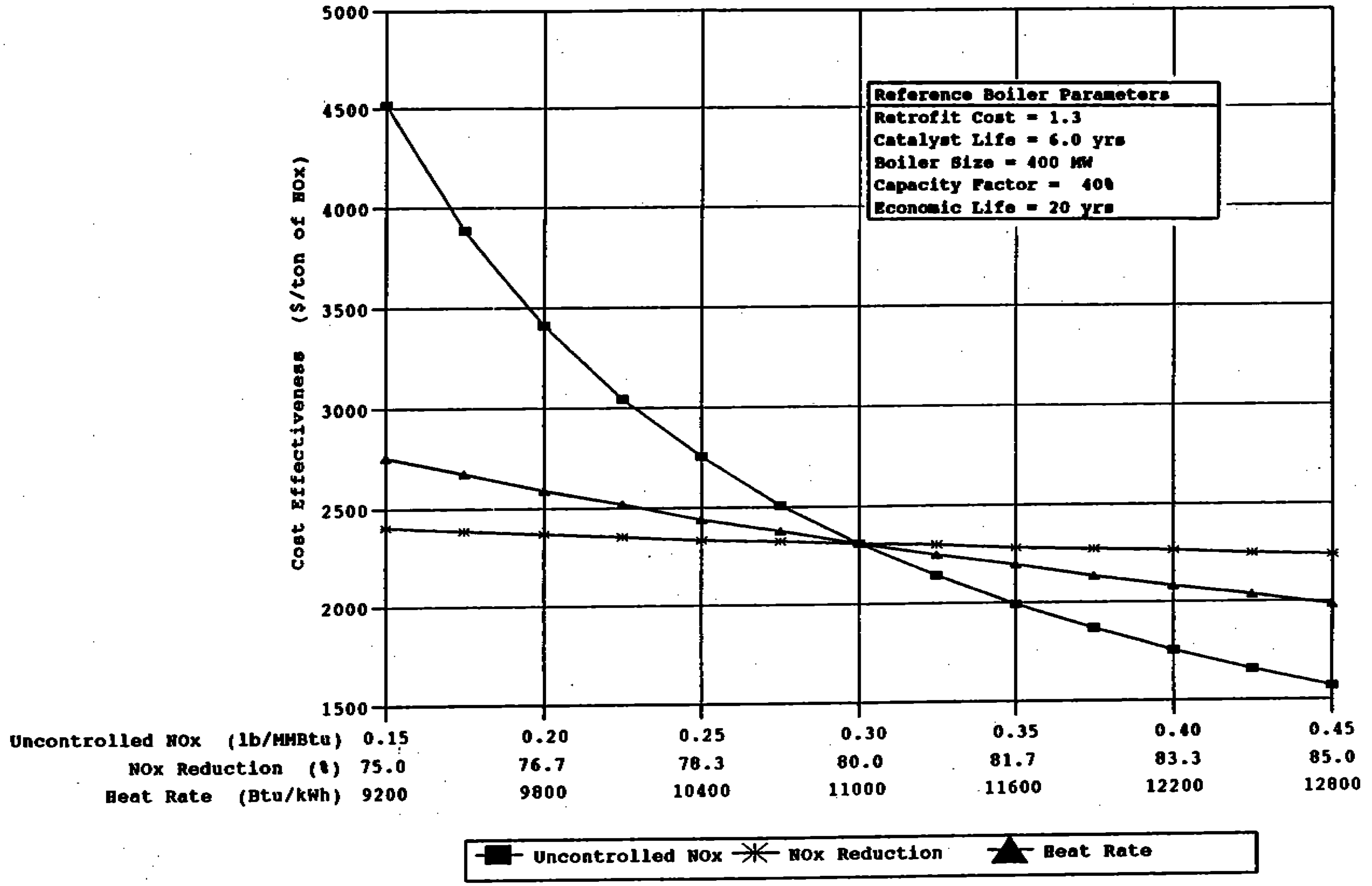

Figure 6-57. Impact of NO_x emission characteristics and heat rate on SCR cost effectiveness for natural gas-fired tangential boilers.

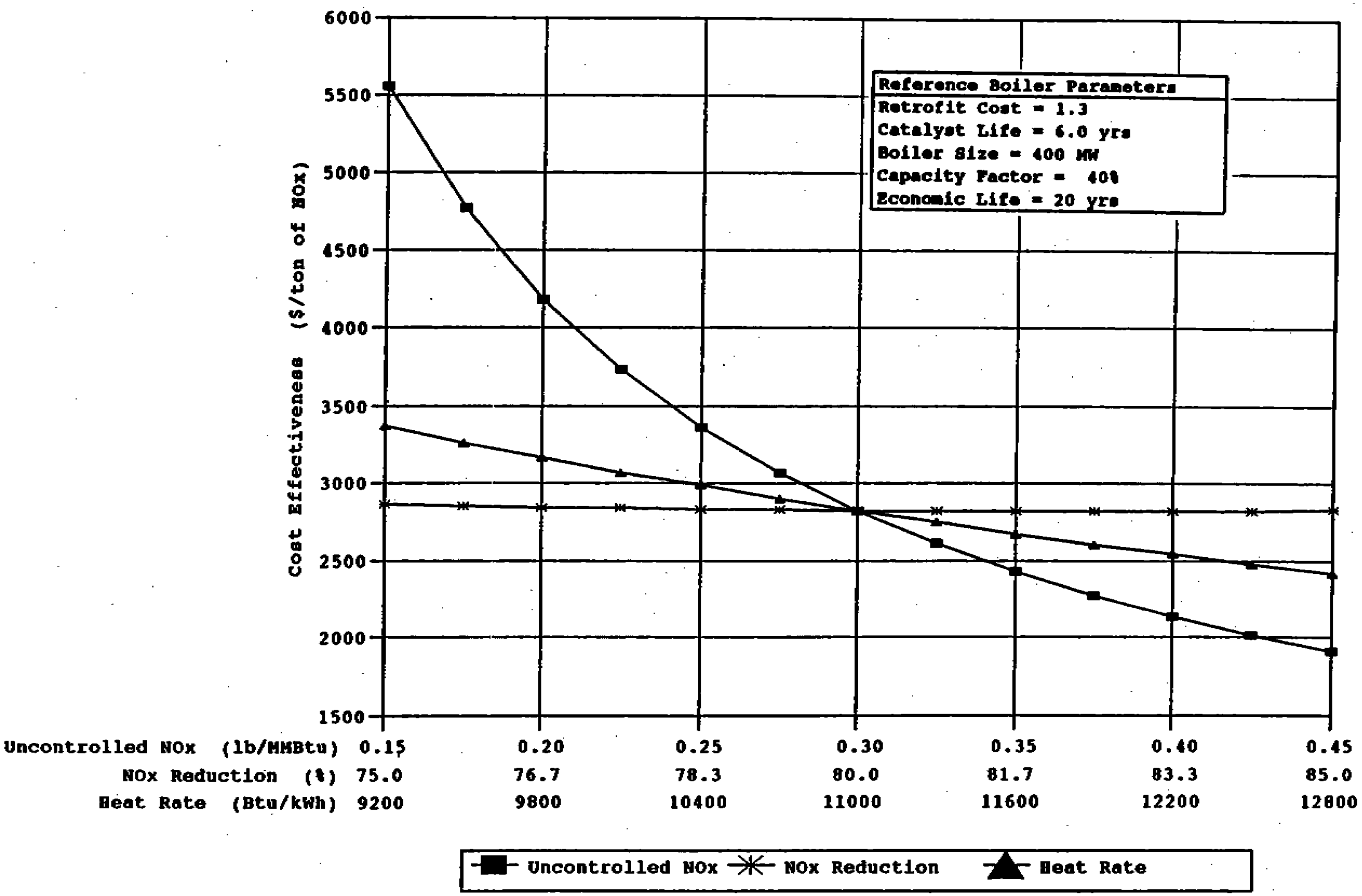

Figure 6-58. Impact of NO_x emission characteristics and heat rate on SCR cost effectiveness for oil-fired tangential boilers.

fired reference boiler's cost effectiveness and busbar cost are approximately $2,800 per ton of NO_x removed and 4.0 mills/kWh. The cost effectiveness value and busbar cost for SCR applied to natural-gas fired boilers are lower than for oil-fired boilers because of the smaller catalyst volumes on natural-gas boilers. Similarly, cost effectiveness and busbar cost for SCR applied to natural gas- and oil-fired tangential boilers are lower than for the coal-fired tangential boilers because of the smaller catalyst volumes and expected longer catalyst life on natural gas- and oil-fired boilers. The sensitivity curves follow the same general trends as with SCR applied to coal-fired wall boilers.

6.5.3 Low NO_x Burners with Selective Non-Catalytic Reduction

Cost estimates for the combination control of LNB + SNCR are presented in this section for coal-fired and natural gas- and oil-fired wall and tangential boilers.

6.5.3.1 Costing Procedures. To develop the cost algorithms for the combination control LNB + SNCR, the individual capital, variable O&M, and fixed O&M cost algorithms for LNB and SNCR were combined. Refer to sections 6.3.1, 6.4.2, and 6.5.1 for these costing procedures.

6.5.3.2 Model Plant Results.

6.5.3.2.1 Coal-fired model plants. The capital cost, busbar cost, and cost effectiveness for the ten wall- and tangentially-fired boilers are presented in table 6-18. An economic life of 20 years and a NO_x reduction efficiency of 45 percent for LNB and 45 percent for SNCR were assumed for all boilers. The urea price of each boiler was varied from $140 to $260 per ton for a 50-percent urea solution. For the 600 MW baseload boiler, the estimated cost effectiveness ranged from $370 to $478 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $2,750 to $2,860 per ton.

Cost per ton of NO_x removed with LNB + SNCR on tangentially-fired boilers is slightly lower than for wall-fired boilers because of lower capital cost associated with

TABLE 6-18. COSTS FOR LNB + SNCR APPLIED TO COAL-FIRED BOILERS

Plant identification	Total capital cost,[a] $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Urea cost ($/ton)	140	200	260	140	200	260	140	200	260
Wall-fired boilers[b]									
100 MW, Peaking[c]	57	57	57	10.8	11.0	11.2	2,750	2,810	2,860
100 MW, Baseload[d]	57	57	57	2.05	2.22	2.39	652	706	760
300 MW, Cycling[e]	37	37	37	2.54	2.73	2.92	737	791	845
300 MW, Baseload	37	37	37	1.41	1.58	1.75	449	503	557
600 MW, Baseload	29	29	29	1.16	1.33	1.50	370	424	478
Tangentially-fired boilers[f]									
100 MW, Peaking	33	33	33	7.40	7.56	7.72	2,420	2,480	2,530
100 MW, Baseload	33	33	33	1.44	1.57	1.70	589	643	696
300 MW, Cycling	23	23	23	1.78	1.92	2.07	663	716	770
300 MW Baseload	23	23	23	1.00	1.14	1.27	411	465	519
600 MW, Baseload	18	18	18	0.84	0.97	1.10	344	398	452

[a]LNB retrofit factor and indirect cost factor are 1.15 and 1.3 respectively. SNCR retrofit factor and indirect cost factor are 1.0 and 1.3, respectively.
[b]Uncontrolled NO_x levels of 0.90 lb/MMBtu and an LNB + SNCR total NO_x reduction of 70 percent were used for wall-fired boilers.
[c]Peaking = 10 percent capacity factor.
[d]Baseload = 65 percent capacity factor.
[e]Cycling = 30 percent capacity factor.
[f]Uncontrolled NO_x levels of 0.70 lb/MMBtu and an LNB + SNCR total NO_x reduction of 70 percent were used for tangentially-fired boilers.

LNB applied to tangentially-fired boilers. Cost effectiveness for the 600 MW baseload tangentially-fired boiler ranges from \$344 to \$452 per ton. For the 100 MW peaking tangentially-fired boiler, the estimated cost effectiveness ranges from \$2,420 to \$2,530 per ton.

6.5.3.2.2 Natural gas- and oil-fired model plants. The capital cost, busbar cost, and cost effectiveness for the ten wall- and tangentially-fired boilers are presented in table 6-19. An economic life of 20 years and a NO_x reduction efficiency of 45 percent for LNB and 35 percent for SNCR were assumed for all boilers. The urea price of each boiler was varied from \$140 to \$260 per ton for a 50-percent urea solution. For the 600 MW baseload boiler, the estimated cost effectiveness ranged from \$585 to \$697 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from \$5,200 to \$5,300 per ton.

Cost per ton of NO_x removed with LNB + SNCR is higher on tangentially-fired boilers because of lower uncontrolled NO_x levels of these boilers. Cost effectiveness for the 600 MW baseload tangentially-fired boiler ranges from \$641 to \$750 per ton. For the 100 MW peaking tangentially-fired boiler, the estimated cost effectiveness ranges from \$5,830 to \$5,940 per ton.

6.5.3.3 Sensitivity Analysis.

6.5.3.3.1 Coal-fired boiler sensitivity analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and urea solution price on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-59. Figure 6-60 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and the NO_x reduction efficiency of the LNB and SNCR systems) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately \$620 per ton of NO_x removed and 2.1 mills/kWh.

TABLE 6-19. COSTS FOR LNB + SNCR APPLIED TO NATURAL GAS- AND OIL-FIRED BOILERS

Plant identification	Total capital cost,[a] $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Urea cost ($/ton)	140	200	260	140	200	260	140	200	260
Wall-fired boilers[b]									
100 MW, Peaking[c]	56	56	56	10.4	10.5	10.7	5,200	5,250	5,310
100 MW, Baseload[d]	56	56	56	1.82	1.91	2.00	1,130	1,190	1,250
300 MW, Cycling[e]	36	36	36	2.28	2.38	2.48	1,290	1,350	1,400
300 MW, Baseload	36	36	36	1.19	1.28	1.37	738	795	851
600 MW, Baseload	28	28	28	0.94	1.03	1.12	585	641	697
Tangentially-fired boilers[f]									
100 MW, Peaking	32	32	32	7.03	7.09	7.16	5,830	5,890	5,940
100 MW, Baseload	32	32	32	1.21	1.27	1.32	1,260	1,310	1,370
300 MW, Cycling	22	22	22	1.52	1.58	1.63	1,430	1,490	1,540
300 MW Baseload	22	22	22	0.72	0.83	0.89	810	864	919
600 MW, Baseload	17	17	17	0.62	0.67	0.72	641	695	750

[a]LNB retrofit factor and indirect cost factor are 1.15 and 1.3, respectively. SNCR retrofit factor and indirect cost factor are 1.0 and 1.3, respectively.
[b]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an LNB + SNCR total NO_x reduction of 64 percent were used for wall-fired boilers.
[c]Peaking = 10 percent capacity factor.
[d]Baseload = 65 percent capacity factor.
[e]Cycling = 30 percent capacity factor.
[f]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an LNB + SNCR total NO_x reduction of 64 percent were used for tangentially-fired boilers.

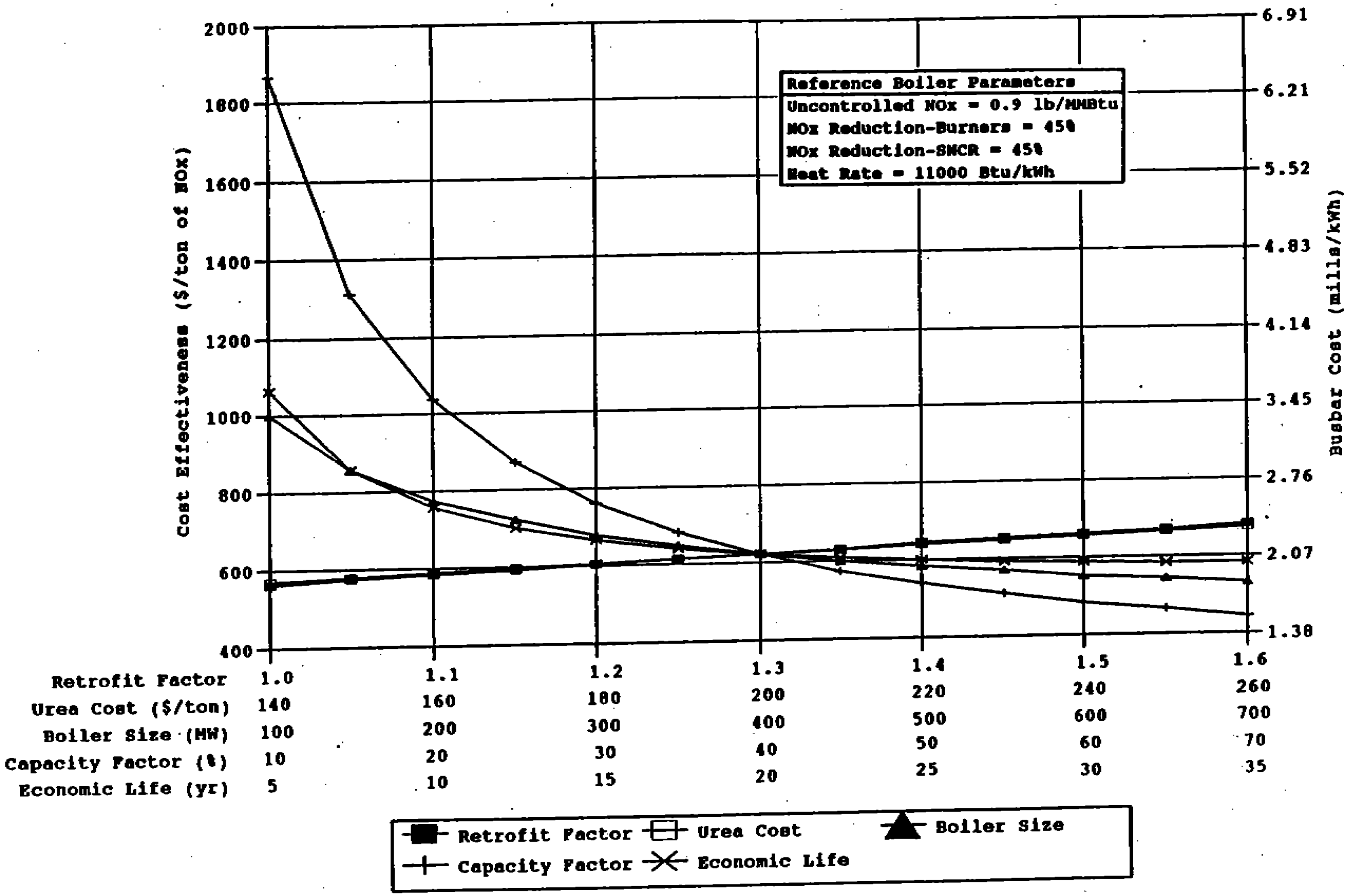

Figure 6-59. Impact of plant characteristics on LNB + SNCR cost effectiveness and busbar cost for coal-fired wall boilers.

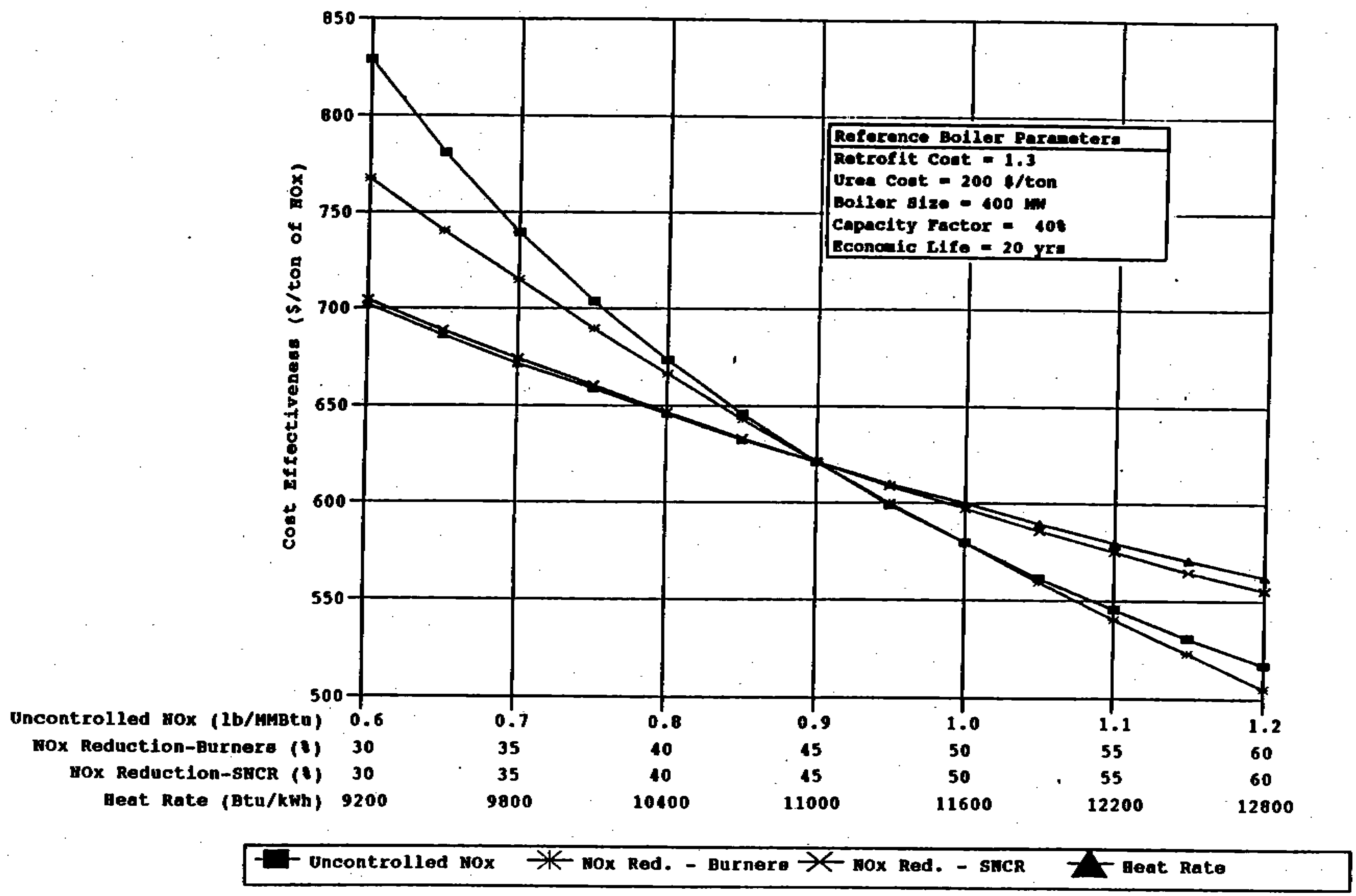

Figure 6-60. Impact of NO_x emission characteristics and heat rate on LNB + SNCR cost effectiveness for coal-fired wall boilers.

Of the parameters shown in figure 6-59, the variation of capacity factor from 10 to 70 percent has the greatest impact on cost effectiveness and busbar cost. The cost effectiveness value and busbar cost are inversely related to capacity factor, and thus, as capacity factor decreases, the cost effectiveness value and busbar cost increase. This is especially noticeable at low capacity factors where a decrease of 75 percent in the reference plant's capacity factor (from 40 to 10 percent) results in an increase in the cost effectiveness value and busbar cost of nearly 200 percent.

Variations in economic life and boiler size follow a trend similar to capacity factor, but do not cause as great a change in cost effectiveness and busbar cost. For example, a decrease of 75 percent in economic life (from 20 to 5 years) results in an increase in the plant's cost effectiveness value and busbar cost of approximately 75 percent. Similarly, a decrease of 75 percent in boiler size (from 400 to 100 MW) results in an increase in the plant's cost effectiveness value and busbar cost of nearly 75 percent.

The cost effectiveness value and busbar cost are linearly related to both retrofit factor and urea cost. An increase or decrease of 0.3 in retrofit factor or $60 per ton in urea cost compared to the reference plant causes a corresponding change in cost effectiveness and busbar cost of less than 5 percent.

Of the parameters shown in figure 6-60, the variation of uncontrolled NO_x from 0.6 to 1.2 lb/MMBtu has the greatest impact on cost effectiveness. Variation in NO_x reduction exhibits an inverse relationship to cost effectiveness. A 33-percent decrease in the reference plants uncontrolled NO_x (from 0.9 to 0.6 lb/MMBtu) results in an increase in the cost effectiveness value of approximately 35 percent.

Variation in the NO_x reduction of LNB from 30 to 60 percent follow a trend similar to the variation in uncontrolled NO_x. A 33-percent decrease of the NO_x reduction of the LNB results in an increase of cost effectiveness of 25 percent. Variation in the NO_x reduction of the SNCR system from 30 to 60 percent follows a trend similar to NO_x reduction of the LNB, but do not cause as great a change in cost effectiveness. A 33-percent decrease in the NO_x reduction of the SNCR system results in an increase in the cost effectiveness value of approximately 15 percent. Variation in heat rate from 9,200 to 12,800 Btu/kWh has nearly an identical effect on cost effectiveness as the potential variation in NO_x reduction by the SNCR system. A 16-percent decrease in heat rate (11,000 to 9,200 Btu/kWh) results in an equivalent increase of cost effectiveness value.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and urea solution price on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-61. Figure 6-62 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and the NO_x reduction efficiency of the LNB and SNCR systems) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $560 per ton of NO_x removed and 1.5 mills/kWh. The cost effectiveness values and busbar cost for LNB + SNCR applied to tangentially-fired boilers are slightly lower than for LNB + SNCR on wall-fired boilers because of lower capital cost associated with LNB applied to tangentially-fired boilers. The sensitivity curves follow the same general trends as with LNB + SNCR applied to wall-fired boilers.

6.5.3.3.2 Natural gas- and oil-fired sensitivity analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and urea solution price on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-63. Figure 6-64 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and the NO_x reduction efficiency of the LNB and SNCR systems) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $1,000 per ton

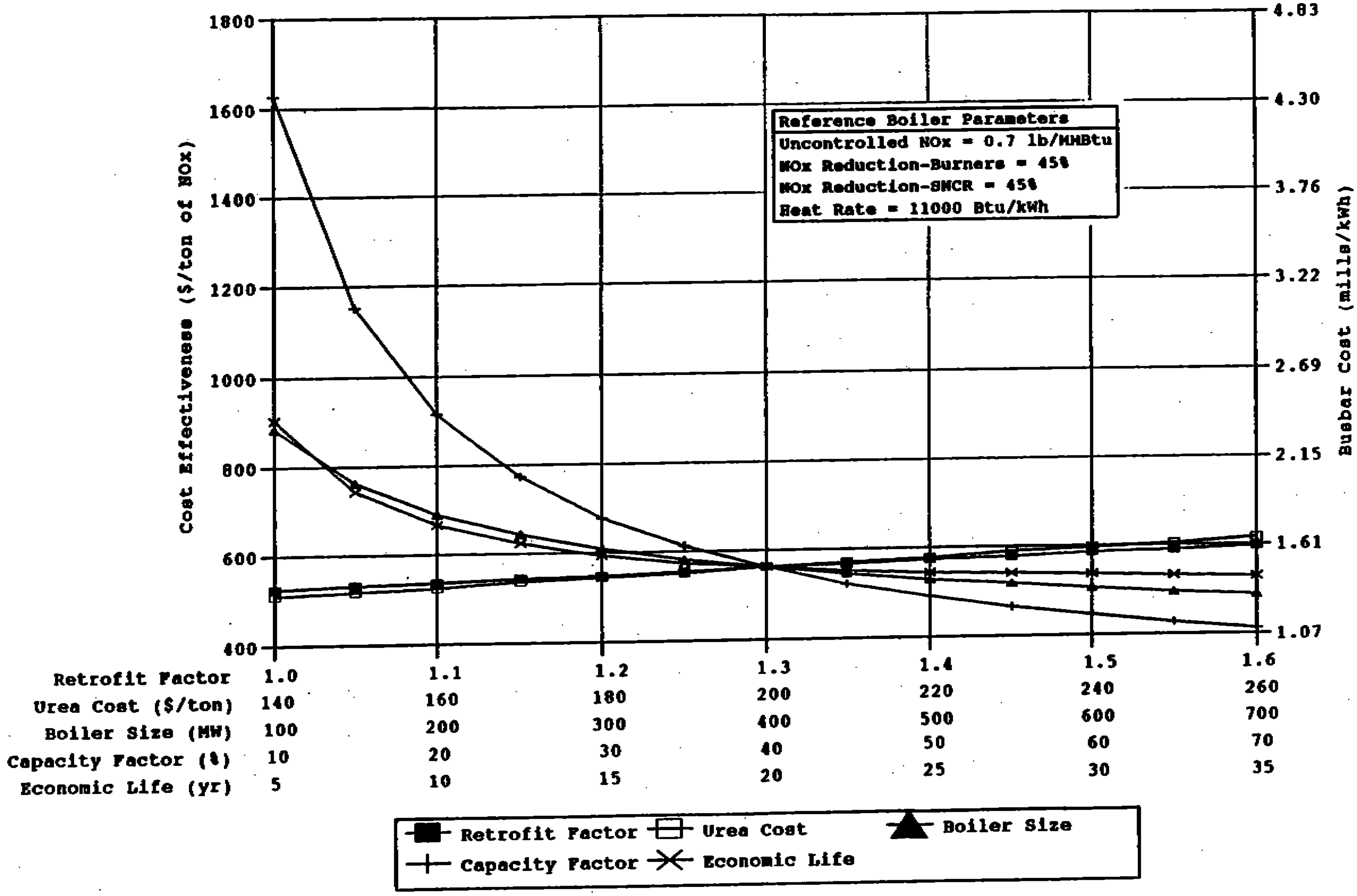

Figure 6-61. Impact of plant characteristics on LNB + SNCR cost effectiveness and busbar cost for coal-fired tangential boilers.

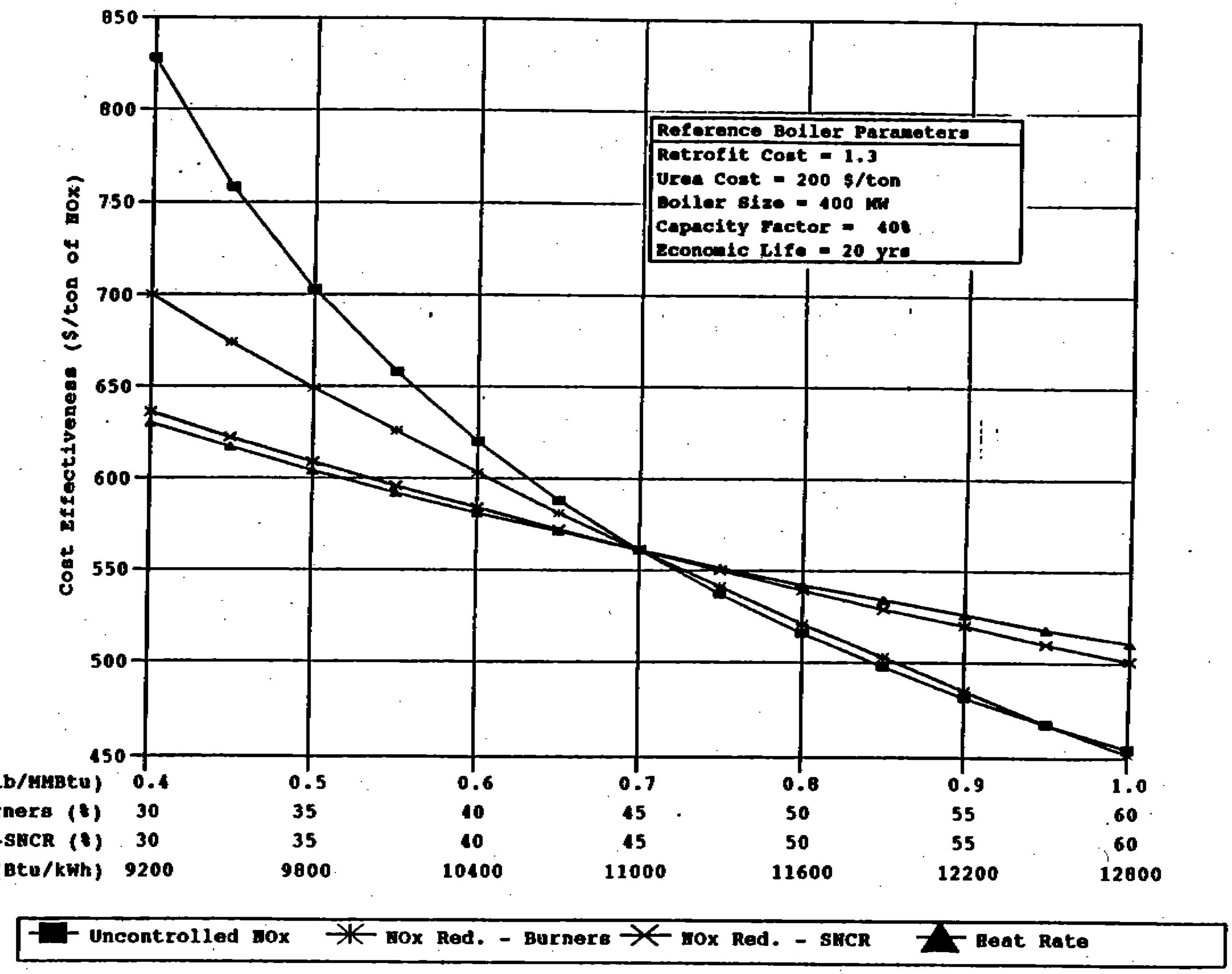

Figure 6-62. Impact of NO_x emission characteristics and heat rate on LNB + SNCR cost effectiveness for coal-fired tangential boilers.

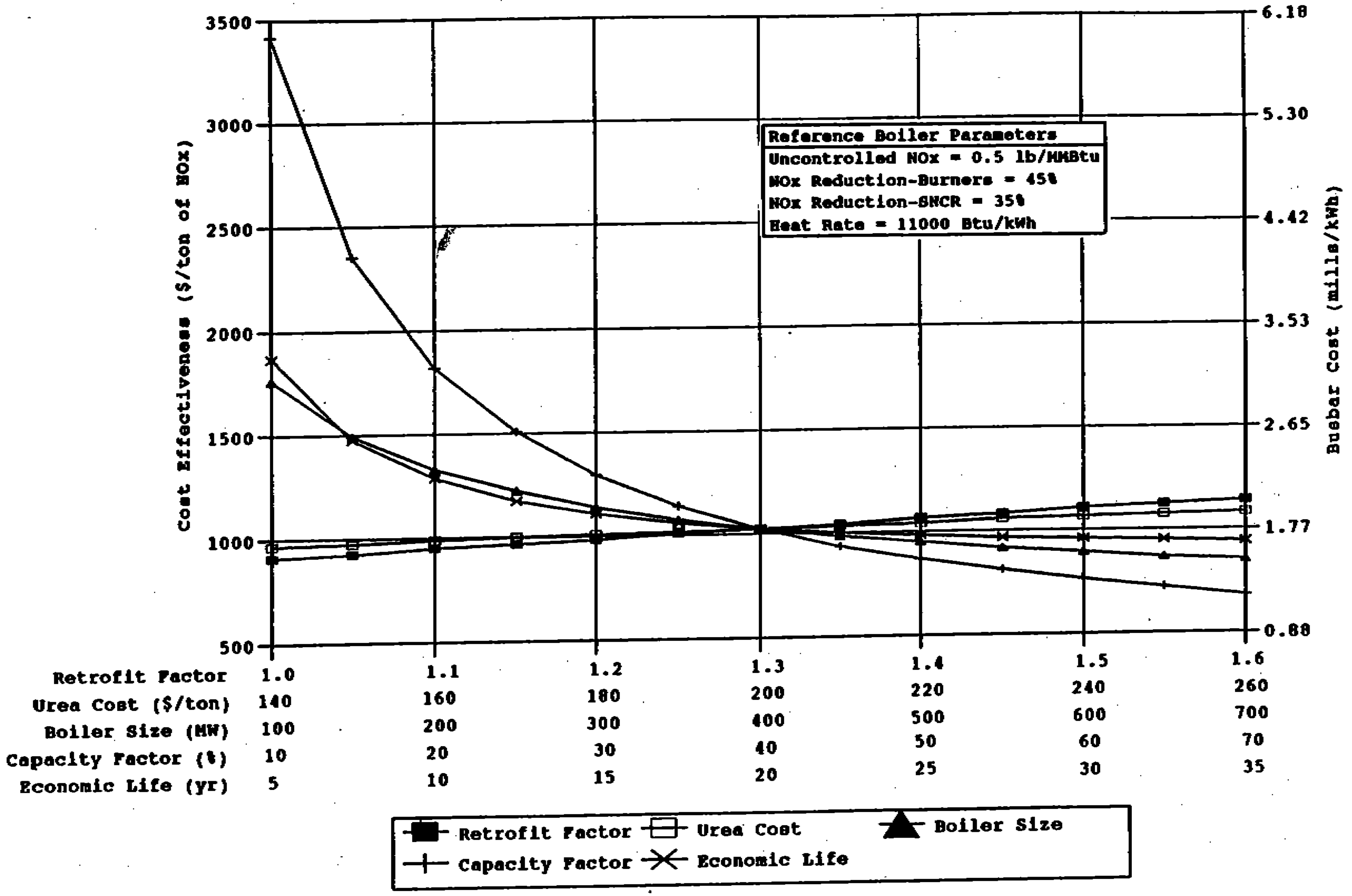

Figure 6-63. Impact of plant characteristics on LNB + SNCR cost effectiveness and busbar cost for natural gas- and oil-fired wall boilers.

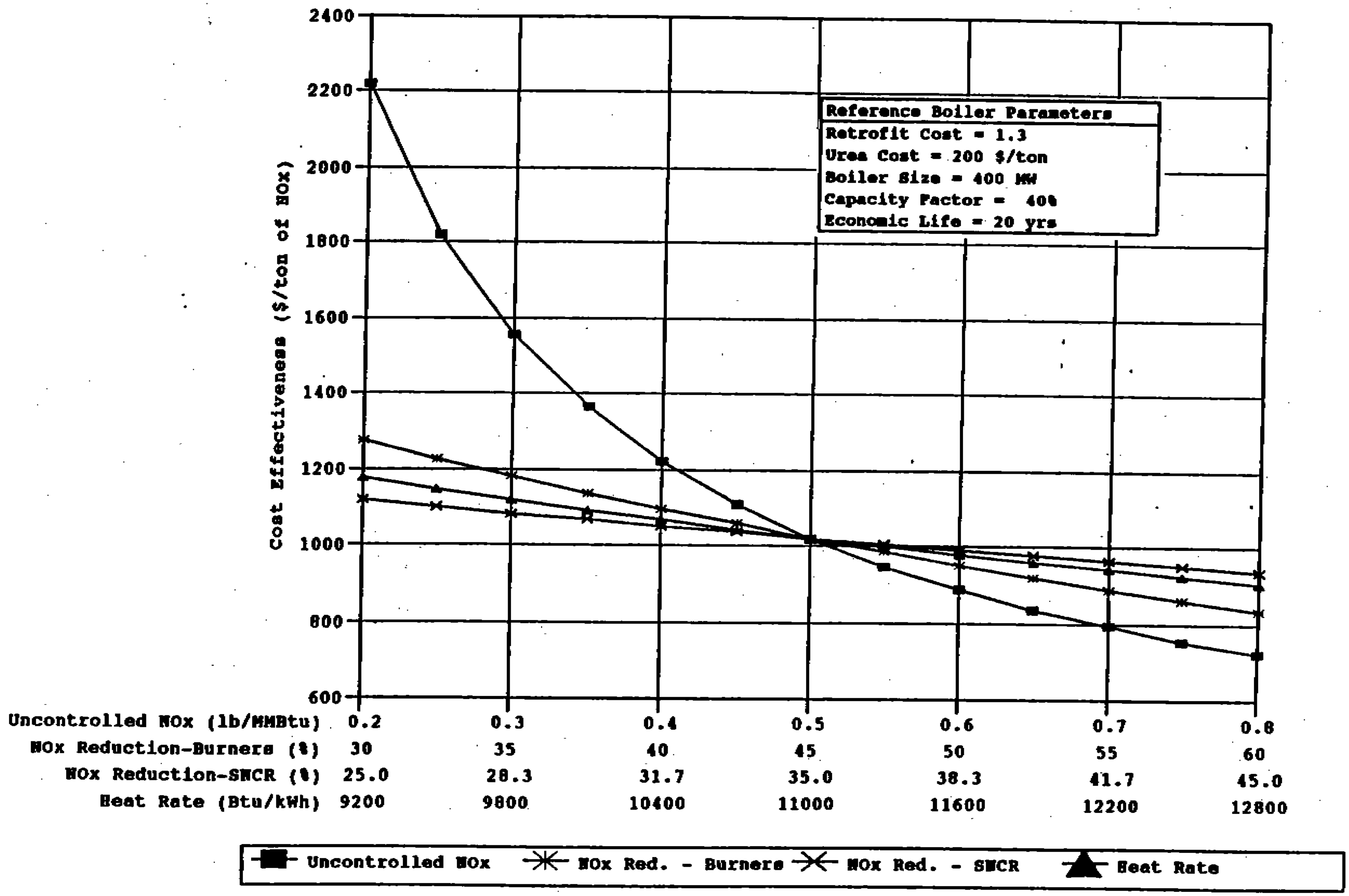

Figure 6-64. Impact of NO_x emission characteristics and heat rate on LNB + SNCR cost effectiveness for natural gas- and oil-fired wall boilers.

of NO_x removed and 1.8 mills/kWh. Cost effectiveness for LNB + SNCR applied natural gas- and oil-fired wall boilers are higher than for LNB + SNCR applied to coal-fired wall boilers because of lower uncontrolled NO_x levels of natural gas- and oil-fired boilers, although the busbar cost is less because of the smaller amount of urea that must be injected to achieve an equivalent percent NO_x reduction. The sensitivity curves follow the same general trends as with LNB + SNCR applied to coal-fired wall boilers.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and urea solution price on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-65. Figure 6-66 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and the NO_x reduction efficiency of the LNB and SNCR systems) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $1,100 per ton of NO_x removed and 1.2 mills/kWh. The cost effectiveness values of LNB + SNCR applied natural gas- and oil-fired tangential boilers are higher than for LNB + SNCR applied to natural gas- and oil-fired wall boilers because of lower uncontrolled NO_x levels of tangentially-fired boilers, although the busbar cost is less because of the smaller amount of urea that must be injected to achieve an equivalent percent NO_x reduction. The sensitivity curves follow the same general trends as with LNB + SNCR applied to coal-fired wall boilers.

6.5.4 Low NO_x Burners with Advanced Overfire Air and Selective Catalytic Reduction

Cost estimates for the combination control of LNB + AOFA + SCR are presented in this section for wall and tangential coal-fired and natural gas- and oil-fired boilers.

6.5.4.1 Costing Procedures. The cost algorithms for LNB + AOFA + SCR were developed by combining the individual capital, variable O&M, and fixed O&M cost algorithms for each

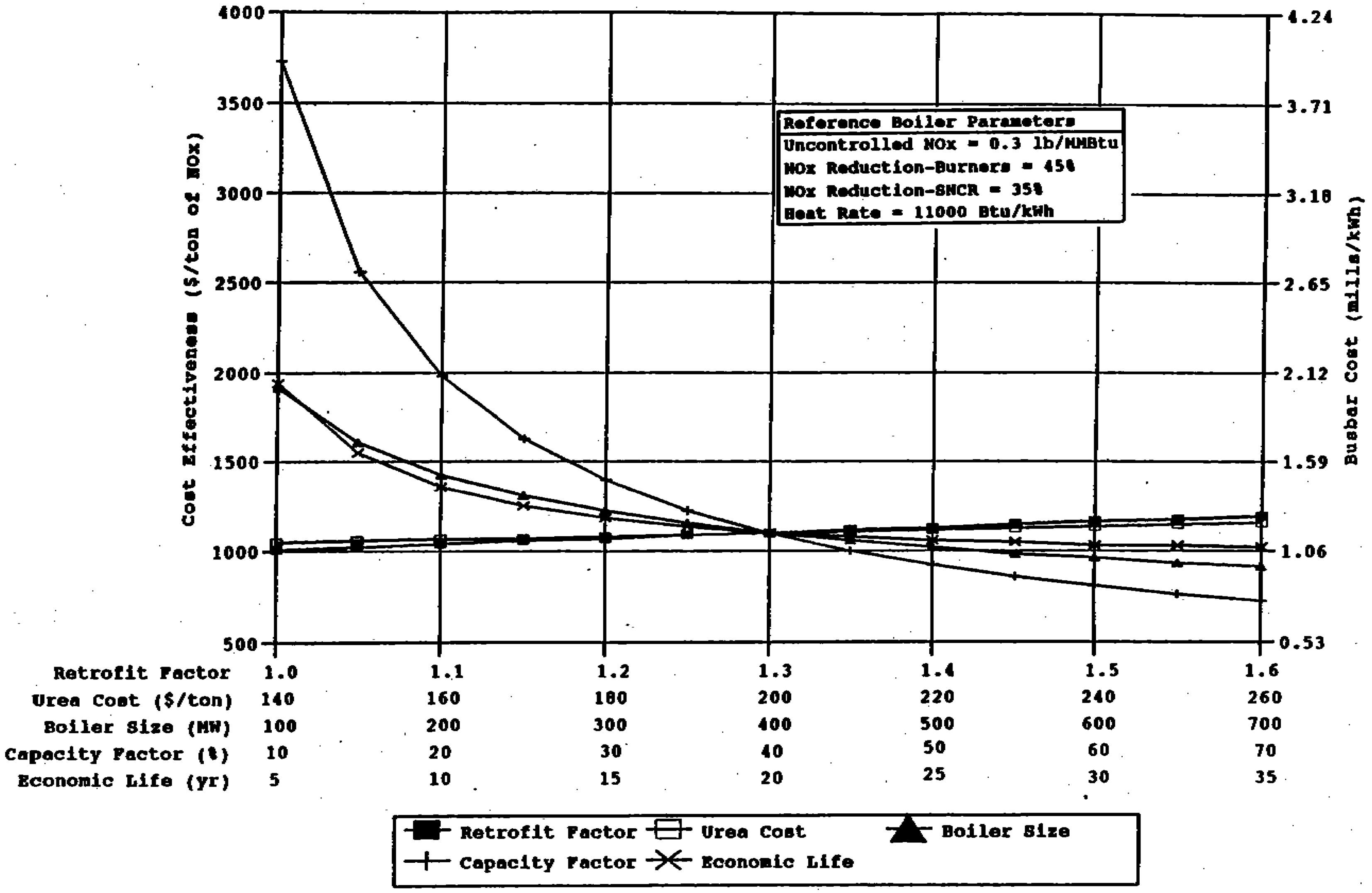

Figure 6-65. Impact of plant characteristics on LNB + SNCR cost effectiveness and busbar cost for natural gas- and oil-fired tangential boilers.

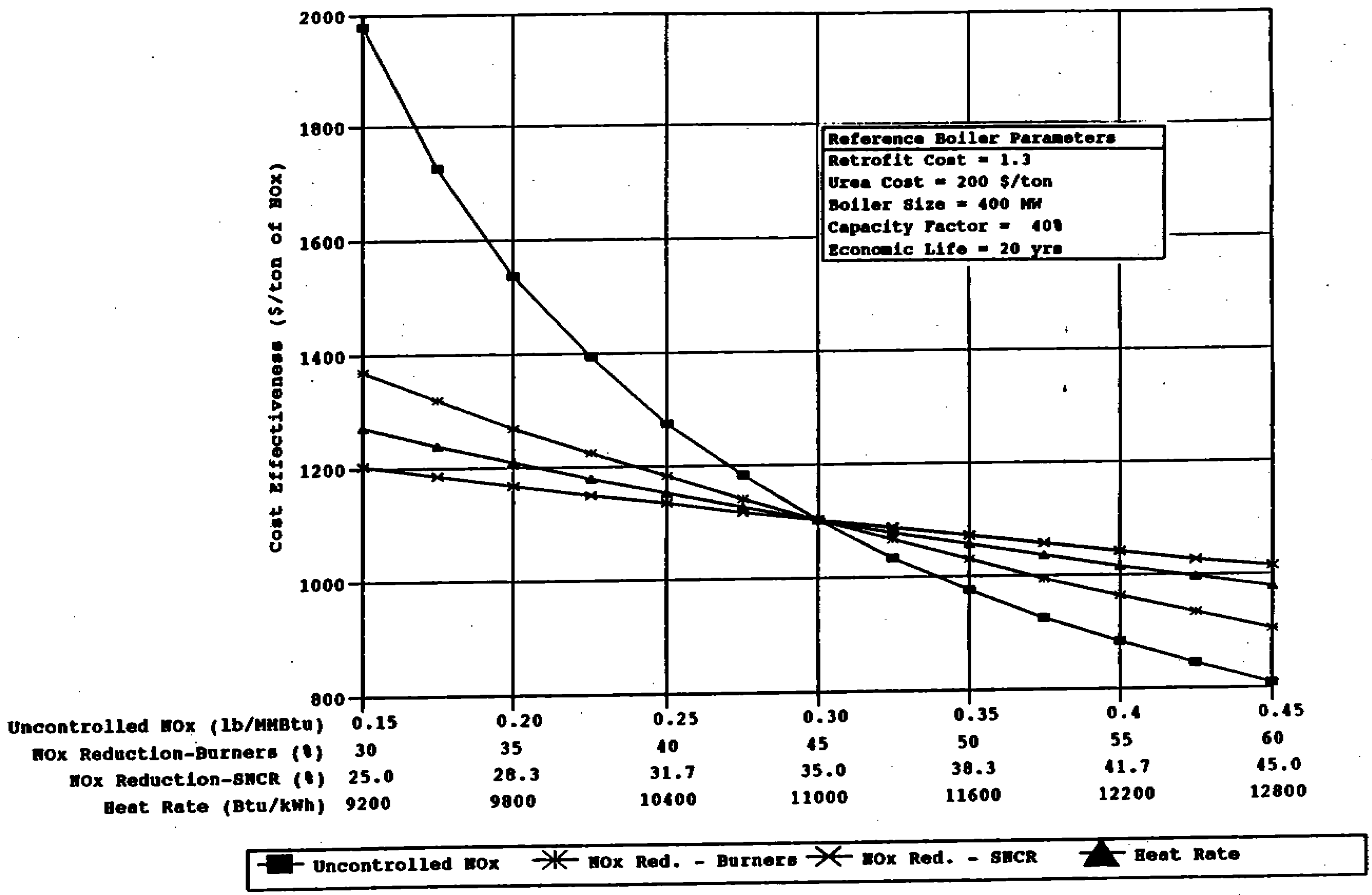

Figure 6-66. Impact of NO_x emission characteristics and heat rate on LNB + SNCR cost effectiveness for natural gas- and oil-fired tangential boilers.

of the three technologies. Refer to sections 6.3.2, 6.4.3, and 6.5.2 for these costing procedures.

6.5.4.2 Model Plant Results.

6.5.4.2.1 Coal-fired model plants. The capital cost, busbar cost, and cost effectiveness for the ten wall- and tangentially-fired boilers are presented in table 6-20. An economic life of 20 years and a NO_x reduction efficiency of 50 percent for LNB + AOFA and 80 percent for SCR were assumed for all boilers. The catalyst price was estimated to be $\$400/ft^3$ for each boiler, and an average retrofit factor of 1.34 was used. For the 600 MW baseload boiler, the estimated cost effectiveness ranged from $1,300 to $1,660 per ton of NO_x removed. For the 100 MW peaking wall-fired boiler, the estimated cost effectiveness ranges from $9,250 to $11,100 per ton.

Cost per ton of NO_x removed with LNB + AOFA + SCR on tangentially-fired boilers is higher than for wall-fired boilers due to the lower baseline NO_x levels associated with tangentially-fired boilers. Cost effectiveness for the 600 MW baseload tangentially-fired boiler ranges from $1,500 to $1,970 per ton. For the 100 MW peaking tangentially-fired boiler, the estimated cost effectiveness ranges from $9,990 to $12,400 per ton.

6.5.4.2.2 Natural gas- and oil-fired model plants. The capital cost, busbar cost, and cost effectiveness for the 10 wall- and tangentially-fired boilers are presented in table 6-21 and 6-22, respectively. An economic life of 20 years and a NO_x reduction efficiency of 50 percent for LNB + AOFA and 85 percent for SCR were assumed for all boilers. The catalyst price was estimated to be $\$400/ft^3$ for each boiler, and an average retrofit factor of 1.34 was used. Space velocities of 14,000/hr and 5,000/hr were assumed for natural gas- and oil-fired boilers, respectively. Cost per ton of NO_x removed with SCR on oil-fired boilers is higher than natural gas-fired boilers because of greater catalyst volume for oil-fired boilers.

TABLE 6-20. COSTS FOR LNB + AOFA + SCR APPLIED TO COAL-FIRED BOILERS

Plant identification	Total capital cost,[a] $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Catalyst life (yr)	2	3	4	2	3	4	2	3	4
Wall-fired boilers[b]									
100 MW, Peaking	203	203	203	55.8	49.5	46.3	11,100	9,880	9,250
100 MW, Baseload	203	203	203	8.93	7.96	7.47	2,230	1,990	1,870
300 MW, Cycling	140	140	140	15.3	13.2	12.2	3,480	3,000	2,760
300 MW Baseload	140	140	140	7.29	6.32	5.83	1,820	1,580	1,460
600 MW, Baseload	113	113	113	6.65	5.67	5.18	1,660	1,420	1,300
Tangentially-fired boilers[f]									
100 MW, Peaking	149	149	149	48.4	42.0	38.9	12,400	10,800	9,990
100 MW, Baseload	149	149	149	7.75	6.78	6.29	2,490	2,180	2,020
300 MW, Cycling	109	109	109	13.8	11.7	10.7	4,040	3,420	3,120
300 MW Baseload	109	109	109	6.59	5.61	5.13	2,110	1,800	1,650
600 MW, Baseload	90.0	90.0	90.0	6.13	5.16	4.67	1,970	1,660	1,500

[a]LNB + AOFA retrofit factor and indirect cost factor are both 1.3. SCR retrofit factor and indirect cost factor are 1.34 and 1.45, respectively.
[b]Uncontrolled NO_x levels of 0.90 lb/MMBtu and an LNB + AOFA + SCR total NO_x reduction of 90 percent were used for wall-fired boilers.
[c]Peaking = 10 percent capacity factor.
[d]Baseload = 65 percent capacity factor.
[e]Cycling = 30 percent capacity factor.
[f]Uncontrolled NO_x levels of 0.70 lb/MMBtu and an LNB + AOFA + SCR total NO_x reduction of 90 percent were used for tangentially-fired boilers.

TABLE 6-21. COSTS FOR LNB + AOFA + SCR APPLIED TO NATURAL GAS-FIRED BOILERS

Plant identification	Total capital cost,[a] $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Catalyst life (yr)	3	6	9	3	6	9	3	6	9
Wall-fired boilers[b]									
100 MW, Peaking[c]	168	168	168	31.5	30.5	30.2	11,000	10,700	10,500
100 MW, Baseload[d]	168	168	168	5.13	4.98	4.93	2,240	2,170	2,150
300 MW, Cycling[e]	107	107	107	7.34	7.01	6.90	2,910	2,780	2,740
300 MW, Baseload	107	107	107	3.57	3.41	3.36	1,560	1,490	1,470
600 MW, Baseload	81.0	81.0	81.0	2.96	2.80	2.75	1,290	1,220	1,200
Tangentially-fired boilers[f]									
100 MW, Peaking	116	116	116	24.4	23.4	23.1	14,200	13,600	13,400
100 MW, Baseload	116	116	116	3.99	3.84	3.79	2,900	2,790	2,750
300 MW, Cycling	77.0	77.0	77.0	5.94	5.61	5.50	3,930	3,710	3,640
300 MW Baseload	77.0	77.0	77.0	2.90	2.74	2.69	2,100	1,990	1,960
600 MW, Baseload	60.0	60.0	60.0	2.47	2.32	2.27	1,800	1,690	1,650

[a]LNB + AOFA retrofit factor and indirect cost factor are both 1.3. SCR retrofit factor and indirect cost factor are 1.34 and 1.45, respectively.
[b]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an LNB + AOFA + SCR total NO_x reduction of 93 percent were used for wall-fired boilers.
[c]Peaking = 10 percent capacity factor.
[d]Baseload = 65 percent capacity factor.
[e]Cycling = 30 percent capacity factor.
[f]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an LNB + AOFA + SCR total NO_x reduction of 93 percent were used for tangentially-fired boilers.

TABLE 6-22. COSTS FOR LNB + AOFA + SCR APPLIED TO OIL-FIRED BOILERS

Plant identification	Total capital cost,[a] $/kW			Busbar cost, mills/kWh			Cost effectiveness, $/ton		
Catalyst life (yr)	3	6	9	3	6	9	3	6	9
Wall-fired boilers[b]									
100 MW, Peaking[c]	175	175	175	36.3	33.4	32.5	12,700	11,700	11,300
100 MW, Baseload[d]	175	175	175	5.86	5.42	5.27	2,560	2,360	2,300
300 MW, Cycling[e]	114	114	114	8.93	7.97	7.65	3,540	3,160	3,030
300 MW, Baseload	114	114	114	4.30	3.86	3.71	1,870	1,680	1,620
600 MW, Baseload	88.0	88.0	88.0	3.69	3.25	3.10	1,610	1,420	1,350
Tangentially-fired boilers[f]									
100 MW, Peaking	123	123	123	29.2	26.3	25.3	16,900	15,300	14,700
100 MW, Baseload	123	123	123	4.72	4.28	4.14	3,400	3,110	3,010
300 MW, Cycling	85.0	85.0	85.0	7.53	6.57	6.25	4,970	4,340	4,130
300 MW Baseload	85.0	85.0	85.0	3.63	3.19	3.04	2,690	2,300	2,210
600 MW, Baseload	68.0	68.0	68.0	3.20	2.76	2.61	2,330	2,010	1,900

[a]LNB + AOFA retrofit factor and indirect cost factor are both 1.3. SCR retrofit factor and indirect cost factor are 1.34 and 1.45, respectively.
[b]Uncontrolled NO_x levels of 0.50 lb/MMBtu and an LNB + AOFA + SCR total NO_x reduction of 93 percent were used for wall-fired boilers.
[c]Peaking = 10 percent capacity factor.
[d]Baseload = 65 percent capacity factor.
[e]Cycling = 30 percent capacity factor.
[f]Uncontrolled NO_x levels of 0.30 lb/MMBtu and an LNB + AOFA + SCR total NO_x reduction of 93 percent were used for tangentially-fired boilers.

For the 600 MW baseload boiler, the estimated cost effectiveness ranged from $1,200 to $1,290 per ton of NO_x removed for the natural gas-fired boilers and $1,350 to $1,610 per ton of NO_x removed for oil-fired boilers. For the 100 MW peaking natural gas- and oil-fired wall boilers, the estimated cost effectiveness ranges from $10,500 to $11,000 per ton and $11,300 to $12,700 per ton, respectively.

Cost per ton of NO_x removed with LNB + AOFA + SCR on tangentially-fired boilers is higher than for wall-fired boilers due to the lower baseline NO_x levels associated with tangentially-fired boilers. Cost effectiveness for the 600 MW baseload tangentially-fired boilers range from $1,650 to $1,800 per ton for the natural gas-fired boiler and $1,900 to $2,330 per ton of NO_x removed for oil-fired boilers. For the 100 MW peaking natural gas- and oil-fired tangential boilers, the estimated cost effectiveness range from $13,400 to $13,200 per ton and $14,700 to $16,900 per ton of NO_x removed for oil-fired boilers.

6.5.4.3 Sensitivity Analysis

6.5.4.3.1 Coal-fired boilers sensitivity analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and catalyst life on cost effectiveness and busbar cost for wall-fired boilers is shown in figure 6-67. Figure 6-68 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency for both LNB + AOFA and SCR) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $2,120 per ton of NO_x removed and 9.5 mills/kWh.

Of the parameters shown in figure 6-67, the variation of capacity factor from 10 to 70 percent has the greatest impact on cost effectiveness and busbar cost. The cost effectiveness value and busbar cost exhibit an inverse relationship with capacity factor, and thus, as capacity factor decreases, the cost effectiveness value and busbar cost increase. This is especially noticeable at low capacity factors where a decrease

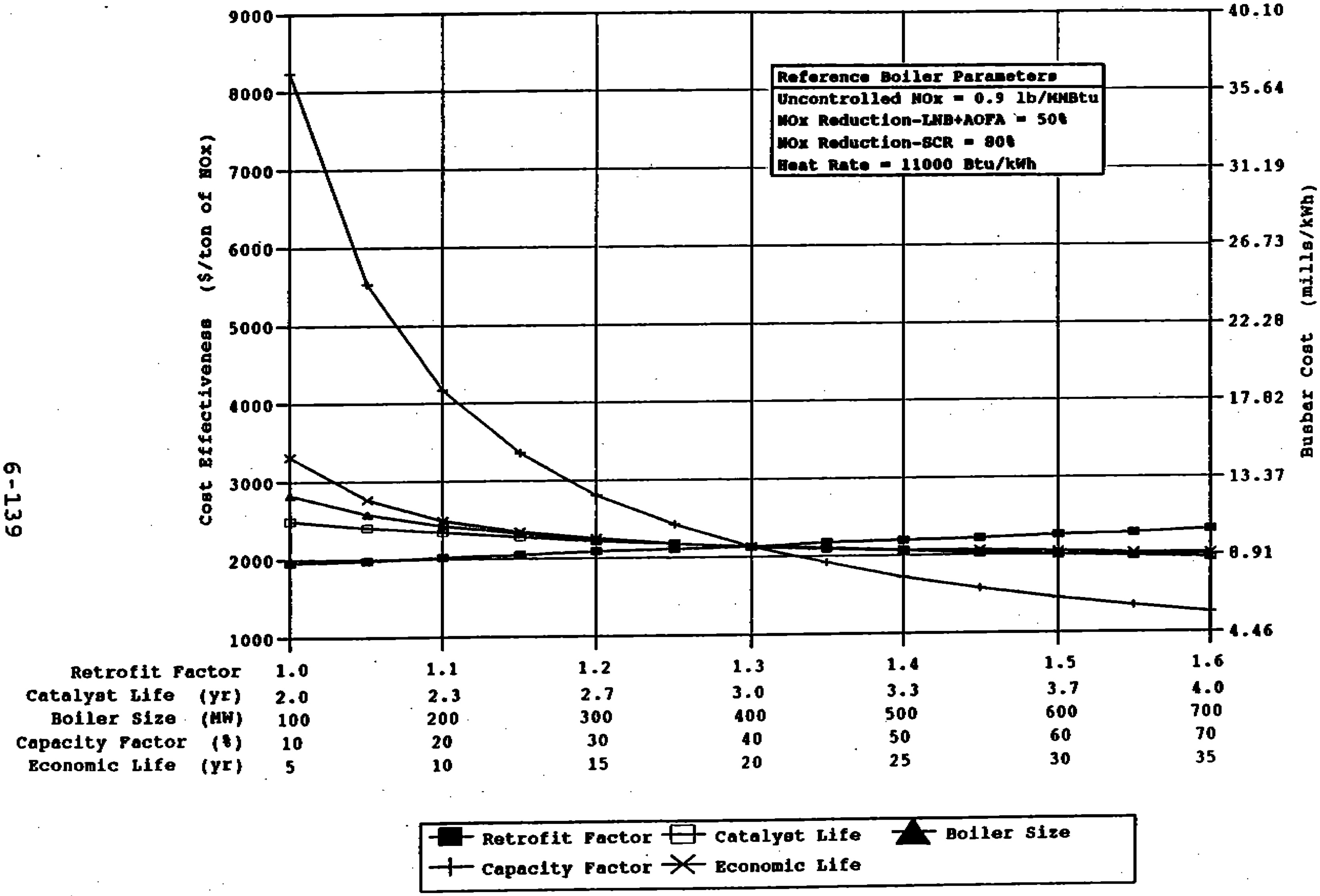

Figure 6-67. Impact of plant characteristics on LNB + AOFA + SCR cost effectiveness and busbar cost for coal-fired wall boilers.

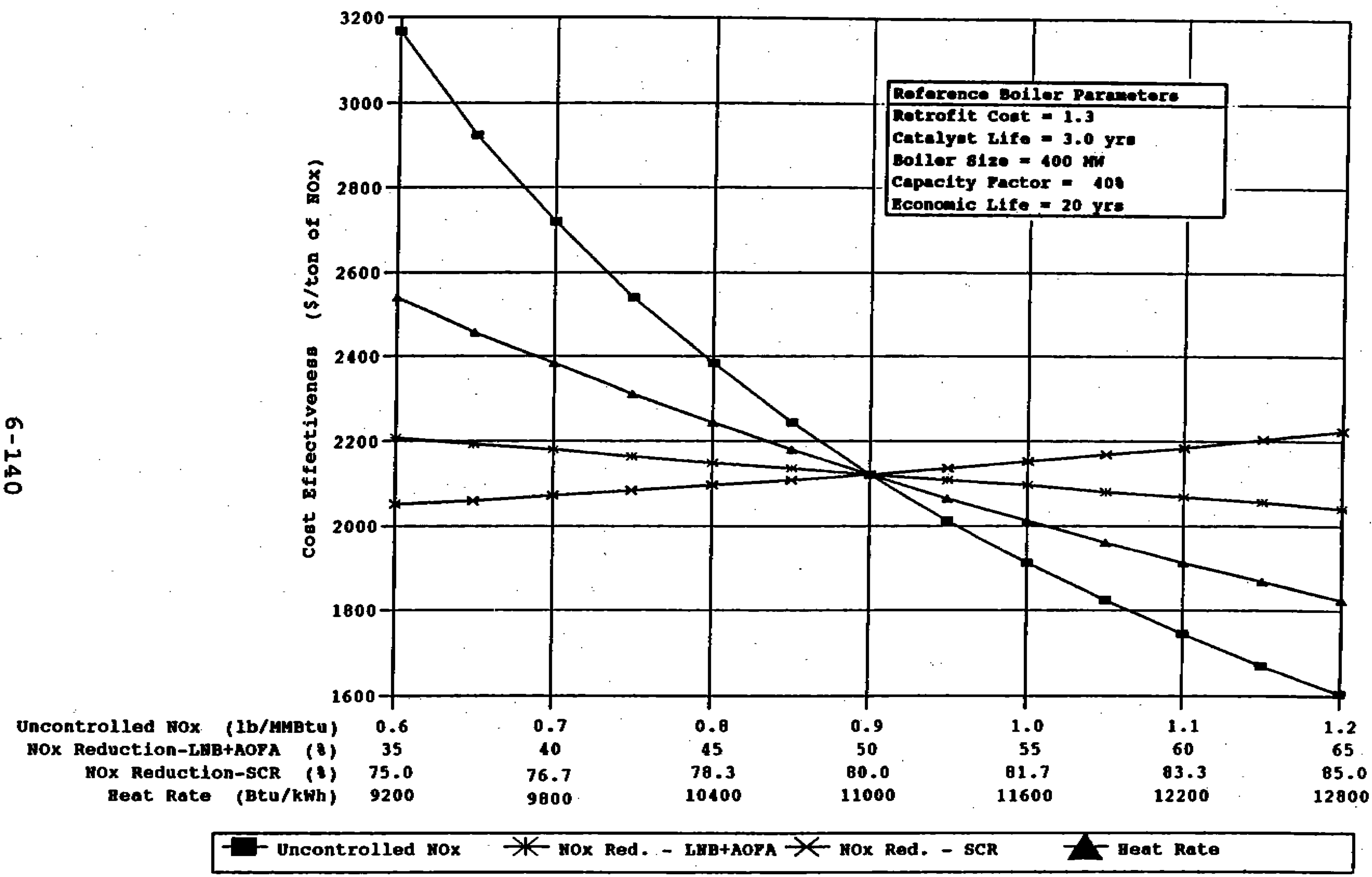

Figure 6-68. Impact of NO_x emission characteristics and heat rate on LNB + AOFA + SCR cost effectiveness for coal-fired wall boilers.

of 75 percent in the reference plant's capacity factor (from 40 to 10 percent) results in an increase in the cost effectiveness value and busbar cost of nearly 300 percent.

Variations in catalyst life, economic life, and boiler size follow a trend similar to capacity factor, but do not cause as great a change in cost effectiveness and busbar cost. For example, a decrease of 33 percent of the catalyst life (from 3 years to 2 years) increases the cost effectiveness value approximately 20 percent. Similarly, a decrease of 75 percent in economic life (from 20 to 5 years) results in an increase in the plant's cost effectiveness value and busbar cost of approximately 60 percent, and a decrease of 75 percent in the boiler size (from 400 to 100 MW) results in an increase in the plant's cost effectiveness value and busbar cost of nearly 35 percent.

The cost effectiveness value and busbar cost are linearly related to retrofit factor. An increase or decrease of 0.3 from the reference plant's retrofit factor of 1.3 causes a corresponding change in the cost effectiveness valu and busbar cost of less than 10 percent.

Of the parameters shown in figure 6-68, the variation of uncontrolled NO_x from 0.6 to 1.2 lb/MMBtu has the greatest impact on cost effectiveness. Variation in NO_x reduction exhibits an inverse relationship to the cost effectiveness value. A 33-percent decrease in the reference plants uncontrolled NO_x (from 0.9 to 0.6 lb/MMBtu) results in an increase in the cost effectiveness value of approximately 50 percent.

Variation in the heat rate from 9,200 to 12,800 Btu/kWh follows a trend similar to the variation in uncontrolled NO_x. A 16-percent decrease in heat rate (11,000 to 9,200 Btu/kWh) results in an increase of the cost effectiveness value of approximately 20 percent. Potential variations in the NO_x reduction efficiency of LNB + AOFA or SCR result in less than a 5 percent change in cost effectiveness.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and catalyst life on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figure 6-69. Figure 6-70 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency for both LNB + AOFA and SCR) and heat rate. As shown in the figures, the reference boiler's cost effectiveness and busbar cost are approximately $2,450 per ton of NO_x removed and 8.5 mills/kWh. The cost effectiveness values for LNB + AOFA + SCR applied to tangentially-fired boilers are slightly higher than on wall-fired boilers because of lower uncontrolled NO_x levels of tangentially-fired boilers, although the busbar cost is lower because of the higher capital and O&M costs associated with LNB + AOFA + SCR applied to wall-fired boilers. The sensitivity curves follow the same general trends as with LNB + AOFA + SCR applied to wall-fired boilers.

6.5.4.3.2 Natural gas- and oil-fired boiler sensitivity analysis. The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and catalyst life on cost effectiveness and busbar cost for natural gas- and oil-fired wall boilers is shown in figure 6-71 and 6-72, respectively. Figures 6-73 and 6-74 presents the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency for both LNB + AOFA and SCR) and heat rate. As shown in figures 6-71 and 6-72, the natural gas-fired reference boiler's cost effectiveness and busbar cost are approximately $1,900 per ton of NO_x removed and 4.8 mills/kWh and the oil-fired reference boilers cost effectiveness and busbar cost are approximately $2,200 per ton of NO_x removed and 5.6 mills/kWh. The cost effectiveness values and busbar costs for LNB + AOFA + SCR applied to natural gas-fired boilers are lower than for oil-fired boilers because of the smaller catalyst volumes on natural gas boilers. Similarly,

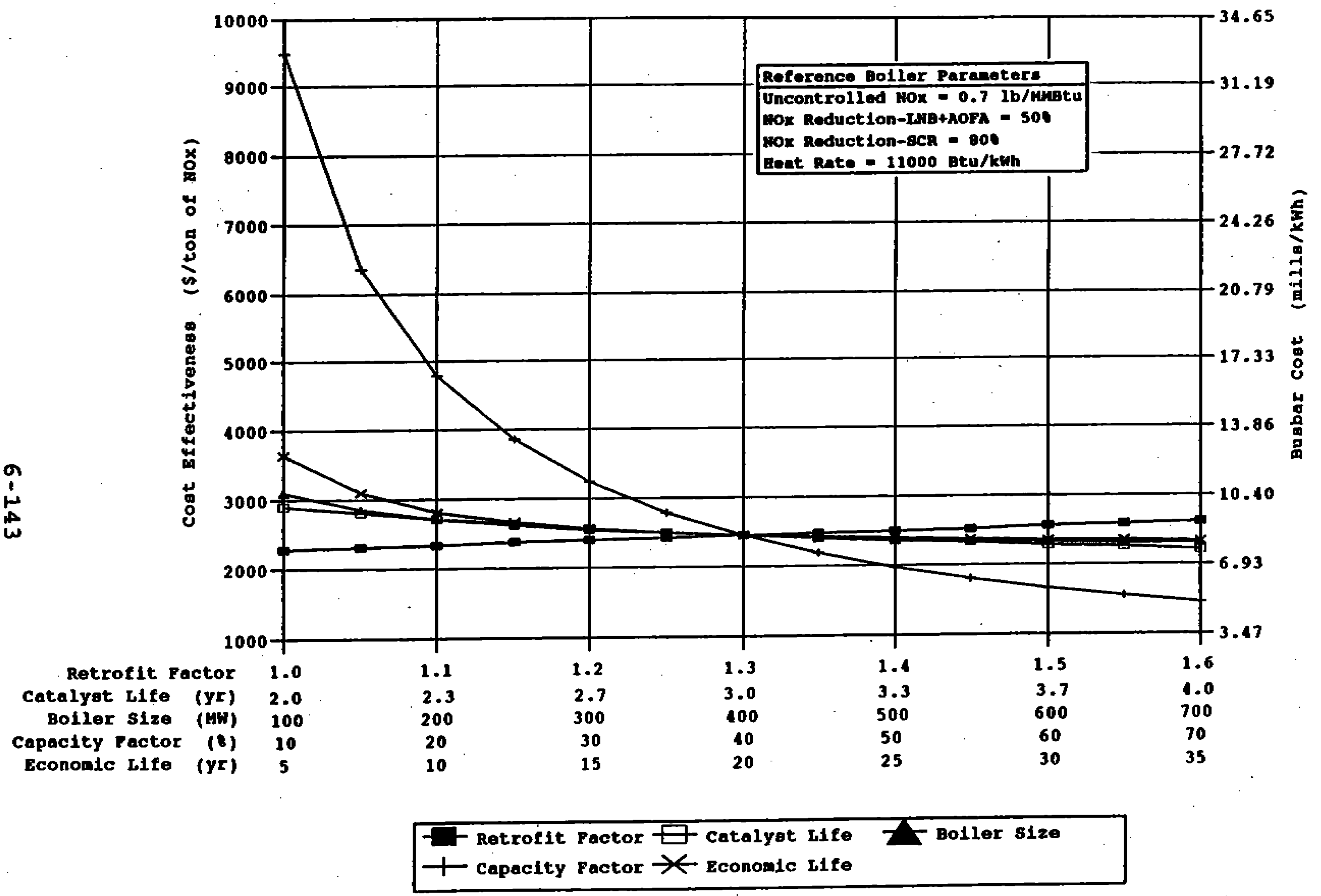

Figure 6-69. Impact of plant characteristics on LNB + AOFA + SCR cost effectiveness and busbar cost for coal-fired tangential boilers.

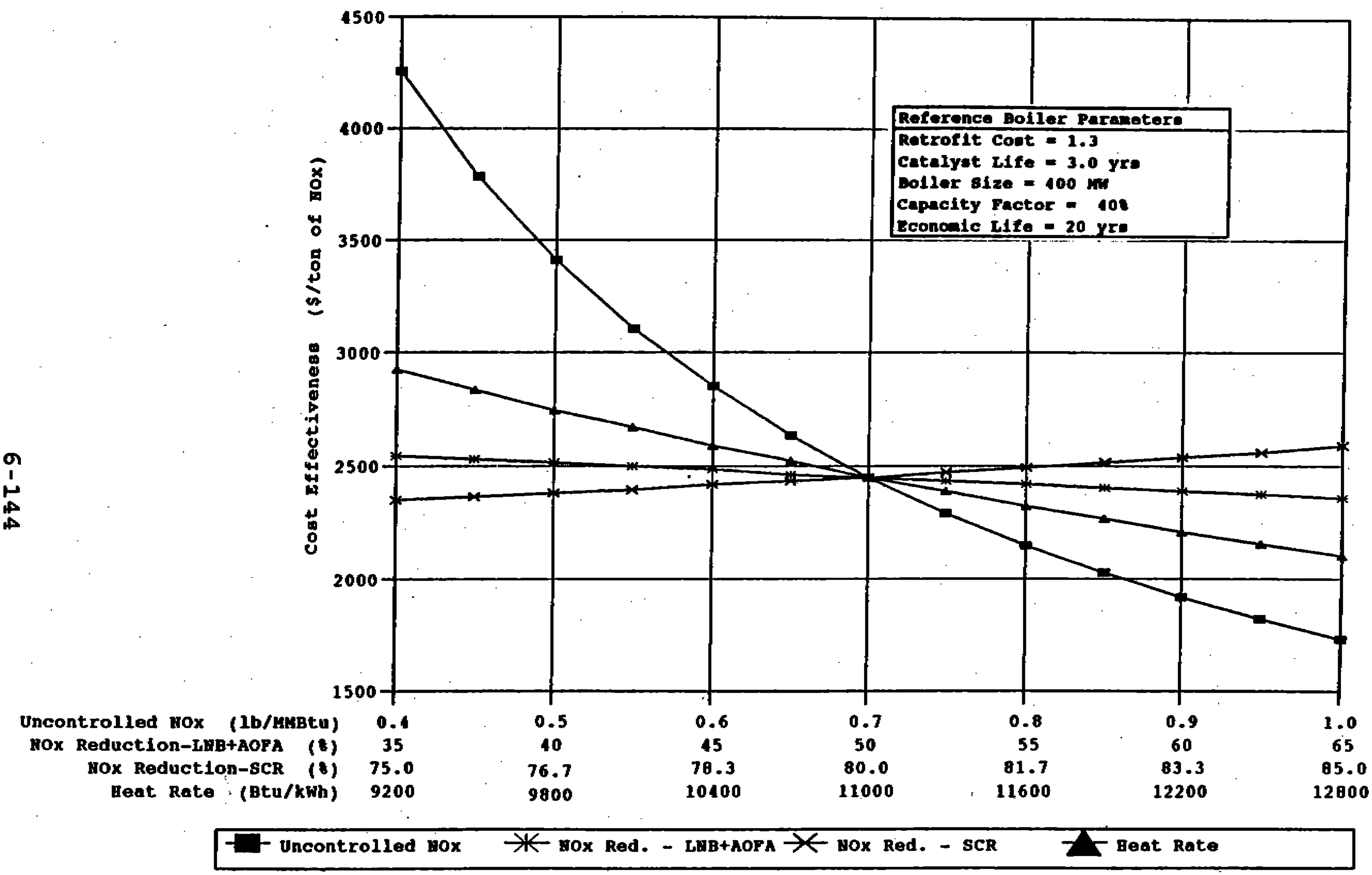

Figure 6-70. Impact of NO_x emission characteristics and heat rate on LNB + AOFA + SCR cost effectiveness for coal-fired tangential boilers.

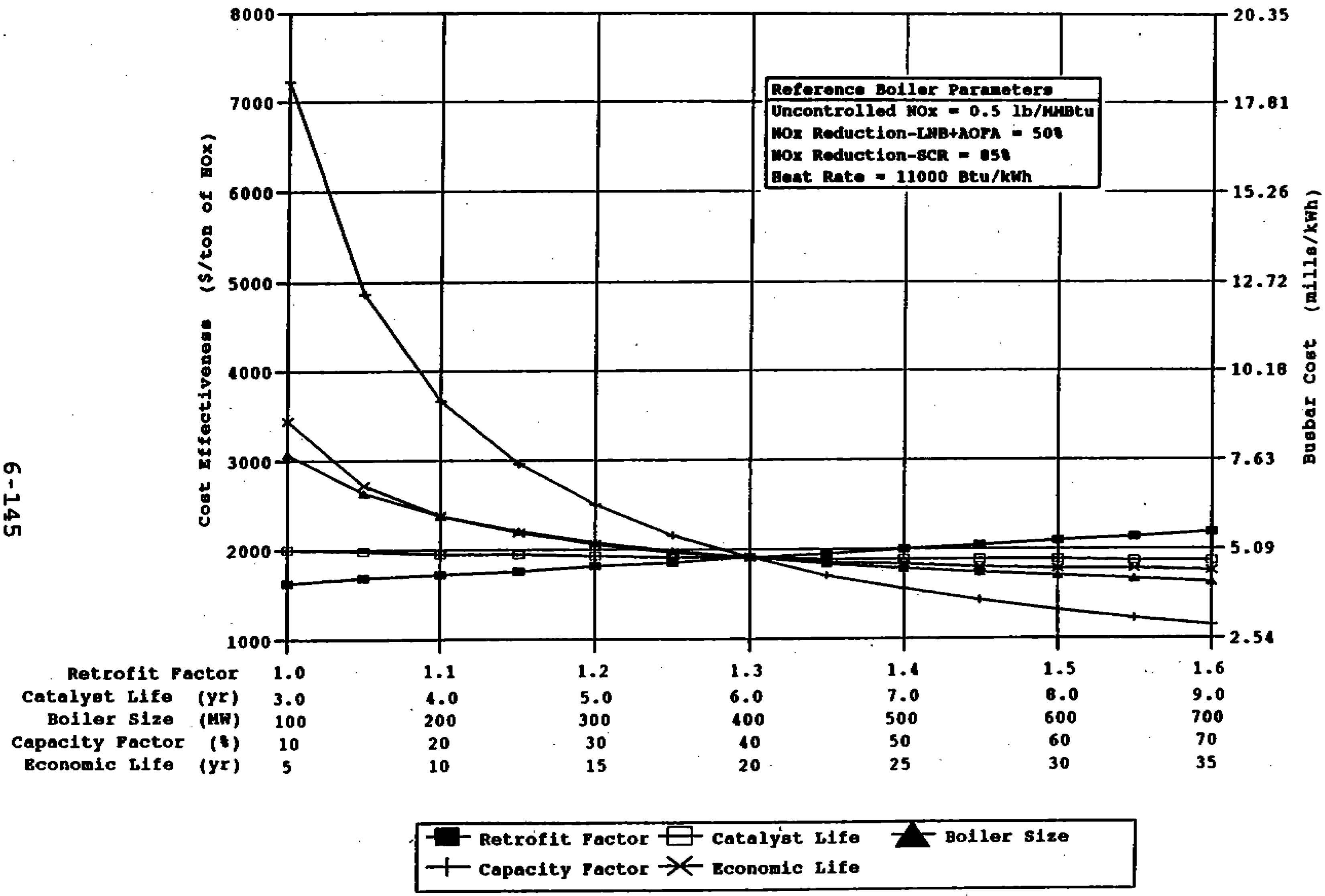

Figure 6-71. Impact of plant characteristics on LNB + AOFA + SCR cost effectiveness and busbar cost for natural gas-fired wall boilers.

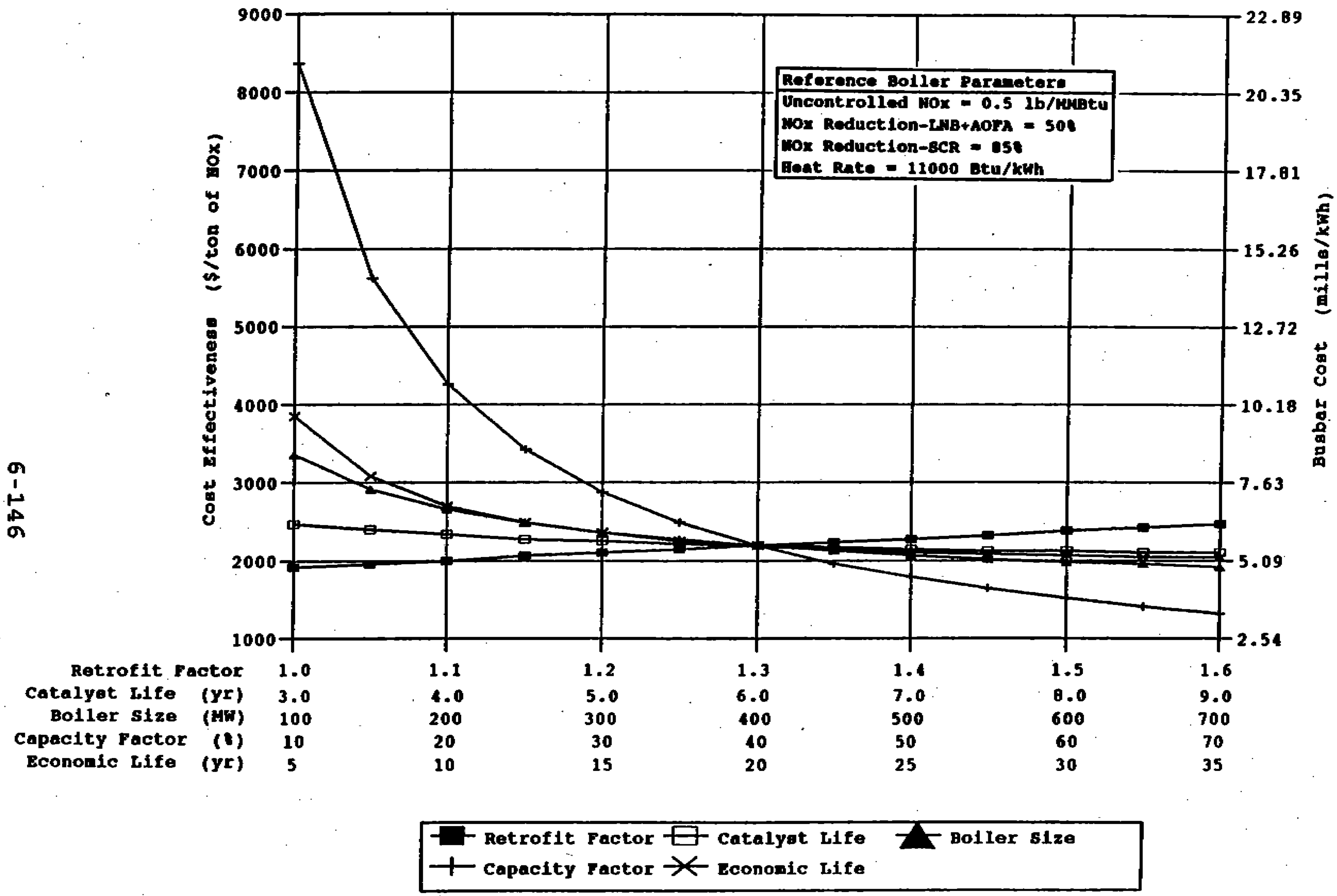

Figure 6-72. Impact of plant characteristics on LNB + AOFA + SCR cost effectiveness and busbar cost for oil-fired wall boilers.

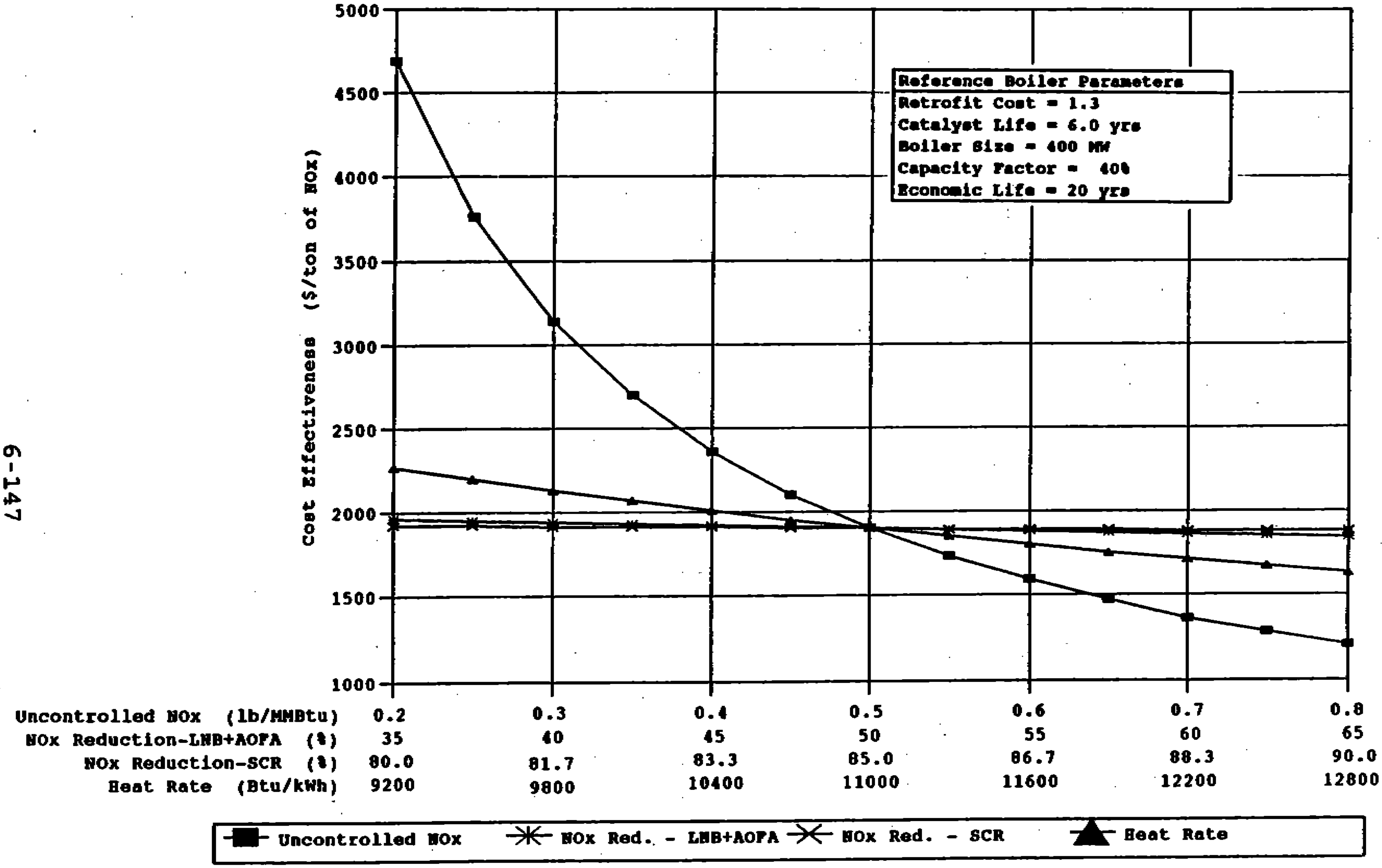

Figure 6-73. Impact of NO_x emission characteristics and heat rate on LNB + AOFA + SCR cost effectiveness for natural gas-fired wall boilers.

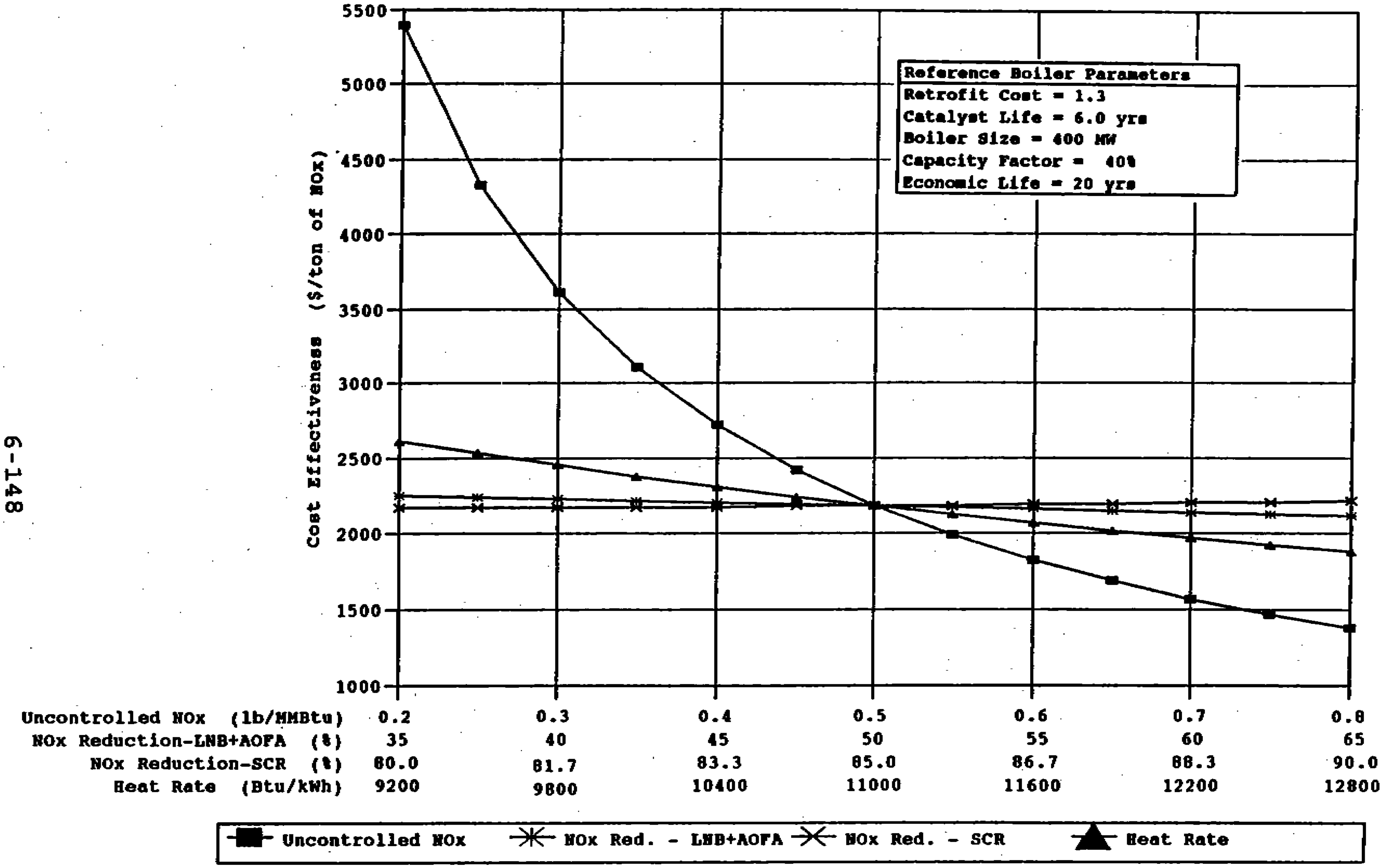

Figure 6-74. Impact of NO_x emission characteristics and heat rate on LNB + AOFA + SCR cost effectiveness for oil-fired wall boilers.

cost effectiveness values for LNB + AOFA + SCR applied to natural gas- and oil-fired wall boilers are slightly higher than on coal-fired wall boilers because of lower uncontrolled NO_x levels of natural gas- and oil-fired boilers, although the busbar cost is lower because of the smaller catalyst volumes and longer catalyst life associated with SCR applied to natural gas- and oil-fired boilers. The sensitivity curves follow the same general trends as with LNB + AOFA + SCR applied to coal-fired wall boilers.

The effect of plant characteristics (retrofit factor, boiler size, capacity factor, and economic life) and catalyst life on cost effectiveness and busbar cost for tangentially-fired boilers is shown in figures 6-75 and 6-76. Figures 6-77 and 6-78 present the sensitivity of cost effectiveness to NO_x emission characteristics (uncontrolled NO_x level and NO_x reduction efficiency for both LNB + AOFA and SCR) and heat rate. As shown in figures 6-76 and 6-78, the natural gas-fired reference boiler's cost effectiveness and busbar cost are approximately $2,600 per ton of NO_x removed and 3.9 mills/kWh and the oil-fired reference boilers cost effectiveness and busbar cost are approximately $3,000 per ton of NO_x removed and 4.6 mills/kWh. The cost effectiveness value and busbar costs for LNB + AOFA + SCR applied to natural gas-fired boilers are lower than for oil-fired boilers because of the smaller catalyst volumes on natural gas boilers. Similarly, cost effectiveness values for LNB + AOFA + SCR applied to natural gas- and oil-fired tangential boilers are slightly higher than on coal-fired wall boilers because of lower uncontrolled NO_x levels of natural gas- and oil-fired boilers, although the busbar cost is lower because of the smaller catalyst volumes and longer catalyst life associated with SCR applied to natural gas- and oil-fired boilers. The sensitivity curves follow the same general trends as with LNB + AOFA + SCR applied to coal-fired wall boilers. Tangentially-fired boilers are slightly higher than on wall-fired boilers because of lower uncontrolled NO_x levels of

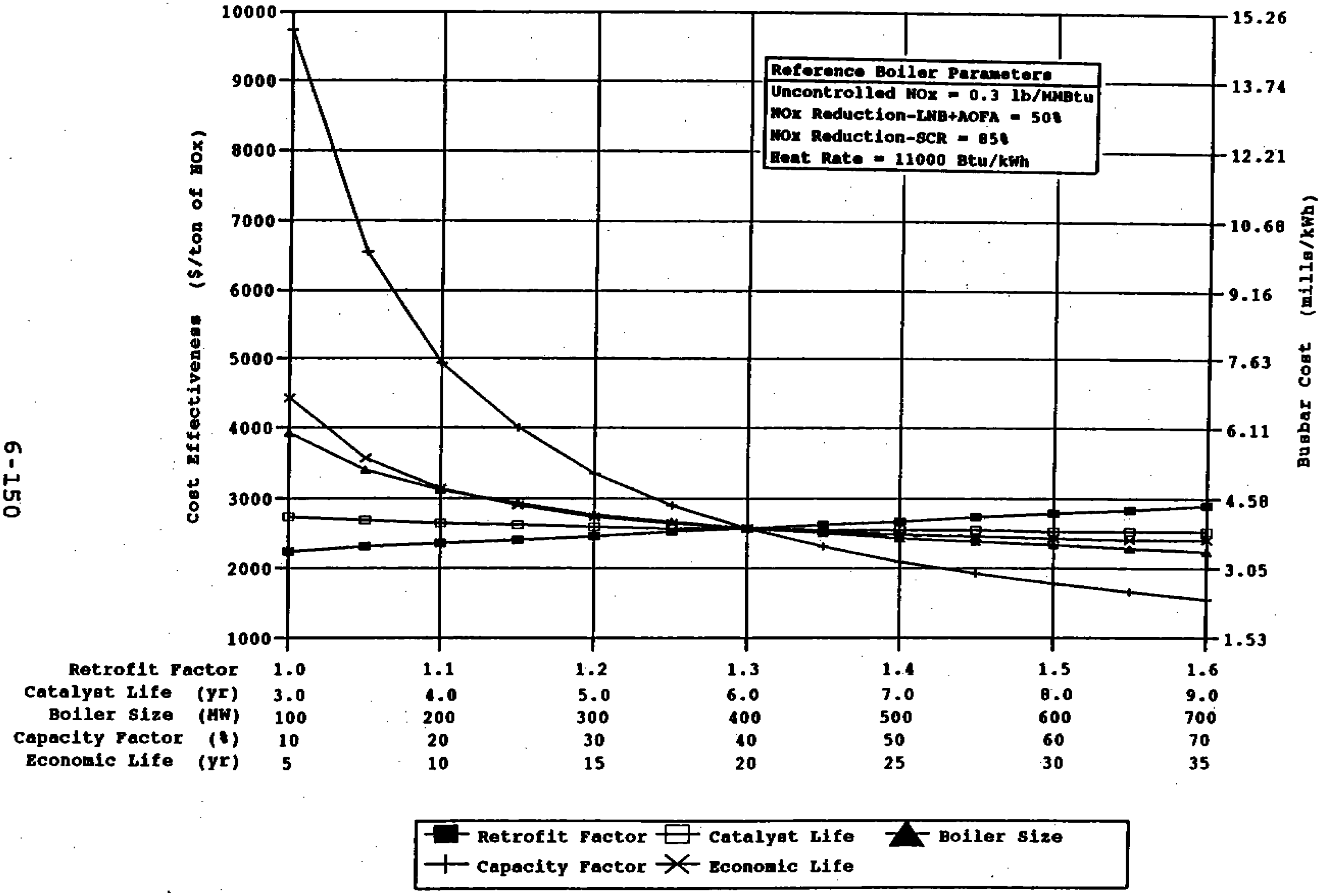

Figure 6-75. Impact of plant characteristics on LNB + AOFA + SCR cost effectiveness and busbar cost for natural gas-fired tangential boilers.

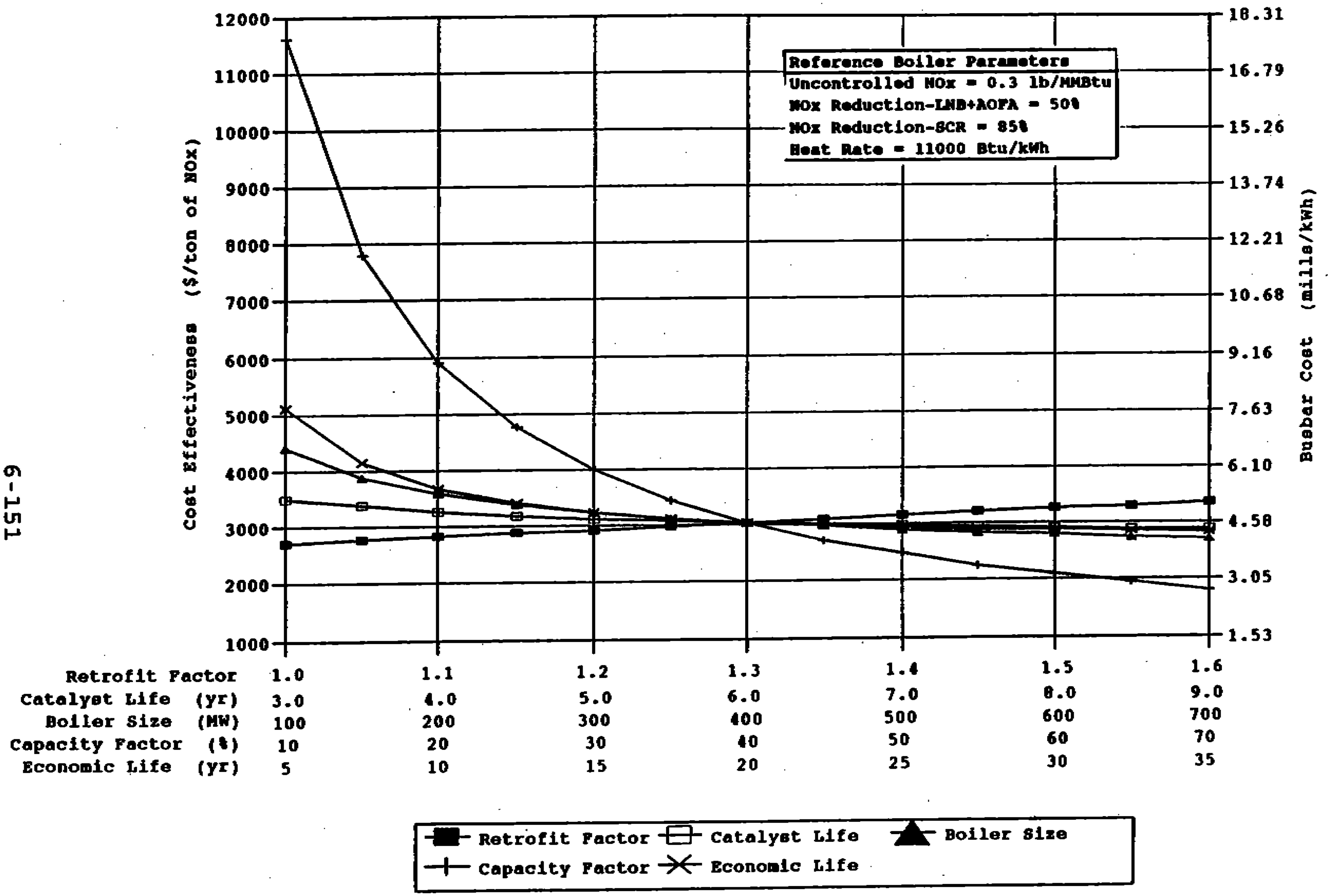

Figure 6-76. Impact of plant characteristics on LNB + AOFA + SCR cost effectiveness and busbar cost for oil-fired tangential boilers.

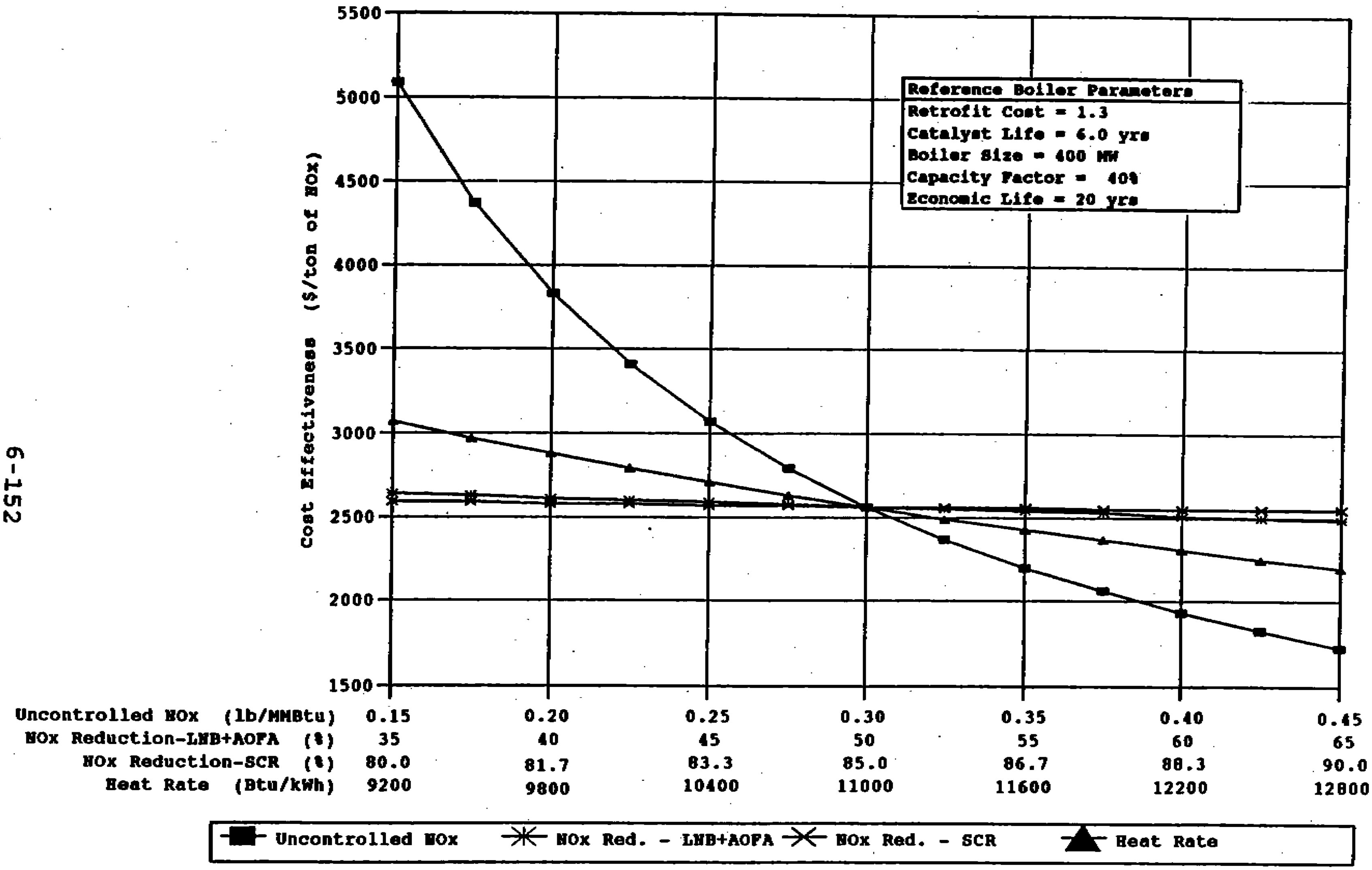

Figure 6-77. Impact of NO_x emission characteristics and heat rate on LNB + AOFA + SCR cost effectiveness for natural gas-fired tangential boilers.

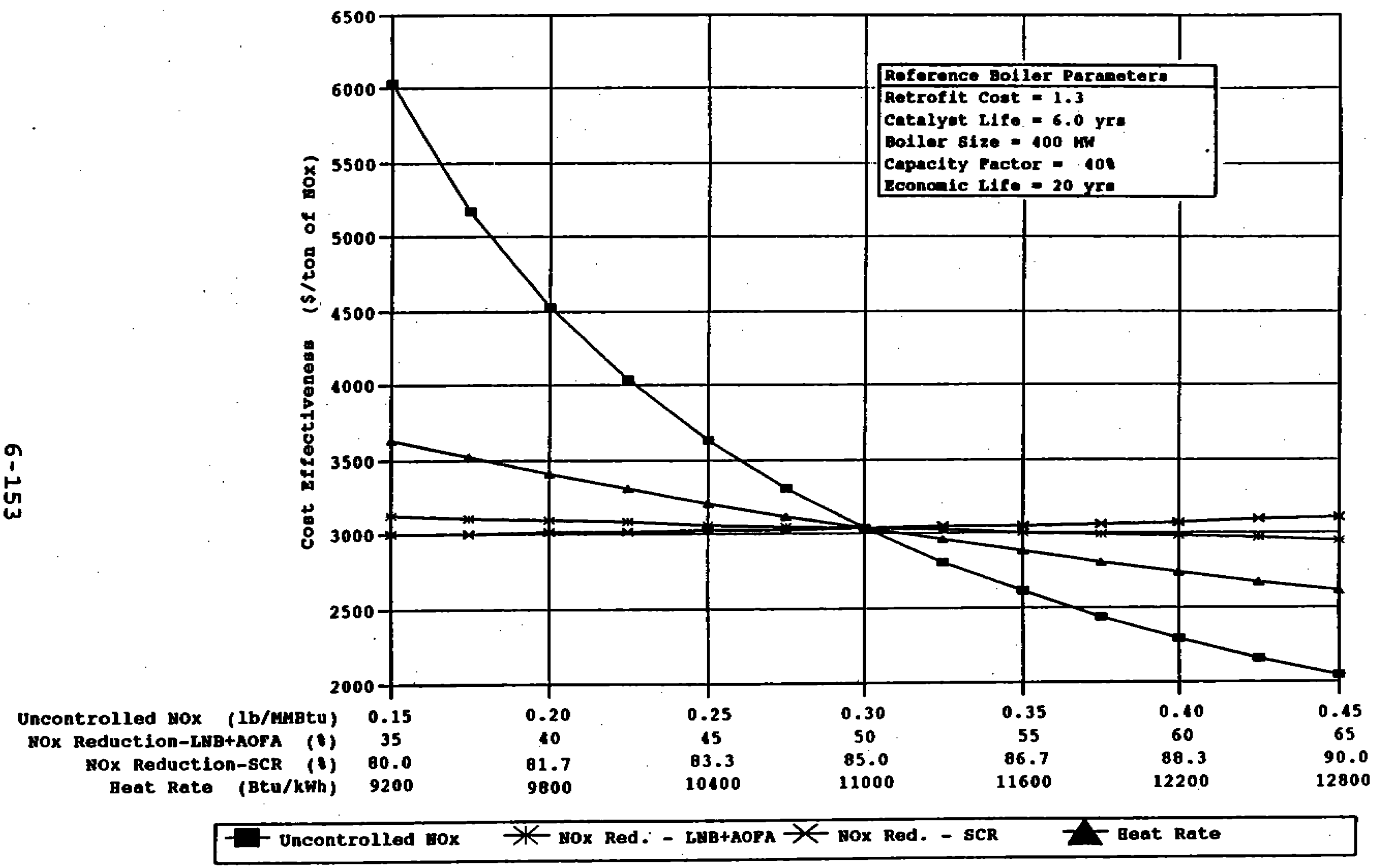

Figure 6-78. Impact of NO_x emission characteristics and heat rate on LNB + AOFA + SCR cost effectiveness for oil-fired tangential boilers.

tangentially-fired boilers, although the busbar cost is lower because of the higher capital and O&M costs associated with LNB + AOFA + SCR applied to wall-fired boilers. The sensitivity curves follow the same general trends as with LNB + AOFA + SCR applied to wall-fired boilers.

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7.0 ENVIRONMENTAL AND ENERGY IMPACTS OF NO_x CONTROLS

This chapter presents the reported effects of combustion modifications and flue gas treatment controls on boiler performance and secondary emissions from new and retrofit fossil fuel-fired utility boilers. Since most of these effects are not routinely measured by utilities, there are limited data available to correlate boiler performance and secondary emissions with nitrogen oxides (NO_x) emissions or NO_x reduction. These effects are combustion-related and depend upon unit-specific factors such as furnace type and design, fuel type, and operating practices and restraints. As a result, the data in this chapter should be viewed as general information on the potential effects of NO_x controls, rather than a prediction of effects for specific boiler types.

The effects of combustion controls on coal-fired boilers, both new and retrofit applications, are given in section 7.1. The effects of combustion controls on natural gas- and oil-fired boilers are presented in section 7.2. The effects of flue gas treatment controls on conventional and fluidized bed combustion (FBC) boilers are given in section 7.3.

7.1 EFFECTS FROM COMBUSTION CONTROLS ON COAL-FIRED UTILITY BOILERS

Combustion NO_x controls suppress both thermal and fuel NO_x formation by reducing the peak flame temperature and by delaying mixing of fuel with the combustion air. This can result in a decrease of boiler efficiency and must be considered during the design of a NO_x control system for any new or retrofit application.

In coal-fired boilers, an increase in unburned carbon (UBC) indicates incomplete combustion and results in a reduction of boiler efficiency. The UBC can also change the properties of the fly ash and may affect the performance of the electrostatic precipitator. Higher UBC levels may make the flyash unsalable, thus increasing ash disposal costs for plants that currently sell the flyash to cement producers.

Other combustion efficiency indicators are carbon monoxide (CO) and total hydrocarbon (THC) emissions. An increase in CO emissions also signals incomplete combustion and can reduce boiler efficiency. Emissions of THC from coal-fired boilers are usually low and are rarely measured.

7.1.1 Retrofit Applications

7.1.1.1 Carbon Monoxide Emissions. The results from combustion modifications on coal-fired boilers are presented in table 7-1. Carbon monoxide emissions are presented for burners-out-of-service (BOOS), advanced overfire air (AOFA), low NO_X burners (LNB), LNB + AOFA, and reburn. For several of these applications, the data show increased CO emissions with retrofit combustion controls. For other units, however, the CO levels after application of controls were equal to or less than the initial levels.

For the only reported BOOS application, the CO emissions increased from 357 parts per million (ppm) to 392-608 ppm. The corresponding NO_X reduction was 30 to 33 percent.

While there were four units mentioned in section 5.1.2.3 that have NO_X emission data from retrofit AOFA, only one unit (Hammond 4) had corresponding CO emissions data. This unit is an opposed-wall unit firing bituminous coal. Data are presented for different loads prior to and after the retrofit of an AOFA system. The CO levels prior to the retrofit of AOFA range from 20 to 100 ppm over the load range. With the AOFA system, the CO levels decreased to an average of 15 ppm across the load range. The NO_X reduction was 10 to 25 percent across the load range. These data indicate a large decrease in CO; however, the CO levels were not routinely monitored

TABLE 7-1. SUMMARY OF CARBON MONOXIDE EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Carbon monoxide (ppm) Uncontrolled	Carbon monoxide (ppm) Control	NO_x reduction (%)	Reference
OPERATIONAL MODIFICATIONS, BITUMINOUS COAL									
Gulf Power Co.	Crist 7 (Pre)	Wall	500	BOOS	85	357	392-608	30-33	1
OVERFIRE AIR, BITUMINOUS COAL									
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	AOFA (FW)	100 80 60	100 30 20	15 15 15	25 -- 10	2,3
LOW NO_x BURNERS, BITUMINOUS COAL									
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	190	LNCFS I (ABB-CE)	95 71 60	12 15 15	15 10 20	42 39 34	4,5
Ohio Edison Co.	Edgewater 4 (Pre)	Wall	105	XCL + SI (B&W)	100 78 63	16 16 16	100 130 170	39 43 42	6
Tennessee Valley Authority	Johnsonville 8 (Pre)	Wall	125	IFS (FW)	100	50	--	55	7,8
Board of Public Utilities	Quindaro 2 (Pre)	Wall	137	RO-II (ABB-CE)	90 70 55	-- -- --	50 50 95	-- -- --	9
Alabama Power Co.	Gaston 2 (Pre)	Wall	272	XCL (B&W)	100 68 50	60 -- --	60 50 --	50 46 43	10,11
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	CF/SF (FW)	100 80 60	100 30 20	8 8 8	45 -- 50	2,3,12
Dayton Power & Light Co.	JM Stuart 4 (Pre)	Cell	610	LNCB (B&W)	100 75 56	26 17 20	35 28 10	55 54 47	13

TABLE 7-1. SUMMARY OF CARBON MONOXIDE EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS (CONTINUED)

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Carbon monoxide (ppm)		NO_x reduction (%)	Reference
						Uncontrolled	Control		
LOW NO_x BURNERS, SUBBITUMINOUS COAL									
Board of Public Utilities	Quindaro 2 (Pre)	Wall	137	RO-II (ABB-CE)	80 70 55	-- -- --	70 70 50	-- -- --	9
Arizona Public Service Co.	Four Corners 4 (Pre)	Wall	818	CF/SF (FW)	105 69 49	53 35 30	86 33 41	57 29 6	14
Arizona Public Service. Co.	Four Corners 5 (Pre)	Wall	818	CF/SF (FW)	93	--	<50	50	14
LOW NO_x BURNERS + OVERFIRE AIR, BITUMINOUS COAL									
Public Service Co. of CO	Valmont 5 (Pre)	Tan	165	LNCFS II (ABB-CE)	91 75 50	<30 -- --	<30 -- --	52 26 27	15
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	190	LNCFS II (ABB-CE)	95 71 60	12 15 15	28 22 20	39 35 30	4,5,10
Public Service Co. of CO	Cherokee 4 (Pre)	Tan	350	LNCFS II (ABB-CE)	100 71 45	<30 -- --	<30 -- --	46 31 35	16
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	190	LNCFS III (ABB-CE)	95 71 60	12 15 15	45 25 22	48 47 39	4,5,10
Ohio Edison Co.	Sammis 6 (Pre)	Wall	630	DRB-XCL (B&W)	100 55	17.4-25.8 31.8	225-670 55		17
Public Service Co. of CO	Arapahoe 4 (Pre)	Roof	100	DRB-XCL + OFA (B&W)	100 80 60	48 42 39	38 21 12	66 71 63	18

TABLE 7-1. SUMMARY OF CARBON MONOXIDE EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS (CONCLUDED)

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Carbon monoxide (ppm)		NO_x reduction (%)	Reference
						Uncontrolled	Control		
REBURN, BITUMINOUS COAL									
Illinois Power Co.	Hennepin 1 (Pre)	Tan	75	NGR (EERC)	100	2	2	63	19,20
Wisconsin Power and Light Co.	Nelson Dewey 2 (Pre)	Cyc	114	Coal Reburn (B&W)	100 75 50	60-70 40-70 80-94	90-110 80-100 80-100	53 50 36	21
Ohio Edison Co.	Niles 1 (Pre)	Cyc	125	NGR (EERC)	100 85 79 75	25-50 -- -- --	312 214 50 103	47 43 34 36	22

[a]Standard: Pre = Pre-NSPS

[b]Unit Type: Cell = Cell Burner; Cyc = Cyclone; Roof = Roof-fired; Tan = Tangentially-fired; and Wall = Wall-fired.

[c]Control Type: AOFA = Advanced Overfire Air; BOOS = Burners-out-of-service; CF/SF = Controlled Flow/Split Flame LNB; DRB-XCL = Dual Register Axial Control LNB; IFS = Internal Fuel Staged LNB; LNCB = Low NO_x Cell Burner; LNCFS, I, II, II = Low NO_x Concentric Firing System, Level I, II, III; NGR = Natural Gas Reburn; OFA = Overfire Air; RO-II = RO-II LNB; SI = Sorbent Injection for Sulfur Dioxide Control; and XCL = Axial Controlled LNB.

[d]Vendors: ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock & Wilcox; EERC = Energy and Environmental Research Corporation; and FW = Foster Wheeler.

-- = data not available.

prior to the retrofit and the decrease may be attributable to plant operating personnel taking action to reduce CO emissions after the retrofit.[2]

For the one tangential boiler with retrofit LNB (Lansing Smith 2), the uncontrolled CO emissions were 12 to 15 ppm while the CO emissions were 10 to 20 ppm with the Low NO_X Concentric Firing System (LNCFS) Level I which incorporates close-coupled OFA (CCOFA). The corresponding NO_X reduction was 34 to 42 percent across the load range.

For all but two of the wall-fired boilers firing bituminous coal with LNB, the reported uncontrolled CO emissions were 100 ppm or less and the controlled CO emissions were 60 ppm or less. However, for Edgewater 4, the CO increased from 16 ppm up to 100 to 170 ppm following retrofit of LNB. At reduced load, Quindaro 2 reported a CO level of 95 ppm with LNB. The CO level without LNB was not reported. The largest decrease in CO emissions was at the Hammond 4 unit. However, as previously discussed, the CO level was not routinely measured prior to the retrofit and the decrease may be attributable to plant operating personnel taking action to reduce the CO emissions after the retrofit. For the one cell-fired unit, J.M. Stuart 4, the CO emissions with LNB were slightly higher than uncontrolled levels at full-load and intermediate load. The CO emissions were less with LNB at low load. The corresponding NO_X reductions ranged from 47 to 55 percent.

The Four Corners 4 unit, which converted from cell firing to an opposed-wall circular firing configuration, showed a small increase in CO emissions with LNB when firing subbituminous coal. The corresponding NO_X reduction for Four Corners 4 ranged from 6 to 57 percent across the load range. Quindaro 2 was also tested on subbituminous coal and the CO ranged from 50-70 ppm across the load range.

There are four applications of LNB and AOFA on tangential boilers shown in table 7-1. The LNB represented are the LNCFS Levels II and III which incorporates separated OFA (SOFA) and a combination of SOFA and CCOFA, respectively. Three of these units (Valmont 5, Lansing Smith 2, and Cherokee 4) have the LNCFS II technology. For these units, the CO emissions for both uncontrolled and controlled conditions were less than 30 ppm. For the one unit employing LNCFS III technology (Lansing Smith 2), the CO emissions increased from uncontrolled levels of 12 to 15 ppm up to controlled levels of 22 to 45 ppm.

One wall-fired boiler, Sammis 6, was originally a cell-fired boiler and was retrofitted with LNB + OFA. At full-load, the CO increased to more than 225 ppm from baseline levels of 17-25 ppm. At reduced load, the CO also increased almost two-fold to 55 ppm. The reason for the large in CO at full-load was not reported. The NO_x reduction was approximately 65 percent. The one roof-fired boiler, Arapahoe 4, reported decreases in CO and ranged from 12-38 ppm with LNB + OFA. The NO_x reduction ranged from 63-71 percent across the load range.

For the tangentially-fired unit (Hennepin 1) with retrofit reburn, the CO emissions for both uncontrolled and controlled conditions were 2 ppm. Carbon monoxide data from two cyclone units with reburn are also given in table 7-1. One unit (Nelson Dewey 2), uses pulverized coal as the reburn fuel while the other unit (Niles 1), uses natural gas as the reburn fuel. The CO emissions for the cyclone boilers increased with the reburn system. For Nelson Dewey 2, the CO emissions were 60 to 94 ppm without reburn and 80 to 110 ppm with reburn. The corresponding NO_x reduction was 36 to 53 percent across the load range. For Niles 1, the CO emissions increased greatly from 25 to 50 to 312 ppm at full load. At lower loads, the CO emissions were still at elevated levels of 50 to 214 ppm. The corresponding NO_x reduction was 36 to 47 percent.

To summarize, the CO emissions may increase with retrofit combustion modifications. However, as shown in table 7-1, with few exceptions, the CO emissions were usually less than 100 ppm with retrofit combustion controls.

7.1.1.2 <u>Unburned Carbon Emissions and Boiler Efficiency</u>. Table 7-2 presents UBC and boiler efficiency data from 18 applications of retrofit combustion NO_x controls on coal-fired boilers. For Hammond 4, the AOFA resulted in an increase of UBC two or three times the uncontrolled level. Uncontrolled levels of UBC at Hammond 4 ranged from 2.3 percent at low load to 5.2 percent at full load. With the AOFA, the UBC levels increased to 7.1 percent at low load and 9.6 percent at full load. The boiler efficiency at low load decreased by 0.7 percentage points and by 0.4 percentage points at full load. The corresponding NO_x reduction with AOFA was 10 percent at low load and 25 percent at full load.

For the tangential unit with LNCFS I technology, Lansing Smith 2, the UBC levels range from 4.0 to 5.0 percent without LNB and 4.0 to 5.3 percent with LNB. The boiler efficiency with LNB decreased slightly to 89.6 percent.

The UBC from all of the wall-fired boilers increased with the retrofit of LNB and LNB with OFA. For Edgewater 4, the uncontrolled UBC levels increased from 2.7 to 3.2 percent to 6.6 to 9.0 percent with the LNB. The corresponding NO_x reduction was 39 to 43 percent across the load range. The boiler efficiency decreased by 1.3 percentages points at full load with the LNB.

For Gaston 2, the UBC increased from 5.3 to 6.3 percent at low load and 7.4 to 10.3 percent at full load. The corresponding NO_x reduction at Gaston 2 ranged from 43 to 50 percent across the load range. Boiler efficiency data were not available for this unit. For Hammond 4, the UBC increased from 2.3 to 5.8 percent at low load and 5.2 to 8.0 percent at full load with LNB. Increased UBC levels such as these could limit the sale of fly ash to cement producers that typically require UBC levels of 5 percent or less. The corresponding

TABLE 7-2. SUMMARY OF UNBURNED CARBON AND BOILER EFFICIENCY DATA FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Unburned carbon (%)		Boiler efficiency (%)		NO_x reduction (%)	Reference
						Uncon-trolled	Control	Uncon-trolled	Control		
OVERFIRE AIR, BITUMINOUS COAL											
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	AOFA (FW)	100 80 60	5.2 4.8 2.3	9.6 10.2 7.1	89.5 -- 90.0	89.1 -- 89.3	25 -- 10	2,3,12
LOW NO_x BURNERS, BITUMINOUS COAL											
Ohio Edison Co.	Edgewater 4 (Pre)	Wall	105	XCL + SI (B&W)	100 78 63	2.7 2.7 3.2	6.6 7.6 9.0	88.6 --	87.3 --	39 43 42	6
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	200	LNCFS I (ABB-CE)	95 71 60	5.0 4.2 4.0	4.6 5.3 4.0	89.7 90.7 90.9	89.6 -- --	42 39 34	4,5,10
Alabama Power Co.	Gaston 2 (Pre)	Wall	272	XCL (B&W)	100 68 50	7.4 5.7 5.3	10.3 8.3 6.3	-- -- --	-- -- --	50 46 43	10,11
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	CF/SF (FW)	100 80 60	5.2 4.8 2.3	8.0 5.0 5.8	89.5 -- 90.0	88.1 -- 88.8	45 -- 50	2,3,12
Dayton Power & Light Co.	JM Stuart 4 (Pre)	Cell	610	LNCB (B&W)	100 75 56	1.7 1.6 1.1	1.6 1.0 --	89.6 89.7 90.2	90.0 90.0 90.1	55 54 47	13
Monogahela Power Co.	Pleasants 2 (Da)	Wall	626	CF/SF (FW)	100 83	(2.5) --	4.5 3.8	-- --	-- --	53 --	22,23
LOW NO_x BURNERS, SUBBITUMINOUS COAL											
Arizona Public Service Co.	Four Corners 4 (Pre)	Wall	818	CF/SF (FW)	105 69 49	0.04 0.04 0.03	0.1 0.1 0.1	-- -- --	86.6 87.7 87.6	57 29 6	14

TABLE 7-2. SUMMARY OF UNBURNED CARBON AND BOILER EFFICIENCY DATA FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS (CONTINUED)

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Unburned carbon (%)		Boiler efficiency (%)		NO_x reduction (%)	Reference
						Uncon-trolled	Control	Uncon-trolled	Control		
LOW NO_x BURNERS, SUBBITUMINOUS COAL (CONTINUED)											
Arizona Public Service Co.	Four Corners 5 (Pre)	Wall	818	CF/SF (FW)	93	--	0.1	--	88.0	50	14
LOW NO_x BURNERS AND OVERFIRE AIR, BITUMINOUS COAL											
Public Service Co. of CO	Valmont 5 (Pre)	Tan	165	LNCFS II (ABB-CE)	91 75 50	1.9 1.6 0.4	1.4 1.0 1.0	86.6 -- --	86.4 -- --	52 26 27	15
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	200	LNCFS II (ABB-CE)	95 71 60	5.0 4.2 4.0	4.4 3.9 3.9	89.7 90.7 90.9	89.1 89.6 90.0	39 35 30	4,5,10
Public Service Co. of CO	Cherokee 4 (Pre)	Tan	350	LNCFS II (ABB-CE)	100 71 45	2.2 1.1 0.3	2.5 1.7 0.6	-- -- --	-- -- --	46 31 35	16
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	200	LNCFS III (ABB-CE	95 71 60	5.0 4.2 4.0	6.0 5.9 6.8	89.7 90.7 90.9	89.4 90.1 90.3	48 47 39	4,5,10
Ohio Edison Co.	Sammis 6 (Pre)	Wall	630	DRB-SCL + OFA (B&W)	100 55	1.6- 2.6 3.7	8.0- 9.7 4.6	-- --	-- --	60-70 37	17
LOW NO_x BURNERS AND OVERFIRE AIR, SUBBITUMINOUS COAL											
Kansas Power and Light Co.	Lawrence 5 (Pre)	Tan	448	PM + OFA (CE-MHI)	100	0.4	0.3	--	--	49	25
REBURN, BITUMINOUS COAL											
Illinois Power Co.	Hennepin 1 (Pre)	Tan	75	NGR (EERC)	100	2.5	1.5	88.3	86.7	63	19,20

TABLE 7-2. SUMMARY OF UNBURNED CARBON AND BOILER EFFICIENCY DATA FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS (CONCLUDED)

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Unburned carbon (%)		Boiler efficiency (%)		NO_x reduction (%)	Reference
						Uncon-trolled	Control	Uncon-trolled	Control		
REBURN, BITUMINOUS COAL (CONTINUED)											
Wisconsin Power and Light Co.	Nelson Dewey 2 (Pre)	Cyc	114	Coal (B&W)	100 75 50	4-16 3-13 11-23	15-21 13-24 21-28	88.2 88.6 88.5	88.1 88.3 87.0	53 50 36	21
Ohio Edison Co.	Niles 1 (Pre)	Cyc	125	NGR (EERC)	100	--	--	90.7	90.1	47	22

[a]Standard: Da = Subpart Da; and Pre = Pre-NSPS

[b]Unit Type: Cell = Cell Burner; Cyc = Cyclone; Tan = Tangential; and Wall = Wall-fired;

[c]Control Type: CF/SF = Controlled Flow/Split Flame Low NO_x Burner; IFS = Internal Fuel Staged Low NO_x Burner; LNCB = Low NO_x Cell Burner; LNCFS, I, II, II = Low NO_x Concentric Firing System, Level I, II, III; NGR = Natural Gas Reburn; OFA = Overfire Air; PM = Pollution Minimum Burner; SI = Sorbent Injection for Sulfur Dioxide Control; and XCL = Axial Controlled Low NO_x Burner.

[d]Vendors: ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock & Wilcox; CE-MHI = Combustion Engineering-Mitsubishi Heavy Industries; EERC = Energy and Environmental Research Corporation; and FW = Foster Wheeler.

-- = data not available.

NO_x reductions were 50 and 45 percent, respectively. The boiler efficiency at Hammond 4 decreased from 89.5 to 88.1 percent at full load and from 90 to 88.8 percent at low load.

At Pleasants 2, the UBC increased from approximately 2.5 to 4.5 percent with a NO_x reduction of 53 percent. Boiler efficiency data were not available. The UBC level at Four Corners 4 increased from 0.04 to 0.1 percent due to the LNB across the load range. The NO_x reduction achieved at this plant ranged from 6 percent at low load to 57 percent at full load.

The effects on UBC for the tangential units with LNB and OFA were relatively small. For Valmont 5 with LNCFS II technology, the UBC at full load decreased from 1.9 to 1.4 percent. At low load, the UBC increased slightly from 0.4 to 1.0 percent. The corresponding NO_x reduction was 27 to 52 percent across the load range. The boiler efficiency at high load decreased from 86.6 to 86.4 percent. For Cherokee 4, the UBC increased from 2.2 to 2.5 percent at full load and 0.3 to 0.6 percent at low loads. The NO_x reduction across the load range was 35 to 46 percent.

Lansing Smith 2 reported data for both a LNCFS II and a LNCFS III retrofit. The UBC level decreased with the LNCFS II and increased with the LNCFS III; however, the increase in UBC with LNCFS III cannot be solely attributed to the LNB retrofit, but rather may have been caused by different mill performance levels during the testing.[4,5,10] With LNCFS II, the UBC decreased at full-load from 5.0 to 4.4 percent. At low load, the UBC decreased from 4.0 to 3.9 percent. The corresponding NO_x reduction was 30 to 39 percent across the load range. The boiler efficiency decreased by 0.6 to 0.9 percentage points with the LNCFS II technology. With LNCFS III technology, the UBC increased from 5.0 to 6.0 percent at full-load and from 4.0 to 6.8 percent at low load. The NO_x reduction across the load range was 39 to

48 percent. The boiler efficiency decreased by 0.3 to 0.6 percentage points. For the remaining tangential boiler, Lawrence 5, the UBC decreased from 0.4 to 0.3 percent at full-load with LNB and OFA. The NO_x reduction was 49 percent.

For Sammis 6, originally a cell-fired boiler, the UBC increased from uncontrolled levels of 1.6-2.6 percent to 8-9.7 percent at full-load with LNB + OFA. At reduced load, the UBC increased only slightly.

There are UBC data for two of the three boilers with reburn as a retrofit NO_x control technique. For the tangential boiler with natural gas reburn, Hennepin 1, the UBC decreased from 2.5 to 1.5 percent at full-load with a NO_x reduction of 63 percent. The boiler efficiency decreased from 88.3 to 86.7 percent, primarily due to the increased flue gas moisture content resulting from the higher hydrogen content of the natural gas as compared to coal.[19,20]

For Nelson Dewey 2, the UBC increased at all load ranges with the pulverized coal reburn system. At full load, the UBC ranged from 4 to 16 percent without reburn and 15 to 21 percent with reburn. At low load, the UBC ranged from 11 to 23 percent without reburn and 21 to 28 percent with the reburn system. The NO_x reduction across the load range was 36 to 53 percent. The boiler efficiency at full-load was relatively unchanged; however, at low load the boiler efficiency decreased from 88.5 to 87.0 percent. Niles 1 did not report UBC levels, but did report a decrease in boiler efficiency at full-load from 90.7 to 90.1 percent with reburn.

7.1.1.3 <u>Summary of Particulate Matter and Total Hydrocarbon Emissions</u>. Table 7-3 summarizes the PM and THC emissions from seven applications of combustion NO_x controls on coal-fired boilers. The PM emissions at Hammond 4 increased from 1.58 gr/scf prior to retrofit, to 1.68 gr/scf with AOFA and 1.96 gr/scf with LNB. The corresponding NO_x reduction with AOFA was 25 percent and was 45 percent with LNB. The THC emissions for Hammond 4 were not reported.

TABLE 7-3. SUMMARY OF TOTAL HYDROCARBON AND PARTICULATE MATTER DATA FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested (%)	Total hydrocarbon (ppm) Uncontrolled	Total hydrocarbon (ppm) Control	Particulate matter (gr/scf) Uncontrolled	Particulate matter (gr/scf) Control	NO_x reduction (%)	Reference
OVERFIRE AIR, BITUMINOUS COAL											
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	AOFA (FW)	100	--	--	1.58	1.68	25	2,3,12
LOW NO_x BURNERS, BITUMINOUS COAL											
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	CF/SF (FW)	100	--	--	1.58	1.96	44	2,3,12
Dayton Power & Light Co.	JM Stuart 4 (Pre)	Cell	610	LNCB (B&W)	100 75 56	2 1 --	1 -- --	0.067 0.04 --	0.031 0.023 --	55 54 47	13
LOW NO_x BURNERS + OVERFIRE AIR											
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	200	LNCFS II (ABB-CE)	91	--	<10	--	--	45	4,5,10
LOW NO_x BURNERS + OVERFIRE AIR, SUBBITUMINOUS COAL											
Kansas Power and Light Co.	Lawrence 5 (Pre)	Tan	448	PM + OFA (CE-MHI)	100	--	--	4.0	2.7	49	25
REBURN, BITUMINOUS COAL											
Illinois Power Co.	Hennepin 1 (Pre)	Tan	75	NGR (EERC)	100	0.8	--	0.032	--	63	19,20
Wisconsin Power and Light	Nelson Dewey 2 (Pre)	Cyc	100	Coal Reburn (B&W)	100 75 50	-- -- --	-- -- --	0.017 0.014 0.017	0.015 0.014 0.01	53 50 36	21

[a]Standard: Pre = Pre-NSPS
[b]Unit Type: Cell = Cell Burner, Cyc = Cyclone, Tan = Tangential, Wall = Wall-fired
[c]Control Type: AOFA = Advanced Overfire Air, CF/SF = Controlled Flow/Split Flame Low NO_x Burner, LNCB = Low NO_x Cell Burner, LNCFS II = Low NO_x Concentric Firing System, Level II, NGR = Natural Gas Reburn, OFA = Overfire Air, PM = Pollution Minimum Burner,
[d]Vendors: ABB-CE = Asea Brown Boveri-Combustion Engineering, B&W = Babcock & Wilcox, CE-MHI = Combustion Engineering-Mitsubishi Heavy Industries, EERC = Energy and Environmental Research Corporation, FW = Foster Wheeler
-- = data not available.

For J.M. Stuart 4, the THC emissions at full load were 2 ppm without LNB and 1 ppm with LNB. The PM emissions decreased from 0.067 to 0.031 gr/scf with LNB at full-load and decreased from 0.04 to 0.023 gr/scf at 75 percent load. The corresponding NO_x reduction was 54 to 55 percent. Lansing Smith 2 reported THC emissions of less than 10 ppm with the LNCFS II technology.

There are no THC data reported for reburn technology; however, the PM emissions for Nelson Dewey 2 decreased from 0.017 to 0.015 gr/scf at high load and from 0.017 to 0.01 gr/scf at low load. The corresponding NO_x reduction was 36 to 53 percent across the load range.

7.1.2 New Applications

Table 7-4 presents a summary of CO, UBC, and PM emissions from nine new units subject to the subpart Da standards. These boilers have either LNB or LNB and OFA as original equipment. The CO emissions for one wall-fired boiler with LNB were reported to be less than 50 ppm. Three applications of LNB and OFA on tangential boilers had CO emissions of 39 to 59 ppm.

The UBC for new units with LNB was in the range of 1.1 to 6.1 percent on boilers firing bituminous coal which is similar to the UBC from retrofit applications. The UBC was in the range of approximately 0.01 to 1 percent for boilers with LNB and OFA firing either subbituminous or lignite coal.

The PM emissions from the new boilers with LNB were less than 0.02 lb/MMBtu. The low PM emissions are expected since these units are subject to the subpart Da standards and would be equipped with high efficiency particulate control devices. The corresponding NO_x emissions from the boilers with LNB range from 0.33 to 0.52 lb/MMBtu with LNB and 0.35 to 0.48 lb/MMBtu with LNB and OFA at full load.

TABLE 7-4. SUMMARY OF CARBON MONOXIDE, UNBURNED CARBON, AND PARTICULATE MATTER DATA FROM NEW COAL-FIRED UNITS WITH COMBUSTION NO_x CONTROLS

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested (%)	Carbon monoxide (ppm)	Unburned carbon (%)	Particulate matter (lb/MMBtu)	NO_x emissions (lb/MMBtu)	Reference
LOW NO_x BURNERS, BITUMINOUS COAL										
Baltimore Gas & Electric	Brandon Shores 1 (Da)	Wall	260	D-R (B&W)	100	--	6.1	0.022	0.50	26
Baltimore Gas & Electric	Brandon Shores 2 (Da)	Wall	260	D-R (B&W)	100	--	4.7	0.031	0.52	26
Utah Power & Light	Hunter 3 (Da)	Wall	430	D-R (B&W)	100	--	2-5	0.009	0.39	27
Cincinnati Gas & Electric	Zimmer 1 (Da)	Wall	1300	D-R (B&W)	100	--	2	0.005	0.4	28
Los Angeles Dept. of Water & Power	Intermountain 2 (Da)	Wall	900	D-R (B&W)	94	<50	1.1	0.005	0.33	29
LOW NO_x BURNERS + OVERFIRE AIR, SUBBITUMINOUS COAL										
Muscatine Power & Water	Muscatine 9 (Da)	Tan	161	LNB + OFA (ABB-CE)	100 70 40	-- -- --	1.07 0.22 0.37	-- -- --	0.38 0.44 0.66	30
Houston Lighting & Power	W.A. Parrish 8 (Da)	Tan	615	LNB + OFA (ABB-CE)	98	59	<0.01	--	0.35	31
LOW NO_x BURNERS + OVERFIRE AIR, LIGNITE COAL										
Houston Lighting & Power	Limestone 1 (Da)	Tan	810	LNB + OFA (ABB-CE)	100	39	0.01	--	0.48	32
Houston Lighting & Power	Limestone 2 (Da)	Tan	810	LNB + OFA (ABB-CE)	97	53	<0.01	--	0.46	33

[a]Standard: Subpart Da
[b]Unit Type: Tan = Tangential-fired, Wall = Wall-fired
[c]Control Type: D-R = Dual Register Low NO_x Burner, LNB + OFA = Low NO_x burner and Overfire Air
[d]Vendor: ABB-CE = Asea Brown Boveri - Combustion Engineering, B&W = Babcock and Wilcox
-- = data not available.

7.2 EFFECTS FROM COMBUSTION CONTROLS ON NATURAL GAS- AND OIL-FIRED BOILERS

Carbon monoxide emissions from three natural gas-fired boilers with operational controls are given in table 7-5. Data from the two Broadway units show decreases in CO emissions with bias firing. The uncontrolled CO emissions ranged from 40 to 150 ppm across the load range while controlled CO emissions ranged from 15 to 50 ppm. The corresponding NO_x emissions were 14 to 30 percent across the load range. The reduction was attributed to the CO formed in the fuel-rich lower burners being completely burned out as it passed through the fuel-lean upper zone.

For the South Bay Unit 1, BOOS increased the CO emissions from 200 to 4,000 ppm at full load while bias firing reduced the CO to less than 50 ppm at full load. Similar increases in CO were also seen at lower loads with BOOS. The extreme level of CO with BOOS may be the result of poor air/fuel distribution which is exaggerated with BOOS.[35]

For the flue gas recirculation (FGR) test results, on a natural gas-fired boiler, the CO increased across the load range. At full-load, the CO increased from 97 ppm up to 163 ppm with NO_x reductions of approximately 30 percent. At half-load, the CO increased from 82 ppm up to 112 ppm with NO_x reductions of 35 percent.

For two oil-fired boilers (Port Everglades 3 and 4), the CO emissions decreased to less than 3 ppm with LNB. The NO_x reduction for these two boilers was 29 to 35 percent. The same large decrease in CO emissions were seen at the same units when firing natural gas.

With the natural gas-firing at the Alamitos 6 unit, the range of uncontrolled CO emissions were 117 to 156 ppm while the range of CO emissions were 151 to 220 ppm with retrofit LNB. The NO_x reduction was 42 to 65 percent. The CO emissions at the oil-fired unit, Salem Harbor 4, were 73 ppm with LNB.

TABLE 7-5. SUMMARY OF CARBON MONOXIDE DATA FROM NATURAL GAS- AND OIL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS

Utility	Unit (standard)[a]	Unit type	Rated capacity (MW)	Control type[a] (vendor)[b]	Capacity tested (%)	Carbon monoxide (ppm) Uncontrolled	Carbon monoxide (ppm) Control	NO_x reduction (%)	Reference
OPERATIONAL CONTROLS, NATURAL GAS									
City of Pasadena Water & Power Dept.	Broadway 1 and 2 (Pre)	Wall	45	Bias	70 50 38	150 75 40	50 30 15	14 29 30	34
San Diego Gas & Electric Co.	South Bay 1 (Pre)	Wall	153	BOOS	100 67 33	200 <100 <50	4000 1000 900	--	35
San Diego Gas & Electric Co.	South Bay 1 (Pre)	Wall	153	BIAS	100 67 33	200 <100 <50	<50 <100 <50	--	35
FLUE GAS RECIRCULATION, NATURAL GAS									
Southern California Edison	Etiwanda 3 (Pre)	Tan.	320	FGR	97 82 67 52 37	97 300 149 82 22	163 184 165 112 136	29 33 38 35 29	36
LOW NO_x BURNERS, FUEL OIL									
Florida Power & Light	Port Everglades 3 (Pre)	Wall	400	LNB (Todd)	96	144	1.4	29	37
Florida Power & Light	Port Everglades 4 (Pre)	Wall	400	LNB	96	127	2.6	35	37
New England Power Service Co.	Salem Harbor 4 (Pre)	Wall	475	LNB	--	--	73	--	38
LOW NO_x BURNERS, NATURAL GAS									
Florida Power & Light	Port Everglades 3 (Pre)	Wall	400	LNB (Todd)	96	161	1.7	2.3	37

TABLE 7-5. SUMMARY OF CARBON MONOXIDE DATA FROM NATURAL GAS- AND OIL-FIRED BOILERS WITH COMBUSTION NO_X CONTROLS (CONCLUDED)

Utility	Unit (standard)[a]	Unit type	Rated capacity (MW)	Control type[a] (vendor)[b]	Capacity tested (%)	Carbon monoxide (ppm)		NO_x reduction (%)	Reference
						Uncontrolled	Control		
LOW NO_x BURNERS, NATURAL GAS									
Florida Power & Light	Port Everglades 4 (Pre)	Wall	400	LNB	96	270	6.9	34	37
Southern California Edison	Alamitos 6 (Pre)	Wall	480	LNB (Todd)	95 77 54	156 117 133	220 160 151	42 65 58	39
COMBINED CONTROLS, NATURAL GAS									
Pacific Gas and Electric Co.	Pittsburg 7 (Local)	Tan	745	OFA + FGR	100 50 30	-- -- --	26 21 17	89 86 87	40
Pacific Gas and Electric Co.	Pittsburg 6 (Local)	Wall	330	OFA + FGR	100 50 32	-- -- --	228 27 63	82 66 50	40
Pacific Gas and Electric Co.	Contra Costa 6 (Local)	Wall	345	OFA + FGR	100 50 25	-- -- --	833 361 49	65 6 0	40
Southern California Edison	Redondo 8 (Pre)	Wall	480	BOOS + FGR + OFA	100 75 33	100 750 0	90 60 0	-- -- --	41
Pacific Gas and Electric Co.	Moss Landing 7 (Local)	Wall	750	OFA + FGR	100 80 60	-- -- --	108 11 8	92 95 91	40

[a]Standard: Local = Local area standard
Pre = Pre-NSPS

[b]Control Type: Bias = Biased Firing, BOOS = Burners-Out-of-Service, FGR = Flue Gas Recirculation, OFA = Overfire Air, LNB = Low NO_x Burners

[c]Vendor: Todd = Todd Combustion

-- = data not available.

Five natural gas-fired units reported CO emissions with retrofit combination controls. For the combination of OFA and flue gas recirculation (FGR) on four boilers, the CO emissions ranged from 8 to 833 ppm. The CO emissions for these boilers were higher at full-load conditions than at the low load conditions. These boilers did not report the uncontrolled CO levels. For one application with BOOS, FGR, and OFA, the CO emissions at full-load decreased from 100 to 90 ppm. At intermediate load, the CO emissions decreased greatly from 750 to 60 ppm and at low load, CO emissions were reported to be zero.

7.3 EFFECTS FROM FLUE GAS TREATMENT CONTROLS

This section discusses the possible energy and environmental impacts from selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) systems on fossil fuel utility boilers. The SNCR process involves injecting ammonia (NH_3) or urea into high-temperature zones of the boiler with flue gas temperatures of approximately 930 to 1,040 $^{\circ}C$ (1,700 to 1,900 $^{\circ}F$). Under these conditions, the injected reagents can react with the NO_x to produce nitrogen (N_2) and water. However, since the possible chemical paths leading to the reduction of NO_x involve reaction between nitrogen oxide (NO) and nitrogen species, a possible byproduct of the process is nitrous oxide (N_2O), a greenhouse gas.[42]

Recent chemical kinetic calculations and pilot-scale tests show that N_2O can be a product of the SNCR process. These tests indicate that NH_3 injection yielded lower N_2O levels (as a fraction of the NO_x reduced) than did the urea injection. Injection of NH_3 yielded N_2O levels equal to 4 percent of the NO_x reduced, while urea injection yielded N_2O levels of 7 to 25 percent of the NO_x reduced.[42]

Unreacted SNCR reagents can be emitted in the form of NH_3 slip. The NH_3 slip can be emitted to the atmosphere or can be absorbed onto the fly ash, which could present disposal problems or prevent the sale of the fly ash to cement producers that may have upper limits of NH_3-in-ash that they would accept. In addition, as mentioned in section 5.3.1, the SO_3 generated when firing fuel oil or coal can react with NH_3 to form ammonium bisulfate or ammonium sulfate compounds as shown in figure 5-35, which can plug and corrode the air heater. Ammonium bisulfate has also been identified as a problem in baghouses after a spray dry scrubber. It has been reported that when the recycled scrubber residue is collected in the baghouse and returned to the scrubber absorber vessel for reinjection, the NH_3 slip from the SNCR is being collected by the ash and concentrated during the recycle process. As a result, the low temperatures in the baghouse causes ammonium bisulfate to form on the bags and increased the pressure drop which eventually blinds the bags.[43]

Another potential impact is the reaction of NH_3 and HCl to form solid ammonium chloride:

$$NH_3 + HCl \dashrightarrow NH_4Cl(s) \qquad (7\text{-}1)$$

Ammonium chloride forms at temperatures below 110 ^{o}C (250 ^{o}F), which with ESP-equipped boilers can occur after the flue gases leave the stack. The resulting fine particulate may be observable as a detached plume above the stack.

There are several energy demands associated with operation of a SNCR system. Injection of an aqueous reagent into the furnace will result in a loss of energy equal to the energy required to vaporize the liquid. High energy injection systems (i.e., systems that use of a separate transport gas to provide the energy to mix the reagent with the flue gas) require the use of compressors or blowers to provide transport gas. Additional minor energy losses are associated with pumps, heaters, and control systems, that are part of the SNCR system.

Selective catalytic reduction involves injecting NH_3 into the boiler flue gases in the presence of a catalyst to reduce NO_x to N_2 and water. The catalyst lowers the activation

TABLE 7-6. SUMMARY OF POTENTIAL IMPACTS DUE TO SCR SYSTEMS[44]

Component	Potential impact
Air Heater	• Ammonium bisulfate fouling • Higher exit gas temperature • Higher leakage • Higher steam sootblow rate • Higher water wash rate • Additional dampers for on-line wash
Forced Draft Fan	• Higher mass flow • Provide dilution air • Higher horsepower consumption
Electrostatic Precipitator	• Higher inlet gas volume • Higher gas temperature • SO_3/NH_3 conditioning • Higher pressure drop • Resistivity affected
Induced Draft Fan	• Higher mass and volumetric flow • Higher pressure drop
Flue Gas Desulfurization	• Volume increase • Higher inlet temperature • Increase in H_2O evaporation • SO_2 concentration dilution • FGD wastewater treatment for NH_3 • Mist eliminator operation critical
Stack	• Increase opacity • Increased temperature • Increased volume
Plant	• Net plate heat rate increase • Reduced kW • Natural gas may be required (cold-side) • Additional plant complexity
Water Treatment	• Treat water wash for nitrogen compounds
Fly Ash	• Marketability impact • Odor problems

TABLE 7-7. SUMMARY OF CARBON MONOXIDE, AMMONIA SLIP, AND NITROUS OXIDE EMISSIONS FROM CONVENTIONAL BOILERS WITH SNCR

Utility	Unit (Standard)[a]	Rated Capacity (MW)	Capacity Tested (%)	Reagent Type	Carbon Monoxide (ppm)		Ammonia Slip (ppm)	Nitrous Oxide (ppm)	NO_x Reduction (%)	Reference
					Uncontrolled	Control				
BITUMINOUS COAL										
Wisconsin Electric Power Co.	Valley 4 (Pre)	68	100 34	Urea	16.4 34	17.3 50	-- --	-- --	59[b] 56[b]	45
FUEL OIL										
San Diego Gas and Electric	Encina 2 (Pre)	110	100 72	Urea	-- --	increase of 60-80 ppm from uncontrolled levels	10-55 3-75	-- --	-- 42[b]	46
Long Island Lighting Co.	Port Jefferson 3 (Pre)	185	100 50	Urea	--	No reported increase	5-10 5-10	Increase of 10-15 ppm	38 48	47
NATURAL GAS										
San Diego Gas and Electric	Encina 2 (Pre)	110	100 72	Urea	--	increase of 60-80 ppm from uncontrolled levels	10-50	-- --	35-50[b] 45-50[b]	46
Southern Cal. Edison Co.	El Segundo 1 (Pre)	156	111 50 19	Urea	-- -- --	-- -- --	15 13 18	-- -- --	26 41 40	48
Southern Cal. Edison Co.	Alamitos 4 (Pre)	333	76 45 21	Urea	11 0 3	8 0 11	9 7 6	-- -- --	12 7 14	48
Souther Cal. Edison Co.	El Segundo 3 (Pre)	342	98 42 20	Urea	-- -- --	-- -- --	7 12 17	-- -- --	36 23 28	48
Pacific Gas & Electric Co.	Morro Bay 3 (Pre)	345	100[a] 83[a]	Ammonia	100-200 125	100-200 125	110 50	4 2	30 30	49
Pacific Gas & Electric Co.	Morro Bay 3 (Pre)	345	100[a] 83[a]	Urea	100-200 100-200	100-200 100-200	110 80	14 6	30 30	49

[a]Standard: Pre = Pre-NSPS

[b]Results shown for a normalized stoichiometric ratio $\left(\frac{\text{Actual Molar Ratio of Reagent to initial NO}}{\text{Stoichiometric Molar Ratio of Reagent to initial NO}}\right) = 1$

-- = data not available.

or without SNCR. However, it should be noted that for every mole of urea (NH_2CONH_2) injected there is a potential to emit one mole of CO if the CO bound in urea is not fully oxidized to CO_2. Typically, most of the CO in urea is oxidized to CO_2. In NH_3 based SNCR systems, there is no bound CO; therefore, there is no potential to emit CO from the NH_3 SNCR reagent.

Other impacts from SNCR include the NH_3 slip and N_2O emissions. The data indicates that the NH_3 slip for the oil-fired units ranged from 5 to 75 ppm. The data from Encina 2 showed an increase of NH_3 emissions as the NSR was increased. The data from this unit also showed an increased NO_x removal with increasing normalized stoichiometric ratio (NSR) up to a point. At a certain point, any further increase in NSR results in a very small or no increase in NO_x removal.[46]

The NH_3 slip from five urea-based SNCR applications on natural gas firing ranged from 6 to 110 ppm across the load range with NO_x reductions of 7 to 50 percent. However, a test installation of both NH_3- and urea-based SNCR at the Morro Bay 3 unit resulted in NH_3 slip levels of 50 to 110 ppm at NO_x reduction of 30 percent. The N_2O emissions ranged from 2 to 14 ppm for two natural gas applications.

7.3.1.2 Fluidized Bed Units. Table 7-8 summarizes CO, NH_3 slip, and THC emissions from eight FBC boilers with NH_3-based SNCR as original equipment. The CO emissions ranged from 8.4 to 110 ppm. Only three FBC units reported NH_3 slip emissions and were 28 ppm or less. All units reported THC data, five of which were less than 3.7 ppm.

7.3.2 Results for SCR

High NH_3 emissions indicate a loss of catalyst activity or poor ammonia distribution upstream of the catalyst. A summary of NH_3 data from three pilot and one full-scale SCR system are given in table 7-9. Two of the pilot units are coal-fired applications and one is an oil-fired application. At an NH_3-to-NO_x ratio of 0.8, the NH_3 slip for the three pilot SCR systems ranged from less than 5 to 20 ppm.

TABLE 7-8. SUMMARY OF CARBON MONOXIDE, AMMONIA SLIP, AND TOTAL HYDROCARBON EMISSIONS FROM FLUIDIZED BED BOILERS WITH SNCR

Utility	Unit	Rated capacity (MW)	Coal[a] type	Capacity tested	SNCR reagent type	Carbon monoxide (ppm)	NH_3 slip (ppm)	Total hydrocarbon (ppm)	NO_x emissions (lb/MMBtu)	Reference
BUBBLING FLUIDIZED BED										
POSDEF Power Co., L.P.	Stockton A	25	Unk.	Max	NH_3	110	28	12	0.033	50
POSDEF Power Co., L.P.	Stockton B	25	Unk.	Max	NH_3	110	28	12	0.033	50
CIRCULATING FLUIDIZED BED										
Ultrapower Constellation Operating Services	Rio Bravo Jasmin	37	Bit	Max	NH_3	61.8	--	2.1	0.075	51
Ultrapower Constellation Operating Services	Rio Bravo Poso	37	Bit	Max	NH_3	98	--	2.11	0.078	51
Energy Systems	Stockton Cogen	56	Unk	Max	NH_3	8.4	--	2.7	0.034	52
Pyro-Pacific Operating Co.	Mt. Poso Cogeneration Plant	57	Unk	Max	NH_3	<93	<20	<20	--	53
Applied Energy Services	Barbers Point A	203	Unk	Max	NH_3	41	--	3.64	0.1	54
Applied Energy Services	Barbers Point B	203	Unk	Max	NH_3	41	--	3.64	0.1	54

[a]Coal Type: Bit = Bituminous
Unk = Unknown

-- = data not available.

TABLE 7-9. SUMMARY OF AMMONIA SLIP FROM U. S. SELECTIVE CATALYTIC REDUCTION APPLICATIONS

Utility	Unit	Fuel	SCR size	Type[a]	Ammonia slip (ppm)[b]	NO_x reduction (%)[b]	NH_3-to-NO_x ratio[b]	Reference
NY State Electric & Gas	Kintigh	Coal	Pilot 1 MW	Cold	<1 <1	80 80	0.8 0.8	55
Tennessee Valley Authority	Shawnee	Coal	Pilot 1 MW	Hot	1-7 2-20	75-80 75-80	0.8 0.8	56
Niagara Mohawk	Oswego	Oil	Pilot 1 MW	Hot	<20 <50	75-80 60-80	0.8 0.8	57
Southern California Edison	Huntington Beach 2	Oil	107 MW	Hot	10-40[c]	90	--	58

[a]Type: Cold = Cold-side SCR (after air preheater) and Hot = Hot-side SCR (before air preheater).

[b]Results are given for two different catalyst.

[c]10 ppm during 2,000-7,000 hrs of operation, 40 ppm after 17,000 hrs of operation.

The NH_3 emissions from the full-scale SCR system at Huntington Beach 2 ranged from 10 to 40 ppm. The design specifications of 10 ppm maximum were only marginally met during the initial period (2,000 to 7,000 hours of operation) and then increased with catalyst use. After 17,000 hours of operation, the NH_3 had increased to 40 ppm. While operating the SCR on oil at Huntington Beach 2, the air preheater had to be cleaned more frequently to eliminate the ammonium bisulfate deposits. After 1,400 hours of operation on oil, there were heavy deposits of ammonium-iron sulfate in the intermediate zone of the air preheater. This resulted in a 50-percent increase in pressure drop.[58]

This demonstration of SCR at Huntington Beach 2 did not fully establish catalyst performance and life. However, it did provide a rough estimate of how often the catalyst must be replaced to control deposits in the air preheater at this facility. The catalyst life on oil was estimated to be 15,000 hours or 2 years and 30,000 hours or 4 years on natural gas.[58]

The power requirement for the SCR system at Huntington Beach 2 was approximately 725 kW. This represents an auxiliary power consumption of approximately 0.7 percent of full load generator output and 7 percent of minimum load generator output. The booster fan used to overcome the pressure drop across the catalyst bed consumed the majority of this energy.[58]

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APPENDIX A

COSTING PROCEDURES

A.1 METHODOLOGY

The basic methodologies used to determine NO_X control cost and cost effectiveness are provided in this section. The application of this methodology to individual NO_X control technologies is provided in sections A.2-A.11.

A.1.1 Basic System Cost

The equation to calculate basic system cost is:

$$BSC = a * MW^b \tag{A.1}$$

where:

BSC = Basic system cost ($/kW)
a = Constant derived from regression analysis
MW = Boiler size (MW)
b = Constant derived from regression analysis

For a 100 MW wall coal-fired boiler retrofitting LNB, "a" and "b" were determined to be 220 and -0.44 (refer to section A.2), respectively, the calculation is:

$$BSC = 220 * 100^{-0.44}$$
$$= \$29/kW$$

A.1.2 Retrofit and Indirect Cost Factors

The equation to calculate a retrofit factor is:

$$RF = 1 + (RC/BSC) \tag{A.2}$$

where:

RF = Retrofit factor
RC = Retrofit cost ($/kW)

The equation to calculate an indirect cost factor is:

$$ICF = 1 + [IC/(BSC + RC)] \qquad (A.3)$$

where:

ICF = Indirect cost factor
IC = Indirect cost ($/kW)

For a 100 MW wall coal-fired boiler retrofitting LNB with a basic system cost of $29/kW, retrofit costs of $5/kW, and indirect costs of $9/kW, calculations of retrofit and indirect cost factors are:

$$\begin{aligned} RF &= 1 + (\$5/kW)/(\$29/kW) \\ &= 1 + 0.17 \\ &= 1.17 \end{aligned}$$

$$\begin{aligned} ICF &= 1 + (\$9/kW)/(\$29/kW + \$5/kW) \\ &= 1 + 0.26 \\ &= 1.26 \end{aligned}$$

A.1.3 Total Capital Cost

The equation to calculate total capital cost is:

$$TCC (\$/kW) = BSC * RF * ICF \qquad (A.4)$$

where:

TCC = Total capital cost ($/kW)

For a 100 MW wall coal-fired boiler retrofitting LNB with a basic system cost of $29/kW, an indirect cost factor of 1.3, and a retrofit factor of 1.3, the total capital cost is:

$$\begin{aligned} TCC (\$/kW) &= \$29/kW * 1.3 * 1.3 \\ &= \$49/kW \end{aligned}$$

A.1.4 Operating and Maintenance Costs

Operating and maintenance (O&M) costs include fixed and variable components. Fixed O&M costs are independent of capacity factor and are estimated by either:

$$\text{FO\&M } (\$/\text{yr}) = a * \text{MW}^b \qquad \text{(A.5)}$$

where:

FO&M = Fixed operation & maintenance costs ($/yr)
a = Constant derived from regression analysis
b = Constant derived from regression analysis

or

$$\text{FO\&M } (\$/\text{yr}) = c + d * \text{MW} \qquad \text{(A.6)}$$

where:

FO&M = Fixed operation & maintenance costs ($/yr)
c = Constant derived from regression analysis
d = Constant derived from regression analysis

Variable O&M (VO&M) cost equations are specific for each technology. For more information on these equations, refer to each technology's section in this appendix.

A.1.5 Busbar Costs

The equation for calculating busbar costs is:

$$\begin{matrix}\text{Busbar} \\ \text{Cost}\end{matrix} \left[\frac{\text{mills}}{\text{kWh}}\right] = \frac{(\text{ACC} + \text{FO\&M} + \text{VO\&M}) * 1000 \text{ mills}/\$}{\text{AEO}} \qquad \text{(A.7)}$$

Supporting equations include:

$$ACC\ (\$/yr) = TCC * MW * CRF * 1000 \qquad (A.8)$$

where:

ACC = Annualized capital costs (\$/yr)
CRF = Capital Recovery Factor
1000 = Factor to convert MW to KW

$$CRF = i\ (1 + i)^n / [(1 + i)^n - 1] \qquad (A.9)$$

where:

i = Interest rate (decimal fraction)
n = Economic life of the equipment (years)

Assuming an interest rate of 0.10 and a economic life of 20 years:

$$\begin{aligned} CRF &= 0.10\ (1 + 0.10)^{20} / [(1 + 0.10)^{20} - 1] \\ &= 0.673/5.73 \\ &= 0.12 \end{aligned}$$

With a total capital requirement of \$49/kW, a capital recovery factor of 0.12, annualized capital costs would be:

$$\begin{aligned} ACC\ (\$/yr) &= \$49/kW * 100\ MW * 0.12 * 1000\ kW/MW \\ &= \$588{,}000/yr \end{aligned}$$

$$AEO = MW * CF * 8{,}760{,}000 \qquad (A.10)$$

where:

AEO = Annual electrical output (kWh/yr)
CF = Average Annual Capacity Factor (decimal fraction)
8,780,000 = Factor to convert MW-yr to kWh

For a 100 MW wall coal-fired boiler retrofitting LNB with annualized capital costs of \$588,000 per year, negligible O&M costs, and a capacity factor of 0.10, the busbar cost is:

$$\text{Busbar Cost} \left[\frac{\text{mills}}{\text{kWh}}\right] = ((\$588{,}000/\text{yr} + 0) * 1000\ \text{mills}/\$)\ /(100\ \text{MW} * 0.10 * 8{,}760{,}000)$$

$$= 6.7\ \text{mills/kWh}$$

A.1.6 Cost Effectiveness

The equation for calculating cost effectiveness is:

$$CE\ (\$/\text{ton}) = (ACC + FO\&M + VO\&M)\ /\ (\text{Tons } NO_x) \qquad (A.11)$$

where:

CE = Cost effectiveness (\$/ton)
Tons NO_x = Tons NO_x removed (tons/yr)

$$\text{Tons } NO_x = UncNO_x * NO_x\ \text{Reduction} * HR * MW * CF * 0.00438 \qquad (A.12)$$

$UncNO_x$ = Uncontrolled NO_x emission rate (lb/MBtu)
NO_x Reduction = NO_x control performance (decimal fraction)
HR = Boiler net heat rate (Btu/kWh)
0.00438 = factor to convert lb NO_x/kWh to tons NO_x/MW-yr

For a 100 MW wall coal-fired boiler retrofitting LNB with a baseline NO_x level of 0.9 lb/MBtu, a heat rate of 12,500 Btu/kWh, and a NO_x reduction of 40 percent, the tons of NO_x removed per year are:

$$\text{Tons } NO_x = 0.90\ \text{lb/MBtu} * 0.40 * 12{,}500\ \text{Btu/kWh} * 100\ \text{MW} * 0.40 * 0.00438$$

$$= 788\ \text{tons } NO_x/\text{yr}$$

With annualized capital costs of $588,000 per year and negligible O&M costs, the cost effectiveness is:

$$CE = (\$588,000/yr + 0)/788 \text{ tons } NO_x /yr$$
$$= \$745/\text{tons of } NO_x \text{ removed}$$

A.2 LNB APPLIED TO COAL-FIRED WALL BOILERS

A.2.1 Data Summary

The data used to develop cost equations for applying LNB to wall-fired boilers are shown in Table A-1. Presented in the table are utility and plant name, boiler size, basic system cost, retrofit system cost, indirect system cost, total capital cost, fixed O&M, and variable O&M. Fixed O&M costs were provided for only one unit, and variable O&M costs were not provided for any units.

The data for three of the units were obtained from questionnaire responses and are actual installation costs for existing retrofit projects.[1,3,4] The data for the other seven units were obtained from the EPA's "Analysis of Low NO_x Burner Technology Costs" report and represent cost estimates for retrofitting LNB, rather than actual installations.[2]

A.2.2 Basic System Cost

Based on linear regression analysis of the natural logarithms of basic system cost ($/kW) and boiler size (MW) data, the cost coefficients for equation A.1 were calculated to be a = 220 and b = -0.44. Therefore, the basic system cost algorithm for LNB is:

$$BSC\ (\$/kW) = 220 * MW^{-0.44}$$

Figure A-1 presents the plot of the data and the curve calculated from this equation.

A.2.3 Retrofit Cost

Based on the data in Table A-1, retrofit factors for LNB range from 1.1 to 1.6. Based on the post construction installation cost data provided by Plants D and G, a retrofit factor of 1.15 was used for estimating retrofit costs.[3,4] Specific cost elements associated with these retrofit factors are summarized in Section 6.3.1.

TABLE A-1. UTILITY LNB COST DATA
(COAL-FIRED UNITS)

Utility	Plant Name	Unit	Size (MW)	Basic System Cost ($/kW)	Retrofit System Cost ($/kW)	Indirect System Cost ($/kW)	Total Capital Cost ($/kW)	Fixed O&M ($/kWyr)	Variable O&M ($/kWyr)	Reference
Consumer's Power	J.H. Campbell	3	800	10.3	1.3	2.9	14.5	0.02	--	1
	A		142	23.7	14.0	13.2	50.9	--	--	2
	B		130	26.9	4.5	6.4	37.8	--	--	2
	C		150	23.7	3.9	5.5	33.1	--	--	2
	D		150	24.7	4.6	8.7	38.0	--	--	3
	E		155	25.3	3.8	5.8	34.9	--	--	2
	F		155	23.3	3.8	5.5	32.6	--	--	2
	G		200	20.0	2.0	6.9	28.9	--	--	4
	H		200	19.2	3.4	4.4	27.0	--	--	2
	I		500	17.1	4.4	4.3	25.8	--	--	2

-- = Not provided.

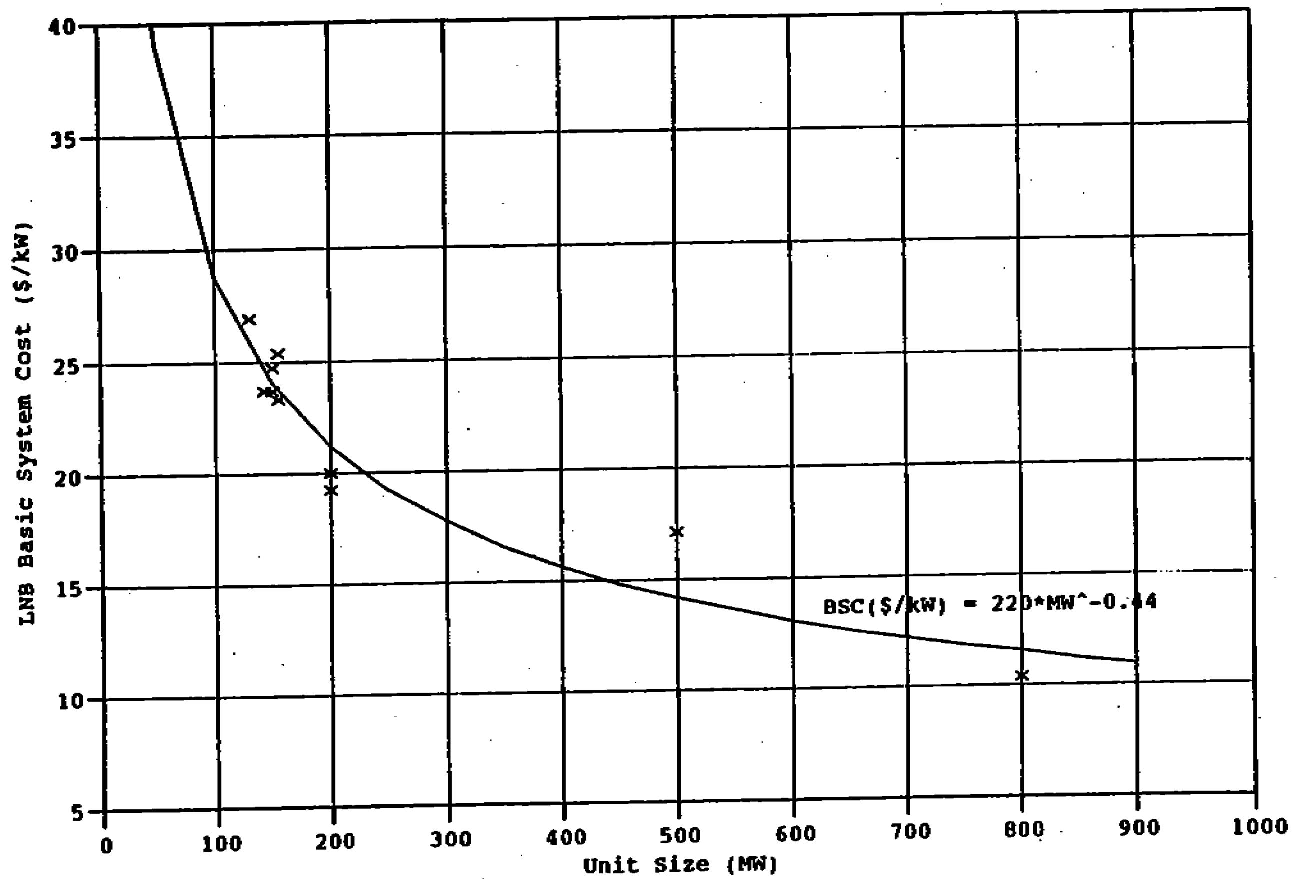

Figure A-1. LNB basic system cost ($/kW) algorithm and raw data.

A.2.4 Indirect Cost

Indirect cost factors based on Table A-1 range from 1.20 to 1.35. Based on the completed installation cost data provided by Plants D and G, an ICF of 1.30 was assumed to be typical.[3,4]

A.2.5 Fixed O&M Cost

Fixed O&M costs include operating, maintenance, and supervisory labor; maintenance materials, and overhead. Because of the limited number of moving parts and the expected low operating labor and maintenance requirements associated with LNB, fixed O&M costs were not included in the cost procedures.

A.2.6 Variable O&M Cost

The major variable O&M expense associated with LNB is any increase in fuel expenses resulting from a decrease in boiler efficiency. The magnitude of this O&M expense will vary depending on the extent of the efficiency loss and the price of fuel. As discussed relative to boiler operational modifications, such as LEA + BOOS, this expense is estimated at less than 0.2 mills/kWh for most boilers. In most instances, this expense equates to a cost impact of less than 20 percent compared to the annualized capital expense associated with LNB. Because of their small impact for most boilers, variable O&M costs associated with LNB were not included in the cost procedures. To include the impact of efficiency losses on boiler operating expenses, convert the efficiency loss to an equivalent Btu/kWh and multiply this value by the fuel price in mills/Btu.

A.3 LNB APPLIED TO COAL-FIRED TANGENTIAL BOILERS

A.3.1 Data Summary

There were no available cost data for retrofitting LNB alone on tangentially-fired boilers. As a result, the basic system cost algorithm was developed based on the relative price differentials between LNCFS I (LNB with close-coupled overfire air) and LNCFS III (LNB plus close-coupled and separated overfire air) (see appendix A.5 on LNCFS III). Based on information presented by ABB-Combustion Engineering, the ratio of LNCFS III basic system cost to LNCFS I basic system cost is 9 to 5.[5] This difference corresponds generally to the price differential between LNB and LNB + AOFA (see appendix A.4 on LNB + AOFA).

The economy of scale was assumed to be 0.60 for LNCFS I (corresponding to b = -0.40). This economy of scale is similar to that for LNB (b = -0.44), and is lower than for LNCFS III (b = -0.49), which is believed to reflect the lower economy of scale associated with LNB versus AOFA.

A.3.2 Basic System Cost

Using the relative price differential for LNCFS III to LNCFS I of 1.8, the basic system cost algorithm for LNCFS III (see appendix A.5) was modified to develop the algorithm for LNCFS I.

Dividing the LNCFS III algorithm applied to the 400 MW reference plant by 1.8 yields the basic system cost for the 400 MW LNCFS I system:

$$\begin{aligned} \text{BSC (\$/kW)} &= 247 * 400^{-0.49} / 1.8 \\ &= \$7.3/\text{kW} \end{aligned}$$

Then, using b = -0.40, the coefficient "a" was determined:

$$\begin{aligned} \$7.3/\text{kW} &= a * 400^{-0.4} \\ a &= 80 \end{aligned}$$

From this, the basic system cost algorithm for LNCFS I is:

$$BSC (\$/kW) = 80 * MW^{-0.4}$$

A.3.3 Retrofit Cost

The retrofit and factor for LNCFS I was assumed to be 1.3, the same as for LNCFS III (see appendix A.5).

A.3.4 Indirect Cost

The indirect cost factor for LNCFS I was assumed to be 1.3, the same as for LNCFS III.

A.3.5 Fixed O&M Cost

Fixed O&M costs include operating, maintenance, and supervisory labor; maintenance materials, and overhead. Because of the limited number of moving parts and the expected low operating labor and maintenance requirements associated with LNB, fixed O&M costs were not included in the cost procedures.

A.3.6 Variable O&M Cost

The major variable O&M expense associated with LNB is any increase in fuel expenses resulting from a decrease in boiler efficiency. The magnitude of this O&M expense will vary depending on the extent of the efficiency loss and the price of fuel. As discussed relative to boiler operational modifications, such as LEA + BOOS, this expense is estimated at less than 0.2 mills/kWh for most boilers. In most instances, this expense equates to a cost impact of less than 20 percent compared to the annualized capital expense associated with LNB. Because of their small impact for most boilers, variable O&M costs associated with LNB were not included in the cost procedures. To include the impact of efficiency losses on boiler operating expenses, convert the efficiency loss to an equivalent Btu/kWh and multiply this value by the fuel price in mills/Btu.

A.4 LNB + AOFA APPLIED TO COAL-FIRED WALL BOILERS

A.4.1 Data Summary

There are limited detailed data available on LNB + AOFA for wall-fired boilers. Therefore, the basic system cost algorithm for LNB + AOFA was based on relative price differentials between LNB and LNB + AOFA.

Information from Southern Company Services on installed cost estimates for a 100 MW boiler and a 500 MW boiler indicates ratios of LNB + AOFA to LNB of 2.0 for both boiler sizes.[6] Information in the EPA's "Analysis of Low NO_X Burner Technology Costs" report presents ratios of total installed costs ranging from 1.6 to 1.88.[2] Based on review of these data, a ratio of 1.75 for LNB + AOFA to LNB was assumed.

Because of the expected economies of scale for windbox and air handling systems compared to LNB systems, the scaling factor for the addition of AOFA is expected to be higher than for LNB (corresponding to a more negative "b" coefficient in the basic system cost equation). For LNCFS III, b = -0.49, and for LNB, b = -0.44. Based on review of LNCFS III and LNB + AOFA data in the EPA cost report, "b" was assumed to equal -0.5 for LNB + AOFA.[2]

A.4.2 Basic System Cost

Using the 400 MW reference plant and the LNB cost algorithm for basic system cost multiplied by 1.75, the reference plant cost for LNB + AOFA was determined:

$$\begin{aligned} \text{BSC (\$/kW)} &= 220 * \text{MW}^{-0.44} * 1.75 \\ &= 220\ 400^{-0.44} * 1.75 \\ &= \$27.6/\text{kW} \end{aligned}$$

Then, using b = -0.5, the coefficient "a" was determined:

$$\begin{aligned} \$27.6/\text{kW} &= a * 400^{-0.5} \\ a &= 552 \end{aligned}$$

From this, the basic system cost algorithm for LNB + AOFA is:

$$BSC (\$/kW) = 552 * MW^{-0.5}$$

A.4.3 Retrofit Cost

The retrofit factor for LNB + AOFA was assumed to be 1.3, the same as for LNCFS III.

A.4.4 Indirect Cost

The indirect cost factor for LNB + AOFA was assumed to be 1.3, the same as for LNB only and for LNCFS III.

A.4.5 Fixed O&M Cost

Fixed O&M costs include operating, maintenance, and supervisory labor; maintenance materials, and overhead. Because of the limited number of moving parts and the expected low operating labor and maintenance requirements associated with LNB + AOFA, fixed O&M costs were not included in the cost procedures.

A.4.6 Variable O&M Cost

The major variable O&M expense associated with LNB + AOFA is any increase in fuel expenses resulting from a decrease in boiler efficiency. The magnitude of this O&M expense will vary depending on the extent of the efficiency loss and the price of fuel. As discussed relative to boiler operational modifications, such as LEA + BOOS, this expense is estimated at less than 0.2 mills/kWh for most boilers. In most instances, this expense equates to a cost impact of less than 20 percent compared to the annualized capital expense associated with LNB + AOFA. Because of their small impact for most boilers, variable O&M costs associated with LNB + AOFA were not included in the cost procedures. To include the impact of efficiency losses on boiler operating expenses, convert the efficiency loss to an equivalent Btu/kWh and multiply this value by the fuel price in mills/Btu.

A.5 LNB + AOFA APPLIED TO COAL-FIRED TANGENTIAL BOILERS

A.5.1 Data Summary

The cost data for tangentially-fired boilers retrofitting LNCFS III are shown in Table A-2. Presented in the table are utility and plant name, boiler size, basic system cost, retrofit cost, indirect system cost, total capital cost, fixed O&M, and variable O&M. Fixed and variable O&M costs were not provided for any of the units. These cost data are from the EPA's "Analysis of Low NO_x Burner Technology Costs."[2]

A.5.2 Basic System Cost

A linear regression analysis of the natural logarithms of the basic system cost ($/kW) and boiler size (MW) data was performed, and the cost coefficients were calculated to be a = 247 and b = -0.49. Therefore, the basic system cost algorithm for LNCFS III is:

$$BSC\ (\$/kW) = 247 * MW^{-0.49}$$

Figure A-2 presents the plot of the data and the curve calculated from this equation.

A.5.3 Retrofit Cost

The retrofit factors for LNCFS III ranged from 1.14 to 1.65, with a mean of approximately 1.30.

A.5.4 Indirect Cost

Indirect cost factors ranged from 1.20 to 1.45. For the cost procedures, an indirect cost factor of 1.30 was assumed.

A.5.5 Fixed O&M Cost

Fixed O&M costs include operating, maintenance, and supervisory labor; maintenance materials, and overhead. Because of the limited number of moving parts and the expected low operating labor and maintenance requirements associated with LNB + AOFA, fixed O&M costs were not included in the cost procedures.

A.5.6 Variable O&M Cost

The major variable O&M expense associated with LNB + AOFA is any increase in fuel expenses resulting from a decrease in boiler efficiency. The magnitude of this O&M expense will vary

TABLE A-2. UTILITY LNCFS III COST DATA (COAL-FIRED UNITS)

Plant Name	Size (MW)	Basic System Cost ($/kW)	Retrofit System Cost ($/kW)	Indirect System Cost ($/kW)	Total Capital Cost ($/kW)	Fixed O&M ($/kWyr)	Variable O&M ($/kWyr)	Reference
J	165	13.3	4.6	7.6	25.5	--	--	2
K	238	13.9	4.5	6.9	25.3	--	--	2
L	180	20.7	10.2	9.9	40.8	--	--	2
M	900	6.4	2.3	2.7	11.3	--	--	2
N	124	29.0	4.0	6.7	39.7	--	--	2
O	145	23.4	3.4	5.5	32.3	--	--	2
P	203	17.7	4.9	4.6	27.2	--	--	2
Q	203	18.7	4.9	4.8	28.4	--	--	2
R	261	25.3	3.8	5.8	34.9	--	--	2
S	288	16.7	3.5	4.0	24.2	--	--	2
T	500	10.8	3.2	2.8	16.8	--	--	2
U	905	11.0	3.3	2.9	17.2	--	--	2
V	350	14.6	9.5	10.8	34.9	--	--	2
W	880	11.0	3.9	6.7	21.6	--	--	2

-- = Not provided.

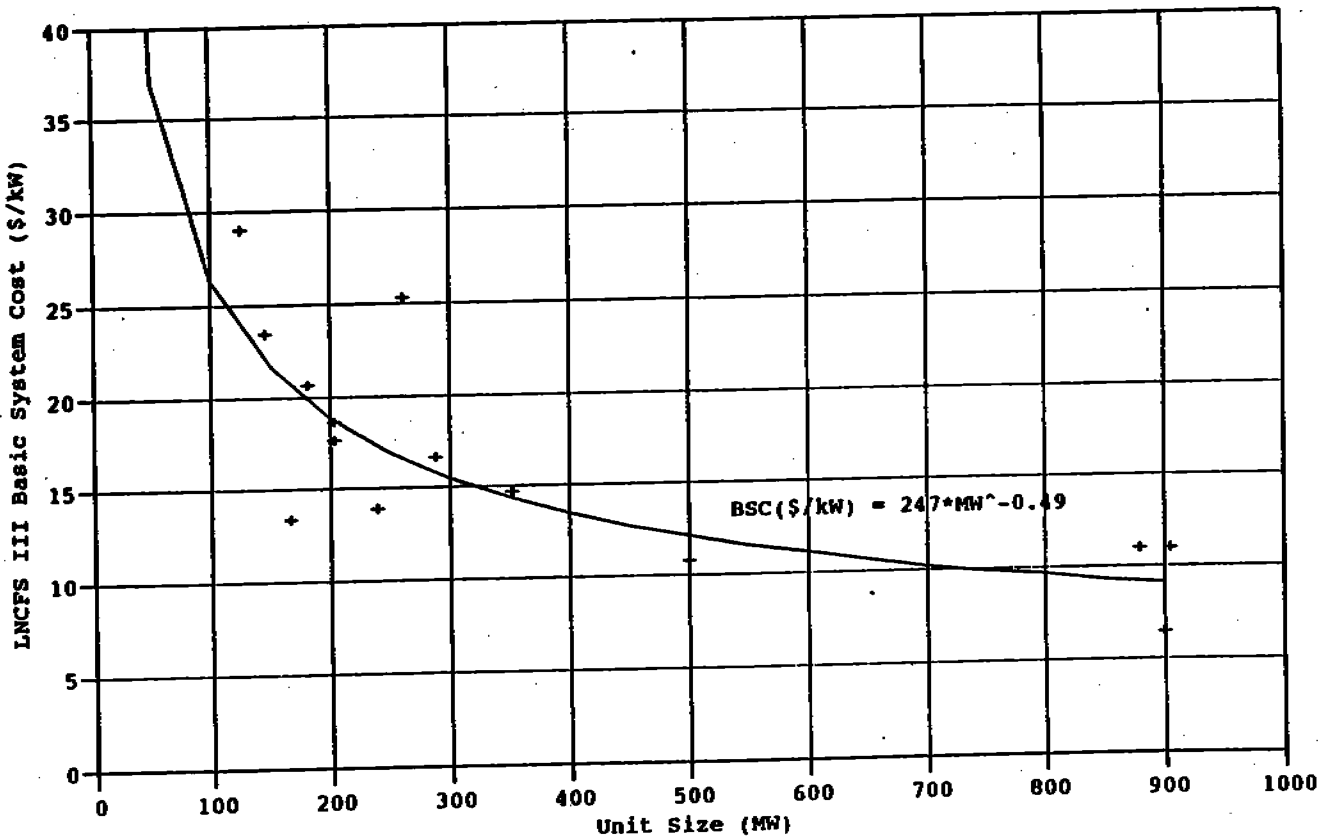

Figure A-2. LNCFS III basic system cost ($/kW) algorithm and raw data.

depending on the extent of the efficiency loss and the price of fuel. As discussed relative to boiler operational modifications, such as LEA + BOOS, this expense is estimated at less than 0.2 mills/kWh for most boilers. In most instances, this expense equates to a cost impact of less than 20 percent compared to the annualized capital expense associated with LNB + AOFA. Because of their small impact for most boilers, variable O&M costs associated with LNB + AOFA were not included in the cost procedures. To include the impact of efficiency losses on boiler operating expenses, convert the efficiency loss to an equivalent Btu/kWh and multiply this value by the fuel price in mills/Btu.

A.6 NATURAL GAS REBURN APPLIED TO COAL-FIRED BOILERS

A.6.1 Data Summary

Limited cost data on natural gas reburn for coal-fired boilers were obtained from vendor and utility questionnaire responses. These data are presented in Table A-3. As shown, the total capital cost follow no obvious trend. Therefore, the reburn costs were based upon the 172 MW unit (Cherokee 3), whose size is more representative of most utility boilers.[7]

A.6.2 Basic System Cost

The economy of scale was assumed to be 0.6 for the reburn basic system cost algorithm (corresponding to b = -0.4). Using the estimated basic system cost of the 172 MW unit to solve for "a", the reburn basic system cost algorithm is:

$$BSC\ (\$/kW) = 229 * MW^{-0.4}$$

A.6.3 Retrofit Cost

The vendor questionnaires indicated that retrofit of natural gas reburn would cost 10 to 20 percent more than a reburn system applied to a new boiler. From this, the retrofit factor was assumed to be 1.15.[7]

A.6.4 Indirect Cost

An indirect cost factor of 1.40 was used for the cost analysis.

A.6.5 Fixed O&M Cost

Fixed O&M costs include operating, maintenance, and supervisory labor; maintenance materials, and overhead. Because of the limited number of moving parts and the expected low operating labor and maintenance requirements associated with NGR, fixed O&M costs were not included in the cost procedures.

A.6.6 Variable O&M Cost

Variable O&M costs were the total of the additional fuel costs, due to the higher price of natural gas versus coal, and utility savings on SO_2 credits, due to lower SO_2 emission levels when using natural gas reburn on a coal-fired boiler. The additional fuel costs were calculated using the fuel prices

TABLE A-3. REBURN COST DATA (COAL-FIRED UNITS)

Utility	Plant Name	Unit	Size (MW)	Basic System Cost ($/kW)	Retrofit System Cost ($/kW)	Indirect System Cost ($/kW)	Total Capital Cost ($/kW)	Fixed O&M ($/kWyr)	Variable O&M ($/kWyr)	Reference
Springfield City	Lakeside	7	33	--	--	--	149	--	--	7
Public Service of Colorado	Cherokee	3	172	--	4	--	42	--	--	7
Illinois Power	Hennepin	1	72	--	--	2.5	10.5	--	--	8

-- = Not provided.

listed in Table 6-3. The SO_2 emissions are calculated using typical sulfur and calorific content of coal from Chapter 3 (Table 3-2) and an average AP-42 emission factor for bituminous and subbituminous coal.[9] The SO_2 credit was assumed to be \$500/ton of SO_2.[10] The equation to determine savings from SO_2 credits is:

$$EF * Sulfur * MW * HR * CF * Credit * Reburn * 2.19$$

where:

EF	=	AP-42 SO_2 Emission Factor (lb SO_2/ton coal * sulfur % of coal)
Sulfur	=	Sulfur % of coal
Credit	=	SO_2 credit (\$/ton)
Reburn	=	Heat input of reburn fuel fired divided by total boiler heat input (decimal fraction)
2.19	=	Conversion factor

A.7 OPERATIONAL MODIFICATIONS (LEA + BOOS) ON NATURAL GAS- AND OIL-FIRED BOILERS

A.7.1 Overview

Cost estimates for LEA + BOOS were prepared for wall- and tangentially-fired boilers. The LEA + BOOS cost analysis was used as an example of operational modifications.

A.7.2 Basic System Cost

The direct capital costs required for LEA + BOOS are the cost for conducting a 4-week emissions and boiler efficiency test to determine optimum fuel-air settings. The cost for the 4-week testing period was estimated at $75,000. Testing costs were not assumed to be dependent upon boiler size.

A.7.3 Retrofit Cost

A retrofit factor of 1.0 was used in the cost analysis.

A.7.4 Indirect Cost

Indirect costs were estimated at 25 percent of the direct costs. Therefore, the indirect cost factor was assumed to be 1.25.

A.7.5 Fixed O&M Cost

Fixed O&M costs include operating, maintenance, and supervisory labor; maintenance materials, and overhead. Because of the limited number of moving parts and the expected low operating labor and maintenance requirements associated with LEA + BOOS, fixed O&M costs were not included in the cost procedures.

A.7.6 Variable O&M Cost

The only variable O&M cost impact examined for BOOS was reduced boiler efficiency. The variable O&M cost caused from the efficiency loss was calculated using the following equation:

$$\text{VO\&M (\$/yr)} + MW * HR * CF * \frac{\text{Effloss}}{1\text{-Effloss}} * \text{Fuel Cost} * 8.76$$

where:

MW, HR, and CR are as previously defined

Effloss = efficiency loss of boiler (decimal fraction)

Fuel Cost	=	fuel cost ($/MMBtu)
8.76	=	conversion factor

A 0.3 percent average decrease in boiler efficiency was used for the cost analysis.[11] Other variable O&M costs were assumed to be negligible.

A.8 LNB APPLIED TO NATURAL GAS- AND OIL-FIRED WALL BOILERS

A.8.1 Data Summary

Capital cost data for LNB applied to natural gas and oil wall-fired boilers were limited to the three points shown in Table A-4. All three points reflect total capital cost. Two of the data points are pre-construction estimates.[11] The third data point is from a questionnaire response and reflects actual installed costs.[12]

A.8.2 Basic System Cost

To estimate the basic system cost for natural gas- and oil-fired LNB, the total capital cost data in Table A-4 were compared to the estimated total capital costs for coal-fired wall boilers (described in Section A.2). This comparison, shown in Figure A-3, suggests that the total capital costs for natural gas- and oil-fired boilers are comparable to the total capital costs for coal-fired boilers.

Analysis of this conclusion (i.e., that costs for natural gas- and oil-fired LNB are comparable to those for coal-fired LNB) suggests that (1) the major costs associated with LNB technology are associated with development, testing, engineering, and marketing activities, and (2) differences in the cost of natural gas- and oil-fired LNB compared to coal-fired LNB caused by differences in physical design or fabrication requirements are small. Based on this conclusion and the limited cost data for LNB designed for natural gas and oil firing, the cost procedures developed for coal-fired LNB were used to estimate basic system costs for LNB applied to natural gas- and oil-fired boilers.

A.8.3 Retrofit Cost

There were no specific data on retrofit costs associated with installing LNB on natural gas- and oil-fired boilers. Therefore, the retrofit factors were assumed to be the same as those used for coal-fired boilers.

A.8.4 Indirect Cost

Indirect costs were estimated at 25 percent of direct costs. Therefore, an indirect cost factor of 1.25 was assumed.

TABLE A-4. UTILITY LNB COST DATA
(GAS- AND OIL-FIRED UNITS)

Utility	Plant	Unit	MW	Total Capital Cost[a] ($/kW)	Reference
City of Los Angelos	Haynes	3	230	26.0	11
--	--	--	350	20.0	11
Florida Power & Light	Martin	1	863	19.1	12

[a]Breakdown of total capital cost not provided.

-- = Not provided.

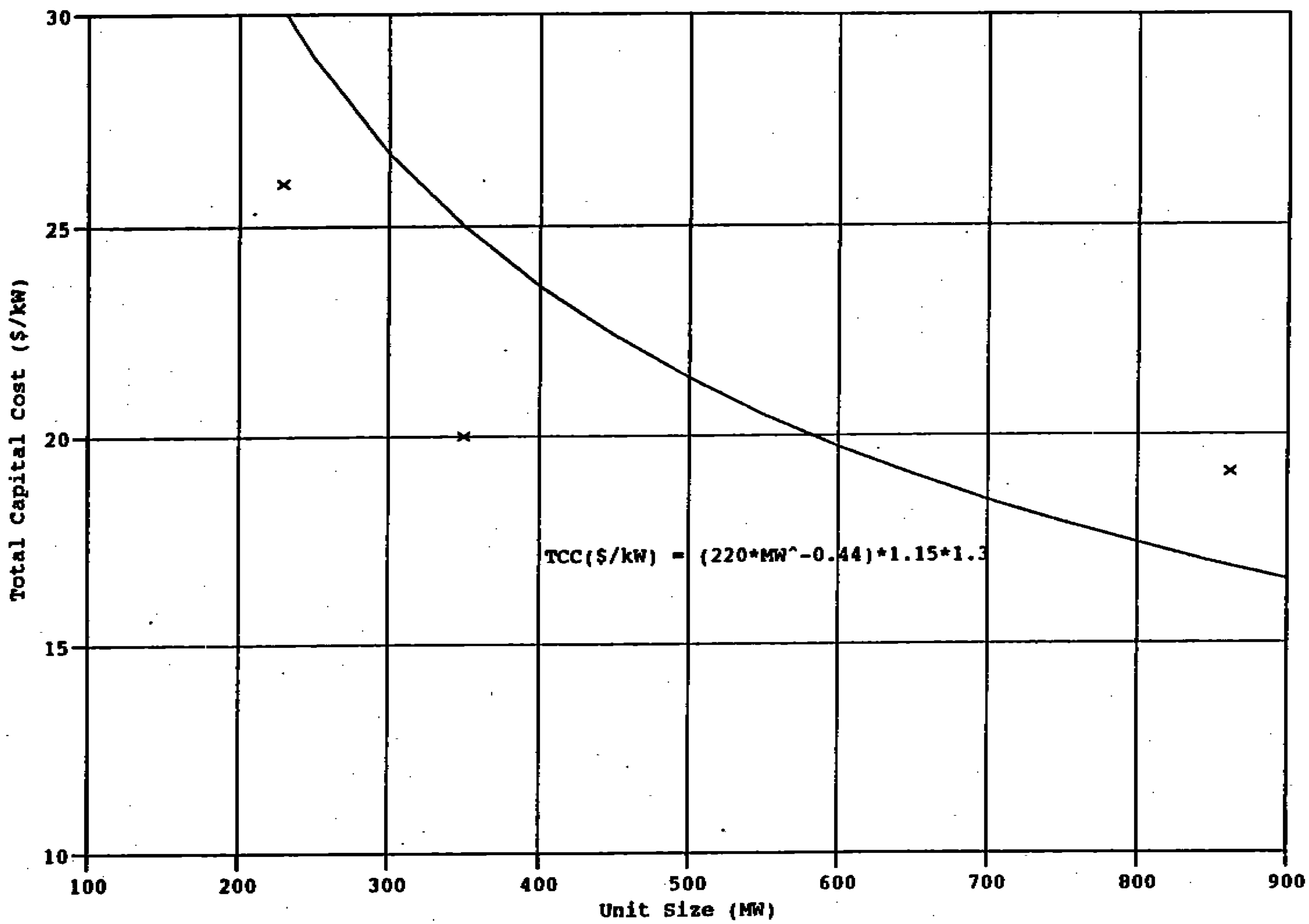

Figure A-3. Comparison of LNB total capital cost of natural gas- and oil-fired boiler data and coal-fired boiler algorithm.

A.8.5 Fixed O&M

Fixed O&M costs include operating, maintenance, and supervisor labor; maintenance materials, and overhead. Because of the limited number of moving parts and the expected low operating labor and maintenance requirements associated with LNB, fixed O&M costs were not included in the cost procedures.

A.8.6 Variable O&M

The major variable O&M expense associated with LNB is any increase in fuel expenses resulting from a decrease in boiler efficiency. The magnitude of this O&M expense will vary depending on the extent of the efficiency loss and the price of fuel. As discussed relative to boiler operational modifications, such as LEA + BOOS, this expense is estimated at less than 0.2 mills/kWh for most boilers. In most instances, this expense equates to a cost impact of less than 20 percent compared to the annualized capital expense associated with LNB. Because of their small impact for most boilers, variable O&M costs associated with LNB were not included in the cost procedures. To include the impact of efficiency losses on boiler operating expenses, convert the efficiency los to an equivalent Btu/kWh and multiply this value by the fuel price in mills/Btu.

A.9 LNB (TANGENTIALLY-FIRED), LNB + AOFA, AND NATURAL GAS REBURN APPLIED TO NATURAL GAS- AND OIL-FIRED BOILERS

There were no cost data available for applying LNB to natural gas- and oil-fired tangential boilers or LNB + AOFA and natural gas reburn to natural gas- and oil-fired wall and tangential boilers.[1] Based on the apparent similarity in cost for wall-fired LNB firing natural gas, oil, and coal (see Section A.8), the cost of applying tangentially-fired LNB, LNB + AOFA, and natural gas reburn to natural gas- and oil-fired boilers were used to estimate the cost for coal-fired boilers. Refer to the appropriate appendix section for coal-fired boilers for specific cost procedures and information.

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[1]For the application of natural gas reburn to oil-fired boilers, the SO_2 emissions are calculated using a typical sulfur and calorific content of oil from Chapter 3 (Table 3-4) and an AP-42 emission factor.[9]

A.10 SNCR

A.10.1 Data Summary

To estimate the cost of urea-based SNCR systems, a detailed engineering model was used. The detailed model was developed by Radian based upon information on basic system and indirect costs[13,14] and on system operating parameters.[15]

A total of 15 case studies were evaluated: 100 MW, 300 MW, and 600 MW for five boiler types (wall, tangential, and cyclone coal-fired boilers, plus wall and tangential natural gas- and oil-fired boilers). The results for these case studies were used to develop simplified costing algorithms for use in this study.

For the case studies, the SNCR system operated at an N/NO ratio of 1.0, and contained two levels of wall injectors and one convective pass level of injectors. No enhancer was assumed to be injected with the urea solution. Cost and material rates were equal to those listed in Table 6-2.

A.10.2 Basic System Cost

Basic system cost categories included the urea storage system, the reagent injection system, air compressors, and installation costs. The algorithm coefficients were derived by linear regression of cost data from the 15 case studies using the methodology described in section A.1. The coefficients were nearly identical for the three coal-fired boiler types. Therefore, the following algorithm was used to characterize the costs for all three:

$$BSC\ (\$/kW) = 32 * MW^{-0.24}$$

Similarly, the cost coefficients were nearly identical for both gas- and oil-fired boiler types and the following algorithm was used to characterize costs for both:

$$BSC\ (\$/kW) = 31 * MW^{-0.25}$$

A.10.3 Retrofit Cost

There were no retrofit cost data available for the analysis. A retrofit factor of 1.0 was assumed based upon the assumption that the retrofit difficulty of SNCR is small.

A.10.4 Indirect Cost

The SNCR model calculated two categories of indirect costs: a contingency factor and engineering support costs. The engineering cost is determined as a function of the unit size, whereas the contingency is calculated as a percentage of direct capital costs. The indirect costs typically ranged between 20 to 30 percent of the total direct costs. An overall indirect cost factor of 1.3 was assumed for the calculation of total capital cost.

A.10.5 Fixed O&M Cost

Fixed O&M costs for SNCR include operating labor, supervision, maintenance labor, maintenance materials, and overhead. Fixed O&M costs were estimated for each of the five boiler types using the SNCR model, and found to be independent of fuel and boiler firing type. Therefore, the following equation, determined by the methods described in section A.1, estimated fixed O&M costs for all five types of boilers:

$$\text{FO\&M } (\$/\text{yr}) = 86{,}000 * \text{MW}^{-0.21}$$

A.10.6 Variable O&M Cost

Variable O&M costs for SNCR include urea, energy penalty associated with vaporization of the urea solution and mixing air, dilution water, and electricity. The urea cost was determined from the following equation:

$$\text{Urea Cost } (\$/\text{yr}) = \text{UncNO}_x * \text{HR} * \text{Cost} * \text{NSR} * 6.52 \times 10^{-7} * \text{MW} * 8760 * \text{CF}$$

where:

Unc NO_x = Uncontrolled NO_x level of the boiler (lb/MBtu)
HR = Heat rate of the boiler (Btu/kW-hr)
Cost = Purchase price of the urea solution ($/ton)
NSR = Normalized Stoichiometric Ratio (N/NO)

Based upon the 15 case studies, the other variable O&M costs were estimated to be 11 percent of the yearly urea cost.

A.11 SCR

A.11.1 Data Summary

The SCR cost estimates are based upon the SCR module in Version 4.0 of EPA's IAPCS[16], publised SCR cost information[17,18], and utility questionnaire responses[19,20]. The existing IAPCS algorithms were used to estimate ammonia handling and storage, flue gas handling, air heater modifications, and catalyst costs. However, the following changes were made to the algorithms:

- IAPCS reactor housing costs were reduced by 71 percent [based on the ratio of reactor housing cost estimates from published information[17,18] ($3.56 million) and from IAPCS ($12.5 million)].[16]
- Process control equipment costs were reduced to $350,000 (versus $1,840,000 in IAPCS).
- Fan costs were excluded for new boilers. For retrofits, fan costs are boiler specific and depend on whether fan modifications are possible or a new fan is needed.
- A catalyst cost of $\$400/ft^3$ was used for all fuel types.
- A space velocity of 14,000/hr was used for gas-fired boilers.
- A flue gas flow rate of approximately 100 Nft^3/kWh was used for oil and gas, and 126 Nft^3/kWh for coal.
- A 45 percent indirect cost factor was applied to process capital (10 percent for engineering overhead, 10 percent for general facilities, 15 percent project contingency, and 10 percent process contingency).
- A 15-25 percent indirect cost factor was applied to the catalyst cost (15 percent for gas, 20 percent for oil, and 25 percent for coal. This factor includes 10 percent for project contingency and the balance for process contingency).
- A cost of $\$160/ft^3$ of catalyst was added to cover installation and disposal of replacement catalyst.

A total of 15 case studies were developed using the modified IAPCS output. These case studies were for boilers of 100 MW, 300 MW, and 600 MW, for each of five boiler types (wall, tangential, and cyclone coal-fired boilers, plus wall and tangential natural gas- and oil-fired boilers). The results from these case studies were then used to develop simplified costing algorithms for use in this study.

The IAPCS algorithms are based on hot-side SCR technology (i.e., the catalyst is located between the boiler economizer and air preheater). For the case studies, catalyst life was assumed to be three years for coal-fired boilers and six years for natural gas- and oil-fired boilers. A NO_x reduction of 85 percent was assumed for all case studies. At this NO_x reduction, catalyst space velocities were assumed to be 2,500/hr for coal-fired boilers and 5,000/hr for oil-fired boilers, and 14,000/hr for natural gas-fired boilers.

A.11.2 Basic System Cost

Basic system cost for SCR includes both process capital and the initial catalyst charge:

BSC ($/kW) = process capital + initial catalyst charge.

Process capital includes NH_3 handling, storage, and injection; catalyst reactor housing; flue gas handling; air preheater modifications; and process control. The cost coefficients for process capital were derived by linear regression of cost data from the 15 case studies. The coefficients for each of the five boiler types are:

Fuel	Boiler Type	a	b
Coal	Wall	174	-0.30
	Tangential	165	-0.30
	Cyclone	196	-0.31
Oil/Gas	Wall	165	-0.324
	Tangential	156	-0.329

The equation for estimating the cost of the initial catalyst charge is based on IAPCS documentation:

$$\text{Catalyst (\$/kW)} = \text{Flow} * \text{Cat\$} / \{SV_f * [\ln(0.20) / \ln(1-NO_x\text{Red})]\}$$

where:

Flow = fuel-specific flue gas flowrate (ft^3/kWh)
(126 ft^3/kWh for coal, 100 ft^3/kWh for gas and oil)
Cat$ = catalyst cost ($/$ft^3$)
SV_f = fuel-specific space velocity
(2,500/hr for coal, 5,000/hr for oil, and 14,000/hr for gas)
NO_xRed = target NO_x reduction (in decimal fraction form)

Total capital cost is calculated by multiplying the process capital by the retrofit and process capital indirect cost factor, multiplying the initial catalyst charge by the catalyst indirect cost factor, and adding these two products together.

A.11.3 Retrofit Cost

Retrofit cost factors for SCR were obtained from an EPA analysis of SCR costs.[21] This reference estimates retrofit factors of 1.02 (low), 1.34 (moderate), and 1.52 (high) based on data obtained from hot-side SCR retrofits on German utility boilers. For cost estimating purposes, the retrofit factor was assumed to be 1.34.

A.11.4 Indirect Costs

Separate indirect cost factors were used for the process capital and the catalyst cost. Indirect costs for the process capital were estimated at 45 percent. Indirect costs for catalysts costs were estimated at 25 percent for coal-fired boilers, 20 percent for oil-fired boilers, and 15 percent for gas-fired boilers.

A.11.5 Fixed O&M Cost

Fixed O&M costs for SCR include operating labor, supervision, maintenance labor, maintenance materials, and overhead. Fixed O&M costs in $/yr were estimated for each of the five boiler types using IAPCS.[16] The resulting data were then used to develop a cost algorithm as discussed in section A.1. The results of this analysis are:

Fuel	Boiler Type	c	d
Coal	Wall	284,600	5,141
	Tangential	276,400	5,103
	Cyclone	305,100	5,243
Oil/Gas	Wall	264,800	3,260
	Tangential	256,600	3,219

A.11.6 Variable O&M Cost

Variable O&M costs for SCR include catalyst replacement, ammonia, electricity, steam, and catalyst disposal. Cost for these elements were derived from IAPCS.[16] The equation used in the ACT study for estimating catalyst replacement cost in $/kW-yr was based on the case studies and the IAPCS documentation:

$$\text{Flow} * (\text{Cat\$} + 160) \;/\; \{SV_f * [\ln(0.20) \;/\; \ln(1-NO_x\text{Red})]\} \;/\; CL$$

where:

Flow, Cat$, SV_f, and NO_xRed are as previously defined

160 = cost to cover installation disposal of replacement catalyst ($/ft^3)

CL = catalyst life (years).

The equation for estimating costs for the other four variable O&M components in $/kW-yr was also based on the case study data and the IAPCS documentation:

$$[1.88 + (4.3 * \text{Unc}NO_x * NO_x\text{Red})] * CF$$

where:

NO_xRed is as previously defined

UncNO_x = uncontrolled NO_x (lb/MBtu)

CF = capacity factor (in decimal fraction form).

A.12 COMBINATION CONTROLS - LNB + SNCR AND LNB + AOFA + SCR

The costs of the combined control technologies LNB + SNCR and LNB + AOFA + SCR applied to coal-fired and natural gas- and oil-fired wall and tangential boilers were determined by combining individual cost algorithms for each technology. For example, the individual capital, variable P&M, and fixed O&M cost algorithms for LNB were combined with those for SNCR. Similarly, the LNB + AOFA cost algorithms were combined with the SCR cost algorithms. Refer to each individual section for the specific cost information.

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16. ABSTRACT

This alternative control techniques document describes available techniques for reducing NOx emissions from utility boilers. Discussion of the formation of NOx and uncontrolled emission levels are included. Control techniques include overfire air, low NOx burners, flue gas recirculation, reburn, selective noncatalytic reduction and selective catalytic reduction.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Utility Boilers Nitrogen Oxide (NOx) Emissions NOx Control Techniques Low NOx Burners Overfire Air Selective Catalytic Reduction Selective Noncatalytic Reduction		

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(This Report)*	21. NO. OF PAGES 528
	20. SECURITY CLASS *(This page)*	22. PRICE

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