United States
Environmental Protection
Agency
Air

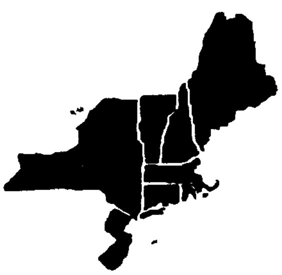
Office of Air Quality
Planning and Standards
Research Triangle Park, NC 27711

EPA-453/R-96-002
Final Report
November 1995

EPA

PHASE II NO_X CONTROLS FOR THE MARAMA AND NESCAUM REGIONS

Northeast States
for Coordinated
Air Use Management
(NESCAUM)



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EPA-453/R-96-002

PHASE II NO_X CONTROLS FOR THE MARAMA AND NESCAUM REGIONS

Sponsored by

Emission Standards Division
Office of Air Quality Planning and Standards
U. S. Environmental Protection Agency
Research Triangle Park, NC 27711

and
Mid-Atlantic Regional Air Management Association
115 Pine Street
Harrisburg, PA 17101

and
Northeast States for Coordinated Air Use Management
129 Portland Street
Boston, MA 02114

November 1995

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ACKNOWLEDGMENTS

This project was funded by the U.S. Environmental Protection Agency's Office of Air Quality Planning and Standards(OAQPS), the Mid-Atlantic Regional Air Management Association (MARAMA), and the Northeast States for Coordinated Air Use Management (NESCAUM).

The project was managed by Bill Neuffer and Ken Durkee of the U. S. EPA's Emission Standards Division of OAQPS, Jim Hambright of MARAMA and Praveen Amar of NESCAUM. In addition, Acurex Environmental was assisted in the development of this document by the NESCAUM Stationary Source Review Committee. A draft of this document was distributed for review to associations representing the utility companies, air pollution control vendors and the natural gas industry.

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GLOSSARY

ABB-CE — Asea Brown Boveri — Combustion Engineering
ACT — Alternative Control Techniques
AGR — Advanced Gas Reburning
AH-CR — Air Heater Selective Catalytic Reduction
AUS — Applied Utility Systems
B&W — Babcock & Wilcox Company
BACT — Best Available Control technology
BAHR — Burner Area Heat Release Rate
BOOS — Burners out of Service
CAT-AH — Catalytic Air Heater
CCT — Clean Coal Technology Program
CTR — Combustion Controls
DOE — Department of Energy
EERC — Energy and Environmental Research, Company
EPA — Environmental Protection Agency
EPRI — Electric Power Research Institute
ESP — Electrostatic Precipitator
EVA, Inc — Energy Ventures Analysis, Inc.
EWG — Exempt wholesale generators
FEGT — Furnace Exit Gas Temperature
FGR — Flue Gas Recirculation
FGT — Flue Gas Treatment
FSW — Boilers that are considered for fuel switching to comply with RACT regulations
GR — Gas Reburn
GRI — Gas Research Institute
ICAC — Institute of Clean Air Companies
IFRF — International Flame Research Foundation
IPPs — Independent Power Producers
KP&L — Kansas Power & Light Company
LADWP — Los Angeles Department of Water and Power
LILCO — Long Island Lighting Company
LNB — Low NO_x Burners
LNCB — Low NO_x Cell Burner
LNCFS — Low NO_x Concentric Firing Systems
MARAMA — Mid Atlantic Regional Air Management Association
MMBtu — Million Btu
MOU — Memorandum of Understanding
MWe — Megawatt of electrical generation (generator gross output)
NEPCO — New England Power Company
NESCAUM — Northeast State for Coordinated Air Use Management
NFT — Nalco Fuel Tech.
NGC — Natural gas Conversion

NGR	–	Natural Gas Reburn
NRP	–	Not reported
NSPS	–	New Source Performance Standards
NRP	–	Boilers with unreported control strategies
NSR	–	Normalized Stoichiometric Ratio
NSR	–	New Source Review
NUG	–	Non Utility Generator
O&M	–	Operation and Maintenance
OEM	–	Original Equipment Manufacturer
OFA	–	Overfire Air
OTC	–	*Ozone Transport Commission*
OTR	–	Ozone Transport Region
PG&E	–	Pacific Gas and Electric Company
PRB	–	*Powder River Basin*
PSE&G	–	Public Service Electric and Gas Company
PSNH	–	Public Service of New Hampshire
PURPA	–	*Public Utility Regulatory Act*
RACT	–	Reasonable Available Control Technology
RET	–	Boilers that are retired or planned for retirement/decommission
RPW	–	*Power Plants that have* Repowered with Gas turbine Generators
SCE	–	Southern California Edison Company
SCR	–	Selective Catalytic Reduction
SIECO	–	Southern Indiana Electric Company
SNCR	–	Selective Noncatalytic Reduction
SNR	–	Staged NO_x Reduction
SOFA	–	Separate Overfire Air
TAG	–	Technology Assessment Guide
TVA	–	Tennessee Valley Authority
UEC	–	United Engineers and Constructors
UNC	–	Utility boilers currently uncontrolled for NO_x
WP&L	–	Wisconsin Power & Light Company

CHAPTER 1

SUMMARY

Utility fossil-fuel-fired boilers in the 14 states of the Northeast and Mid-Atlantic Regions of the United States exceed 400 units and have an electric generating capacity of about 86,000 MWe. Many of these boilers are located within the Ozone Transport Region (OTR) that stretches from Northern Virginia to Maine and from Rhode Island to Pennsylvania. Ambient zone attainment plans for the OTR include a first-phase of retrofit NO_x controls on these boilers and other major NO_x emission sources. By enacted regulations, these controls were to be in place by May 31, 1995. Although the NO_x reductions on utility boilers from these first retrofits are large, additional controls may be necessary to attain the ambient ozone standard. The September 27, 1994, memorandum of understanding (MOU), signed by 10 Northeastern states and the District of Columbia, requires a second and third round of controls starting in 1999 and 2003, respectively. The full text of the MOU can be found in Appendix A. Beginning in 1999, major sources in the more polluted inner corridor can reduce NO_x to either 0.20 lb/MMBtu or achieve 65 percent reduction from 1990 baseline levels. Sources in the less polluted outer region will require a 55 percent reduction. Further tightening to either 0.15 lb/MMBtu or 75 percent reduction will be required in 2003 throughout the region.

Seasonal and year-around controls and emission averaging are planned for the year 1999 and beyond to meet the MOU requirements. Because seasonal controls target NO_x reductions during the peak ozone season, they are often less costly and less burdensome on the utility industry. Recent years have seen the widespread implementation of several NO_x controls on utility boilers both in the U.S. and abroad. Performance improvements have been documented for many combustion and gas treatment controls. In addition, the cost of key control technologies have reflected downward trends in part due to recent technological advances and increased market competition.

This report presents an overview of utility boiler NO_x emissions in the fourteen states[1] that comprise the NESCAUM and MARAMA air quality regions and discusses the application, performance, and cost of retrofit controls that are commercially available control options to further reduce NO_x beyond levels achieved with the implementation of RACT. Because this report attempts to cover a multitude of boiler types, fuels, and control technologies, it is not possible to address all feasible retrofit scenarios. Although NO_x reduction performance and costs for some actual retrofits may deviate from estimates provided in this study, the vast majority of retrofits will be able to reduce NO_x emissions in the range reported and at a cost estimated in this study. These estimates are supported, by and large, by a growing experience base in commercial and technology demonstration retrofits.

1.1 UTILITY BOILER NO_x INVENTORY AND INDUSTRY TRENDS

Figures 1-1 and 1-2 illustrate the distribution of utility boiler NO_x emissions among the NESCAUM and MARAMA states, respectively. The majority of 86,000 MWe capacity is concentrated in the eight states of Pennsylvania, New York, North Carolina, Massachusetts, Maryland, New Jersey, Virginia and Connecticut. Electric power generation in MARAMA is heavily dependent on coal, whereas in NESCAUM oil and gas are the principal fuels for utility boilers. North Carolina's boiler power generation is entirely coal-based. In Pennsylvania, 75 percent of the utility boiler capacity is coal-based. The vast majority of boilers, regardless of

[1] The 14 states are New York, Massachusetts, New Jersey, Connecticut, New Hampshire, Maine, Rhode Island, and Vermont that comprise the Northeast States for Coordinated Air Use Management (NESCAUM) and Pennsylvania, North Carolina, Maryland, Virginia, Delaware, and District of Columbia that comprise the Mid Atlantic Regional Air Management Association (MARAMA). North Carolina and Southern Virginia are not part of the OTR and therefore are not required to install RACT controls this May 1995. Utility boiler inventory in these non-OTR states is included here nonetheless to treat the MARAMA Region as a whole.

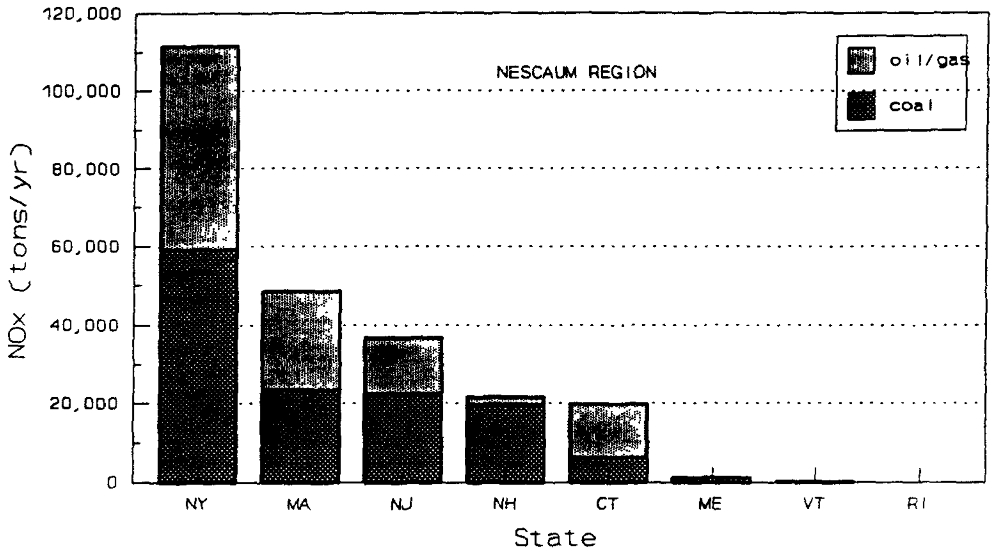

Figure 1-1. Post-RACT 1995 utility boiler NO_x emissions by state — NESCAUM region

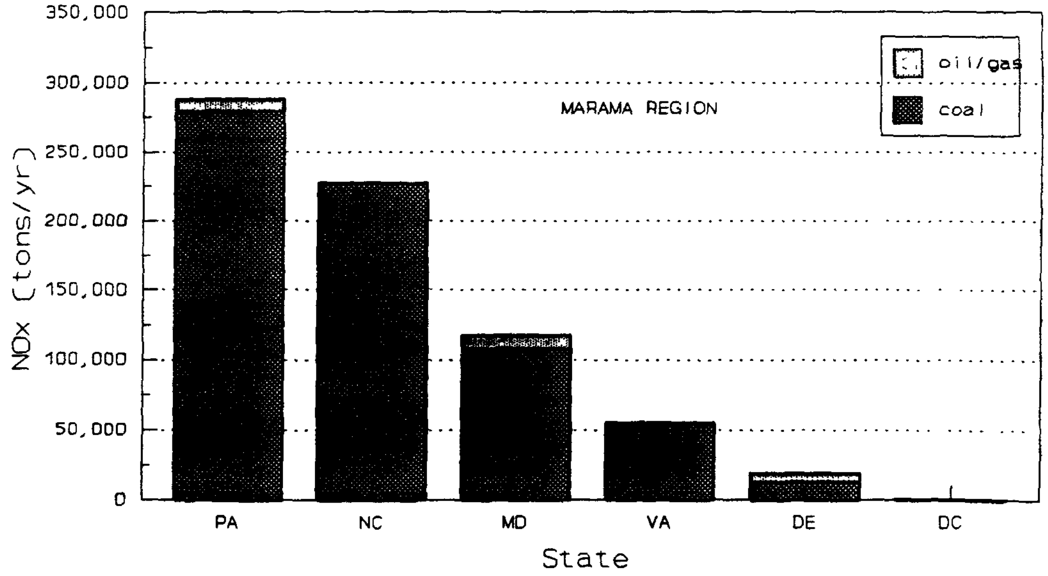

Figure 1-2. Post-RACT 1995 utility boiler NO_x emissions by state — MARAMA region

fuel used, have been in service for 20 to 50 years. The average age for all boilers is approximately 35 years. Total NO_x emissions from utility boilers in NESCAUM, following the implementation of RACT, is estimated to be about 235,000 tons/year. In MARAMA, the total NO_x emissions are estimated to be nearly 710,000 tons/year, dominated by coal-fired power plants.

Figures 1-3 and 1-4 illustrate the total NO_x emissions for all utility boilers segregated according to the type of RACT control technology that was in place by May 31, 1995. The information was generated from a survey of RACT plans in each state, supplemented by selected data from utilities. The control technologies include:

- LNB = Low-NO_x burners with or without separate overfire air, and Low-NO_x Cell Burners (LNCBs)
- UNC = Boilers that will remain uncontrolled because they are either not required to install RACT (e.g., all boilers in the non-OTR state of North Carolina) or because they are included in averaging or are scheduled for early retirement
- CTR = Combustion controls such as flue gas recirculation (FGR), burners out of service, burner tuning, biased firing, low excess air firing, or gas reburning
- FGT = Flue gas treatment controls that include either selective catalytic (SCR) or noncatalytic (SNCR) reduction or a combination of these
- RPW = Repowering with either gas turbine or other technology
- FSW = Fuel switching to cleaner burning natural gas
- RET = Retired or decommissioned boilers

Because the survey was not complete, an additional category, labeled NRP, is also included for boilers whose RACT compliance was not yet defined by the utilities or for those who elected not to participate in the survey.

Figure 4-1 illustrates the dominance of combustion controls for RACT compliance for oil/gas-fired boilers in the NESCAUM Region and LNB controls for coal units. The disproportionate application of coal-fired LNB controls in the MARAMA Region compared to the

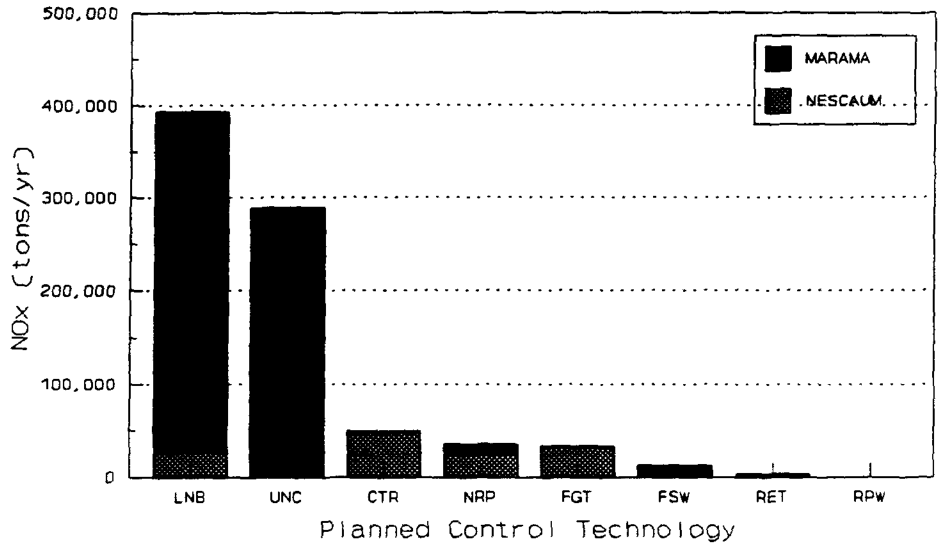

Figure 1-3. Post-RACT 1995 utility boiler control technologies — coal-fired NO_x emissions

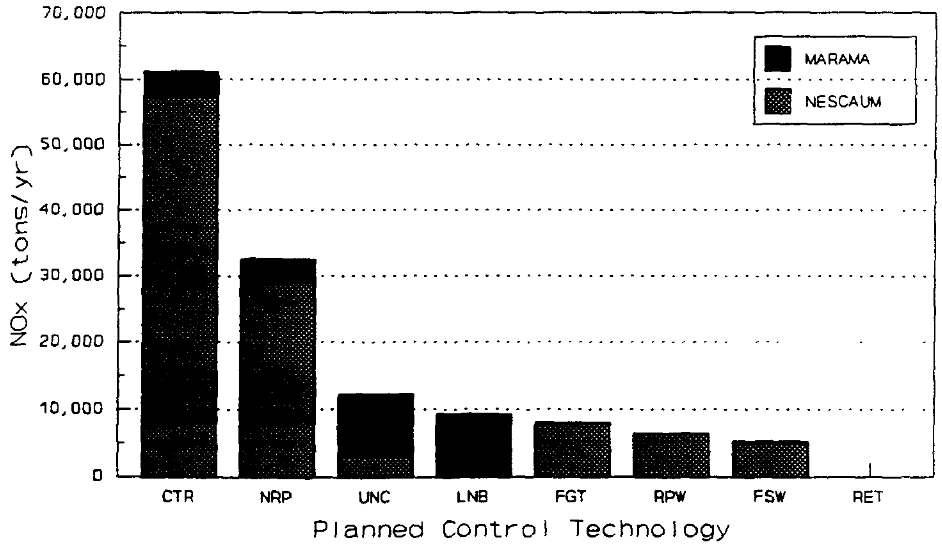

Figure 1-4. Post-RACT 1995 utility boiler control technologies — projected oil/gas-fired NO_x emissions

NESCAUM Region is principally due to many coal-plants in Pennsylvania that have undergone retrofit of a variety of LNB controls for wall and tangential boilers, including LNCFS II and LNCFS III technology, and LNCB. The total NO_x emissions from LNB-controlled units is estimated to be about 400,000 tons per year by 1995. An estimate 290,000 tons/yr are emitted from uncontrolled coal-fired units, principally in North Carolina and Virginia. Boilers controlled with FGT technologies include the recent retrofits at the Public Service of New Hampshire (PSNH) Merrimack coal-fired cyclones Units 1 and 2 and several Public Service Electric and Gas (PSE&G) units in New Jersey. The total post-RACT utility boiler NO_x inventory for NESCAUM and MARAMA is estimated at about 940,000 tons/yr.

Table 1-1 lists the NO_x emission levels for individual units following RACT implementation, where applicable, after May 1995. The data were compiled in response to a utility survey of emission levels following the implementation of RACT controls. The data represent a mix of actual emissions or permitted levels. No specific averaging time is intended. The average reported values, instead, are calculated arithmetic averages for the population of boiler firing types and weighed according to boiler capacity within each population group.

Table 1-1. Post RACT NO_x emission factors for utility boilers in NESCAUM and MARAMA, lb/MMBtu

	Coal-fired Boilers		Gas/Oil-fired Boilers	
RACT Control Technology	Range	Average[a]	Range	Average[a]
Uncontrolled	0.50 to 1.2 (W) 0.45 to 0.70 (T)	0.90 (W) 0.55 (T)	0.30 to 0.70 (W) 0.30 to 0.50 (T)	0.50 (W) 0.40 (T)
Low-NO_x burners (LNBs)	0.38 to 0.70 (W) 0.35 to 0.75 (T)	0.50 (W) 0.45 (T)	0.28 to 0.45 (W) 0.28 to 0.50 (T)	0.43 (W) 0.40 (T)
Combustion controlled	0.45 to 0.55 (W) 0.42 to 0.45 (T)	0.45 (W) 0.42 (T)	0.25 to 0.40 (W) 0.25 to 0.45 (T)	0.25 (W) 0.28 (T)
Flue gas treatment (FGT)	0.37 to 0.55 (W) 0.90 to 1.4 (C)	0.48 (W) 1.2 (C)	0.22 to 0.25 (W) 0.22 to 0.25 (T)	0.25 (W) 0.25 (T)

W = wall-fired boiler; T = tangential-fired boiler; C = cyclone-fired boiler.
[a]Capacity weighted average.

The length of averaging time can play an important role in quantifying the performance limits of a given technology. For example, on a short-term basis, controlled NO_x levels can be influenced by many boiler operating factors including load, fuel quality, and equipment maintenance. These factors tend to raise the NO_x levels on a short-term basis. Over a period of a year, however, the influence of many of these factors is greatly diminished and much lower average NO_x levels are possible. Because the data presented in this report are not sufficient to distinguish between averaging times, it is prudent to view all reported NO_x reduction efficiencies and controlled levels as annual average levels until more detailed performance data are made available.

On average, LNB-controlled coal-fired boilers are lower than the Acid Rain presumptive limits of 0.45 and 0.50 lb/MMBtu for tangential and wall units respectively. Calculated averages for these LNB-retrofitted boilers are 0.43 lb/MMBtu for wall-fired and 0.40 lb/MMBtu for tangential boilers. However, the range in NO_x levels shows LNB-controlled emissions as high as 0.75 lb/MMBtu for some tangential-fired units. Uncontrolled coal units, principally in North Carolina and parts of Virginia, where RACT does not apply, continue to show emission levels as high as 1.2 lb/MMBtu.

Recent SNCR and SCR controls for coal-fired units have lowered NO_x emissions to levels in the range of about 0.37 to 0.55 lb/MMBtu for four wall-fired units and to levels in the range of 0.90 to 1.4 lb/MMBtu for four high NO_x emitting cyclone boilers. For gas/oil-fired boilers, a combination of combustion controls and low-NO_x burners will maintain NO_x levels in the 0.25 to 0.45 lb/MMBtu for the most part. Actual NO_x levels will depend on fuel type, grade of oil, and RACT control level.

1.2 POST-RACT NO_x CONTROLS

Table 1-2 lists retrofit NO_x controls considered candidates for post-RACT NO_x reductions from utility boilers. Control candidates exclude "first-round" combustion controls such as LNB for coal units and a variety of combustion modifications such as FGR, OFA, BOOS, etc. for gas/oil-fired boilers. Separate overfire air (SOFA), often included in tangential LNB retrofits, is not

Table 1-2. List of candidate retrofit controls for Phase II NO_x reductions

Coal-fired Utility Boilers			Oil/Gas-fired Utility Boilers	
Cyclones	**Corner-fired**	**All Other Firing Types**	**Corner-fired**	**All Other Firing Types**
Coal Reburning	Gas Cofiring	Gas Cofiring	Gas Cofiring	Gas Cofiring
Gas Reburning: • Standard • Advanced	Gas Reburning: • Standard • Close-coupled • Advanced	Gas Reburning: • Standard • Advanced	Gas Reburning: • Standard • Close Coupled • Advanced	Gas Reburning: • Standard • Advanced
	Gas Conversion	Gas Conversion	Gas Conversion (O to G)	Gas Conversion (O to G)
Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • Combined NO_x/SO_x	Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • Combined NO_x/SO_x	Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • Combined NO_x/SO_x	Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • AH-SCR	Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • AH-SCR

considered a viable post-RACT retrofit control for coal-fired wall boilers, unless applied with natural gas reburning control, because of the marginal NO_x reduction performance and the potential for severe operational impacts on some units.

For uncontrolled coal-fired cyclones, candidate controls include coal and gas reburning and a variety of flue gas treatment (FGT) options. Coal and gas reburning are most effective for base-loaded units. Because most utility boilers experience some load reduction during off-peak demand, use of reburning fuel can be curtailed during these times. FGT controls all rely on the properties of ammonia-based compounds to reduce NO_x with or without the presence of catalysts. These FGT options include few commercial NO_x/SO_x combined gas treatment systems with recent demonstrations in the U.S. and commercial applications in Europe. For other coal-fired boiler types, equipped with either low-NO_x concentric firing systems (LNCFS^{TM}) for tangential firing or low-NO_x circular burners for wall firing, controls are similar but exclude coal reburning and include gas cofiring and gas conversion. Many LNBs just recently retrofitted on pulverized coal-fired boilers, do not have gas cofiring capability. Experience with cofiring or gas conversion for LNB-controlled coal units is presently lacking.

For gas/oil-fired boilers, post-RACT controls also include gas cofiring for oil-based units, reburning for either oil- or gas-fired boilers, and gas conversions from oil to gas. SNCR technology has been installed already on three separate oil/gas-fired boilers with a total generating capacity of 530 MWe. SCR technology is also applicable on oil/gas-fired units. However, no SCR controls are yet part of the NO_x control arsenal in NESCAUM or MARAMA. Although SCR technology is certainly feasible for these boilers, technical and economic factors of catalyst use with high-sulfur oil burning are important considerations and possible limitations on their ultimate use. In place of combined NO_x/SO_x controls, catalytic air heaters (AH-SCR) used principally in combination with either SNCR and SCR systems offer additional control options for principally gas-fired boilers, and potentially coal-fired boilers as well. SO_2 reductions for oil/gas-fired boilers are typically not obtained by scrubbers because lower sulfur fuels or cofiring can be used to control SO_2 emissions more cost effectively.

Table 1-3 lists known retrofits and new boilers in the U.S. equipped with post-RACT controls considered in this study. The list includes more than 20,000 MWe of gas-based technologies, principally cofiring and full-scale gas conversions to permit 100 percent gas-firing capacity. Reburning experience with natural gas include about 1,200 MWe of demonstration capacity, focused primarily on the demonstration of the technology on smaller size utility boilers (<200 MWe), although larger retrofit applications are planned. The list of domestic flue gas treatment installations includes 15,000 MWe of retrofit and new boiler capacity. The total commercial SNCR-controlled utility boiler capacity, in place and planned for the near future, amounts to nearly 2,000 MWe. Commercial SCR-controlled capacity amounts to about 9,000 MWe. Most of the capacity is retrofit on dedicated gas-fired boilers located in California. Only 440 MWe is coal-fired retrofits, all on two slagging furnaces. An additional 1,200 MWe coal-fired SCR capacity is in place or planned for new installations. No combined SO_x/NO_x control technologies are either installed or planned in the U.S., with few DOE-sponsored demonstrations showing promising results and some commercial installations in Europe.

Tables 1-4 and 1-5 summarize the range in NO_x percent reductions for these post-RACT control technologies. The data are based on a combustion of recent retrofit short- and long-term test results from commercial and technology demonstration programs. The data suggest that cofiring with up to 20 percent natural gas in coal-fired boilers has a NO_x reduction potential of 10 to about 40 percent, depending on the boiler firing configuration and the location and method of gas use. Gas reburn, with 15 to 20 percent gas can reach NO_x reduction efficiencies as high as 65 percent, whereas full-scale gas conversions can reduce NO_x to a maximum of 75 percent. The actual NO_x reduction achieved with gas conversions, however, depends not only on the intensity of the heat release rate in the furnace (burner zone waterwall area) but also on the degree of combustion controls, such as FGR, associated with the new gas burners. Operational concern with

Table 1-3. Utility boilers in the United States with experience with gas-based and flue gas treatment NO_x control technologies

Control Category	Technology	Station Identification and State (Commercial and Demonstration Sites)	Boiler Capacity and Firing Type
Gas-based Controls	Natural Gas Reburning	2 Units in Illinois 2 Units in Ohio 2 Units in Colorado 1 Unit in Kansas 1 Unit in New York	521 MWe coal-fired tangential 143 MWe coal-fired cyclone 385 MWe coal-fired wall/other 185 MWe oil/gas-fired tangential
	Gas Cofiring	6 Units in Pennsylvania 3 Units in Massachusetts 3 Units in Indiana 2 Units in Texas 1 Unit in Alabama 1 Unit in Kansas 1 Unit in Ohio 7 Units in Illinois 1 Unit in Florida 1 Unit in Michigan 4 Units in Maryland 2 Units in New Jersey 2 Units in Mississippi 2 Units in Wyoming	5,712 MWe coal-fired tangential 3,328 MWe coal-fired wall 2,043 MWe oil/gas-fired
	Natural Gas Conversions	6 Units in Illinois 4 Units in Ohio 2 Units in Michigan 2 Units in Arizona 2 Units in Massachusetts 2 Units in New Jersey 2 Units in New York 2 Units in Connecticut 1 Unit in Colorado 1 Unit In Florida 1 Unit in Indiana	974 MWe coal-fired tangential 620 MWe coal-fired wall 1,124 MWe coal-fired other 4,992 MWe oil-fired
Flue Gas Treatment Controls	SNCR-based Controls	10 Units in California 4 Units in Massachusetts 3 Units in New York 5 Units in New Jersey 1 Unit in Wisconsin 1 Unit in Colorado 2 Units in New Hampshire 1 Unit in Delaware	1,392 MWe coal-fired wall 3,492 MWe gas/oil-fired 421 MWe coal-fired cyclone 741 MWe coal-fired other firing
	SCR-based Controls	21 Units in California 4 Units in New Jersey 1 Unit in Massachusetts 1 Unit in Florida 1 Unit in New Hampshire	6,965 MWe gas-fired 1,582 MWe dry-bottom coal-fired 659 MWe wet bottom and cyclone

Table 1-4. Summary of NO_x percent reductions for coal-fired boilers

Control Type	Wall-fired Boilers		Tangentially-fired Boilers		Cyclone and Slagging Furnaces
	Uncontrolled (0.90 lb/MMBtu)	LNB-Controlled (0.50 lb/MMBtu)	Uncontrolled (0.6 lb/MMBtu)	LNB-Controlled (0.45 lb/MMBtu)	Uncontrolled (1.2 lb/MMBtu)
Cofire	25 to 40	NA	10 to 35	25 to 40	NA
Reburn	40 to 65	30 to 50	65	20 to 25	45 to 60
Conversion	40 to 70	35	70 to 75	NA	45 to 50
SNCR[a]	30 to 65	30 to 40	30 to 50 (est.)	30 to 35 (est.)	30 to 40
SCR	60 to 90	60 to 90	60 to 90	60 to 90	60 to 90
Hybrids: SNCR+SCR[b]	80 to 95	80 to 95	80 to 95	80 to 95	80 to 95
AGR[c]	80 to 85 (est)	80 to 85 (est)	80 to 85 (est)	80 to 85 (est)	80 to 85 (est)
NO_x/SO_x	80 to 85	80 to 85	80 to 85	80 to 85	80 to 85

NA = Not applicable.
[a]SNCR NO_x reduction efficiencies based on maximum of 10 ppm NH_3 slip.
[b]Estimates based on recent demonstration successes at Mercer Station.
[c]Advanced gas reburn (GR+SNCR). Not yet demonstrated.

Table 1-5. Summary of NO_x percent reductions for oil/gas-fired boilers

Control Type	Wall-fired Boilers		Tangentially-fired Boilers		Cyclone and Slagging Furnaces
	Uncontrolled (0.50 lb/MMBtu)	LNB-Controlled (0.35 lb/MMBtu)	Uncontrolled (0.30 lb/MMBtu)	LNB-Controlled (0.25 lb/MMBtu)	Uncontrolled (0.52 lb/MMBtu)
Cofire	20 to 30 (est)	20 to 30 (est)	20 to 30 (est)	20 to 30 (est)	ND
Reburn	50 to 60	50 to 60	50 to 60	30 to 40	ND
Conversion (oil to gas)	30 to 40	40 to 50 (est)	30 to 40	40 to 50 (est)	10 to 20 (est)
SNCR[a]	25 to 40	10 to 40	25 to 40	10 to 40	ND
SCR[b]	80 to 95	80 to 95	80 to 95	80 to 95	ND
Hybrid (SNCR+SCR)[b]	70 to 90	70 to 90	70 to 90	70 to 90	ND

[a]SNCR results based on maximum NH_3 slip of 10 ppm.
[b]Data for SCR and hybrids are for gas-fired boilers only.

gas-based technologies generally increase with increasing heat input from natural gas because of shifts in the heat absorption profile in the furnace leading to increased furnace exit gas temperature and increased loss in efficiency. Although some recent tests confirm NO_x reductions in the 30 to 50 percent range with reburn on one LNB-controlled coal unit, long-term operational experience is generally limited. Gas cofiring and reburning can be particularly effective in reducing NO_x from tangential coal-fired boilers using the top burner elevation for the reburn zone.

Among the various applications of natural gas as a utility boiler fuel, reburning remains the most efficient way of using gas for NO_x reduction. With this technology, the NO_x reduction potential is the highest for a given percent of gas use. Table 1-6 lists ranges in NO_x reductions normalized by the amount of gas used. Cofire, conversion, and seasonal gas use offer either lower NO_x reduction potential or require much higher gas use. Because of the fuel cost differential between gas and coal, the amount of gas needed to reduce NO_x from coal-fired boilers is one of the main utility concerns with the application of gas-based technologies. Additional utility concerns that may limit increased natural gas use solely for NO_x control include:

- Long-term natural gas availability
- Access to gas supply (proximity to pipeline)
- Marginal NO_x reduction beyond LNB

Table 1-6. Documented NO_x reductions from coal-fired boilers with gas-based control technologies[a]

	Wall-fired Boilers		Tangentially-fired Boilers		Cyclone and Slagging Furnaces
Control Type	Uncontrolled (0.90 lb/MMBtu)	LNB-Controlled (0.50 lb/MMBtu)	Uncontrolled (0.6 lb/MMBtu)	LNB-Controlled (0.45 lb/MMBtu)	Uncontrolled (1.2 lb/MMBtu)
Cofire	0.90 to 2.8	NA	0.75 to 1.2	0.56 to 0.90	NA
Reburn	2.5 to 3.4	1.0 to 1.6	2.2	0.56 to 0.90	3.4 to 4.0
Conversion	0.41 to 0.68	0.35	0.42 to 0.45	NA	0.54 to 0.64

[a]All units are in lb of NO_2 reduced per MMBtu of gas used in the control technology. Cofiring gas use less than 8 to 35 percent; reburning 16 to 20 percent; conversion 100 percent gas firing.

- Competitive gas pricing and availability of long-term contracts
- Reburning performance on large-scale coal boilers
- Combustion safety of gas injector designs

Recent estimates on natural gas availability for NO_x control on utility boilers in the OTR project 3,490 MMcfd available in 1997, reducing to 2,830 by the year 2000. A hypothetical scenario where all dry furnaces in both NESCAUM and MARAMA would be retrofitted with 20 percent gas cofiring or reburning capability would necessitate approximately 1,400 MMcfd, considering year around operation with these controls. Therefore, these estimates would suggest that gas will be available to implement the reburning and cofiring techniques, should these be considered by the utilities for their NO_x reduction compliance strategies. A recent study sponsored by the Coalition for Gas Based Environmental Solutions, Inc. also revealed that only about 9 percent (14 out of 155 units) of the total coal-fired generating capacity in the OTR is currently equipped to burn any amount of natural gas. Most of these plants with dual-fuel firing capability only have access to sufficient natural gas for ignition, warm up, and for flame stabilization which require relatively small amounts of gas. Therefore, to adapt these units to either reburning or cofiring with a maximum of 20 percent gas use, it would require installation of new pipelines and burner equipment. The study went on to reveal that, although few power stations have any gas firing capability, nearly half are located less than 5 miles from an existing natural gas pipeline. For oil-fired utility boilers, 39 percent of the existing capacity has gas service, and 20 percent are fully dual fuel boilers capable of supplying full capacity on either oil or gas. Many of the oil-fired boilers are also located within 5 miles of a gas pipeline. The same study also revealed that the current and projected differential cost between coal and natural gas is not attractive to increased gas use in utility plants.

NO_x reduction by natural gas reburning on uncontrolled coal-fired boilers have been reported in the range of 45 to 65 percent depending on amount of gas used, boiler load, and other factors. However, when applied to LNB-equipped boilers the NO_x reduction of gas reburning can fall as low as 20 percent for some tangential boilers to as high as 50 percent for wall-fired units.

The NO_x reduction performance can further deteriorate from these levels when the boilers operate at reduced load. The lower NO_x reduction performance of reburn for LNB-equipped boilers can be an important consideration for load-cycling units. The reduced NO_x reduction of reburning could also affect its competitiveness when compared on a cost-effective basis, especially when fuel differential costs are high.

Although most gas reburning demonstrations to date have been on smaller scale utility boilers, several research efforts are underway to demonstrate the technology on larger utility boilers and improve the gas reburning process for utility applications. This research includes improved gas injection mechanisms to maximize the mixing and possibly reduce the amount of gas required; removing the need for FGR, thus reducing operational complexity and cost; improving OFA port designs to achieve more complete and rapid burnout; combining reburning techniques with selective noncatalytic reduction (SNCR) in advanced reburning concepts; and more efficiently integrating gas reburning into the operation of pulverized coal-fired low-NO_x burners for enhanced NO_x reduction.

The applicability of ammonia-based flue gas treatment controls, whether catalytic or noncatalytic, hinges on several factors such as fuel choice, boiler load dispatch, ease of retrofit access, age of unit, initial NO_x level, gas temperature, and others. Yet these controls installed by themselves or in combination may provide the only feasible approach to deep reductions in NO_x from post-RACT levels. Although experience is growing at a rapid pace, widespread reliance on both non-catalytic and catalytic controls will be more likely once long-term performance has been ascertained and operational impacts and costs fully realized. In the interim, further technical improvements and demonstrations of commercial and novel technologies will likely improve the retrofit potential of many of the flue gas treatment controls.

Retrofit experience to date indicates that SNCR, by itself, for either coal- or oil/gas-fired plants already controlled with RACT, is likely to be able to reduce NO_x in the range of 10 to 40 percent depending on initial NO_x levels and its load dispatch characteristics. Although SNCR commercial experience has been on furnaces with a capacity less than 160 MWe with NO_x reduction levels up to 65 percent, application is deemed also feasible to larger size boilers with optimum performance and ease of operation for base-loaded high NO_x emission boilers. SCR and hybrid technologies offer the potential to exceed 60 percent NO_x reduction in all installations, whether RACT-controlled or not. The range in NO_x reduction in Table 1-4 of 60 to 90 percent reflects the flexibility of SCR to deliver moderate to high percent reduction efficiencies depending on the volume of catalyst and ammonia reagent used, as required to meet regulations. In reality, SCR can achieve 80 percent control or more for most applications, including boilers with low inlet NO_x levels, as demonstrated in California. Therefore, their applications are particularly suitable for retrofit on RACT-controlled boilers. Although the technical and experience gains of recent years on the use of SCR and SNCR+SCR hybrids are obvious, greater experience is necessary to fully document the long-term performance of these novel control approaches. The feasibility of retrofitting SCR by itself or as a hybrid in SNCR+SCR applications must be evaluated on a case by case basis because of the equipment, fuel, and layout constraints that are particular to each installation and because cost and performance of SCR can be affected by these factors.

1.3 COST OF CONTROLS

The influence of site-specific factors on the cost of retrofitting NO_x controls to existing boilers is well accepted. Among process capital and O&M costs are many cost components that are influenced by the location of the plant, its age and operating condition, the configuration of equipment, fuel, and load dispatch. Within some degree of uncertainty, however, it is possible to formulate estimates of actual cost of NO_x controls for utility boilers using costs reported for similar installations and estimating a range that will likely account for many of the site specific effects.

Table 1-7 lists the estimated ranges in the capital and busbar costs, and cost effectiveness for post-RACT controls on coal-, oil-, and gas-fired boilers. The range in NO_x reduction, in lb/MMBtu, reflects the estimated reductions from LNB-controlled wall and tangential boilers. These reduction levels are then used to estimate the cost effectiveness of the controls on a post-RACT basis.

Table 1-7. Summary of costs for retrofit of a 200-MWe boiler

Post-RACT Control	Capital Cost ($/kW)	Coal-fired Boilers			Oil-fired Boilers			Gas-fired Boilers		
		Amount of NO_x Reduced (lb/MMBtu)[a]	Busbar (mill/kWh)	Cost Effectiveness ($/ton)	Amount of NO_x Reduced (lb/MMBtu)[a]	Busbar (mills/kWh)	Cost Effectiveness ($/ton)	Amount of NO_x Reduced (lb/MMBtu)[a]	Busbar (mills/kWh)	Cost Effectiveness ($/ton)
NGR	20-30	0.10 - 0.40	0.93 - 2.0	460 - 3,900	0.15 - 0.20	0.33 - 1.2	320 - 1,800	0.15 - 0.20	0.33 - 0.61	320 - 1,200
NGR[b]	25-35	0.10 - 0.40	1.2 - 2.1	610 - 4,200	0.15 - 0.20	0.47 - 1.4	470 - 2,100	NA	NA	NA
NGC	10-20	0.25 - 0.50	8.2 - 8.3	3,300 - 6,600	0.15 - 0.25	2.5 - 2.7	2,000 - 4,100	NA	NA	NA
NGC[b]	20-30	0.25 - 0.50	8.4 - 8.6	3,400 - 6,900	0.15 - 0.25	2.7 - 2.8	2,200 - 4,200	NA	NA	NA
SNCR	11-14	0.30-0.90[c] 0.10-0.30[d]	1.3 - 3.1 0.77 - 1.3	700 - 880[c] 850 - 1,300[d]	0.10 - 0.20	0.77 to 1.0	1,000 - 1,400	0.10 - 0.20	0.77 to 1.0	1,000 - 1,400
SCR (in-duct)	26-32	NA	NA	NA	0.20 - 0.35	1.5 - 1.6	900 - 1,500	0.20 - 0.35	1.5 - 1.6	900 - 1,500
SCR-AH	25	NA	NA	NA	0.05 - 0.20	1.6 - 2.0	2,000 - 3,200	0.05 - 0.20	1.6 - 2.0	2,000 - 6,000
SCR	78-87	0.60 - 1.7[c] 0.25 - 0.60[d]	3.4 - 5.8 2.6 - 3.4	500 - 1,200[c] 1,200 - 2,800[d]	0.25 - 0.40	2.6 - 3.2	1,600 - 2,000	NA	NA	NA
SNCR + SCR	54-62	0.30 - 0.60	2.5 - 3.5	1,100 - 1,800	NA	NA	NA	0.25 - 0.40	1.8 - 2.0	1,400 - 2,200
AGR	36-46	0.30 - 0.60	2.4 - 2.7	900 - 1,600	NA	NA	NA	NA	NA	NA

[a] NO_x reductions in lb/MMBtu from ranges of post-RACT implementation levels on NESCAUM and MARAMA utility boilers. Calculated from LNB-controlled levels for dry bottom coal-fired boilers and combustion-controlled levels from gas/oil-fired boilers (see Chapter 2 for details of post-RACT levels).
[b] Additional capital cost for access to pipeline.
[c] Cost effectiveness and NO_x reductions for uncontrolled cyclone and wet bottom furnaces.
[d] Cost effectiveness and NO_x reductions for LNB-controlled dry bottom furnaces.
[e] Combination of SNCR, in-duct SCR, or CAT-AH.

Notes: For reburn: Coal-gas fuel price differential = $0.5 to 1.0/MMBtu; Oil-gas price differential = $0.0 to 0.50/MMBtu; no price differential for gas-gas reburn.
For conversion: coal-gas fuel price differential = $1.0/MMBtu; oil-gas price differential = $0.50/MMBtu.
NA = Not applicable or not a probable control option.
Boiler capacity factor = 60 percent in all cases.

The cost for gas-based controls is dominated, by and large, by the fuel price differential between the primary fuel and natural gas and on the value of clean-fuel credits that result from lower SO_2 and fly ash emissions and from reduced plant maintenance. For gas treatment controls, SNCR continues to be the lowest capital cost technology. However, because SNCR has lower NO_x reduction capability compared with SCR, for example, on a cost-effectiveness basis SNCR may not always offer an economic advantage. For example, on uncontrolled high emitting cyclone furnaces, SCR may prove to be slightly more cost effective based on economic assumptions used in the analysis. The capital cost of SCR has shown a large downward trend in recent years, the result of improved technology, more efficient catalyst management extending the life of the catalyst, and increased market competition. Although the SCR experience in the United States is primarily on in-duct catalysts for gas-fired boilers and for full-scale SCR reactors on new coal plants, retrofit of SCR on existing coal-fired units have recently taken place. Although all post-RACT controls considered offer the potential for tailored NO_x reduction, SCR technology has perhaps the greater range in performance. That is, the amount of catalyst can be tailored to the percent NO_x reduction needed. In fact, many of the recent SCR installations on coal plants have an initial NO_x reduction target of 65 percent with provisions for additional catalyst to increase performance to 85 percent or higher.

Among the three gas-based control technologies, natural gas reburn (NGR) offers the lowest cost per ton of NO_x reduced because the amount of gas used is lowest and NO_x reductions are typically larger than other gas-based controls. The capital cost of NGR is considered to fall in the range of \$20 to \$30/kW, except when access to a sufficiently large pipeline is not readily available. Under these conditions, the capital cost can increase by \$5 to \$10/kW to account for the price of installing a 5 to 10 mile pipeline. Busbar costs for NGR on coal-fired boilers are on the order of 0.93 to 2.0 mills/kWh based on a coal-gas price differential of \$0.50 to 1.0/MMBtu. This level is lower for oil-fired boilers because a range between \$0 and \$0.50/MMBtu fuel differential cost was considered. Natural gas conversions have a large busbar cost because the impact of fuel differential cost is much larger.

Pipeline gas supply is one of the most important factors that determine natural gas availability to the utilities. The estimates of fuel differential costs used in these calculations are subject to considerable uncertainty because of the month-to-month volatility in the demand and price of natural gas. In fact, the use of natural gas is very seasonal. In the summer months when the residential and commercial demand is lowest, the price of natural gas becomes more attractive because of the increased pipeline capacity. It is during these particular periods that natural gas can be most cost effective in reducing NO_x from utilities.

SNCR technology has successfully been installed on cyclone as well as other boiler firing types. Estimates of the retrofit cost are \$11 to \$14/kW and a busbar cost in the range 0.77 mills/kWh for low NO_x emitting dry bottom boilers equipped with LNB to as high 3.1 mills/kWh for high NO_x emitting uncontrolled cyclone or wet bottom boilers. Cost effectiveness of SNCR is typically less than \$1,000/ton for most retrofits, especially where larger NO_x reductions are possible. The capital cost of SCR will vary according to the amount of catalyst installed. Smaller catalyst volumes for in-duct and air heater applications will have much lower capital costs than full-scale systems. However, many of these systems are most likely to be retrofitted on gas- and light-oil fired units when used alone, that is, not in an hybrid SNCR+SCR configuration. Cost effectiveness of these systems remains well above the \$1,000/ton because smaller NO_x reductions are possible when the technologies are applied to cleaner burning fuels. Finally, full-scale SCR of average retrofit sufficiently is estimated to have a capital cost in the range of \$78 to \$87/kW for 80 percent NO_x reduction systems on a 200 MWe coal-fired utility boiler. These cost are likely to be lower for cleaner burning fuels or for applications on low dust environments. The cost effectiveness of full-scale (80-percent NO_x reduction) SCR for a coal plant will be lower than \$1,000/ton when NO_x reductions are large, for example in the case of retrofit of some uncontrolled cyclone and wet bottom units such as Merrimack Unit 2 and Mercer Unit 1. For conventional

LNB-retrofit wall and tangential boilers, the cost effectiveness is estimated to be in the range of \$1,200/ton to \$2,000/ton. Hybrid SNCR + SCR systems are considered more cost effective than full scale SCR. This analysis indicates cost effectiveness range in \$1,100 to \$1,800/ton for similar NO_x reduction levels. Because experience is limited or nonexistent in the case of AGR, estimates of capital cost and cost effectiveness should be interpreted with caution.

Figures 1-5 and 1-6 illustrate the cost effectiveness of post-RACT controls on a 200 MWe dry bottom coal-fired boiler equipped with LNB when controls are used all year and only during the ozone season, typically 5 months of the year. The data are plotted versus gas-coal price differential to reflect the sensitivity of gas-based controls to the price of natural gas versus coal. The controls include NGR, SNCR, SCR and Hybrid (SNCR+SCR). The two sloped lines represent the upper and lower range in cost effectiveness for NGR, which among the four selected control types, is the only control that would show a sensitivity to price of natural gas.

In Figure 1-5, the cost effectiveness of SCR and hybrid controls (SNCR + SCR) overlap and are shown to be in the range of about \$900 to \$2,000/ton. The cost effectiveness band for SNCR is lower, in the range of \$850 to \$1,300/ton. As indicated, in Figure 1-5, NGR can be most competitive when both the NO_x reduction achieved is highest, estimated in this report to be about 0.40 lb/MMBtu, and the fuel price differential is below \$0.5/MMBtu. This level of NO_x reduction is more representative of NGR control performance on uncontrolled coal-fired boilers rather than LNB-controlled units. When NO_x reductions for NGR are minimal, perhaps as low as 0.1 lb/MMBtu from well controlled tangential-fired units, NGR promises to be less cost competitive on a year-around application basis.

The conclusions differ somewhat when controls cost effectiveness are viewed on seasonal use basis. Here, gas-based NGR controls can be less costly or equally competitive with most gas treatment ammonia-based controls up to a fuel price differential of \$0.50/MMBtu and the amount of NO_x reduction achieved is 0.25 lb/MMBtu. If the NO_x resolution is large, e.g., approaching 0.4 lb/MMBtu, NGR on a seasonal basis is the most cost-effective approach as long as fuel-price differentials are lower than about \$1.0/MMBtu. For seasonal use of controls, cost effectiveness

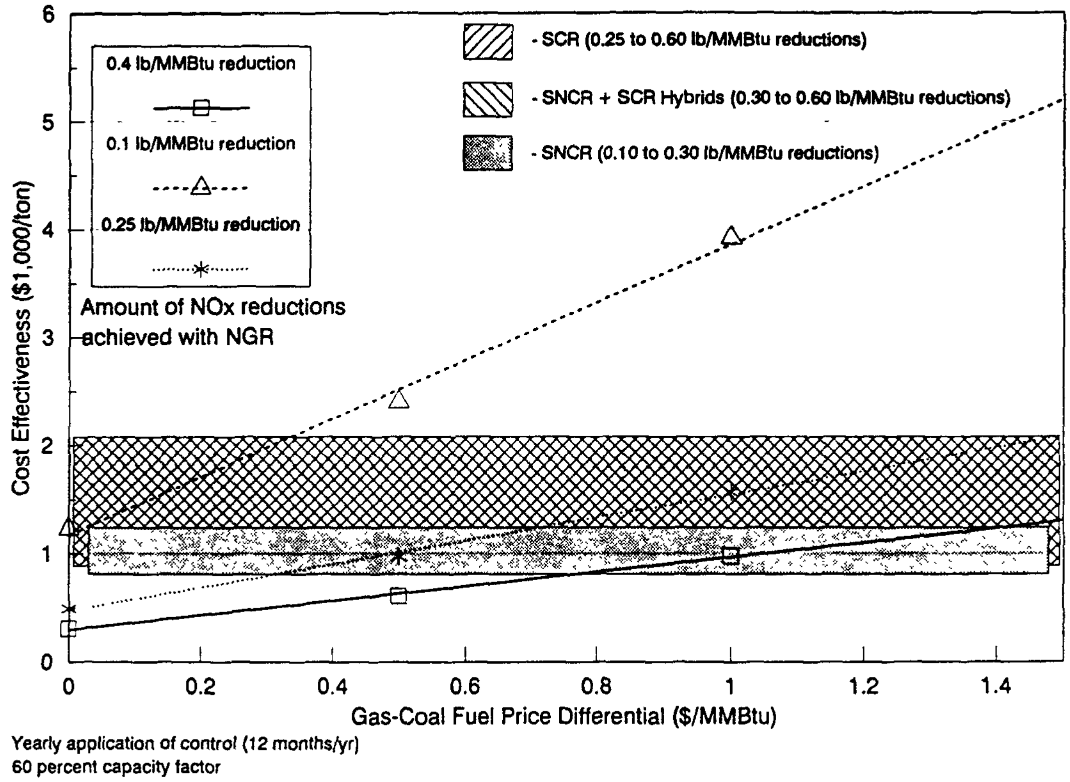

Figure 1-5. Cost effectiveness of controls used all year around

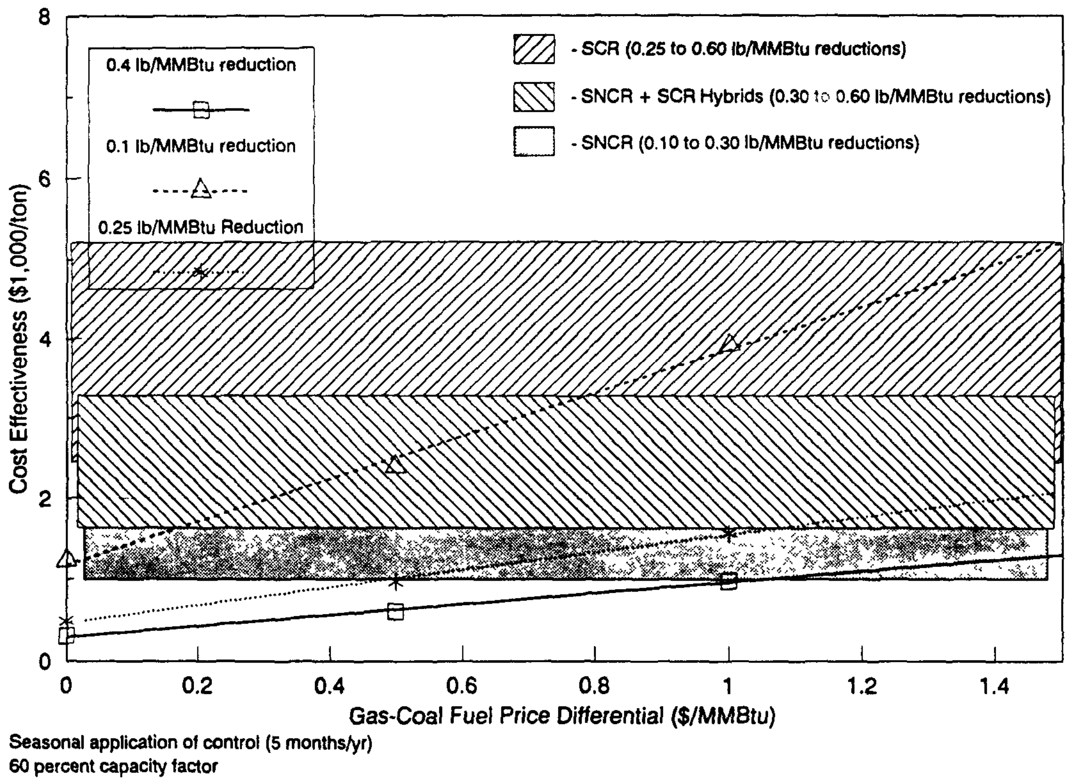

Figure 1-6. Cost effectiveness of controls used on a seasonal basis

generally rises because the capital cost is amortized over fewer kW-hr. For example, the cost effectiveness of SNCR worsens from about $850 to $1,300/ton on a yearly basis to about $1,000 to $1,900/ton on a seasonal basis depending on the level of NO_x achieved. SCR, with the most intensive capital investment has the largest increase in dollars spent per ton of NO_x reduced when going from a yearly use to a seasonal use. These results assume that the catalyst life does not improve with seasonal use of SCR control, a probability of the catalyst cannot be bypassed or removed from the gas stream.

CHAPTER 2

BOILER AND EMISSIONS PROFILES IN MARAMA AND NESCAUM STATES

The objective of this chapter of the report is to provide a profile of the boiler population and NO_x emissions from utility boilers in NESCAUM and MARAMA following the full implementation of RACT controls in May 1995. Because considerable progress in reducing regional NO_x was recently made with the implementation of first round of RACT controls, it is important to update the baseline from where additional NO_x reductions can be evaluated. Fuels types and emission levels have an important impact on the selection of controls, the anticipated NO_x reduction level, and its cost effectiveness. Furthermore, the retrofit feasibility of post-RACT controls and their cost effectiveness are often influenced by decisions made on these first round of controls. For example, boilers undergoing seasonal fuel switch or fuel conversions to natural gas may be better amenable to a whole host of controls. Conventional combustion controls, including gas reburning, can further suppress NO_x from boiler burning natural gas. Post-combustion controls using lower costs in-duct catalysts or hybrid controls that combine noncatalytic and catalytic reduction are also possible. But, because NO_x levels from gas-fired boilers are generally lower, the costs to reduce 1 ton of NO_x can be higher. Coal-based boilers equipped with low NO_x burners (LNB), instead, would have exhausted most combustion control options for further reduction, with the exception, perhaps, of natural gas reburning.[1]

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[1] Throughout the remainder of this report we will refer to reburning as a gas treatment control, although the technology clearly requires modifications to the combustion process to reduce first stage NO_x and suppress second stage NO_x formation via fuel substitution and/or air staging techniques. However, the association of reburning technology with gas treatment is made to distinguish the reburning process from more conventional first-round RACT controls that have relied, principally, on LNB and on several other types of combustion control techniques. In so

The inventory data for this chapter was collected from a combination of sources. For the NESCAUM region, the utility boiler inventory presented in the first study (Castaldini, 1992) was updated using input from individual states in receipt of utilities RACT compliance plans. Where these plans were not available, the information was sought directly from selected utilities using a brief questionnaire. The inventory for the MARAMA states was obtained using input from recent inventories (Tech Environmental, 1994) and data gathered from the individual member states and selected utilities. Although the data are considered the most up-to-date inventory on boiler capacity and NO_x emissions from utilities in the Northeast Ozone Transport Region (OTR), selected parts of the inventory are considered incomplete because retrofit control information for certain utilities could not be obtained. Many RACT plans have only recently been finalized and confirmation of control selection is not yet available for all boilers. Further updates, therefore, will be necessary as the data develops to reflect actual conditions prevalent after May 31, 1995.

The following sections summarize various aspects of the capacity inventory and NO_x emissions. Details of the inventories for NESCAUM and MARAMA can be found in Appendices A and B, respectively. NESCAUM states include Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. MARAMA states include Delaware, District of Columbia, Maryland, New Jersey, North Carolina, Pennsylvania, and Virginia. To prevent double accounting, New Jersey boiler and emission inventories were retained in the NESCAUM region. This is consistent with the inventory presented in an earlier NESCAUM study (Castaldini, 1992).

2.1 FUEL TYPES AND FIRING CAPACITIES

Tables 2-1 and 2-2 list the inventory of boiler types and fuels for the NESCAUM and MARAMA regions, respectively. Fuel type was identified based on the boiler's reported primary fuel. Because many gas- and oil-fired units have dual fuel capability and often fire both fuels

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doing, reburning can then be viewed as an additive control option similar to other gas treatment controls, that can be retrofit to existing combustion (i.e., LNB) controlled boilers without requiring further major changes to the primary combustion zones, thus providing additive NO_x reduction beyond RACT-achieved levels.

Table 2-1. Boiler inventory for the NESCAUM region

Firing Type	Number of Units and Capacity (MWe)[a]		
	Coal	Oil/Gas	Total
Tangential	21 3,140	65 12,900	86 16,000
Wall	19 3,920	74 11,900	93 15,800
Cyclone	4 757	7 1,070	11 1,830
Vertical	4 340	6 297	10 637
Stoker	6 230		6 230
Totals	54 8,390	152 26,200	206 34,600

[a]All MWe values are rounded to three significant figures.

Table 2-2. Boiler inventory for the MARAMA region

Firing Type	Number of Units and Capacity (MWe)[a]		
	Coal	Oil/Gas	Total
Tangential	80 20,900	18 6,760	98 27,600
Wall	66 18,900	28 3,290	95 22,200
Cyclone	2 376	1 156	3 532
Vertical	9 743	—	9 743
Stoker	—	—	—
Totals	157 40,900	47 10,200	204 51,100

[a]All MWe values are rounded to three significant figures.

throughout the year on the basis on availability and pricing, no distinction was made between these fuels in grouping boiler types. This represents a broad generalization because NO_x emissions from burning natural gas or oil can be markedly different considering that fuel oil, especially residual oil, will add fuel NO_x to the total NO_x emissions, whereas natural gas produces only thermal NO_x.

The total NESCAUM utility boiler population in place next year is estimated to be 206 units for a total generating capacity of about 35,000 MWe. The total number of units is five more than the estimate prepared for a 1987 inventory (Castaldini, 1992). The difference is the result of more detailed accounting of multiple units located in the state of New York supplying steam to one generator turbine. These additional boilers are reflected principally in the number of wall oil/gas-fired boilers. The number of utility boilers in MARAMA is nearly identical to the NESCAUM units, however, the generating capacity is about 50 percent higher, topping 51,000 MWe. Also apparent in the inventory data is the much greater proportion of coal-fired units in MARAMA compared to NESCAUM. In fact, the coal to oil/gas capacity ratio is more than reversed, where the ratio is about 4 to 1 in MARAMA compared to 0.3 to 1 in NESCAUM. Total coal-fired capacity in MARAMA is about 41,000 MWe, more than the entire boiler generating capacity in NESCAUM. Figure 2-1 illustrates the inventory capacity data clearly indicating the dominance of coal units in MARAMA accounting for nearly one half of the total 86,000 MWe capacity for both regions.

Figures 2-2 and 2-3 illustrate the distribution of capacity, fuel, and firing designs among each state in NESCAUM. The charts illustrate that New York accounts for nearly the same generating capacity in the other NESCAUM states combined with about 18,000 MWe. Massachusetts and New Jersey are the other major electrical power producing states in NESCAUM. Also noticeable is the dominance of oil/gas-fired boilers accounting for most of the generating capacity in nearly all the states. Tangential coal-fired boilers are located primarily in New York, Massachusetts and Connecticut. Tangential oil/gas-fired boilers are the dominant design in New York and Connecticut. Generating capacity from wall-fired boilers is largest in New York and Massachusetts.

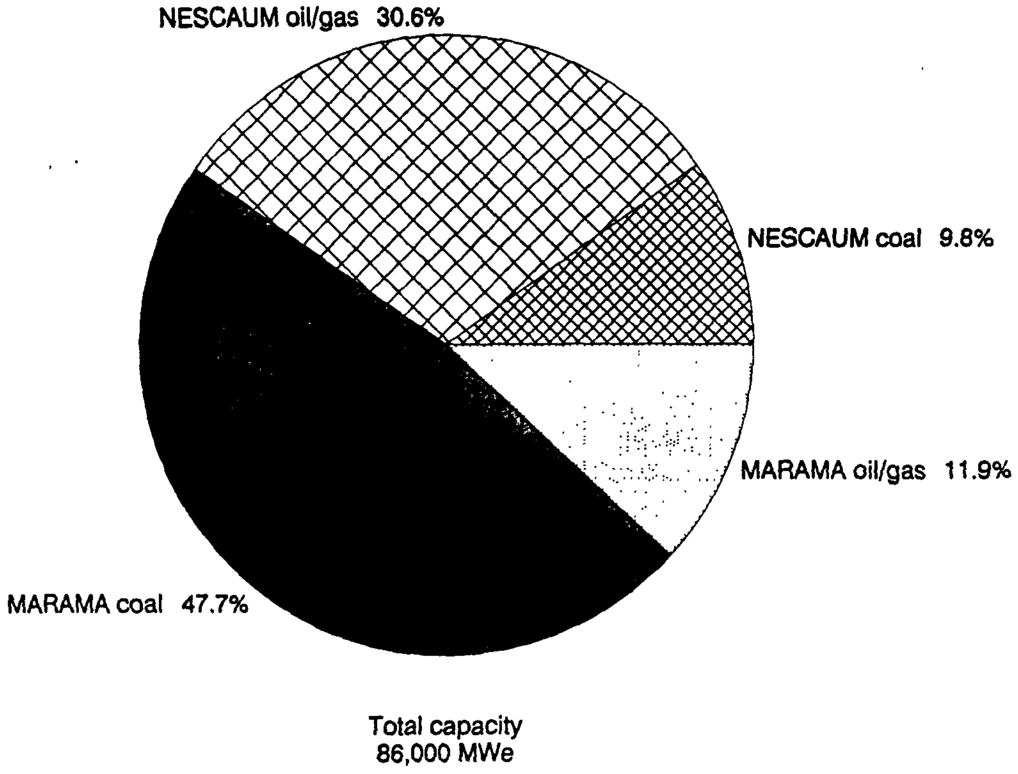


Figure 2-1. 1995 utility boiler capacity by region and primary fuel

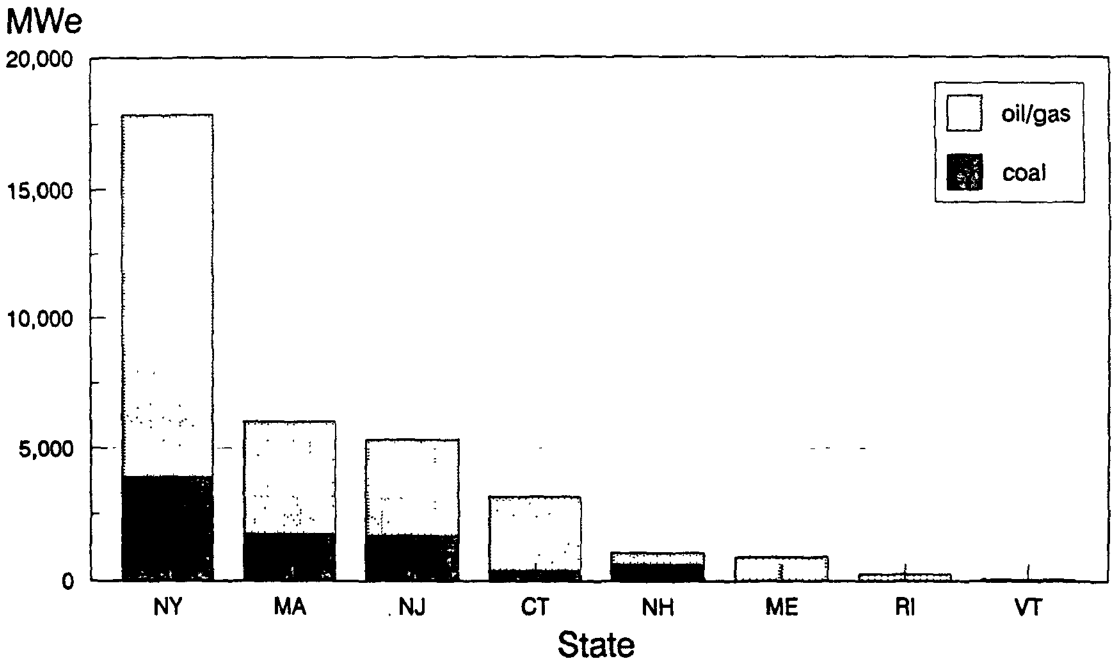


Figure 2-2. 1995 utility boiler capacity by state — NESCAUM region

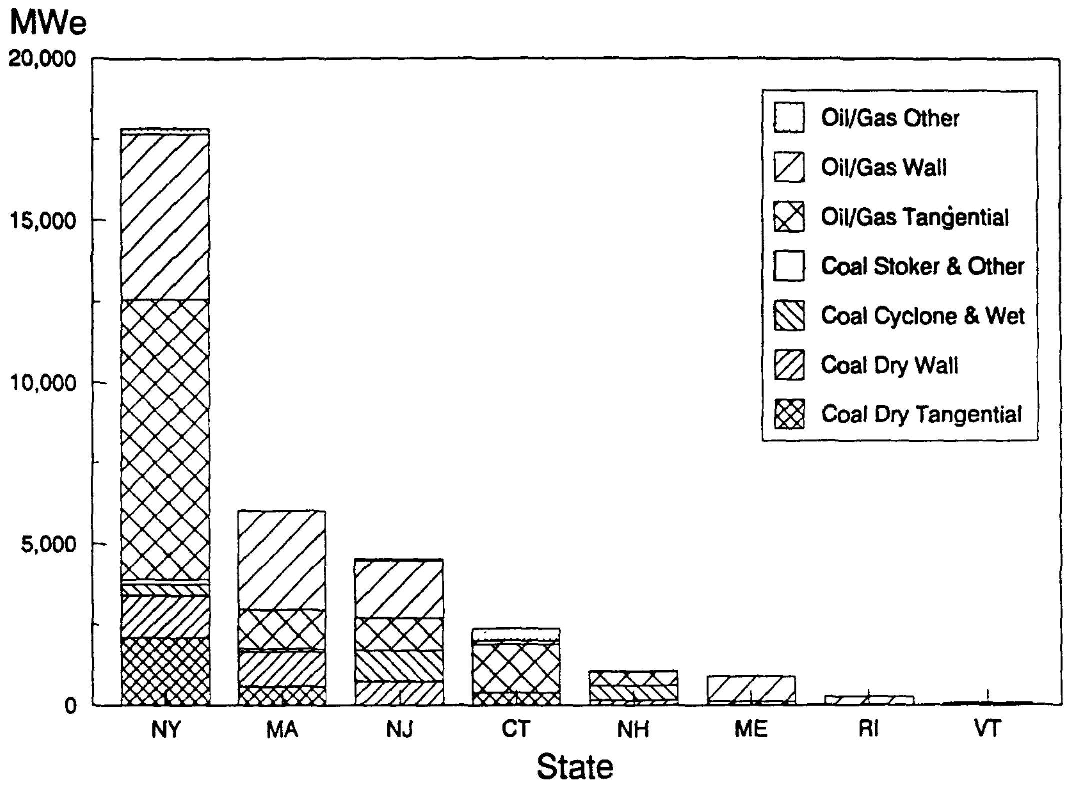


Figure 2-3. 1995 utility boiler capacity by state and firing type — NESCAUM region

In MARAMA, as illustrated in Figure 2-4, Pennsylvania has the highest generating capacity with about 23,000 MWe followed by North Carolina, Maryland and Virginia. The dominance of coal-based power generation in these states is evident. In fact, the entire boiler generating capacity of North Carolina is coal-based. More detail on boiler firing types is given in Figure 2-5. This figure shows that the coal and oil/gas generating capacity in nearly all the states is about equally split between tangential and wall-fired boilers. Coal- and oil/gas-fired cyclones and slagging furnaces are few in this region.

2.2 AGE OF BOILERS AND CAPACITY FACTORS

The age and capacity factor of a utility boiler can have important effects on the selection of most cost-effective NO_x control option. The age and capacity factors for all the boilers in NESCAUM and MARAMA were determined from available data base (Castaldini, 1992, and Tech Environmental, 1994) and from direct input from selected utilities. The age of the boiler is determined based on 1995, the year for RACT compliance in all Northeast and some Mid-Atlantic

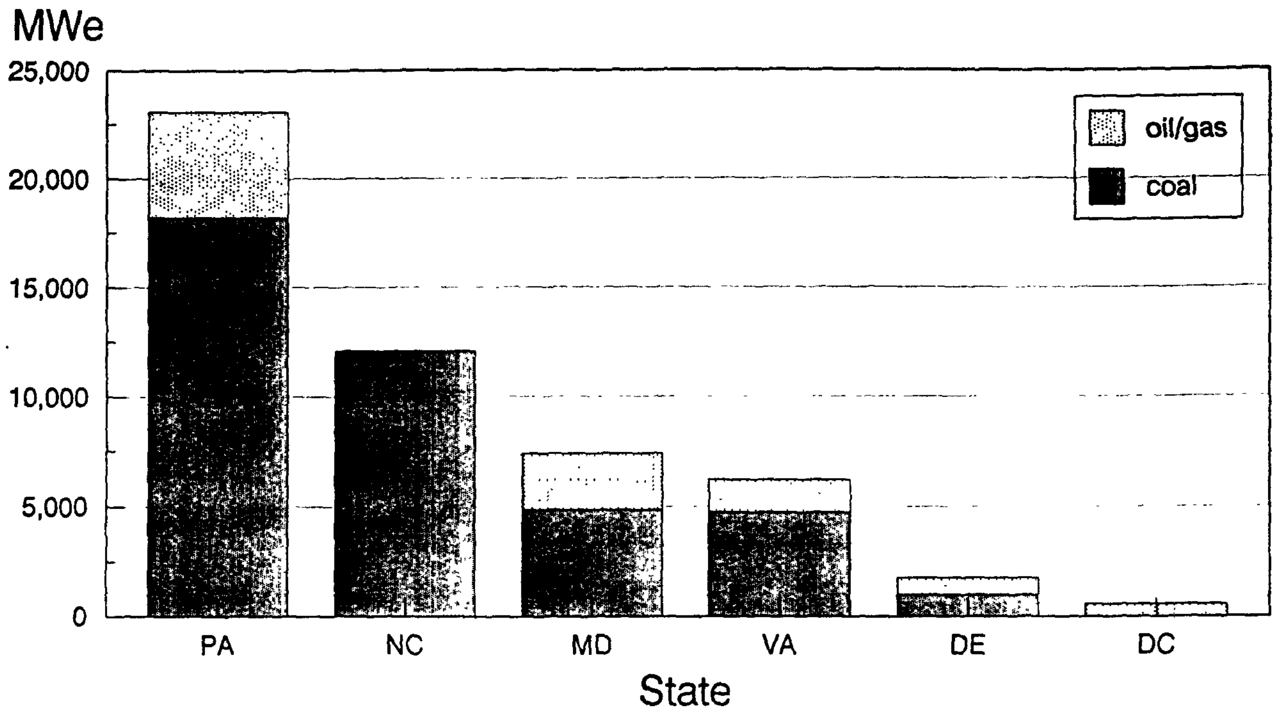


Figure 2-4. 1995 utility boiler capacity by state — MARAMA region

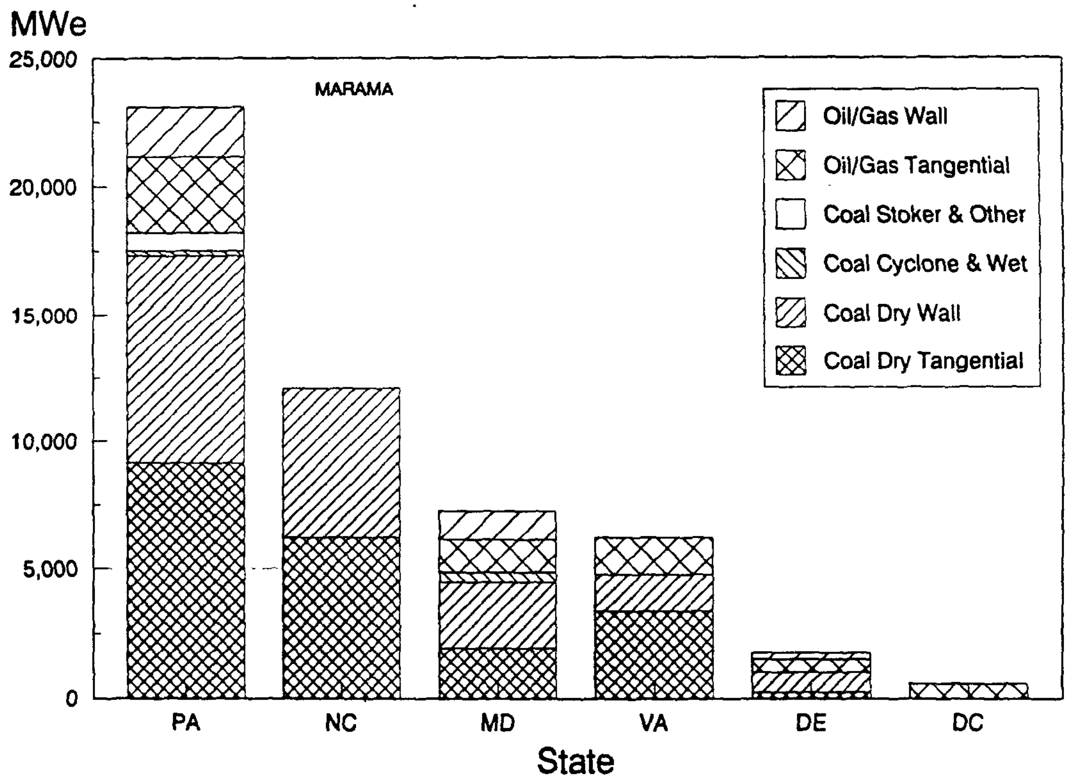


Figure 2-5. 1995 utility boiler capacity by state and firing type — MARAMA region

states. Many units are in an age group where NO_x compliance for their remaining life can add significantly to the operating cost of the control because the initial investment for retrofit can only be amortized over a short period of time. The capacity factor is intended to reflect the overall yearly generation output divided by the capacity of the unit. Therefore, the capacity factor used in this study makes no distinction between seasonal dispatch patterns, load, or outage time. These, of course, are important distinctions because seasonal changes in boiler dispatch can affect NO_x emissions and control performance. For example, low load on a boiler can have a dramatic effect on the percent NO_x reduction efficiency of both selective noncatalytic and catalytic reduction (SNCR and SCR). Also the cost effectiveness of the control can vary significantly.

Figures 2-6 and 2-7 illustrate the relationship between the age of the boilers and their capacity in MWe. In spite of the scatter, the data illustrates that there is a general trend with newer boilers having larger capacity and, most likely, better heat rates. In MARAMA, most of the boilers less than 200 MWe capacity are older than 35 years. These boilers have projected remaining life that approaches 15 years with all life extension modifications available today. In NESCAUM, the population of boilers is slightly older with many more units in the 40 to 50 years of age.

Figure 2-8 illustrates that the average age of the 36,000 MWe boiler capacity in NESCAUM is about 30 years. Figure 2-9 illustrates that in MARAMA, the boiler population is generally younger with the average age on the order of 25 years. Given everything equal, the retrofit of controls on younger boilers should result in less cost per ton of NO_x removed because of longer equipment amortization of initial capital.

Figures 2-10 and 2-11 illustrate the pattern in capacity factors for the two air management regions. In NESCAUM, the mean capacity factor for all the boiler power generating capacity, whether coal- or oil/gas-fired, is about 40 percent. This is lower than the capacity factor reported for a 1987 inventory, probably reflecting a reduction in conventional power generation in the Northeast. A similar curve for MARAMA illustrates that the coal-based power in that region operates at much higher capacity factor. In fact, 50 percent of the total capacity in the region shows

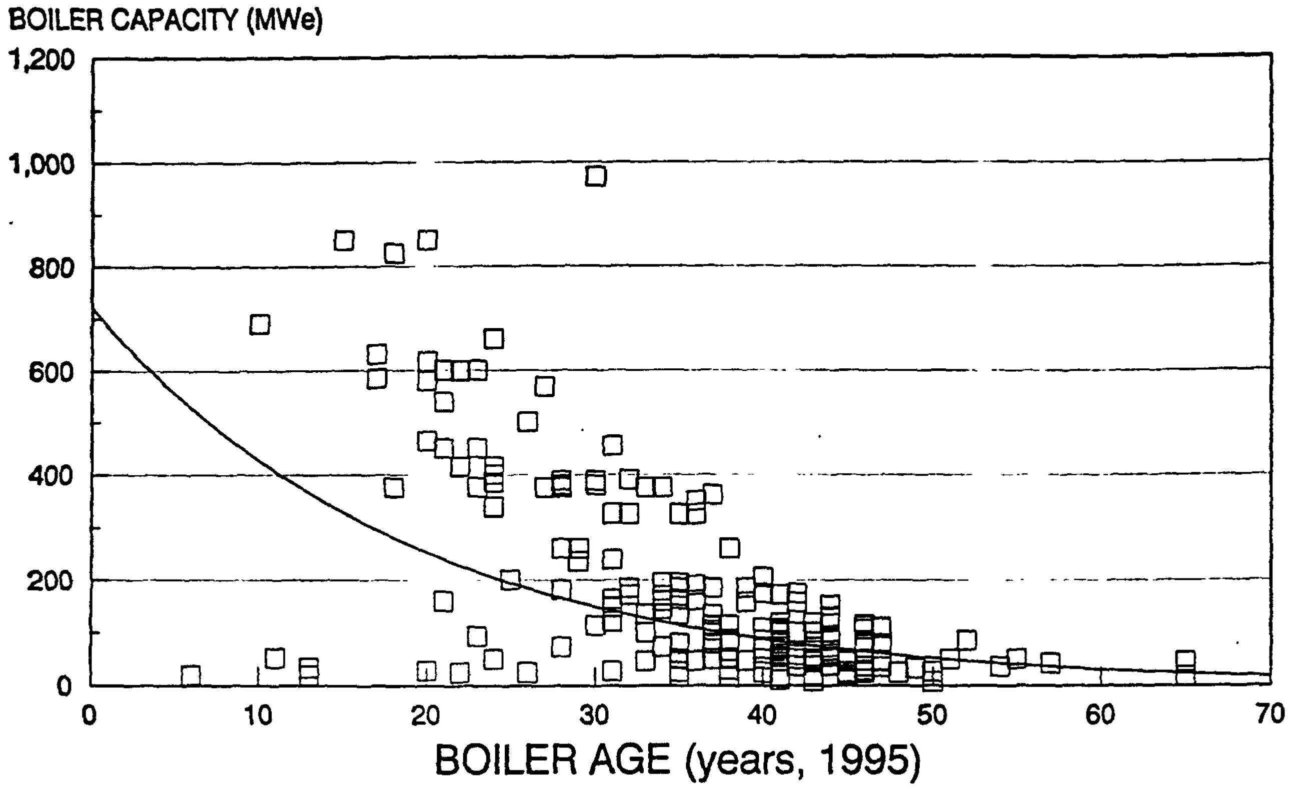


Figure 2-6. 1995 utility boiler capacity versus age — NESCAUM region

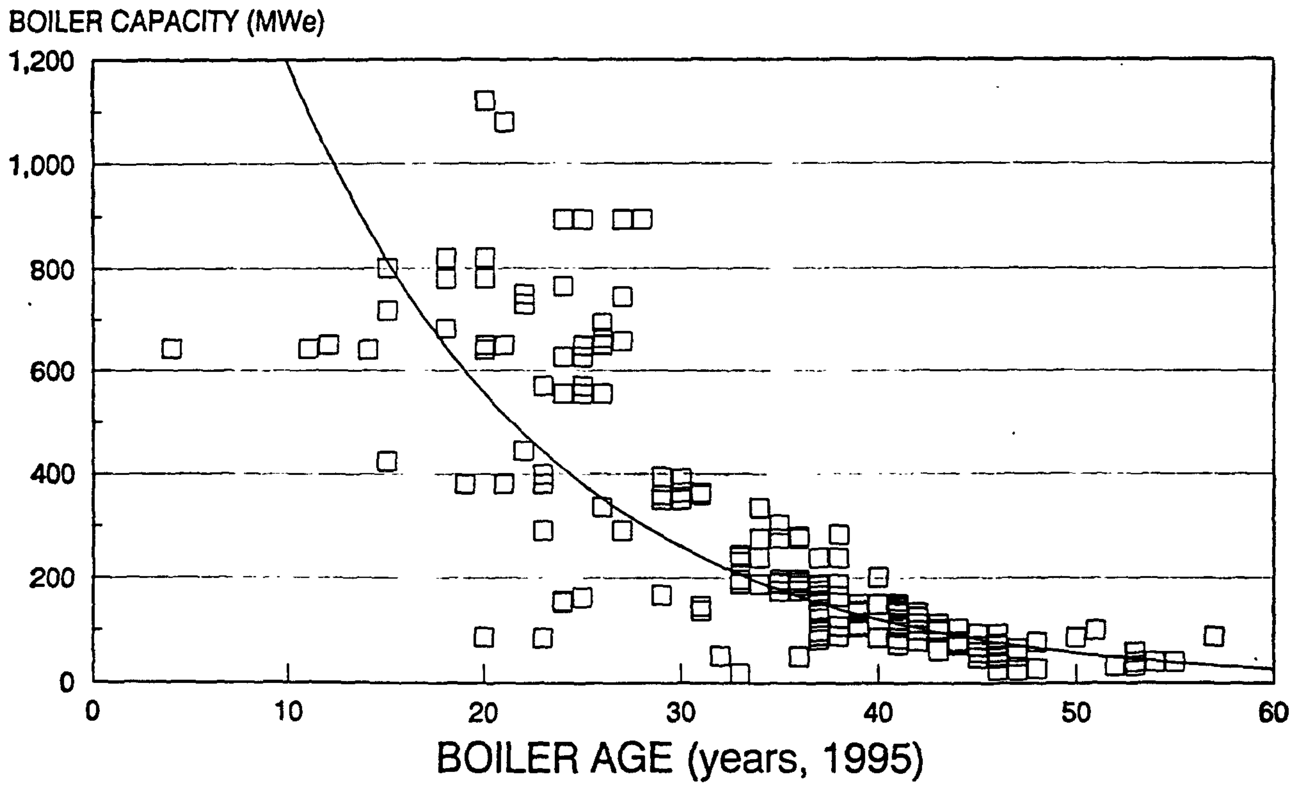


Figure 2-7. 1995 utility boiler capacity versus age — MARAMA region

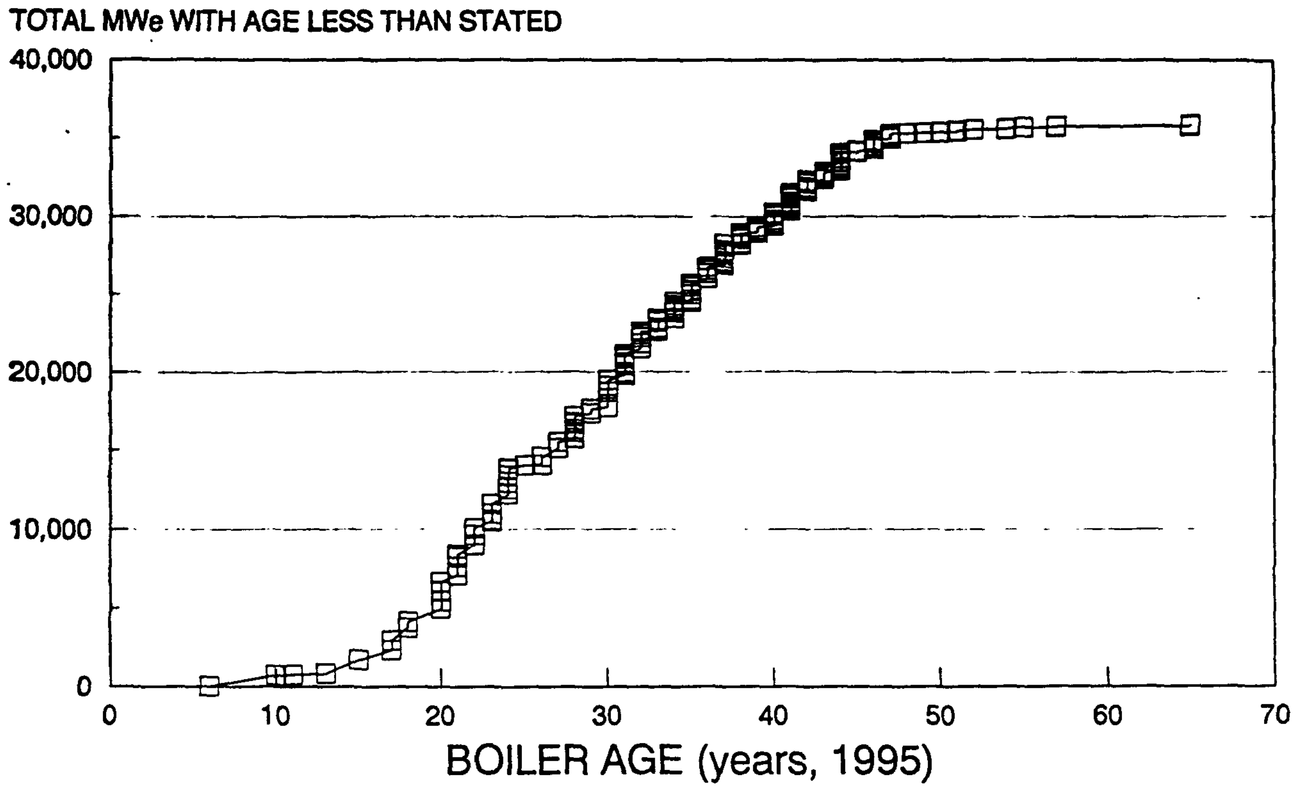


Figure 2-8. 1995 utility boiler total capacity versus age — NESCAUM region

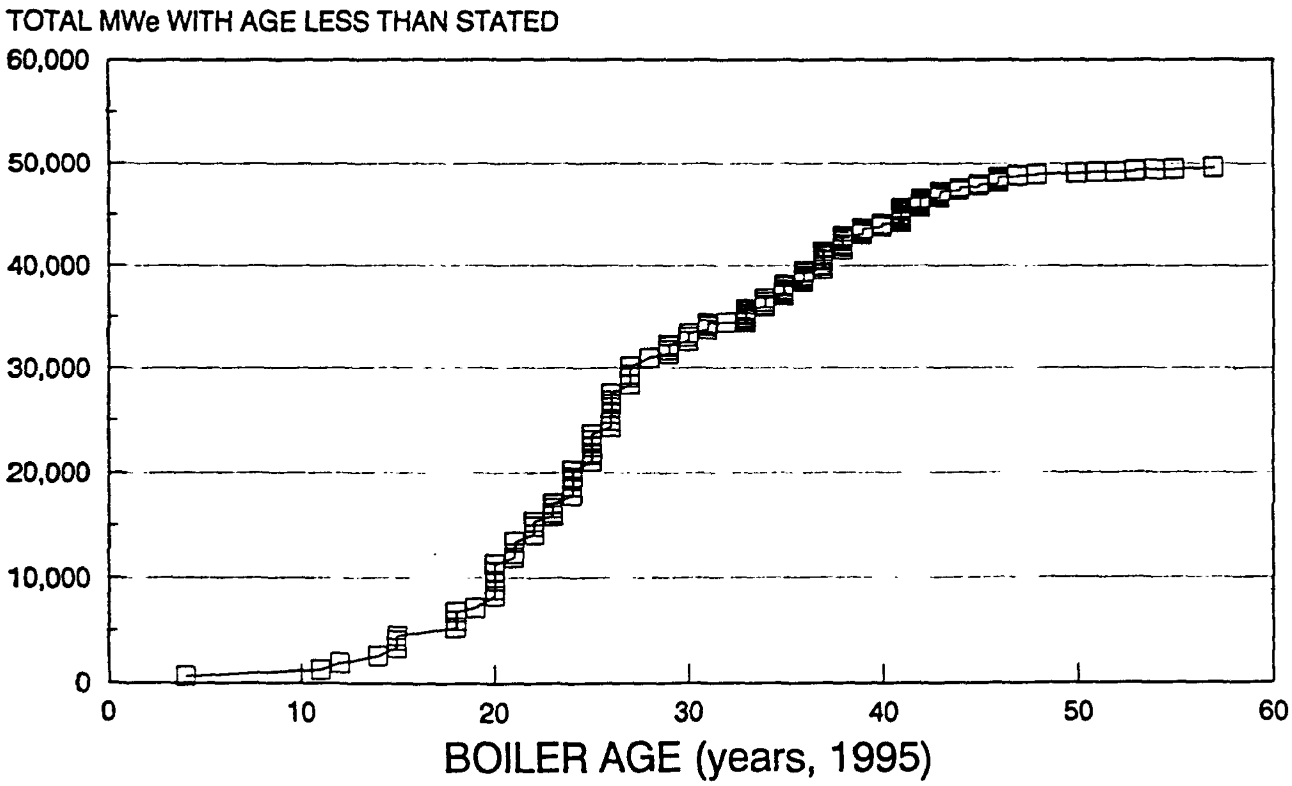


Figure 2-9. 1995 utility boiler total capacity versus age — MARAMA region

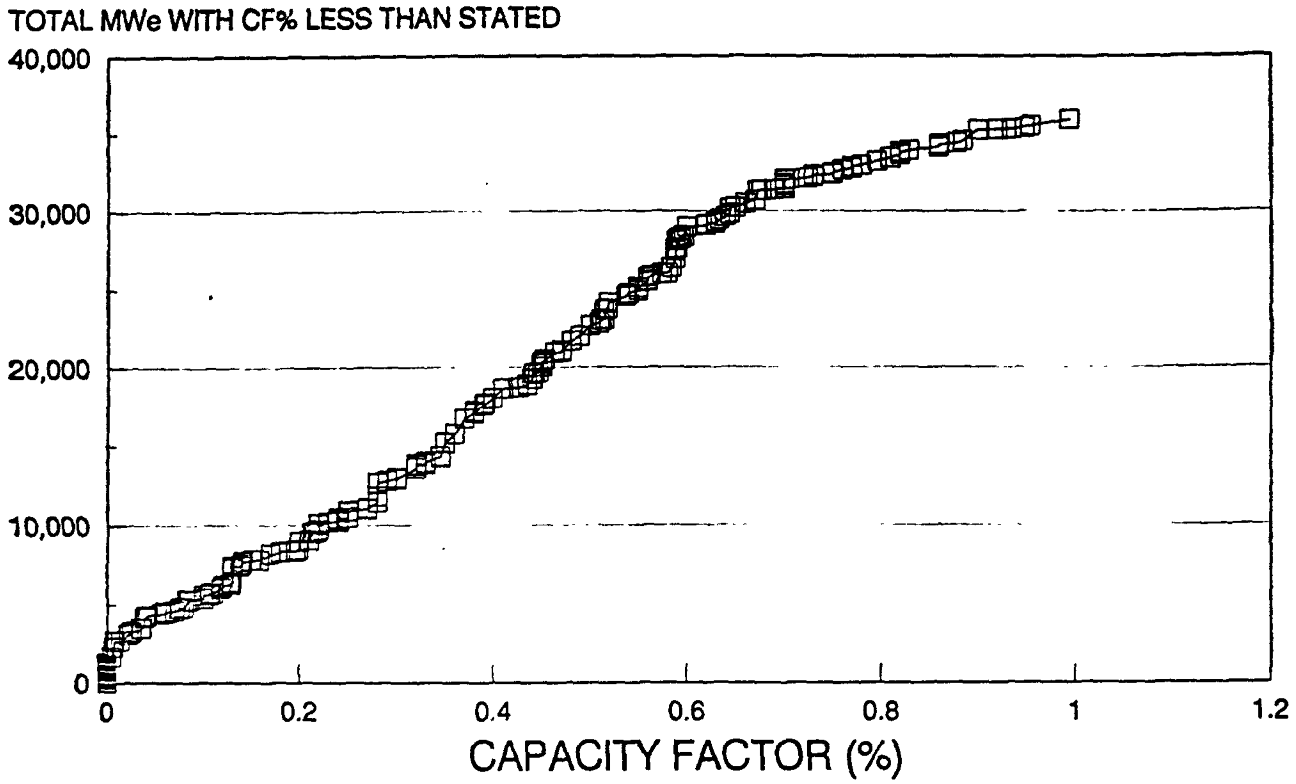


Figure 2-10. 1995 utility boiler total capacity factor — NESCAUM region

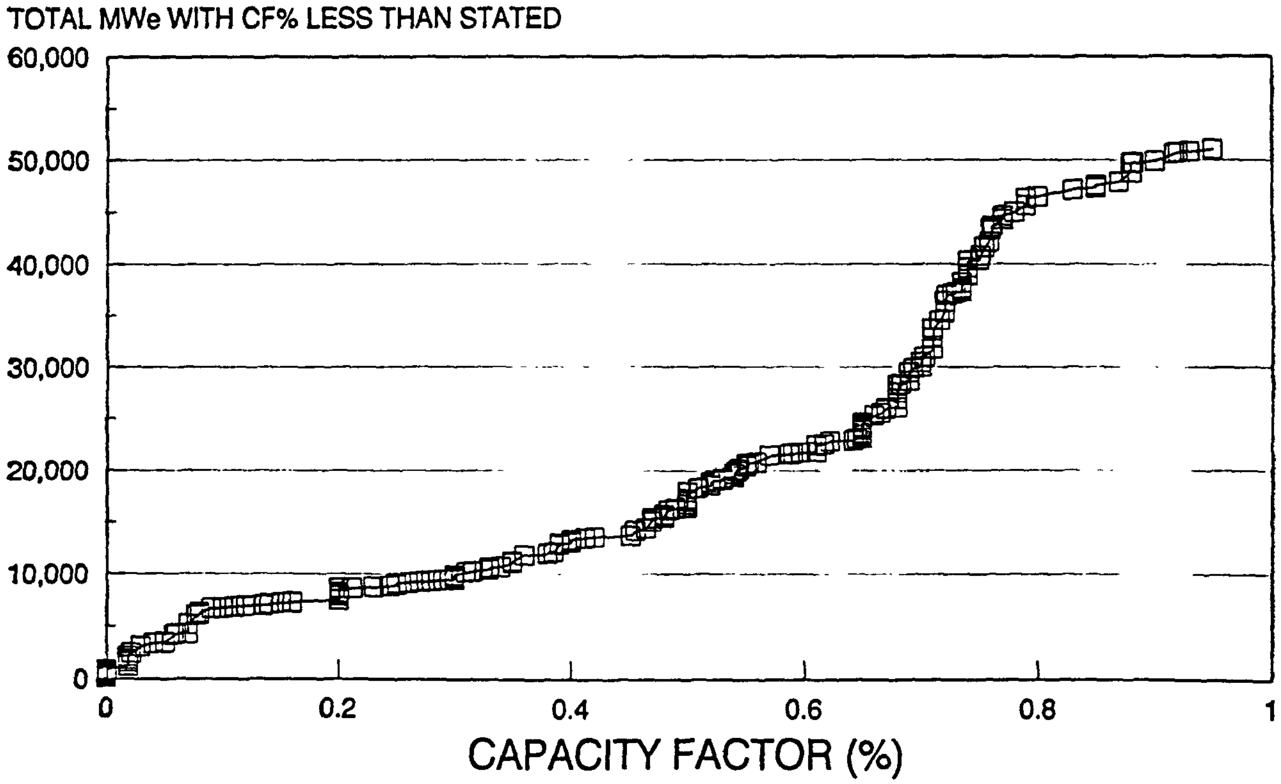


Figure 2-11. 1995 utility boiler total capacity versus capacity factor — MARAMA region

a capacity factor well over 60 percent, compared with about 40 percent for NESCAUM. One reason for this is that in MARAMA the boiler generating capacity is principally coal-based and coal is typically much lower in price and therefore, more economical.

2.3 NO_x EMISSIONS

NO_x emissions inventory data for the population of utility boilers in each region were calculated using an average annual emission factor (lb/MMBtu) multiplied by the size of the boiler (MWe), its average heat rate (Btu/kW-hr), and its capacity factor in percent. The reported emission factor represents the anticipated emission level that each boiler will have following the implementation of RACT controls, if applicable, or its current baseline (uncontrolled) level, if RACT is not applicable and no controls were implemented starting in June 1995. As will be shown later, RACT controls apply primarily in NESCAUM and Pennsylvania where state RACT plans are applicable and utilities have already installed selected controls. Because the retrofit of RACT for some utilities is very recent and data are yet not available, it is likely that the estimates presented here will change somewhat. Also, the selection of one emission level must reflect the average for the year for the purpose of a yearly NO_x inventory.

In many cases, the reported emission level reflects instead a control limit imposed over a much shorter averaging period and may either be lower or higher than its yearly average. This emission level is often influenced by seasonal fuel mix, load dispatch and degree of control applied. Finally, for selected utilities, baseline emission levels are yet to be developed through the planned installation of continuous emission monitors. For such facilities, default emission factors corresponding to RACT mandated emission limits were suggested by the utility as interim levels until more accurate data are available.

The heat rate of the boiler is defined as the heat input to the unit in Btu/hr, from the high heating value of the fuel, divided by the gross power generated in kW-hr. As in the case of NO_x emissions, the value of the heat rate varies with capacity factor, fuel mix, and other plant factors. For this study, no attempt was made to obtain a seasonal heat rate coupled with capacity factor.

Instead, a yearly average heat rate was sought. For many boilers this value was obtained from selected utilities that responded to the questionnaire asking for an estimate of the heat rate for 1995 and beyond. When not available, the average value that was used in the 1987 inventory (Castaldini, 1992) was used or an average of 10,000 Btu/kW-hr when no data was available. With this in mind, the following data represents the estimate of NO_x emission levels expected by June 1995.

Figures 2-12 and 2-13 illustrate the range in NO_x emission factors for the various categories of utility boilers in the NESCAUM and MARAMA regions. The data were developed from a survey of current post-RACT emissions or anticipated emissions following the implementation of planned RACT controls. RACT implementation plans of utilities, and current state emission inventories, were reviewed to obtain this information. Where emissions data were not available, RACT guideline levels of 0.45 lb/MMBtu and 0.5 lb/MMBtu were used for coal-fired tangential and wall-fired boilers, and 0.25 and 0.30 lb/MMBtu for gas- and oil-fired units.

For coal-fired boilers in the NESCAUM region, as illustrated in Figure 2-12, the categories include: low-NO_x burner controlled tangential and wall-fired units; flue gas treatment (FGT)-controlled tangential, wall and cyclone boilers; and boilers controlled with a variety of combustion modifications. Because of the widespread application of RACT in this region, no data are reported for uncontrolled boilers. With the exception of two cyclone boilers equipped with commercial FGT controls, all other boilers exhibit post-RACT NO_x in the range of 0.34 to 0.45 lb/MMBtu, with wall-fired units having a reported controlled level slightly higher than tangential units. In spike of the FGT controls, coal-fired cyclones in NESCAUM, as a group, continue to show the highest NO_x loading.

Figure 2-13 shows similar data for the MARAMA region. Because no commercial FGT controls are in place on coal units in this region, no emission data are shown for this control category. Several coal-fired boilers remain uncontrolled in MARAMA. Tangential units show a range in uncontrolled NO_x between 0.45 and 0.70 lb/MMBtu. Uncontrolled wall-fired boilers show a range of 0.5 to 1.2 lb/MMbtu. LNB-controlled boilers have an average of NO_x level of

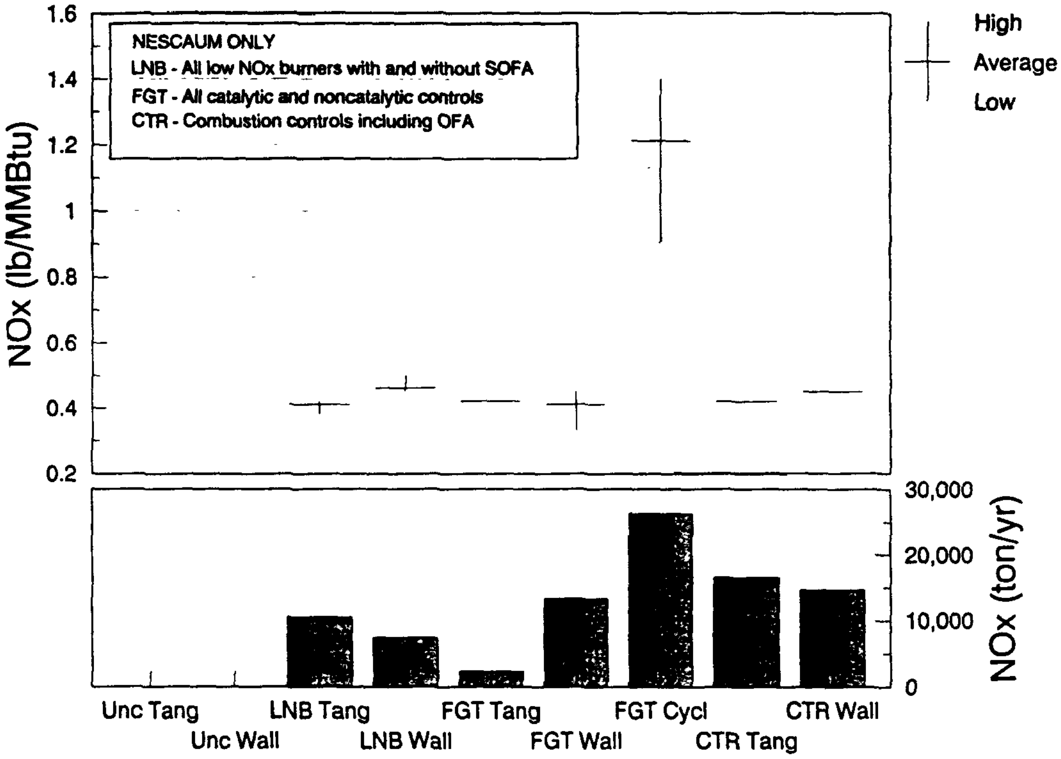


Figure 2-12. 1995 NO_x emission factors and loading — coal-fired boilers in NESCAUM

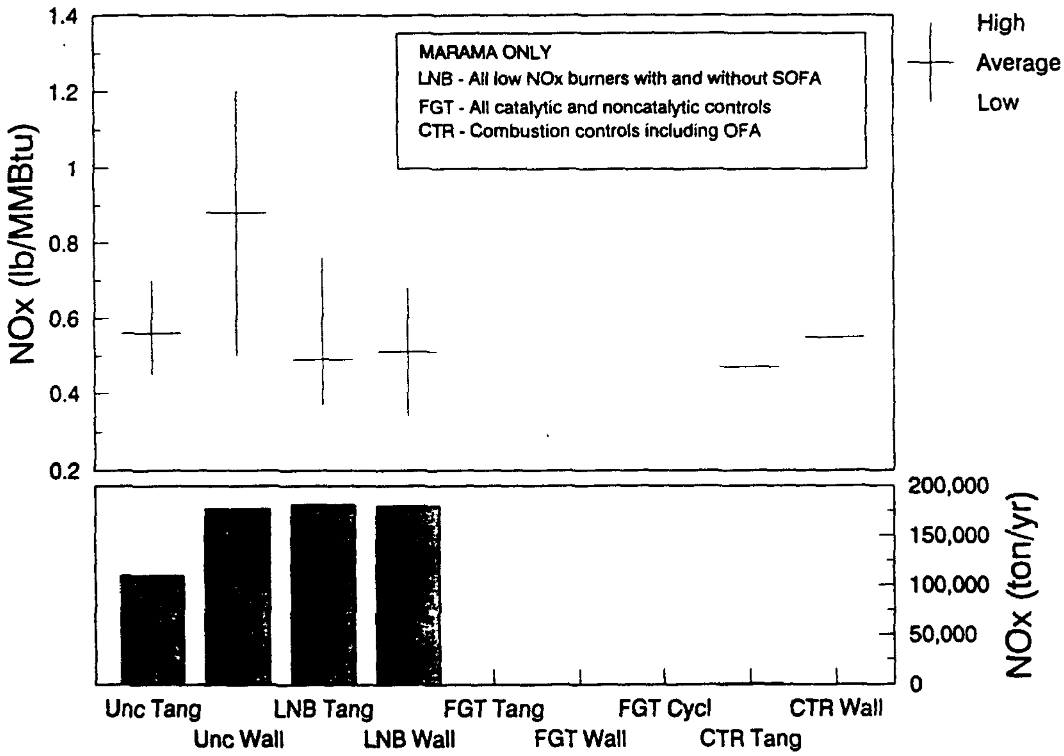


Figure 2-13. 1995 NO_x emission factors and loading — coal-fired boilers in MARAMA

approximately 0.50 lb/MMBtu. Figure 2-14 and 2-15 illustrate the data for oil/gas-fired boilers. In NESCAUM, reported uncontrolled units are few. The vast majority of boilers have conventional combustion controls already in place, while some have reported to fuel switching. In general, average NO_x levels for these units are maintained within the regulated limits of 0.20 to 0.30 lb/MMBtu. As will be discussed later, because of their number and total generating capacity, combustion controlled oil/gas-fired boilers in NESCAUM continue to be responsible for the bulk of the emissions, approximating 55,000 tons/year.

In MARAMA, oil- and gas-fired boilers are few in comparison and consequently the total NO_x loading is lower. NO_x emission levels from either combustion-controlled or uncontrolled boilers are higher, possibly because of greater reliance on residual oils. NO_x levels for uncontrolled boilers average 0.3 lb/MMBtu for tangential units and 0.5 lb/MMBtu for wall-fired units. Reported LNB performance on few boilers averages at 0.45 lb/MMBtu. As stated earlier, these emission levels are greatly influenced by the fuel type and other boiler design factors.

Figure 2-16 illustrates that the total NO_x loading for both regions is estimated to be slightly less than 950,000 tons/yr. Of this, nearly 3/4 is attributable to coal-fired utility boilers in the MARAMA region, principally Pennsylvania and North Carolina as will be shown later. Oil/gas-fired units in MARAMA are not a major source category in contrast with the other major boiler groups.

A recent NO_x inventory estimated that the NESCAUM region emitted 382,000 tons/yr from utility boilers in 1987 (Castaldini, 1992). As shown in Figure 2-17, the 1990 NO_x inventory for all power generation equipment (boilers and gas turbines) in NESCAUM was estimated at 435,000 tons (Tech Environmental, 1994). The post-RACT NO_x inventory for utility boilers in NESCAUM only is estimated to be about 240,000 tons/yr, the result of recent RACT controls already in place as of May 31, 1995. In NESCAUM, this reduction in NO_x is estimated to come more from coal-fired power plants as the proportion of NO_x between coal- and oil/gas-generated NO_x in the post-RACT phase is shifted from more coal-based NO_x in 1987 to a more evenly contribution between the two

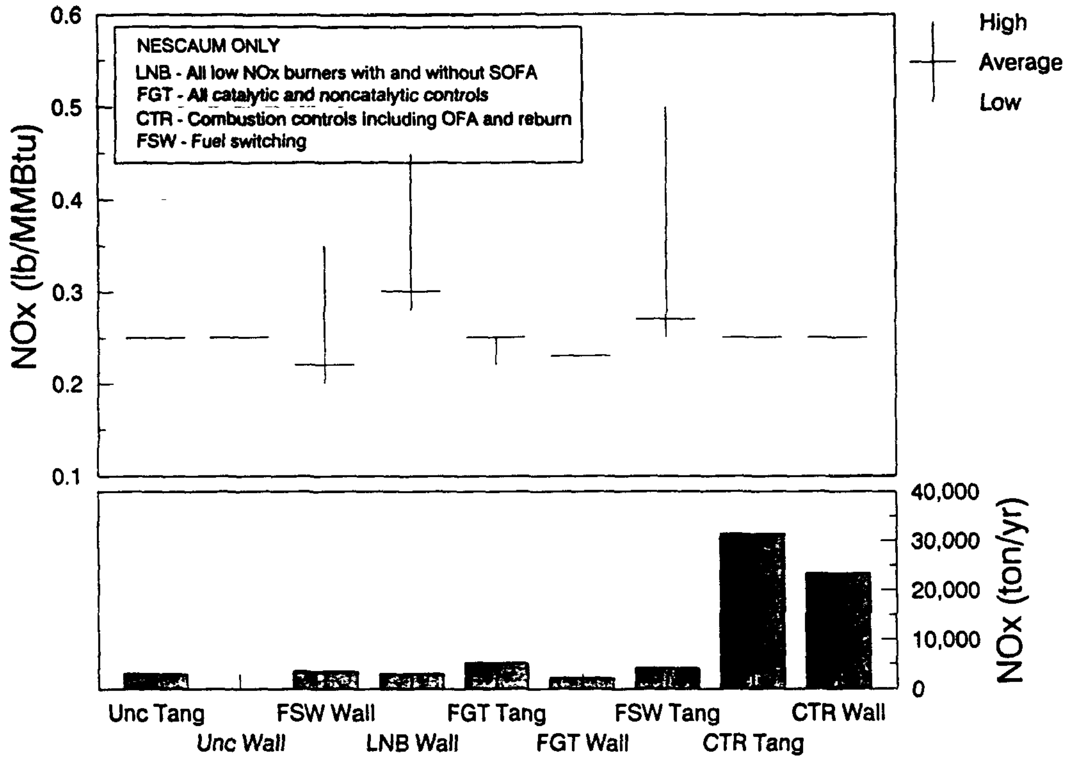


Figure 2-14. 1995 NO_x emission factors and loading — oil/gas-fired boilers in NESCAUM

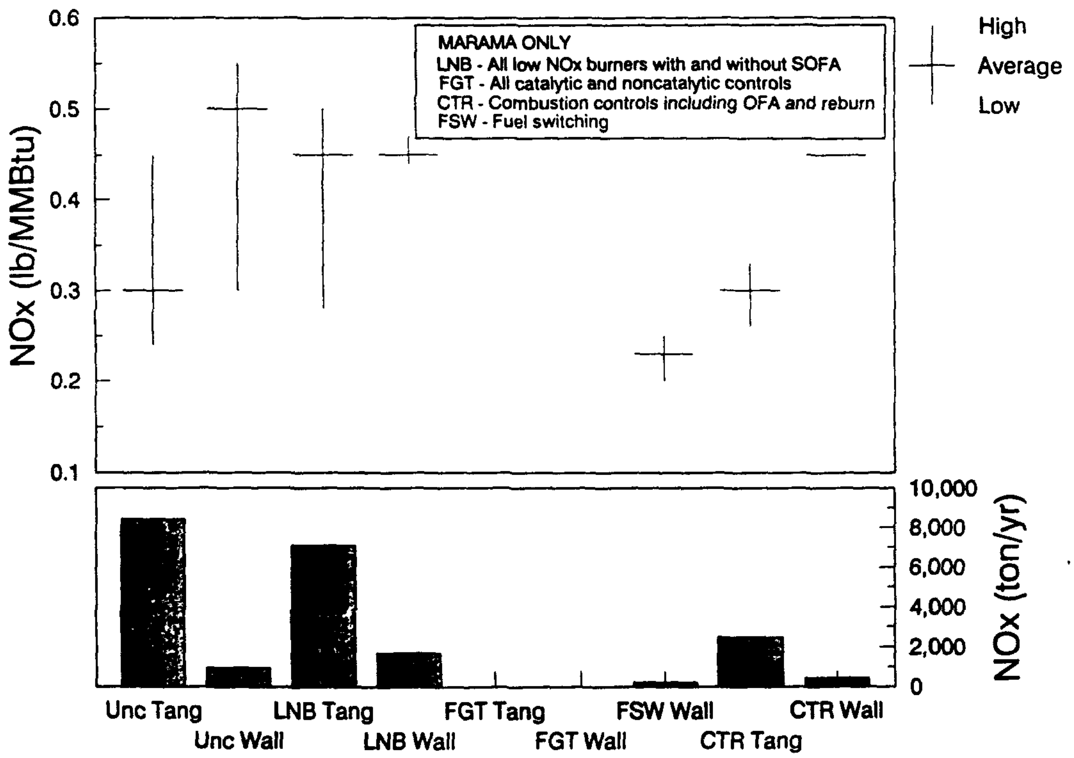


Figure 2-15. 1995 NO_x emission factors and loading — oil-/gas-fired boilers in MARAMA

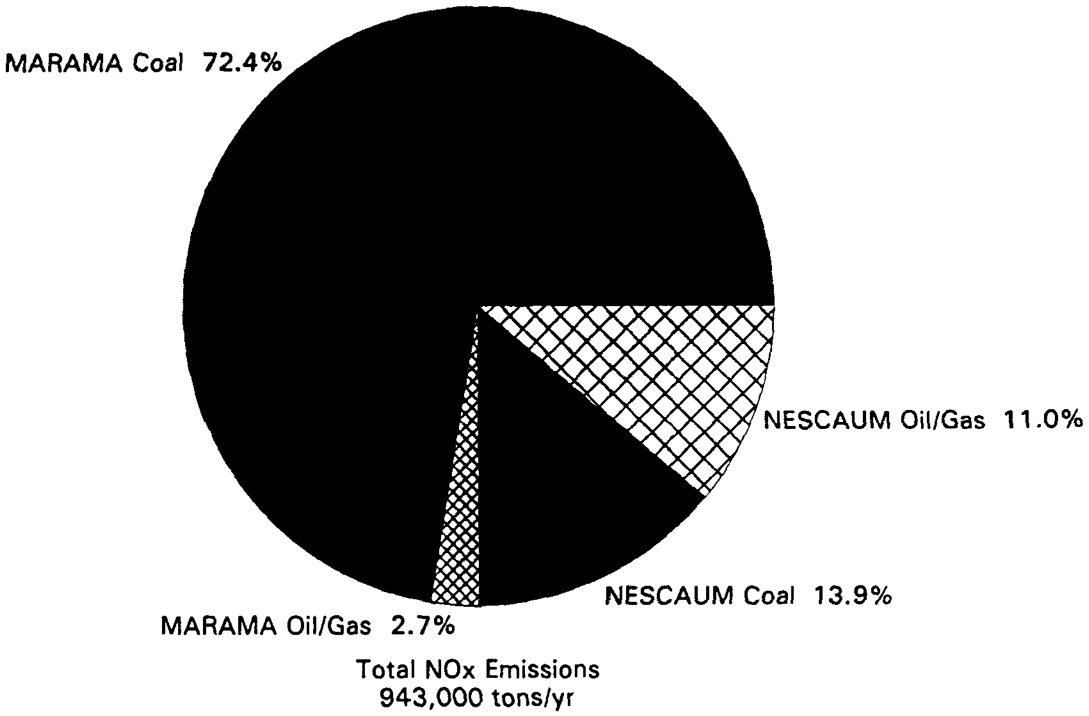
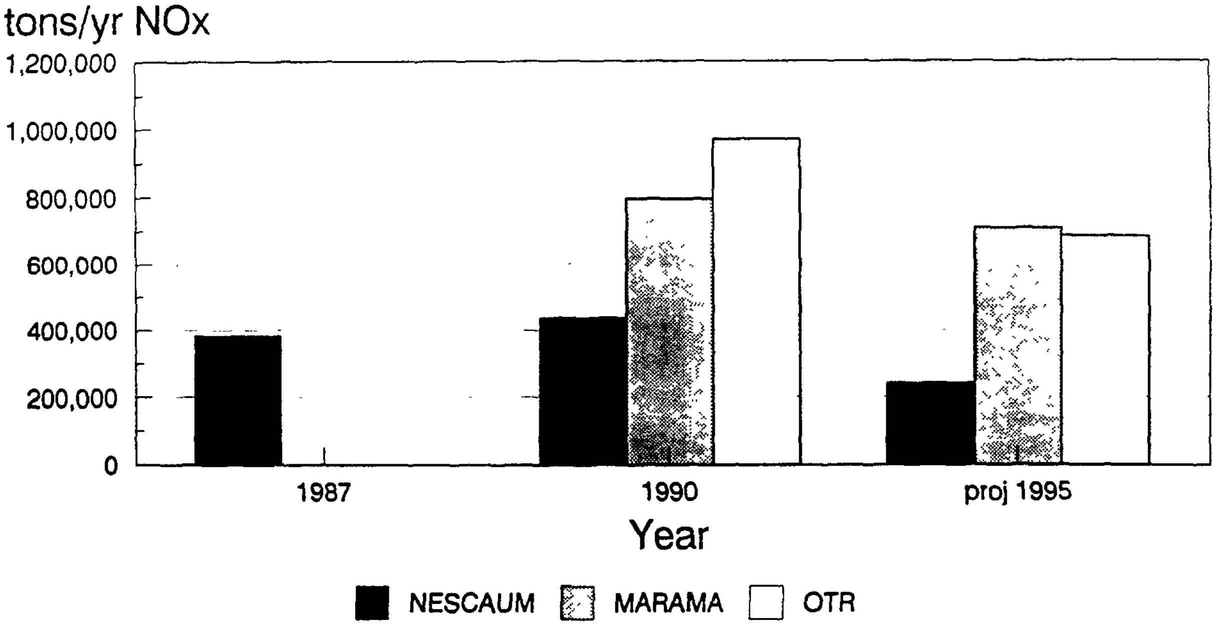


Figure 2-16. Post-RACT 1995 utility boiler NO_x emissions by region



MARAMA 1995 data includes 1990 N. Carolina data.
New Jersey is incl in NESCAUM and not in MARAMA.
OTR excludes NC and includes only portion of VA

Figure 2-17. NO_x emissions reductions from utility boilers

major fuel groups in 1995. For the MARAMA region, the 1990 NO_x inventory was estimated to be about 795,000 tons/yr, more than half contributed by boilers in Pennsylvania. For 1995, the MARAMA inventory is projected to be reduced to 708,000 tons/yr, with the reduction attributed almost entirely to RACT controls applied on Pennsylvania coal-fired boilers. For the OTR, which combines the NESCAUM and MARAMA regions but excludes North Carolina and parts of Virginia, the total utility boiler NO_x inventory is estimated to be about 1 million tons/yr in 1990 and estimated to decrease below the level of the MARAMA inventory at about 680,000 tons/yr in 1995.

Figures 2-18 and 2-19 illustrate the NO_x attributed to each state, again in the post-RACT phase. For NESCAUM, New York continues to dominate followed by Massachusetts and New Jersey. As Figure 2-16 had suggested, the coal- and oil/gas-based NO_x is nearly equal for this region. Of particular note, is the total NO_x level from utility boilers in New Hampshire. Large NO_x reductions from pre-RACT levels were achieved in this state because of the retrofit of the two largest NO_x emitters units in the state and in the entire NESCAUM region. The cyclone units at the Merrimack station were recently retrofitted with gas treatment controls, reducing NO_x from a combined pre-RACT level of more than 33,000 tons/yr to about 18,000 tons/yr. In MARAMA, Pennsylvania will continue to lead in total utility boiler NO_x emissions with about 280,000 tons/yr, even with RACT controls. North Carolina utility boiler, will remain uncontrolled because RACT is not required in the state, emitting an estimated 227,000 tons/yr. Maryland will continue to emit more than twice the level of NO_x from utility boilers in Virginia, even though boilers in Virginia are, for the most part, not required to install RACT controls. District of Columbia has a small level of utility boiler generated NO_x because of its few units and oil/gas-based generation.

Figures 2-20a and 2-20b illustrate the distribution of NO_x by boiler firing design and fuel in each state. Total NO_x emissions from tangential coal-fired boilers are estimated to be about 338,000 ton/yr, about 20 percent less than coal-fired boilers with circular burners. Emissions are typically commensurate with the boiler capacity. For example, in Pennsylvania tangential coal-fired

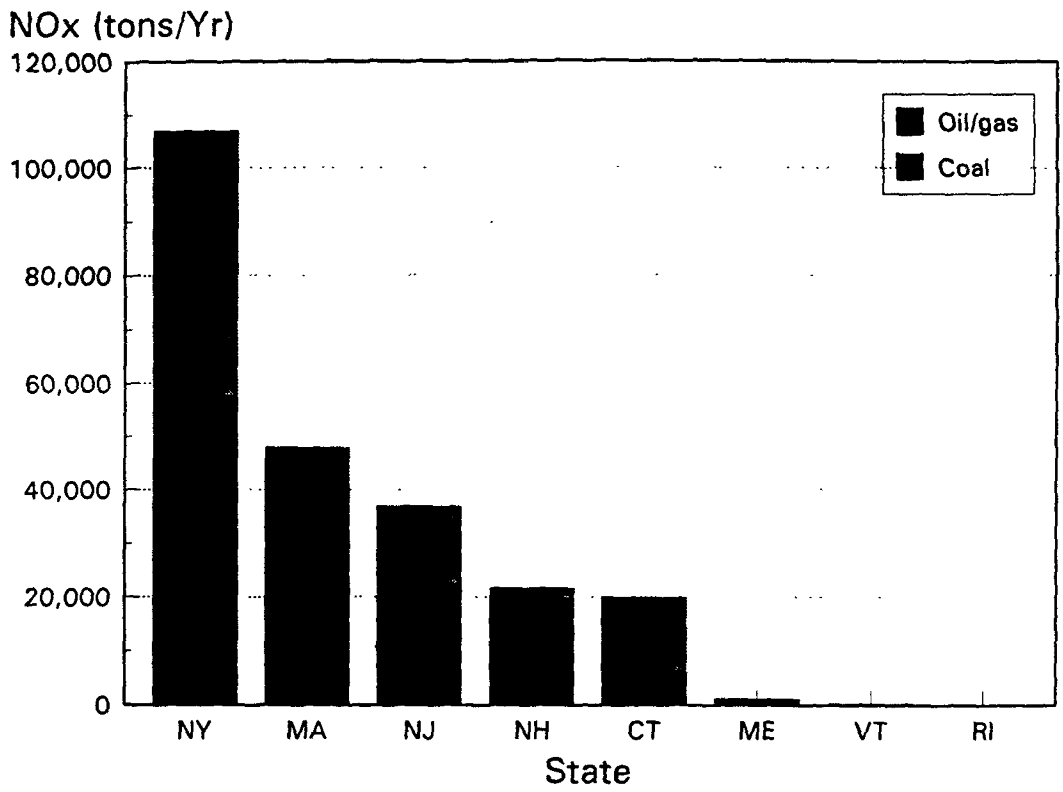


Figure 2-18. Post-RACT 1995 utility boiler NO_x emissions by state — NESCAUM region

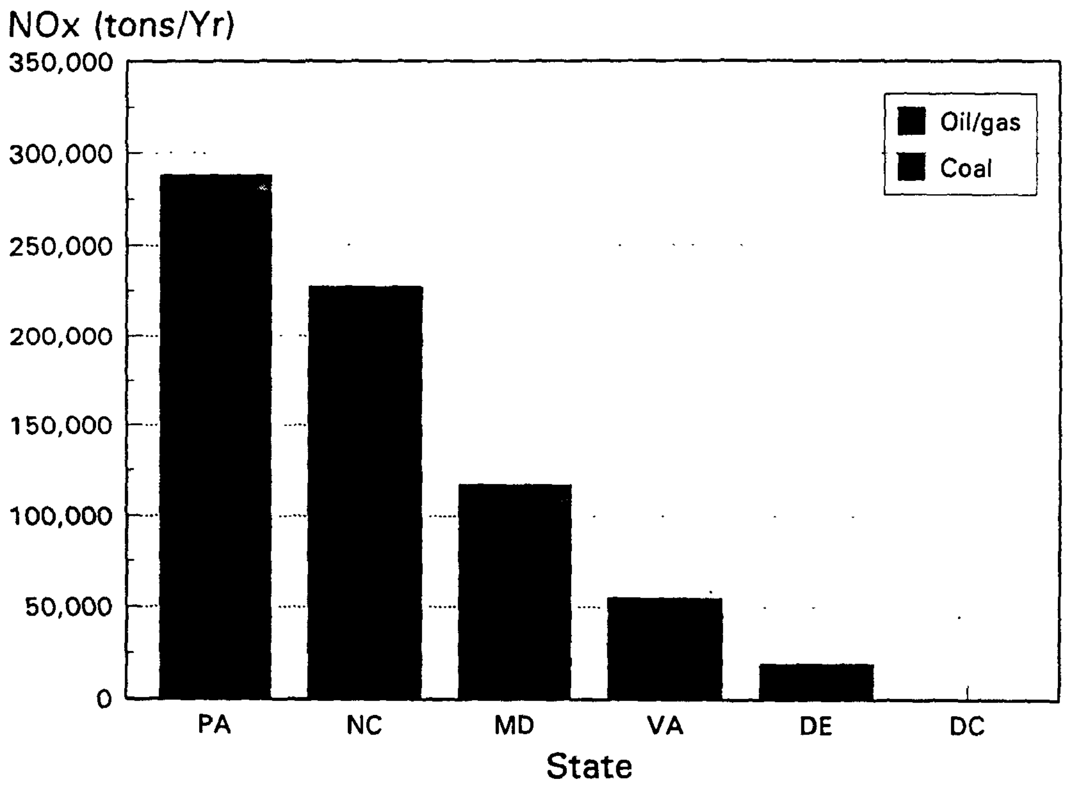
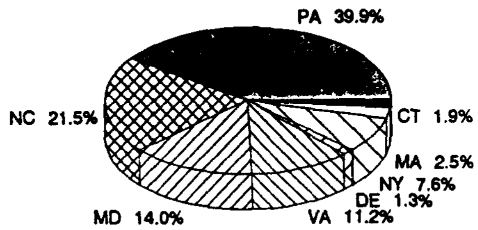
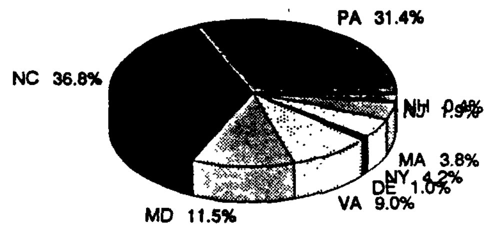


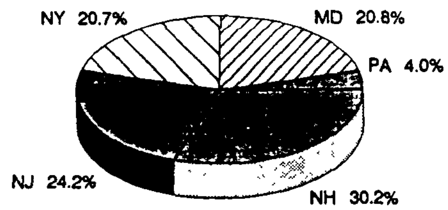
Figure 2-19. Post-RACT 1995 utility boiler NO_x emissions by state — MARAMA region



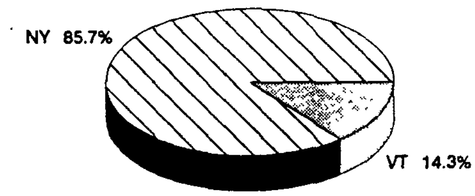
a. Coal, T-fired
337,666 tons/yr



b. Coal, W-fired
403,705 tons/yr

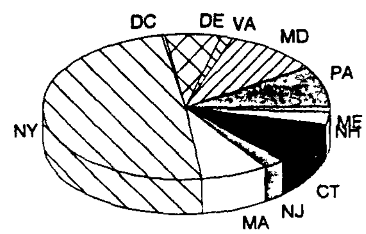


c. Coal, all slagging
59,831 tons/yr

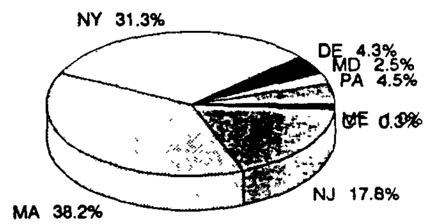


d. Coal and wood stokers
2,122 tons/yr

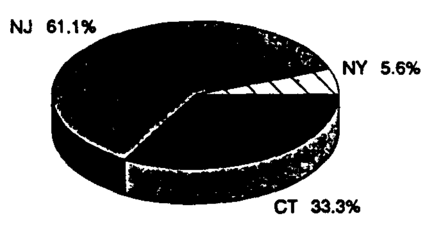
Figure 2-20a. Post-RACT *1995* coal-fired *utility* boiler NO_x *emissions*



a. T-fired
69,100 tons/yr



b. W-fired
52,687 tons/yr



c. Other firing types
7,691 tons/yr

Figure 2-20b. Post-RACT oil/gas-fired utility boiler NO_x emissions

boilers have a greater total generating capacity than wall-fired units, whereas the opposite is true for North Carolina. Also, wall-fired boilers tend to be higher emitters, when uncontrolled, than tangential units. This explains the higher NO_x levels associated with wall-fired boilers and the contribution of North Carolina units to the total NO_x loading from these boiler types. Stokers are principally in two states and emit a total of 2,100 tons/yr of mostly uncontrolled NO_x. Coal-fired cyclone boilers and all other slagging furnaces (wet bottom units) are located principally in four states and combined they emit nearly 60,000 tons/yr, and nearly one half of the NO_x is emitted from boilers already equipped with gas treatment technologies. Oil/gas-fired tangential and wall units are present in most states. New York, Massachusetts, and New Jersey account for the bulk of these emissions. Although fewer in number, tangential oil/gas-fired units tend to have larger capacities than wall-fired units, especially in MARAMA. Therefore, as a whole they account for a larger portion of the total NO_x. Other oil/gas-fired boiler design types emit relatively low levels of NO_x.

2.4 RACT CONTROLS

In recent years, many NO_x emission controls have been implemented in the Northeast and Mid Atlantic regions on existing utility boilers. The requirement for these controls has come from a variety of local and, more recently, state regulations that aim to reduce ground level ozone levels. Depending on the state, several boilers have been retrofitted with low-NO_x burners (LNB), a variety of combustion controls that target a specific NO_x level, or even flue gas treatment with or without combustion controls for low levels of NO_x emissions either as a demonstration project or as a commercial application of the technology to meet RACT limits. Still other units have seen gas cofiring and conversion to permit dual fuel firing capability for either seasonal or continuous NO_x control. Because of ozone nonattainment status and because of their position with respect to the OTR, some states, such as North Carolina and Virginia, did not require RACT controls by May 31, 1995. Consequently, many utility boilers in these states remain uncontrolled.

In order to project the NO_x reduction potential from RACT-controlled sources it is important to assess the level of control and record control technologies that are already in place to permit already reduced levels of NO_x emissions. Therefore, this section provides a brief survey of the control technologies that have been implemented in response to state regulations.

Figure 2-21 illustrates the types of controls in place for the entire utility boiler capacity in both the MARAMA and NESCAUM region. The categories include boilers controlled with:

- Low-NO_x burners (LNB) with or without overfire air, including low NO_x cell burners (LNCB)
- Flue gas treatment controls such as all different applications of selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR), and hybrid systems
- Boiler decommissioning because of planned or preliminary retirement
- A variety of combustion controls such as flue gas recirculation (FGR), burners out of service (BOOS), low excess air, burner tuning, overfire air

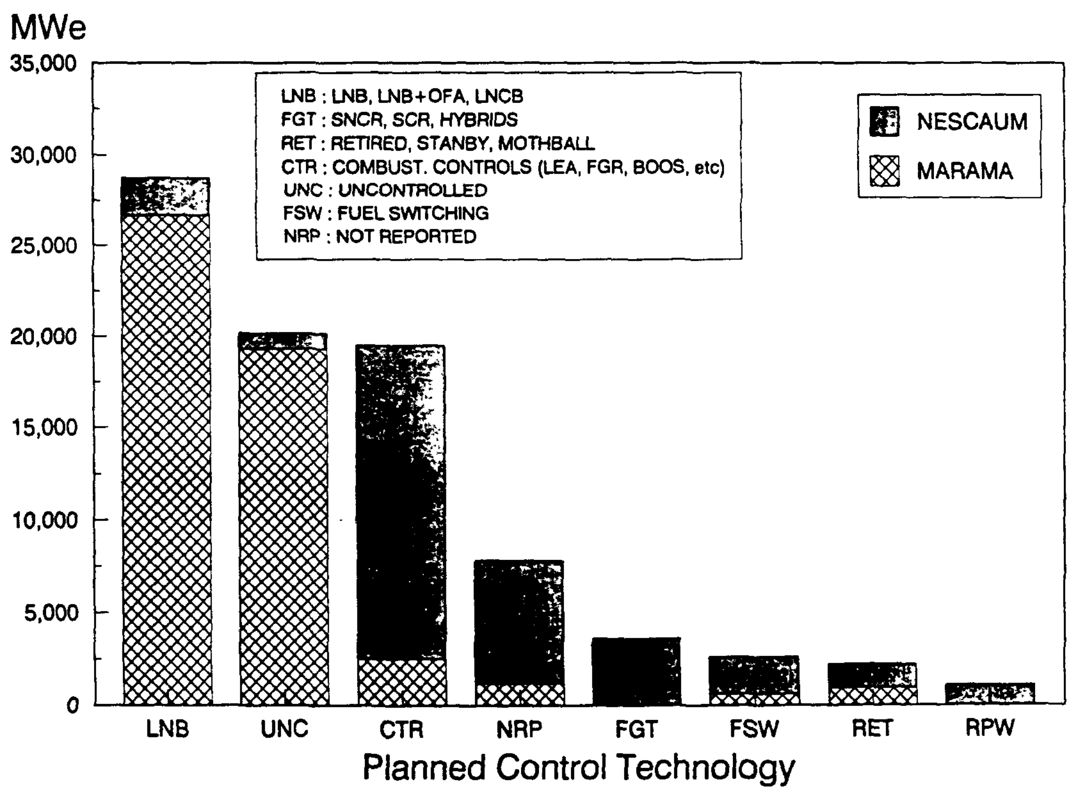


Figure 2-21. Post-RACT 1995 utility boiler control technologies — total plant capacity

- Repowering technologies that aim to boost plant capacity with high efficiency gas turbines with heat recovery steam generators and using existing plant equipment. This approach completely transforms the power generation cycle to include combined cycle (Brayton-Rankine) and cogeneration facilities
- Fuel switching including the installed ability to fire an additional fuel, typically natural gas, on a continuous or seasonal basis, providing either a fraction of the total fuel (cofire) or all the fuel (conversion) requirement. This category also includes some gas reburning approaches installed on oil/gas-fired tangential boilers, such as LILCO's Barrett Station.

Two additional categories were included to account for boilers that have remained uncontrolled past May 31, 1995 because RACT is not required by the governing state, and boilers for which information regarding control plans was considered too sketchy (or completely unavailable) to be reported. These latter units were given the label "not-reported". Uncontrolled boilers also include units that are averaged in with other controlled boilers in a RACT compliance scenario that relies on system-wide averaging rather than unit-by-unit control.

The data in Figure 2-21 illustrate a large capacity of boilers (more than 25,000 MWe) in MARAMA controlled with LNB technologies followed by about 20,000 MWe of uncontrolled boiler capacity, nearly all in MARAMA and nearly an equal amount of combustion-controlled capacity principally in NESCAUM. The large LNB-controlled capacity is attributed primarily to coal-fired boilers in Pennsylvania. Combustion controlled capacity is principally due to oil/gas-fired boilers located in NESCAUM. Uncontrolled boilers are primarily coal-fired units in North Carolina and Virginia where RACT controls are not required by federal statues. Because of the developing data base, a large fraction of the boiler capacity, about 7,500 MWe, has sketchy data on control strategies and RACT compliance plans as of this writing.

Details of Figure 2-21 showing similar data by fuel type are shown in Figures 2-22 and 2-23. The uncontrolled and LNB-controlled coal-fired capacity in MARAMA is evident in Figure 2-22,

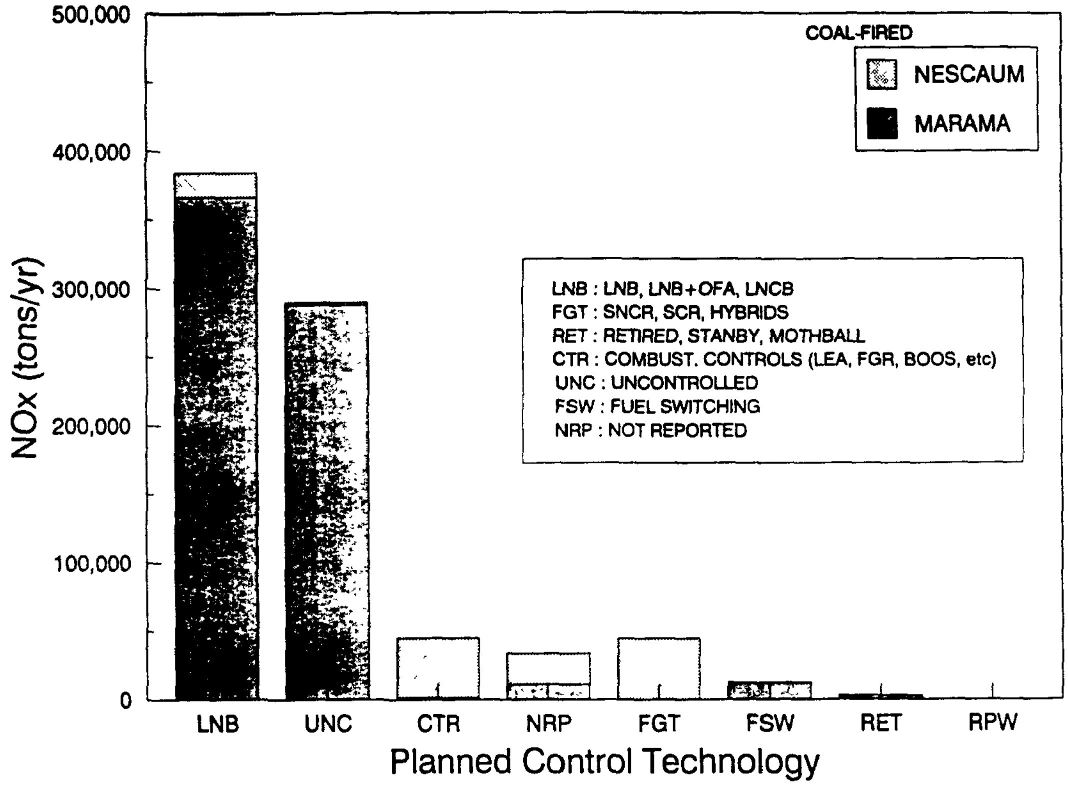


Figure 2-22. Post-RACT 1995 utility boiler control technologies — coal-fired NO_x emissions

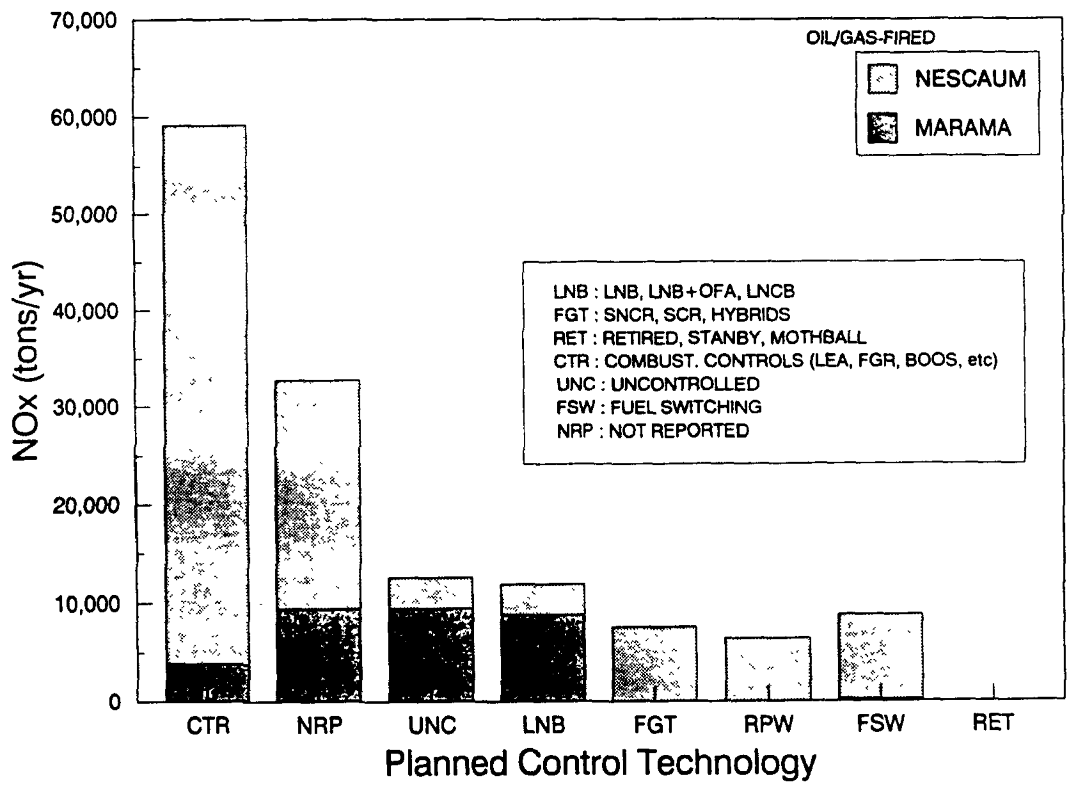


Figure 2-23. Post-RACT 1995 utility boiler control technologies — oil/gas-fired NO_x emissions

and the nearly 15,000 MWe oil/gas-fired capacity that is combustion controlled in NESCAUM is also evident in Figure 2-23. FGT controls are entirely in the NESCAUM region, estimating to reduce NO_x from nearly 4,000 MWe of coal- and oil/gas-fired capacity. Controls include SNCR and SCR on the Merrimack Station boilers, several SNCR controls on oil-fired boilers in Massachusetts and Pennsylvania and other recent SCR installations on boilers in Massachusetts and New Jersey.

Figure 2-24 illustrates the same data on a NO_x emissions basis, comparing the total tonnage of NO_x emitted from utility boilers controlled by various technologies. The LNB-controlled NO_x is nearly 400,000 tons/yr, followed by 300,000 of uncontrolled NO_x, nearly all in MARAMA and more than 100,000 tons of NO_x from combustion-controlled boilers in NESCAUM. Total NO_x still being emitted from FGT-controlled boilers exceeds 50,000 tons/yr.

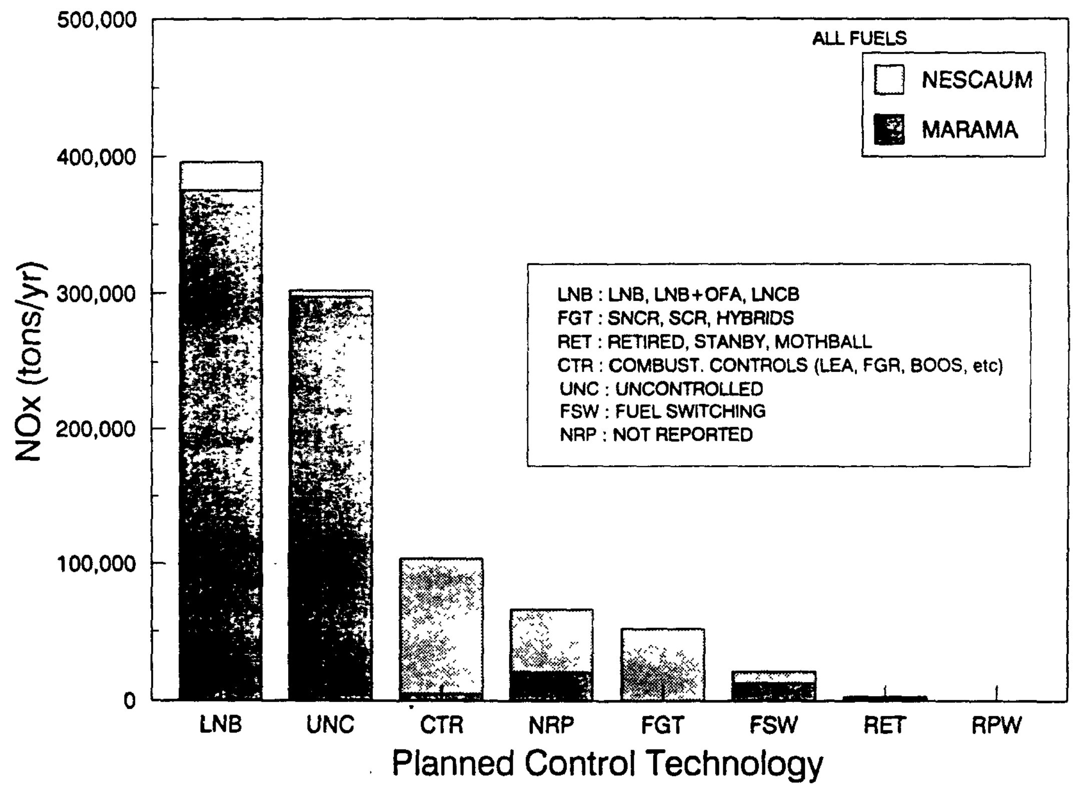


Figure 2-24. Post-RACT 1995 utility boiler control technologies — total NO_x emissions (all fuels)

2.5 TRENDS IN UTILITY POWER GENERATION

The future of the electric power generation in the NESCAUM and MARAMA regions, and throughout the country, is being shaped by important economic forces, energy and environmental policies, and technology advances. These factors will likely change the profile of the just-described power generation mix in these regions in ways that are difficult to project. These changes, however, will have important effects on the NO_x emission profile, the cost of controls, and NO_x reduction compliance options available to the electricity generating industry. Among the most evident factors shaping the future of the industry are:

- Deregulation under the 1978 Public Utilities Regulatory Act (PURPA) and the more recent 1992 PUHCA reform legislation, creating open competition among exempt wholesale generators (EWG): utilities, nonutility generators (NUG), and independent power producers (IPPs) for the generation and retail wheeling of new electrical power on a low-cost basis
- Changing fuels economics affected by current pricing and availability of natural gas compared to residual oil, and environmental benefits of coal switching to meet Acid Rain regulations
- Technological advances in power generation equipment, principally gas-turbine based cogeneration and combined cycle plants, and projected advances in coal-based integrated gasification and combined cycle plants and fluidized bed combustors
- Equipment life extension programs to minimize expenditures by utilities caught in a more competitive environment
- Interplay between NO_x regulations stemming from Title I and Title IV of the Clean Air Act Amendments and potential impact of air toxic controls on utilities from Title III

For the remainder of this century, and into the foreseeable future, the power generation industry will face transition and uncertainty. Open and more intense competition for low-cost electricity are leading to increased deregulation of the electric power industry. The industry was first deregulated with the passage of PURPA and more recently by the amendment of PUHCA that created the Exempt Wholesale Generator (EWG) to enable IPP and utilities to compete for new power generation. This open competition coupled with concerns for the environment and energy saving measures are causing some fundamental changes in the make up of the future mix of power generation equipment. Eventually, these equipment changes will have an effect on the generation of emissions and the application of NO_x control technologies. Most evident is the slower growth in new power generation forecasted for the next decade. Led by voluntary energy savings programs, energy economics, and utilities own demand side management programs, the electricity generation annual growth is forecasted to average only 2 percent, a drop from nearly 3 percent from the past decade (Ford and Griggs, 1993). Much of the forecasted slower growth is in peak capacity and cogeneration/combined cycle base loaded capacity that is being filled by gas turbine based simple and combined cycle plants.

Deregulation in the electric industry has also resulted in intense competition among the once-regulated utilities to retain existing large clients and for new base load growth. Lowest power cost is often being supplied by IPPs and other NUGs in the form of combustion turbine cogeneration and combined cycle plants and even steam generating plants such as conventional coal-fired boilers and fluidized bed combustors. These new plants are allowed to compete for wholesale power sales using existing transmission access. This retail wheeling competition provides a competitive edge to more efficient IPP plants eroding base power generation from utilities conventional power plants. In fact, the demand for electricity from utility plants in the Northeast and elsewhere is at an all time low. Many utility boilers currently operate at historically low capacity factors as power purchase from IPPs increases. Further deterioration in load dispatch from conventional steam cycle plants is anticipated as new IPP-based generation compete more efficiently for electricity demand even with a growth in overall power consumption. Trends shown in Section 2.2 illustrate how in NESCAUM capacity factors are lower on average than just a few years ago.

In an attempt to maintain or increase ratebase, utilities are planning repowering projects, adding peaking capacity, and installing new cogeneration plants using existing infrastructure to serve large industrial clients. Many of these projects will add additional gas turbine based power beyond that already in place and projected from IPPs. New technological advances in large industrial and power generation gas turbines are resulting in very low NO_x emissions and improved heat rate. Also, gas turbine plants have a much lower initial capital requirement providing additional economic incentive for their projected growth. Other forecasted utility trends include life extension program for existing equipment, relegating older and less efficient plants to meeting peaking demand. Life extension of existing older plants will also delay costly decommissioning of older equipment and disposal of asbestos insulated materials.

Fuels pricing and availability also have large effects on the mix of power generation equipment, capacity, load dispatch strategies, and emissions. The favorable prices for natural gas and the availability of long-term gas contracts, coupled with developing environmental regulations for NO_x and SO_2 reduction favoring clean fuels, are responsible in part for the growth of gas turbine-based power generation. Gas availability and competitive pricing is also affecting power dispatch and fuel selection. Several plants with oil/gas firing capability rely more heavily on natural gas rather than oil, for example, altering the baseline NO_x and projected feasibility and effectiveness of controls. Natural gas prices have for the past 10 years been lower than residual oil for the utilities. Some utilities are evaluating alternate low-cost fuels, such as Orimulsion, to increase their economic competitiveness among the new power generation group.

All these trends will affect the current profile of boilers and power generation fuels in the Northeast and mid Atlantic areas of the country in ways that are still evolving. For example, older less efficient boilers can be placed on mothball or cold start-up for peaking capacity. Installation of expensive low-NO_x controls for these units may prove unnecessary as most of the NO_x reduction will be realized from changes in load dispatch. It is important, therefore, to consider that, in addition to environmental controls being mandated on utility boilers, several other economic forces are at play changing the way electrical power is generated and distributed. These forces will likely determine how quickly old plants are retired, which fuels will be burned and the optimum power dispatch that considers lowest power production cost as well as compliance with environmental regulations.

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CHAPTER 3

PHASE II NO_x CONTROL OPTIONS

The previous chapter described a population of utility boilers with a wide range of yearly emission levels that vary with emission factors, boiler capacity, and utilization. Emission factors, in turn, vary because of fuel, firing configuration, furnace heat release rates, and degree of NO_x control already in place because of the May 31, 1995, RACT deadline. For example, a large fraction of the installed coal-fired capacity in two MARAMA states, North Carolina and Virginia, will have few or no NO_x controls. This is because RACT does not apply to all states within the MARAMA region. Therefore, units in North Carolina and in several counties of Virginia tend to have the higher NO_x emission factors. The majority of the boilers in NESCAUM and MARAMA, however, already have some degree of NO_x control. These controls range from LNB-based technologies and combustion modifications to novel flue gas treatment devices. Further reductions from these controlled levels will be possible only with application of technologies that are compatible with existing ones. Retrofit potential for specific controls will hinge on technical feasibility, commercialization status, cost, and many site-specific considerations.

Control candidates considered for post-RACT application on utility boilers exclude conventional "first-round" combustion controls such as LNB, flue gas recirculation (FGR), burners our of service (BOOS), overfire air (OFA), or combination of these. Although not always the case, RACT compliance for coal and oil/gas-fired boilers in the Northeast has relied on these types of controls. Utility boilers that have undergone retrofit of new LNB or combustion modifications such as FGR, BOOS, or OFA have often exhausted the ability for further NO_x reductions with additional combustion controls. Although minor additional NO_x trim is sometimes possible with optimization of existing combustion equipment, NO_x reductions greater than 25 percent from post-RACT levels are often not possible without gas treatment. The only exceptions, perhaps, are gas reburning and cofiring technologies, and full-scale gas conversions. Although viewed as combustion modifications, gas reburning aims to suppress the NO_x already formed in the main burner zone and, in this way, it can achieve the additional reductions being considered for the post-RACT period.

Table 3-1 lists the candidate retrofit controls for NO_x reductions on coal- and oil/gas-fired utility boilers. For uncontrolled coal-fired cyclones, candidate controls include coal and gas reburning and a variety of FGT options. FGT controls all rely on the properties of ammonia-based compounds to reduce NO_x with or without the presence of catalysts. These FGT options include few commercial NO_x/SO_x combined gas treatment systems with recent demonstrations in the U.S. and commercial applications in Europe. For other coal-fired boiler types, equipped with either low-NO_x concentric firing systems (LNCFS™) for tangential firing or low-NO_x circular burners for wall firing, controls are similar but exclude coal reburning and include gas cofiring and gas conversion. However, as discussed later, experience with either gas cofiring and conversion options with low-NO_x burner-equipped boilers is minimal. Further, many LNBs just recently retrofitted on pulverized coal-fired boilers, do not have gas cofiring capability. Although gas cofiring capability can be readily added to coal- and oil-fired units, and several boilers already have, the retrofit of this capability represents an additional cost consideration.

For gas/oil-fired boilers, post-RACT controls also include gas cofiring for oil-based units, reburning for either oil- or gas-fired boilers, and gas conversions from oil to gas. In place of combined NO_x/SO_x controls, catalytic air heaters (AH-SCR or CAT-AH) used alone or in combination with either SNCR or SCR systems offer additional control options for principally gas-fired boilers, and potentially coal-fired boilers as well. SO_2 scrubbing needs for oil/gas-fired boilers are typically not cost-effective because lower sulfur fuels or cofiring can be used to regulate SO_2 emissions.

Table 3-1. List of candidate retrofit controls for Phase II NO_x reductions

Coal-fired Utility Boilers			Oil/Gas-fired Utility Boilers	
Cyclones	**Corner-fired**	**All Other Firing Types**	**Corner-fired**	**All Other Firing Types**
Coal Reburning Gas Reburning: • Standard • Advanced	Gas Cofiring Gas Reburning: • Standard • Close-coupled • Advanced	Gas Cofiring Gas Reburning: • Standard • Advanced	Gas Cofiring Gas Reburning: • Standard • Close Coupled • Advanced	Gas Cofiring Gas Reburning: • Standard • Advanced
	Gas Conversion	Gas Conversion	Gas Conversion (O to G)	Gas Conversion (O to G)
Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • Combined NO_x/SO_x	Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • Combined NO_x/SO_x	Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • Combined NO_x/SO_x	Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • AH-SCR	Flue Gas Treatment: • SNCR • SCR • SNCR+SCR Hybrid • AH-SCR

It is evident from recent retrofit experiences in the U.S. and Europe, for example, that several post-LNB control options have made progress toward greater reliability and improved performance. These recent experiences and successes clearly point to improved feasibility of retrofit to a broader family of boilers, even some difficult retrofits. For example, flue gas treatment and gas-based controls have been applied to uncontrolled and combustion-controlled boilers with significant success and little or no reported operational impacts. In fact, several new and existing boilers in the U.S. have either been retrofitted with these controls or are scheduled to in the next several months. Operational experience is growing rapidly and preliminary results often indicate better than guaranteed performance.

Tables 3-2 and 3-3 list known retrofit and new boilers in the U.S. equipped with post-RACT controls considered in this study. Retrofits include both commercial and demonstration units. The list includes more than 15 GW of gas-based technologies, principally cofiring and full-scale gas conversions to permit 100 percent gas-firing capacity. Reburning technologies have focused primarily on the demonstration of the technology on smaller size utility boilers (<200 MW), although larger retrofit applications are planned. The list of domestic flue gas treatment installations is also large. In fact, the total SNCR- and SCR-controlled utility boiler capacity, in place and planned for the near future, amounts to nearly 15,000 MWe as well. Most of the capacity is dedicated gas-fired and is located in California. However, about 1,200 MWe of coal-based capacity is planned for SCR, about one half new installations and the remaining retrofits of existing plants. No combined SO_x/NO_x control technologies are either installed or planned in the U.S., although DOE-sponsored demonstrations have shown promising results and some installations have taken place in Europe.

The following sections briefly describe the technology, summarize the reported performance and operational experience, and draw some general conclusions about the applicability on RACT-controlled boilers in the Northeast and Mid-Atlantic regions. The description of the various technologies will be limited to brief overview of the fundamental mechanisms that promote NO_x

Table 3-2. Domestic utility boilers experience with gas-based and flue gas treatment NO_x control technologies

Control Technologies	Utility Company	Station Identification and State	Boiler Size and Firing Type
Gas cofiring (in place)	Detroit Edison	Greenwood Unit 1, MI	Oil-fired 815 MWe wall
	Duquesne Light Co.	Cheswick Unit 1, PA	Coal-fired 570 MWe tangential
	Alabama Power Co.	Gadsden Unit 1, AL	Coal-fired 60 MWe tangential
	S. Indiana Gas & Electric/Alcoa	Warrick Unit 1, IN	Coal-fired 150 MWe wall
	Public Service Co. of Oakland	Northeastern Unit 4, OK	Coal-fired 450 MWe tangential
	TU Electric	Big Brown Unit 1, TX	Coal-fired 575 MWe tangential
	Pennsylvania Electric Co.	Conemaugh Units 1 & 2, PA	Coal-fired 936 MWe tangential
	Illinois Power	Hennepin Unit 1, IL	Coal-fired 71 MWe tangential
	Kansas Power & Light	Lawrence Unit 5, KS	Coal-fired 500 MWe tangential
	Texas Municipal	Gibbons Creek, TX	Coal-fired 440 MWe tangential
	Centerior Energy	Eastlake Unit Unit 2, OH	Coal-fired 100 MWe tangential
	Electric Energy	Joppa, Unit 4, IN	Coal-fired 181 MWe tangential
	New England Power Service	Brayton Point Unit 4, MA	Oil-fired 450 MWe wall
	New England Power Service	Brayton Point Unit 1, MA	Coal-fired 250 MWe tangential
	Philadelphia Electric	Cromby Unit 2, PA	Oil-fired 220 MWe tangential
	Illinois Power	Wood River Unit 4, IL	Coal-fired 113 MWe tangential
	Potomac Electric Power Co.	Chalk Point Unit 1, MD	Coal-fired 364 MWe, wall
	Potomac Electric Power Co.	Chalk Point Unit 2, MD	Coal-fired 364 MWe, wall
	Potomac Electric Power Co.	Chalk Point Unit 3, MD	Oil-fired 659 MWe, tangential
	Potomac Electric Power Co.	Chalk Point Unit 4, MD	Oil-fired 659 MWe, tangential
	Public Service Electric & Gas	Hudson Unit 2, NJ	Coal-fired 660 MWe, wall
	Mississippi Power Co.	Jack Watson Unit 4, MS	Coal-fired 250 MWe, wall
	Mississippi Power Co.	Jack Watson, Unit 5, MS	Coal-fired 500 MWe, wall
	Electric Energy Inc.	Joppa Unit 1 , IL	Coal-fired 167 MWe tangential
	Electric Energy, Inc.	Joppa Unit 2, IL	Coal-fired 167 MWe, tangential
	Electric Energy, Inc.	Joppa Unit 3, IL	Coal-fired 167 MWe, tangential
	Electric Energy, Inc.	Joppa Unit 4, IL	Coal-fired 167 MWe, tangential
	Electric Energy, Inc.	Joppa Unit 5, IL	Coal-fired 167 MWe, tangential
	Public Service Electric & Gas	Mercer Unit 1, NJ	Coal-fired 326 MWe, wall
	Pacific Corp.	Naughton Unit 1, WY	Coal-fired 163 MWe, tangential
	Pacific Corp.	Naughton Unit 2, WY	Coal-fired 218 MWe, tangential
	Jacksonville Electric Authority	Northside Unit 1, FL	Oil-fired 275 MWe, wall
Gas cofiring (planned)	S. Indiana Gas & Electric/Alcoa	Warrick Unit 4, IN	Coal-fired 300 MWe wall
	Philadelphia Electric	Eddystone Unit 3, PA	Oil-fired 395 MWe tangential
	Philadelphia Electric	Eddystone Unit 4, PA	Oil-fired 395 MWe tangential
	New England Power Service	Brayton Point Unit 3, MA	Coal-fired 620 MWe wall
	S. Indiana Gas & Electric/Alcoa	Warrick Unit 3, IN	Coal-fired 144 MWE wall
	New England Power Service	Brayton Point Unit 2,	Coal-fired 250 MWe tangential
	Columbus Southern Power	Conesville Unit 3, OH	Coal-fired 165 MWe wall
	Ohio Edison	Edgewater Unit 4, OH	Coal-fired 105 MWe, wall
	Electric Energy Inc.	Joppa Unit 6, IL	Coal-fired 167 MWe, tangential
Gas reburning (in place)	Illinois Power	Hennepin Unit 1, IL	Coal-fired 71 MWe tangential
	City Water, Light & Power	Lakeside Unit 7, OH	Coal-fired 33 MWe cyclone
	Public Service of Colorado	Cherokee Unit 3, CO	Coal-fired 185 MWe wall
	Ohio Edison[a]	Niles Unit 1, OH	Coal-fired 110 MWe cyclone
	Central Illinois Co[a]	Edwards Unit 1, IL	Coal-fired 100 MWe wall
	Public Service of Colorado[a]	Arapahoe Unit , CO	Coal-fired 100 MWe top-fired
	Kansas Power & Light	Lawrence Unit 5, KS	Coal-fired 450 MWe tangential
	Long Island Lighting Co.	Barrett Unit 2, NY	Oil/gas-fired 185 MWe tangential

[a]Demonstration sites technology since removed.

Table 3-2. **Domestic utility boilers experience with gas-based and fuel gas treatment NO_x control technologies (continued)**

Control Technologies	Utility Company	Station Identification and State	Boiler Size and Firing Type
Gas conversion (in place)	Jacksonville	Northside Unit 3, FL	Oil-fired 550 MWe Wall
	Consumers Power	Karn Unit 4, MI	Oil-fired 640 MWe Wall
	Arizona Electric	Apache Units 2 & 3, AZ	Coal-fired 200 MWe turbo
	Potomac Electric	Chalk Point Units 1 & 2, VA	Coal-fired 355 MWe wall
	American Electric Power	Pickway Unit 3, OH	Coal-fired 100 MWe wall
	American Electric Power	Conesville Unit 3, OH	Coal-fired 165 MWe wall
	New England Power	Brayton Point Unit 4, MA	Oil-fired 432 MWe wall
	Public Service of Colorado	Arapahoe Unit 4, CO	Coal-fired 100 MWe top-fired
	Long Island Lighting Co.	Barrett Unit 2, NY	Oil-fired 185 MWe tangential
	Illinois Power	Hennepin Unit 1, IL	Coal-fired 71 MWe tangential
	Illinois Power	Hennepin Unit 2, IL	Coal-fired 231 MWe tangential
	Northern Indiana Public Serv.	Michigan City Unit 12, MI	Coal-fired 540 MWe cyclone
	Northern Indiana Public Serv.	Mitchell Unit 4, IN	Coal-fired 138 MWe tangential
	Commonwealth Edison	Fisk Unit 19, IL	Coal-fired 374 MWe tangential
Gas conversion (planned)	Connecticut Light & Power	Devon Unit 7, CT	Oil-fired 66 MWe wall
	Connecticut Light & Power	Devon Unit 8, CT	Oil-fired 48 MWe wall
	Niagara Mohawk	Oswego Unit 5, NY	Oil-fired 850 MWe wall
	Pennsylvania Power & Light	Martins Creek Unit 3, PA	Oil-fired 820 MWe tangential
	Pennsylvania Power & Light	Martins Creek Unit 4, PA	Oil-fired 820 MWe tangential
	Canal Electric	Canal Unit 2, MA	Oil-fired 581 MWe wall
	American Electric Power	Conesville Unit 1, OH	Coal-fired 148 MWe cyclone
	American Electric Power	Conesville Unit 2, OH	Coal-fired 136 MWe cyclone
	Illinois Power	Vermillion Unit 1, IL	Coal-fired 70 MWe tangential
	Illinois Power	Vermillion Unit 1, IL	Coal-fired 90 MWe tangential
SNCR (in place)	New England Power Co.	Salem Harbor Unit 1, MA	Coal-fired 84 MWe wall
	New England Power Co.	Salem Harbor Unit 2, MA	Coal-fired 84 MWe wall
	New England Power Co.	Salem Harbor Unit 3, MA	Coal-fired 156 MWe wall
	Public Service of Colorado	Arapahoe Unit 4, CO	Coal-fired 100 MWe top-fired
	Long Island Lighting Co.	Port Jefferson Unit 3, NY	Oil/gas-fired 185 MWe tangential
	Atlantic Electric Co.	B.L. England Unit 1, NJ	Coal-fired 138 MWe cyclone
	Public Service Electric & Gas	Mercer Unit 2, NJ	Coal-fired 321 MWe wet-wall
	Public Service Electric & Gas	Mercer Unit 1, NJ	Coal-fired 320 MWe wall
	Wisconsin Electric Co.	Valley Plant Unit 4, WI	Coal-fired 70 MWe wall
	Niagara Mohawk Co.	Oswego Unit 1, NY	Coal-fired 850 MWe wall
	Pacific Gas & Electric Co.	Morro Bay Unit 1, CA	Gas-fired 345 MWe Wall
	San Diego Gas & Electric	Encina Unit 2, CA	Gas-fired 110 MWe wall
	Southern California Edison	Etiwanda Unit 3, CA	Gas-fired 333 MWe tangential
	Southern California Edison	Etiwanda Unit 4, CA	Gas-fired 333 MWe tangential
	Southern California Edison	Alamitos Unit 4, CA	Gas-fired 333 MWe tangential
	Southern California Edison	El Segundo Unit 3, CA	Gas-fired 342 MWe tangential
	Southern California Edison	El Segundo Unit 4, CA	Gas-fired 342 MWe tangential
	Southern California Edison	El Segundo Unit 2, CA	Gas-fired 156 MWe wall
	Southern California Edison	Alamitos Unit 3, CA	Gas-fired 333 MWe tangential
	Los Angeles Dept. of W&P	Scattergood Unit 1, CA	Gas-fired 150 tangential
	New York State Electric & Gas	Milliken Unit 1, NY	Coal-fired 150 MWe tangential
	Connecticut Light & Power	Norwalk Harbor Unit 1, CT	Oil-fired 172 MW tangential
	Connecticut Light & Power	Norwalk Harbor Unit 2, CT	Oil-fired 182 MW tangential
	Pennsylvania Electric Co.	Seaward Unit 5, PA	Coal-fired 148 MW wall
	Public S. of New Hampshire	Merrimack Unit 1, NH	Coal-fired 120 MWe cyclone
	Montaup	Sommerset 5, MA	Coal-fired 100 MWe tangential

Table 3-2. Domestic utility boilers experience with gas-based and fuel gas treatment NO_x control technologies (concluded)

Control Technologies	Utility Company	Station Identification and State	Boiler Size and Firing Type
SCR (in place)	Public S. of New Hampshire	Merrimack Unit 2, NH	Coal-fired 338 MWe cyclone
	Chambers Works	Chambers Unit 1, NJ	Coal-fired 143 MWe wall
	Chambers Works	Chambers Unit 2, NJ	Coal-fired 143 MWe wall
	Public S. Electric & Gas	Mercer Unit 2, NJ	Coal-fired 80 MWe wet wall[b]
	Southern California Edison	Huntington Beach Unit 2, CA	Gas-fired 150 MWe wall
	Southern California Edison	Ormond Beach Unit 1, CA	Gas-fired 750 MWe wall
	Southern California Edison	Ormond Beach Unit 2, CA	Gas-fired 750 MWe wall
	Southern California Edison	Alamitos Unit 6, CA	Gas-fired 480 MWe wall
	Southern California Edison	Redondo Beach Unit 7, CA	Gas-fired 480 MWe wall
	Southern California Edison	Redondo Beach Unit 8, CA	Gas-fired 480 MWe wall
	Southern California Edison	Mandalay Unit 2, CA	Gas-fired 215 MWe wall
	San Diego Gas & Electric	Encina Unit 2, CA	Gas-fired 110 MWe wall
	Los Angeles Dpt. Wtr & Pwr	Haynes Unit 1, CA	Gas-fired 230 MWe wall
	Los Angeles Dpt. Wtr & Pwr	Haynes Unit 2, CA	Gas-fired 230 MWe wall
	Los Angeles Dpt. Wtr & Pwr	Haynes Unit 5, CA	Gas-fired 330 MWe wall
	Los Angeles Dpt. Wtr & Pwr	Haynes Unit 6, CA	Gas-fired 330 MWe wall
SCR (planned)	Orlando Utilities	New Stanton Unit 1, FL	Coal-fired 460 MWe wall
	Keystone Energy	Keystone Unit 1, NJ	Coal-fired 230 MWe wall
	Southern California Edison	Alamitos Unit 3, CA	Gas-fired 320 MWe tangential
	Southern California Edison	Alamitos Unit 4, CA	Gas-fired 320 MWe tangential
	Southern California Edison	Alamitos Unit 5, CA	Gas-fired 480 MWe wall
	Southern California Edison	El Segundo Unit 3, CA	Gas-fired 335 MWe tangential
	Southern California Edison	El Segundo Unit 4, CA	Gas-fired 335 MWe tangential
	Southern California Edison	Etiwanda Unit 3, CA	Gas-fired 320 MWe tangential
	Southern California Edison	Etiwanda Unit 4, CA	Gas-fired 320 MWe tangential
	SEI	Birchwood Station, VA	Coal-fired 245 MWe tangential

[b]At present, only one fourth (80 MWe) of boiler capacity (321 MWe) is treated with SCR.

Table 3-3. Utility boilers in the United States with experience with gas-based and flue gas treatment NO_x control technologies

Control Category	Technology	Station Identification and State (Commercial and Demonstration Sites)	Boiler Capacity and Firing Type
Gas-based Controls	Natural Gas Reburning	2 Units in Illinois 2 Units in Ohio 2 Units in Colorado 1 Unit in Kansas 1 Unit in New York	521 MWe coal-fired tangential 143 MWe coal-fired cyclone 385 MWe coal-fired wall/other 185 MWe oil/gas-fired tangential
	Gas Cofiring	6 Units in Pennsylvania 3 Units in Massachusetts 3 Units in Indiana 2 Units in Texas 1 Unit in Alabama 1 Unit in Kansas 1 Unit in Ohio 7 Units in Illinois 1 Unit in Florida 1 Unit in Michigan 4 Units in Maryland 2 Units in New Jersey 2 Units in Mississippi 2 Units in Wyoming	5,712 MWe coal-fired tangential 3,328 MWe coal-fired wall 2,043 MWe oil/gas-fired
	Natural Gas Conversions	6 Units in Illinois 4 Units in Ohio 2 Units in Michigan 2 Units in Arizona 2 Units in Massachusetts 2 Units in New Jersey 2 Units in New York 2 Units in Connecticut 1 Unit in Colorado 1 Unit In Florida 1 Unit in Indiana	974 MWe coal-fired tangential 620 MWe coal-fired wall 1,124 MWe coal-fired other 4,992 MWe oil-fired
Flue Gas Treatment Controls	SNCR-based Controls	10 Units in California 4 Units in Massachusetts 3 Units in New York 5 Units in New Jersey 1 Unit in Wisconsin 1 Unit in Colorado 2 Units in New Hampshire 1 Unit in Delaware	1,392 MWe coal-fired wall 3,492 MWe gas/oil-fired 421 MWe coal-fired cyclone 741 MWe coal-fired other firing
	SCR-based Controls	21 Units in California 4 Units in New Jersey 1 Unit in Massachusetts 1 Unit in Florida 1 Unit in New Hampshire	6,965 MWe gas-fired 1,582 MWe dry-bottom coal-fired 659 MWe wet bottom and cyclone

reduction, focusing instead on commercialization status, equipment and requirements, and site modifications that influence the applicability and performance on existing facilities. It is not the intent of this chapter to speculate on the optimum selection of any one control option for a specific powerplant or NO_x control target. This is because, the retrofit of controls on existing powerplants can best be evaluated on a case by case basis and often more than one approach is possible to achieve a certain NO_x reduction efficiency or NO_x emission target. Indeed, the selection of a specific control option involves several technical, economic, and strategic decisions that are well beyond the objectives of this report.

3.1 NATURAL-GAS-BASED CONTROLS

The environmental benefits of using natural gas instead of coal or residual oil are for the most part obvious ones. Because natural gas is essentially free of sulfur and nitrogen and without inorganic matter typically present in coal and residual oils, SO_2 emissions can be essentially eliminated; NO_x emissions can be dramatically reduced; and organic and inorganic particulate and air toxic compounds essentially removed from all discharge streams leaving the boiler. With these environmental advantages, it is obvious that natural gas would be viewed as a sound alternative to coal or oil burning in existing powerplants to meet strict emission standards in all categories: SO_2, NO_x, particulate, and air toxics. Natural gas can become even more attractive when small quantities can be used in a particular burner arrangement to maximize the NO_x reduction benefits of this clean burning fuel and improve operation of the plant.

Because of its ease of transport, ease of burning, and relatively low emissions, natural gas is a premium utility boiler fuel. Its use is often relegated to severe nonattainment areas such as Southern California, and to fuel new advanced, high efficiency, gas turbine-based power generation equipment used in combined cycle or cogeneration applications. Also, natural gas is the fuel of choice in many residential and commercial heating applications. Coupled with its normally higher cost (on a Btu basis) compared to coal, utility concerns over long-term availability, especially during severe winter months in the Northeast and other parts of the country, limit its attractiveness solely for environmental benefits. Recently, particular attention has been paid to the other, not-so-obvious, benefits of natural gas use in boilers. These benefits focus on operation improvement, capacity recovery, life extension, etc., that might help mitigate its primary disadvantages due to cost and uncertain long-term availability.

The following subsections discuss the experience gained to date on the various retrofit uses of natural gas in utility boilers. The principal uses of natural gas as a utility boiler fuel are:

- Cofiring with a primary fuel such as coal or oil
- Reburning by special application to maximize its NO_x reduction properties
- Boiler fuel conversion when gas is used to replace coal or oil as the principal fuel

Each of these applications has its own advantages and disadvantages when considering NO_x reduction, overall environmental benefit, cost, operation, retrofit feasibility and other issues. Natural gas use in each of these three applications can also be done on a year-around basis or selectively, i.e., during the peak ozone season when NO_x reductions are most needed and when natural gas is more attractively priced. Seasonal use of controls, particularly natural gas-based controls, can be economically attractive because of lower operating costs and, in the case of gas use, more competitive fuel pricing. Seasonal use of controls, including natural gas controls, is discussed in Section 3.5.

Cofiring and boiler fuel conversions have a long history in the power generation industry. Fuel selection for power generation is based on economic consideration and availability. Various federal regulations and initiatives have also affected utility decisions to burn one fuel over another. In fact, many plants have undergone boiler fuel conversions over the years for a number of reasons other than emission compliance. Reburning, however, is a more recent technological development commercialized principally in response to the NO_x reduction needs under the Clean Air Act Amendments of 1990, especially its Title I ozone attainment provisions. Gas reburning aims specifically to maximize the NO_x reduction potential with a minimum amount of natural gas. Its development has included demonstrations on LNB-controlled boilers to maximize overall NO_x

reduction, whereas similar evaluations have not occurred with either cofiring or full-scale gas conversions. Finally, seasonal gas use has attracted some interest because periods of highest gas availability to the utilities coincide with peak ozone season. NO_x reductions during the peak ozone season are deemed most beneficial to the goal of ground level ozone attainment in the NESCAUM and MARAMA regions.

3.1.1 Cofiring

Gas cofiring involves the utilization of natural gas with another primary fuel, e.g. coal or oil, for the purpose of emission reduction, overcoming load limitations, and for operational improvements such as startups and improved ignition. The gas can be injected into the furnace through existing startup guns, limited-capacity ignitors, or through gas spuds, nozzles or rings in existing burner ports. Although there are no theoretical limits to the amount of gas cofiring, the technology generally implies natural gas utilization less than 20 percent of the total heat input (Harding, 1994).

A recent study sponsored by the Coalition of Gas-Based Solutions puts the number of gas-cofire boilers in the Ozone Transport Region (OTR) at about 30 percent (Energy Venture Analysis, 1994). In the absence of any gas supply and firing capability, the plant would need access to gas supply and install the needed equipment to permit 10-20 percent cofire. This equipment includes gas mains to the plant from the nearest gas transmission pipeline, valves for flow control and shutoff, burner nozzles in existing burner openings, new or modified flame scanners, and associated combustion controls. For boilers with adequate supply of gas, little or no additional equipment changes would be necessary.

The location of new gas nozzles in existing burner openings is important to the optimization of NO_x reduction potential, burner safety, turndown capability, NO_x control level, and control of the furnace exit gas temperature (FEGT) and steam temperatures. Research on tangential boilers, for example, points to the top burner level as the optimum location for gas injection in what is termed "close coupled" reburning (La Flesh, 1993). For circular low-NO_x burners, locating the optimum injection method for NO_x reduction has not been sufficiently researched. Opportunities may be available to use small quantities of natural gas to improve the low-NO_x performance of today's LNBs.

Some of the benefits of cofire are (Harding, 1994):

- Clean startup
- Improved ESP operation
- SO_2 trim for environmental compliance
- 25 to 50 percent NO_x reduction depending on percent cofire
- Reduced flame impingement
- Load recovery with mills out of service
- Improved O_2 control, carbon burnout, furnace slagging

Additional benefits may result from (Folsom, et al., 1993):

- Improved capacity factor
- Recovery of lost capacity due to switching to a lower sulfur, higher ash coal
- Lower CO_2 emissions to alleviate greenhouse gases in the atmosphere
- Reduced air toxics from reduced use of toxic metal-bearing coals
- Improved ash quality, reduced ash disposal needs and associated costs
- Reduced auxiliary power for coal transport and pulverizing
- Lower stack opacity and particulate loading
- Low load combustion stability
- Overall improved powerplant operation and reduced maintenance

NO_x reductions with gas cofiring are possible by various air and fuel staging techniques. To date, gas cofiring methods have not been fully explored. Opportunities may exist to optimize gas injection location to maximize NO_x reduction and operational benefits.

Table 3-4 lists the NO_x reduction data available on selected coal-fired utility boilers cofired with natural gas. Although gas cofiring is being practiced in many more boilers (see Table 3-2), no

Table 3-4. Gas cofiring experience on coal-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Control	NO_x Emission Rate Before Cofire (lb/MMBtu)	NO_x Emissions Rate After Cofire[a] (lb/MMBtu)	Overall Performance and Impacts (References)
Duquesne Light Cheswick Unit 1	570 MWe tangential, twin furnace; five burner elevations, eight corners	None conventional close coupled OFA	0.60 at full load	0.45 for a reduction of 25 percent from baseline with 8% cofire. Short-term	Improved load recovery during pulverizer outages; improved efficiency from lower excess O_2, LOI, and lower A.H. out temperature; eliminated ESP fouling; reduced slagging (Harding, 1994)
Kansas Power & Light Lawrence Unit 5	400 MWe tangential with six levels of coal burners and 7 gas. Full load limited to 325 to 350 MWe with subbituminous coal	CE low-NO_x PM burners	<u>Without SOFA:</u> 0.40 at full load <u>With SOFA:</u> 0.21 at full load	20 to 27 percent NO_x reduction attributed to 10 to 20 percent cofiring. Overall 63 to 69 percent reduction due to staging and cofire. Short term	Optimum gas injection location was proven to be at the highest burner level, just below the closed coupled OFA ports. 35 to 50 MWe increased capacity; <50°F increase in FEGT with 20 percent cofire (Lewis, et al, 1994)
Illinois Power Co. Hennepin Unit 1	71 MWe tangential fired	None (OFA)	0.67 at full load	35 percent NO_x reduction to 0.44 lb/MMBtu with 35 percent gas cofire. Short term tests	Primary benefit is to restore capacity when switching to low sulfur western coal. (Angello, et al. 1993).
Southern Indiana Gas & Electric Co./Alcoa Warrick Unit 1	150 MWe wall fired	None	0.60 to 0.70	0.35 to 0.60 depending on cofire rate and location of cofire	Boiler efficiency decreased 2% with 25% cofire; 0.2 to 0.5% with 6 to 11% cofire. Other impacts minor. (Radian, 1994)
Public Service Company of Oklahoma Northeastern Unit 4	450 MWe corner fired	None (OFA)	0.483 to 0.540 (0.509 four day average)	0.484 to 0.502 (0.496 4-day average)	Primary interest for cofire was to reduce slagging in furnace. Tests limited to 13 percent cofire. Overall no change in NO_x; reduced opacity (Clark, et al., 1993)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

Table 3-4. Gas cofiring experience on coal-fired utility boilers (concluded)

Boiler Site	Boiler Type and Gross Capacity	Combustion Control	NO_x Emission Rate Before Cofire (lb/MMBtu)	NO_x Emissions Rate After Cofire[a] (lb/MMBtu)	Overall Performance and Impacts (References)
New England Power Service; Brayton Point Unit 1	250 MWe tangential	None (OFA)	0.48 to 0.55 at full load	0.30 to 0.33 at full load with 20 percent cofire. Short term tests	Preliminary results for ongoing tests to be made public in 1995 (GRI, September 1994)
Texas Utility Big Brown Unit 1	575 MWe corner fired	None	Not available	Not available	Harding, et al., 1994
Southern Indiana Gas & Electric; Warrick Unit 4	300 MWe wall fired	None	No data available; test ongoing	No data available; tests ongoing	Planned up to 25 percent cofire capacity (Pratapas, 1994)
Electric Energy, Inc. Joppa	181 MWe tangential with five burner elevations	None	No data available; tests ongoing	No data available; tests ongoing	Planned up to 50 percent cofire capacity. Anticipated capacity restoration due to western coal firing (Pratapas, 1994)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

performance data has been reported for these other units. The data listed in Table 3-4 points to a NO_x reduction efficiency in the range of about 25 to 40 percent with natural gas accounting for 8 to 35 percent of the total heat input. All three boilers, for which there is NO_x reduction data, are tangential units equipped with OFA ports. Only the Lawrence Unit 5 has an LNB in place equipped with a separate OFA system (SOFA). For this boiler, the controlled NO_x emissions are particularly low because of the operation of the LNB and because the subbituminous coal burned is particularly conducive to very low NO_x levels with combustion staging. Because the gas was introduced at the top burner level, some reburning effect was also responsible for very low levels of 0.11 lb/MMBtu. In fact, these results are also presented in Section 3.1.2 under the subject of reburning. These controlled levels would not be likely in most NESCAUM and MARAMA boilers because coals are less volatile and furnaces are more compact. Smaller furnaces are generally used for combustion of eastern bituminous coals. These boilers have higher heat release rate per unit of waterwall area. The effect of higher heat release rate on NO_x emissions and NO_x reduction efficiencies with gas use in coal-designed boilers will be revisited during the discussion on gas conversions in Section 3.1.3. Other NO_x cofiring demonstration tests are scheduled for the Warrick Station of SIECO and Joppa Station of Electric Energy (Pratapas, 1994).

Table 3-5 lists boiler sites where gas cofiring is either being practiced or is under planning stages for boilers burning predominantly oil. The results available for this study are limited to the Brayton Point Unit 4 of New England Power Co (NEPCO). This wall-fired boiler is equipped with FGR and was cofired with up to 70 percent gas to document the NO_x reduction benefits. As shown, with 30 percent cofire NO_x was reduced only marginally from 0.29 lb/MMBtu to 0.254 lb/MMBtu without FGR. Once FGR was reinstated, the NO_x was reduced to 0.23 lb/MMBtu with only 10 percent cofire. NEPCO has reported so far that the operation with gas cofire has been satisfactory (Harding, 1994). Heat transfer tube materials in the superheater and reheater were upgraded to sustain the increased FEGT and higher steam attemperation capacity was also installed to permit operation with 100 percent gas.

Table 3-5. Gas cofiring experience on oil-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Control Types	NO_x Emission Rate Before Cofire (lb/MMBtu)	NO_x Emissions Rate After Cofire[a] (lb/MMBtu)	Overall Performance and Measured Impacts
New England Power Brayton Point Unit 4	450 MWe wall-fired with dual fuel capability	FGR	0.290 with 100 percent oil	0.254 with 30 percent gas no FGR 0.217 with 50 percent gas no FGR 0.195 with 70 percent gas no FGR 0.230 with 10 percent gas and FGR	Additional NO_x reduction possible with combination of bias firing and FGR. No operational difficulties were reported. (Harding, 1994)
Philadelphia Electric Cromby Unit 2	220 MWe tangential with dual fuel capability	None OFA rehab.	Not available	Not available	(Harding, 1994)
Philadelphia Electric Eddystone Unit 3	395 MWe tangential; conversion from oil to gas/oil for dual fuel capability	None OFA rehab.	0.28	Not available	Planned retrofit, not yet in place. Expected 23 percent capacity increase. (Harding 1994)
Philadelphia Electric Eddystone Unit 4	395 MWe tangential; conversion from oil to gas/oil for dual fuel capability	None	0.33	Not available	Planned retrofit, not yet in place. Expected 23 percent capacity increase. (Harding, 1994)
Jacksonville Electric Authority Northside Unit 1	275 MWe wall-fired with dual fuel capability	None (BOOS with gas firing)	0.38 (oil only) 0.2 to 0.38 over load range	0.24 to 0.28 at full load	26 to 37 percent reduction depending on method of cofire (Des Chenes, 1992)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

3.1.2 Reburning

In reburning, a fuel is injected above the primary combustion zone to create a "reburning zone" where stoichiometric ratio is maintained fuel rich at 0.9 or lower for optimum NO_x reductions. At these low stoichiometries, various reducing species created from the natural gas fuel react to reduce burner-generated NO_x to molecular nitrogen. In commercial NGR systems, the stoichiometry in the reburn zone can be varied depending on the amount of NO_x control desired. Because sufficient fuel is added to bring the overall stoichiometry fuel rich, it is then necessary to add overfire air above the reburning zone to complete the combustion of the reburning fuel. This final reaction zone is typically referred to as the "burnout zone". Reburning technology has also been referred to as "fuel staging" and "in-furnace NO_x reduction". Figure 3-1 illustrates the overall fuel and air distribution inside a boiler furnace needed to accomplish the reburning process.

The spacing allotted between the three distinct zones is carefully customized to each boiler taking into consideration many furnace design and operating parameters. Efficient mixing of the reburning fuel with the combustion products is also critical to guarantee the maximum NO_x reduction possible with the minimum amount of reburning fuel and with minimal adverse impacts in key furnace operating conditions. One fundamental application criterion is that the furnace must have sufficient room above the main combustion zone for reburning and burnout to take place. Most boilers have sufficient volume above the primary zone to achieve NO_x reduction levels reported in these NGR demonstrations. However, larger primary combustion zones needed for effective LNB operation can reduce the effectiveness of the NGR process precluding economic application. The amount of fuel needed is dictated by the excess air in the main burner zone and by the NO_x reduction required. Reburning fuel is typically in the 15 to 20 percent of the total heat input.

The reburning fuel can be natural gas, propane, oil, and micronized coal. Natural gas is often selected because gas it is easier and quicker to burn, requiring smaller furnace volumes above the burnout zone, thus offering greater retrofit potential. In fact, all boiler types, with the possible

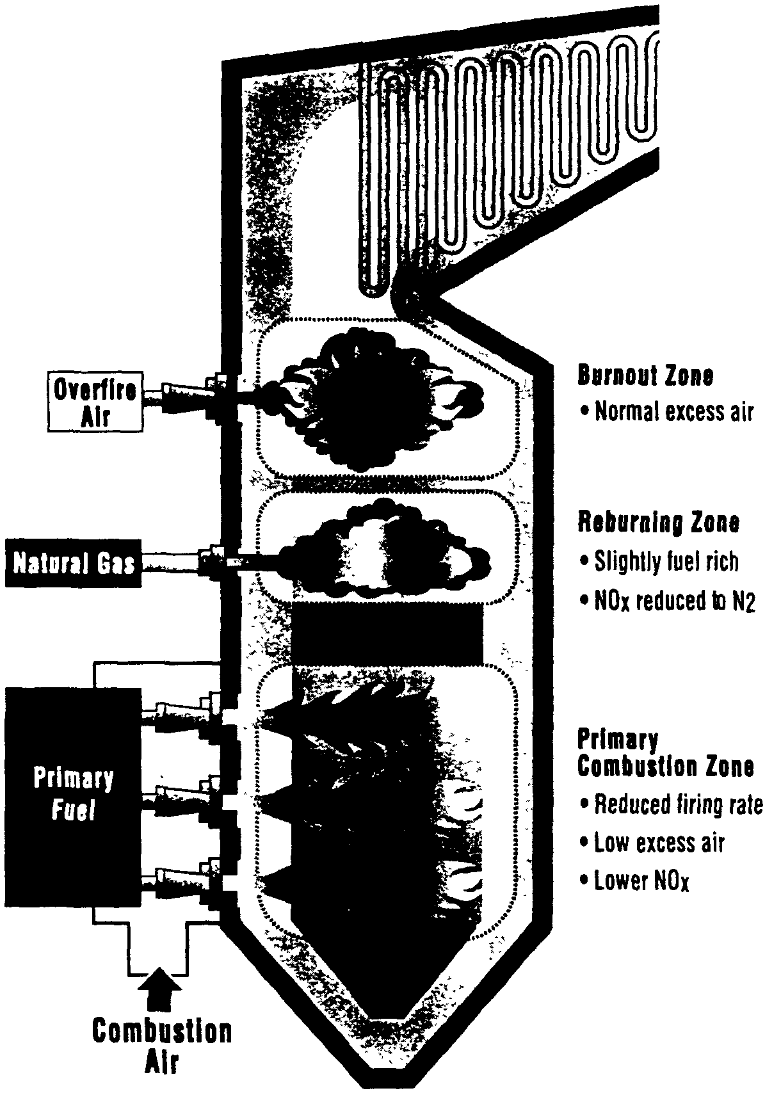


Figure 3-1. Gas reburning for NO_x control (Pratapas, 1994)

exception of very small furnaces with high heat release rates, are candidate retrofits irrespective of primary fuel type and firing configuration, and whether they are equipped with LNB or conventional high turbulence burners. With either coal or oil, instead, the potential for incomplete combustion of reburning fuel is much greater. To date, only one coal-reburning demonstration has taken place on a cyclone boiler. Although this demonstration at the Wisconsin Power & Light Company Nelson Dewey Station showed long term NO_x emission reductions of 53 to 62 percent over the load range (Yiegela, 1993), application of this technology to other cyclones and firing types remains difficult or not feasible because of insufficiency furnace volumes available above the main burner zone. The installation cost of coal-reburning is also much higher than gas reburning (in most cases) because of the requirements for pulverizers and burner penetration. Coal reburning is discussed in Section 3.2.

The technology of reburning using natural gas is commercial and can be applied to all boiler firing types with approximately equal NO_x reduction performance. Boilers that have been retrofitted with LNBs can also use gas reburning because the process targets the destruction of NO_x generated by the main combustion zone adding to the overall NO_x reduction. Utility boiler OEMs such as ABB-CE and B&W are offering the technology on a commercial basis. Energy and Environmental Research Corporation, the firm that undertook many of the demonstrations on utility boilers, is also offering commercial retrofits for gas reburning. These vendors offer slightly different reburning approaches, but the NO_x reduction concept remains the same.

ABB-CE has demonstrated reburning on coal and oil/gas-fired utility boilers and is pursuing commercial applications on slagging furnaces in the Ukraine (LaFlesh and Borio, 1993; LaFlesh, et al., 1993). The ABB-CE approach relies on either a conventional reburning zone separate from the main burner zone or on a "close-coupled" reburning zone. The latter avails itself of the top burner level of the corner-fired system to inject natural gas and is thus considered less capital intensive. The separate OFA system of the LNCFS design can then provide the needed safety of complete burnout air. This approach was tested at the Kansas Power and Light Lawrence 5 boiler retrofitted with a low-NO_x tangential burner system equipped with separate OFA. Because the performance of the close coupled gas reburn was found to be nearly as effective as conventional gas reburn, ABB-CE Services is actively promoting this approach for all gas reburn applications on tangential boilers (La Flesh and Borio, 1993).

Natural gas reburn is presently the most efficient of the gas-based NO_x control technologies. With gas reburn, short-term NO_x reductions up to 70 percent are possible on uncontrolled boilers with as little as 15 to 20 percent gas use (Folsom, 1993). Cofiring instead with this amount of gas use would at best produce about 1/2 of the reburning NO_x reduction performance. Only full-scale conversions to 100 percent gas firing coupled with combustion modifications will be able to reach NO_x reduction performance levels that are attainable with gas reburning.

The exact mechanisms that control the gas reburning process are very complex. What is known is that the NO produced in the burner primary zone is reduced by hydrocarbon (CH) radicals that were generated from the decomposition of the reburn fuel via the following chemical reaction:

$$NO + CH \rightarrow HCN + O \tag{3-1}$$

The cyanide in turn will decompose to molecular nitrogen or re-form NO in the reburn zone. Additionally, NO can decompose by reaction with hydrogen via the following reaction:

$$NO + H \rightarrow HN + O \tag{3-2}$$

Most fuels can provide an adequate pool of CH and H reducing radicals in the reburning zone. Several fuels have been investigated but none have shown greater NO_x reduction efficiencies than natural gas. The principal design parameters for effective reburning are:

- primary burner zone NO_x level
- primary zone stoichiometry
- reburning zone stoichiometry
- reburning zone temperature
- reburning fuel transport medium
- reburning fuel mixing

Higher initial NO_x levels from the primary burner zone tend to produce higher reburning NO_x reduction efficiencies. This finding, reported by several investigators (Wendt, et al., 1991; Takahashi, et al., 1981; and Chen, et al., 1989), suggests that the effectiveness of reburning decreases when applied to LNB-controlled boilers compared to uncontrolled units. In fact, the full-scale data suggests that this is indeed the case, as will be shown later.

The stoichiometry of the primary zone plays an important role insofar as the amount of reburning fuel needed to achieve desired reburning stoichiometry is affected. The higher the excess air in the primary reburn zone, the greater the quantity of reburn fuel is needed to achieve desired reburn stoichiometries. From a NO_x reduction efficiency viewpoint, its effect is secondary to the reburn stoichiometry.

Pilot- and full-scale tests clearly point to the reburn stoichiometry as the principal process parameter affecting NO_x reduction efficiency. The desired reburn stoichiometry is approximately 0.9, indicating that the amount of combustion air in the furnace is 10 percent below the theoretical amount needed for complete combustion of the primary and reburn fuels. At this level, the NO_x emitted from the reburning process is minimized. Further reductions in reburn stoichiometry tend to be either counterproductive or have little additional effect. Tests have also shown that high reburn zone temperatures are more conducive to higher NO_x reduction performance. For this reason, the reburn fuel is often injected as close as possible to the primary burner zone without actually suppressing combustion of the primary fuel. The other benefit of introducing the reburn fuel as close as possible to the primary burners is to maximize the residence time of the gases within the reburning zone before final air is added to complete combustion. Longer residence time increases the effectiveness of reburning at a fixed reburn stoichiometry.

Methods for introducing natural gas into the reburn zone vary among the major gas reburn vendors. For example, B&W uses conventional low NO_x burners to inject gas, combustion air, and flue gas and monitor combustion with flame scanners. This approach provides an additional measure of combustion safety. One such retrofit is being planned for a cyclone boiler at the Eastman Kodak plant in Rochester, NY. This retrofit will demonstrate the use of gas reburn as RACT for smaller utility and large industrial cyclones. ABB-CE uses existing tangential burner ports to introduce the reburn gas in a close coupled approach illustrated in Figure 3-2c. ABB-CE

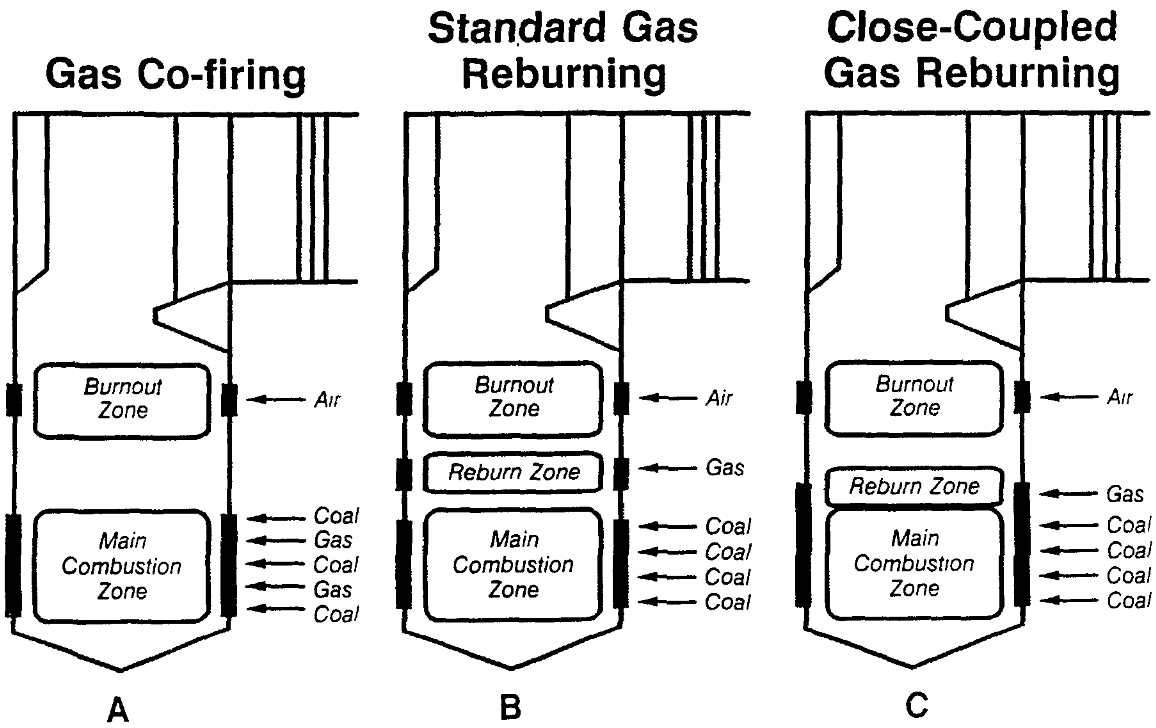


Figure 3-2. Various gas-firing approaches in T-fired coal boilers (Lewis, et al., 1994)

refers to the close coupled reburning concept, illustrated in Figure 3-2c and tested at Kansas Power and Light Lawrence Unit 5, as selective gas cofiring. Gas residence time between coal and gas is minimal, 0.05 to 0.10 seconds, with this configuration (Lewis, 1994). EER, instead, promotes the use of multiple gas injectors. Since EER's gas injectors do not require burner components or an air supply system, they are considerably simpler and require much smaller wall penetrations than the B&W reburning burners. In all cases, natural gas must be injected with sufficient velocity to promote good mixing. For this purpose, a transport medium is usually used. The transport medium for the reburn fuel can be either air or flue gas. The oxidizing capability of the transport medium is a factor in the overall process NO_x reduction efficiency. Because flue gas has much lower oxygen content than air, it tends to produce lower NO_x emissions from the reburning process. Recirculated flue gas is also used to improve the mixing of the reburn fuel. The mixing efficiency of the reburning fuel with the combustion gas can have some impact on the process, especially for reburning fuels other than natural gas.

Table 3-6 lists the results of gas reburn demonstrations performed on coal-fired utility boilers. Reburning has been tested on a total of 670 MWe of coal-fired utility boiler capacity at five demonstration sites. NO_x reduction efficiencies measured over the long-term ranged from 45 to 67 percent. Peak NO_x reductions exceeded 70 percent. It is important to note that when gas reburn is applied on uncontrolled boilers, its NO_x reduction efficiency tends to be higher. Therefore, NO_x reductions recorded at the uncontrolled Lakeside Unit 7, Niles Unit 1, and Hennepin Unit 1 were as high as 67 percent. Gas reburn demonstrations at Cherokee Unit 3 and Lawrence Unit 5, instead, reported NO_x reduction, attributable to reburning only, in the range of about 20 to 50 percent when operating in conjunction with LNB technologies. This is important to keep in mind in the context of post-RACT NO_x reduction capabilities of selected retrofit controls.

Overall, operation of these boilers with gas reburn did not report any operational difficulties. The only reportable impacts are minor changes in FEGT, use of attemperation flow and burner tilt for steam temperature control, and a loss in boiler efficiency attributable to the increase in moisture in the flue gas. The latter is an inevitable consequence of burning a higher hydrogen content fuel.

Table 3-7 lists gas reburning data on the only gas-fired domestic boilers. The Hennepin unit is actually a coal-designed boiler with dual fuel (gas and coal) capability. Because the coal-designed boilers have much larger furnaces than oil- or gas-fired units, the heat release rates per wall area are much different and consequently peak furnace temperatures also vary. For this reason, the very low NO_x levels obtained at Hennepin with gas reburning on gas fuel should not be construed as applicable to other gas-designed units. A similar type of unit is the Barrett Unit 2 boiler of the Long Island Lighting Company which, originally designed as a coal-fired tangential boiler, has always burned either oil or gas and has recently been retrofit with ABB-CE reburning technology. Although no data are available from this retrofit, results similar to Hennepin Unit 1 burning gas are expected. The data show that NO_x level as low as 0.06 lb/MMBtu was achieved on a long term basis using gas reburning when firing gas. This level of NO_x is not much lower than the reported range in NO_x achieved with only OFA control (0.09 to 0.10 lb/MMBtu).

Table 3-6. Gas reburning experience on U.S. coal-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Controls	NO_x Emission Rate Before Reburning (lb/MMBtu)	NO_x Emission Rate After Reburning[a] (lb/MMBtu)	Overall performance and impacts (References)
City Water Power & Light Lakeside Unit 7	33 MWe cyclone	None	0.95	0.32 short-term tests 0.34 long-term	60 to 66 percent NO_x reduction over the long term. No adverse operational impacts. Always below 0.5 lb/MMBtu (Bluestein, 1994; Freedman, et al., 1994; Folsom, 1995; GRI, undated)
Ohio Edison Niles Unit 1	108 MWe cyclone	None	0.85 to 1.0 (600 to 700 ppm)	0.41 to 0.55 (300 to 400 ppm) with reburning stoichiometry of 0.9 and gas use at 16 percent; long term tests	45 to 52 percent reduction. Reburning discontinued. Best applications for base load, summer use, high coal cost units. (Harding 1994)
Illinois Power Hennepin Unit 1	71 MWe corner fired	None (OFA)	0.67 to 0.75	Long term test average reduction of 67 percent to 0.22 to 0.25 lb/MMBtu with 18 percent reburning gas	Thermal efficiency dropped 0.8 to 1.7 percent due to H_2 in fuel. Some increase in LOI. No impacts on the boiler tube wastage and steam temp. control. (Harding, 1994; Freedman, et al., 1994)
Public Service of Colorado Cherokee Unit 3	158 MWe wall fired	LNB	<u>Without LNB:</u> 0.55 to 0.80 over the load range <u>With LNB:</u> 0.32 to 0.55 over the load range	0.20 t 0.28 with LNB over the load range with 16 percent reburn; 35 percent reduction attributed to LNB only	Gas reburn attributed with 32 to 50 percent reduction with LNB in place. Long term 61 to 65 percent reduction with combined LNB + reburn. No adverse impacts (Harding, 1994; Freedman, et al., 1994; Folsom, 1995)
Kansas Power & Light Lawrence Unit 5	300 MWe corner fired	LNB with SOFA	<u>Without SOFA:</u> 0.39 (290 ppm) at baseline load <u>With SOFA:</u> 0.21 (150 ppm) at baseline load	0.082 to 0.090 with 10 to 20 percent close coupled reburn. (0.9 percent stoichiometry)	13 to 38 percent NO_x reduction efficiency (average 25 percent) depending on coal stoichiometry. Minimal operational effect (Lewis, et al., 1994)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

Table 3-7. Gas reburning experience on oil/gas-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Control Types	NO_x Emission Rate Before Reburning (lb/MMBtu)	NO_x Emission Rate After Reburning[a] (lb/MMBtu)	Overall Performance and Measured Impacts
Illinois Power Co. Hennepin Unit 1	71 MWe tangential	None	0.14 to 0.15 (120 ppm) with 100 percent gas firing 0.09 to 0.10 (70 to 80 ppm) with SOFA staging	0.06 lb/MMBtu with 18 percent gas reburning; long term tests	No operation impacts recorded. Only minimal NO_x reduction potential for reburning when compared with OFA results (Angello, et al., 1993)
Long Island Lighting Co. Barrett Unit 1	185 MWe tangential	LNCFS	Not available	Not available	Retrofit ongoing. No data yet available.
Public Service of Colorado Cherokee Unit 3	158 MWe wall fired	LNB	0.32 with 100 percent gas firing at full load	0.14 with stoichiometry of 0.90	55 percent reduction due to reburning. No reported operational impact. Total combined NO_x level (Folsom, 1995).

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

3.1.3 Gas Conversion

Gas conversion and cofire are similar only that conversion implies the ability to reach the design steaming capacity of the boiler with 100 percent gas firing. As with cofiring, the equipment retrofit to implement a complete fuel conversion or create a dual-fuel capability is dependent on the existing burner equipment and control system. For conventional or low-NO_x circular burners on one or opposed walls of the furnace, the retrofit of 100 percent gas firing can be accomplished with the addition of gas spuds, canes, or ring on each existing burner. Tangential burners in the corners of the furnace, can also be readily modified to accommodate gas firing without removing the coal or oil-firing capability. Because of the tilting capability of tangential burners, furnace exit gas temperatures (FEGT) and superheat/reheat steam temperatures can more readily be controlled. Steam attemperation is also a common powerplant practice for superheater and reheater temperature control. Some boiler conversion engineering and architect firms believe that it is easier to convert a coal-fired boiler than an oil-fired boiler to gas firing (Harding, 1994). This is because the lower waterwall radiation from gas flames is offset by the cleaner waterwalls in the absence of slagging.

In general, however, as discussed above, the firing of 100 percent natural gas in larger coal-fired furnaces tends to result in lower than expected FEGT effects. Although the gas flame is much less radiative than coal or oil and therefore hotter, the combined effect of a large volume, cleaner waterwalls and lower combustion air volumes tends to compensate for the hotter flame. The equipment that must be evaluated before the conversion includes fans, burners, spray attemperators, boiler tube metals, and economizer steaming capacity (Harding, et al., 1994).

Table 3-8 summarizes the reported NO_x emissions with 100 percent gas burning in coal-designed utility boilers. The boilers include units that were merely tested with 100 percent gas firing on a short term basis because of readily available gas and existing equipment. The table also includes boiler that have recently added 100 percent gas firing capability to either replace coal or oil firing entirely or to be able to supplement either fuel as necessary. The reported NO_x reduction

Table 3-8. Experience with 100 percent gas firing in coal-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Controls	NO_x Emission Rate Before Conversion (lb/MMBtu)	NO_x Emission Rate After Conversion[a] (lb/MMBtu)	Overall Performance and Measured Impacts
Public Service Electric & Gas Company Mercer Unit 2	321 MWe wet bottom wall fired twin furnace	With and without simulated OFA (BOOS)	0.52 to 1.65 (low to full load)	Without combustion controls: 0.27 to 0.89 (low to full load) With combustion controls: 0.58 to 0.91 (full load only) Short term	45 percent reduction at full load Average NO_x reduction reported at 52.8 percent (Hewson, 1994; Gibbons, et al., 1994)
Arizona Public Service Apache Unit 2	200 MWe turbo-fired	LNB	0.63 lb/MMBtu	0.18 lb/MMBtu	71 percent NO_x reduction (Hewson, 1994)
Arizona Public Service Apache Unit 3	200 MWe turbo-fired	LNB	0.59 lb/MMBtu	0.18 lb/MMBtu	69 percent NO_x reduction (Hewson, 1994)
American Electric Power Columbus & Southern Pickway Unit 3	180 MWe wall-fired	None	Not available	Not available	Conversion to be completed in 1995 (Harding, 1994)
American Electric Power Columbus and Southern Conesville Unit 3	165 MWe wall-fired	None	Not available	Not available	Conversion to be completed in 1995 (Harding, 1994)
Illinois Power Co. Hennepin Unit 1	71 MWe tangential-fired	None	Without OFA: 0.62 (450 ppm) With OFA: 0.41 (300 ppm)	Without OFA: 75 percent NO_x reduction to 0.15 lb/MMBtu With OFA: 70 percent reduction to about 0.12 lb/MMBtu (90 ppm) Short term	No impacts with gas firing; burner tilts were used to control superheat and reheat; ASME boiler efficiency suffered a drop from 88.26 to 83.75 percent (Hura, 1994; Harding, 1994)
Kansas Power & Light Lawrence Unit 5	300 MWe tangentially-fired	LNB with SOFA	Without SOFA: 0.39 (290 ppm) With SOFA: 0.21 (150 ppm) baseline 0.12 (89 ppm) part load	With SOFA: 0.053 (38 ppm) at part load short term	Only part load data available. Drop in boiler efficiency from 90.21 to 85.12% (Lewis, et al., 1994)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

Table 3-8. Experience with 100 percent gas firing in coal-fired utility boilers (concluded)

Boiler Site	Boiler Type and Gross Capacity	Combustion Controls	NO_x Emission Rate Before Conversion (lb/MMBtu)	NO_x Emission Rate After Conversion[a] (lb/MMBtu)	Overall Performance and Measured Impacts
Long Island Lighting Co. Barrett Unit 2	185 MWe tangential	None	Although designed for coal, boiler never fired coal	0.24 full load 0.11 at full load with combustion staging (BOOS) Short term	Boiler efficiency decrease from 87.5 percent with oil to 84.7 percent with 100 percent gas firing (Hura, 1994).
Public Service of CO Cherokee Unit 3	158 MWe wall-fired	LNB	0.75 at full load w/o LNB; 0.48 at full load w/LNB 0.50 at half load w/ LNB	Projected 0.32 at full load with LNB Measured 0.1 at half load with LNB Short term	55 percent reduction from full load levels. 80 percent reduction due to gas conversion at half load. Full load reduction is anticipated to be lower (Hura, 1994; Folsom, 1995)
Public Service of CO Arapahoe Unit 4	100 MWe top-fired	LNB	Not available	0.76 with minimal OFA; 0.26 with maximum OFA Short term	No operational impacts reported (Hura, 1994)
Northern Indiana Public Service Co. (NIPSCO) Michigan City Unit 12	540 MWe cyclone	None	2.10 with Illinois bituminous coal 1.35 with low sulfur western coal	1.20 irrespective of coal	43 percent NO_x reduction with bituminous coal; but only 11 percent reduction with low-sulfur coal blend (Hewson, 1994)
Northern Indiana Public Service Co. (NIPSCO) Mitchell Unit 4	138 MWe corner-fired	None	0.40	0.30	25 percent reduction on 70 percent Power River Basin Coal (Hewson, 1994)
Illinois Power Wood River Unit 4	113 MWe corner-fired	None	0.70	0.25	64 percent NO_x reduction (Hewson, 1994)
Illinois Power Hennepin Unit 2	231 MWe corner-fired	None	0.70	0.25	64 percent reduction in NO_x (Hewson, 1994)
Commonwealth Edison Fisk Unit 19	374 MWe corner-fired	None	0.70	0.28	60 percent reduction in NO_x (Hewson, 1994)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

experience is based on a total of about 2,300 MWe of originally coal-fired boiler capacity, 2,000 MWe principally wall-fired and the rest corner-fired.

The NO_x level measured with 100 percent gas firing is reported to vary from as low as 0.11 lb/MMBtu, measured with combustion staging at the Arapahoe Power Station boiler, to as high as 0.83 lb/MMBtu, measured at the Mercer Power Station boiler without any combustion controls. This very large range in emissions is the result of two principal effects: the burner zone heat release rate and the degree of combustion air staging implemented. The impact of burner zone area heat release rate is dramatic. The higher the heat released in a small burner zone, the higher is the peak flame temperature and the more the Thermal NO_x production. Because Thermal NO_x is the principal form of NO_x from natural gas combustion, the effect of BAHR is very important, as illustrated in Figure 3-3. Therefore, because Mercer Unit 2 is a high temperature slagging boiler

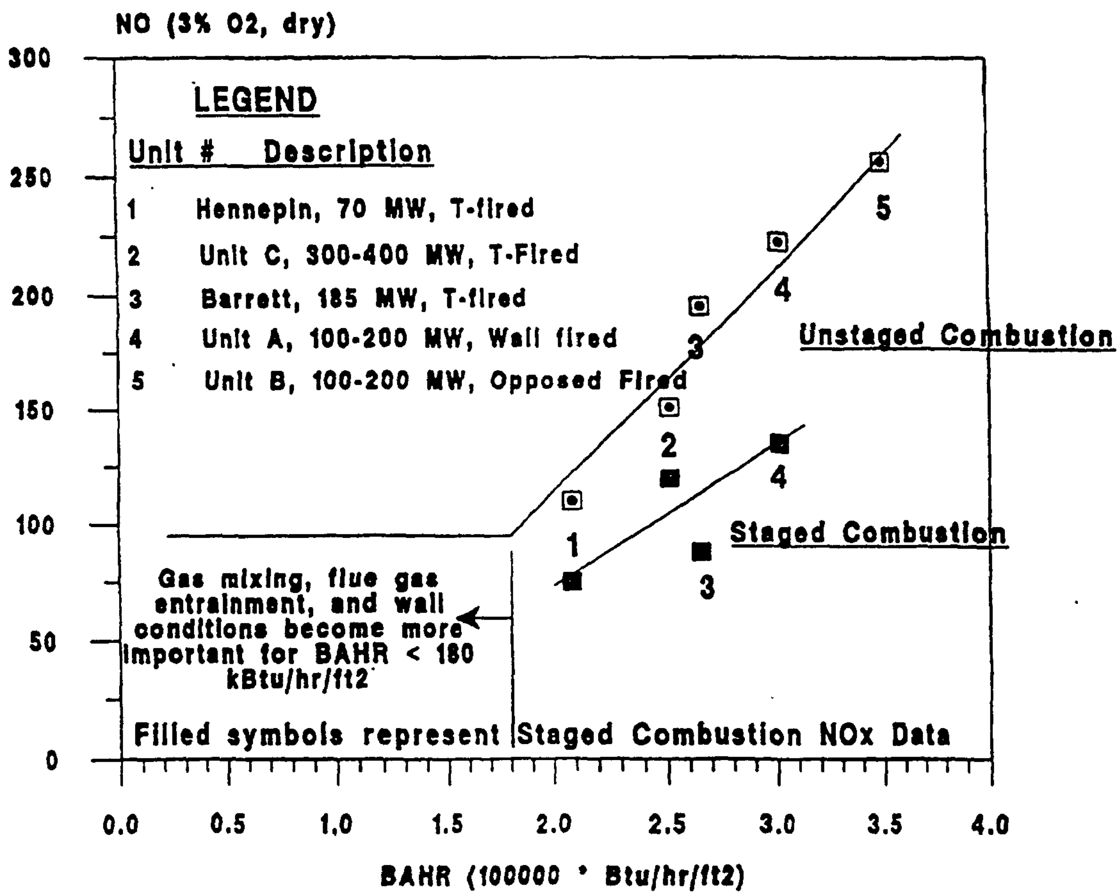


Figure 3-3. NO_x versus burner area heat release rate (BAHR) correlation for coal designed boilers firing 100 percent natural gas (Hura, 1994)

with a high BAHR compared to Hennepin, the resulting NO_x is much higher. However, these NO_x levels can be reduced with conventional combustion modifications often applied to gas-fired boilers. These controls would include air staging by taking burners out of service or the addition of flue gas recirculation. The latter is probably less desirable because of cost and because it has the greatest likelihood of aggravating an expected increase in FEGT.

Table 3-9 lists experience reported for oil-designed boilers tested with 100 percent gas firing. The only data available for this study is limited to the Brayton Point Unit 4. The result show a 31 percent reduction without FGR use and a 38 percent reduction with FGR. It is important to note that the additional NO_x reduction compared with 10 percent cofire and FGR is only 0.05 lb/MMBtu, from 0.23 lb/MMBtu (see Table 3-5) to 0.18 lb/MMBtu, only about 20 percent NO_x reduction. Considering the potential cost differential between gas and oil, and the reduction in boiler efficiency between 1.5 to 2 percent when operating on 100 percent gas, full conversion from oil to gas firing may not be justified strictly from the point of view of NO_x reduction.

From an operations point of view, the burning of 100 percent gas instead of coal or oil brings about one inevitable impact: lower thermal efficiencies. Although some efficiency reduction is likely with cofiring and reburning, the reduction in boiler efficiency is much more evident with full conversion to gas. This reduction is principally the result of increased moisture content in the flue gas, the inevitable effect of higher hydrogen content in the fuel. The ability to burn gas at lower excess air levels will recover a fraction of this thermal efficiency loss. The reported data shows that boiler efficiencies were reduced in a range from about 3 to 4.5 percentage points, using the ASME heat loss method. Other considerations for gas conversions include (Harding, et al., 1994):

- Boiler operating duty cycle
- Physical condition of the site
- Remaining economic life of unit

Table 3-9. Experience with 100 percent gas firing in oil-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Controls	NO_x Emission Rate Before Conversion (lb/MMBtu)	NO_x Emission Rate After Conversion[a] (lb/MMBtu)	Overall Performance and Impacts (References)
New England Power Brayton Point Unit 4	450 MW wall fired with 24 burners in o 6x4 matrix	FGR	0.290 with 100 percent oil at full load	Without FGR: less than 0.20 With FGR: 0.18 Short term	FGR was found to be necessary to optimize NO_x reduction. Upgrades to convective tubes and desuperheater spray. Efficiency loss of 1.5 to 2 percent (Harding, 1994)
Jacksonville Electric Northside Unit 3	550 MWe wall fired; designed for oil firing	FGR	No data available	No data available	Some equipment upgrade not attributed to the conversion (Harding, 1994)
Consumers Power Co. Karn Unit 4	640 MWe wall fired; designed for oil/gas firing	FGR LNB	No data available	No data available	Some gas pressure problems during startup required redesign (Harding, 1994)
Jacksonville Electric Northside Unit 1	275 MWe wall fired designed for oil firing	BOOS during gas firing	0.20 to 0.38 over load range	0.10 to 0.32 over load range with burner adjustment and BOOS	BOOS was found to be necessary to maintain NO_x emissions below those of oil (Des Chenes, 1992)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

Boilers that operate with variable load can benefit from gas conversions because of the operational flexibility that gas provides especially at reduced loads. The physical condition of the plant and the remaining economic life of the plant will play important roles in the economic justification for the capital investment of converting the boiler to gas fuel and increased operating cost of gas burning.

3.1.4 Potential for Retrofit of Gas-based Controls

Gas is a clean fuel with wide operational flexibility, documented operational benefits, and proven NO_x reduction potential. Among the various applications of natural gas as a utility boiler fuel, reburning remains the most efficient way of using gas for NO_x reduction. With this technology, the NO_x reduction potential is the highest for a given percent of gas use. Cofire, conversion, and seasonal gas use offer either lower NO_x reduction potential or require much higher gas use. Because of the fuel cost differential between gas and coal, the amount of gas needed to reduce NO_x from coal-fired boilers is one of the main utility concerns with the application of gas-based technologies.

The realized retrofit potential of gas-based controls for utility boilers hinge on the following utility concerns:

- Natural gas availability
- Access to gas supply
- Marginal NO_x reduction beyond LNB
- Competitive gas pricing and availability of long-term contracts
- Reburning performance on large-scale coal boilers
- Combustion safety of gas injector designs

Before gas reaches the burner, adequate supplies are needed to ensure the long-term availability of this fuel. Figure 3-4 illustrates the amount of gas needed for two hypothetical utility boiler retrofit scenarios: reburn or cofire for all coal dry furnace PC-fired boilers with a maximum of 20 percent heat input from gas, and full conversion of these units to 100 percent gas firing capability. These estimates reflect the quantities of natural gas needed over and above what is

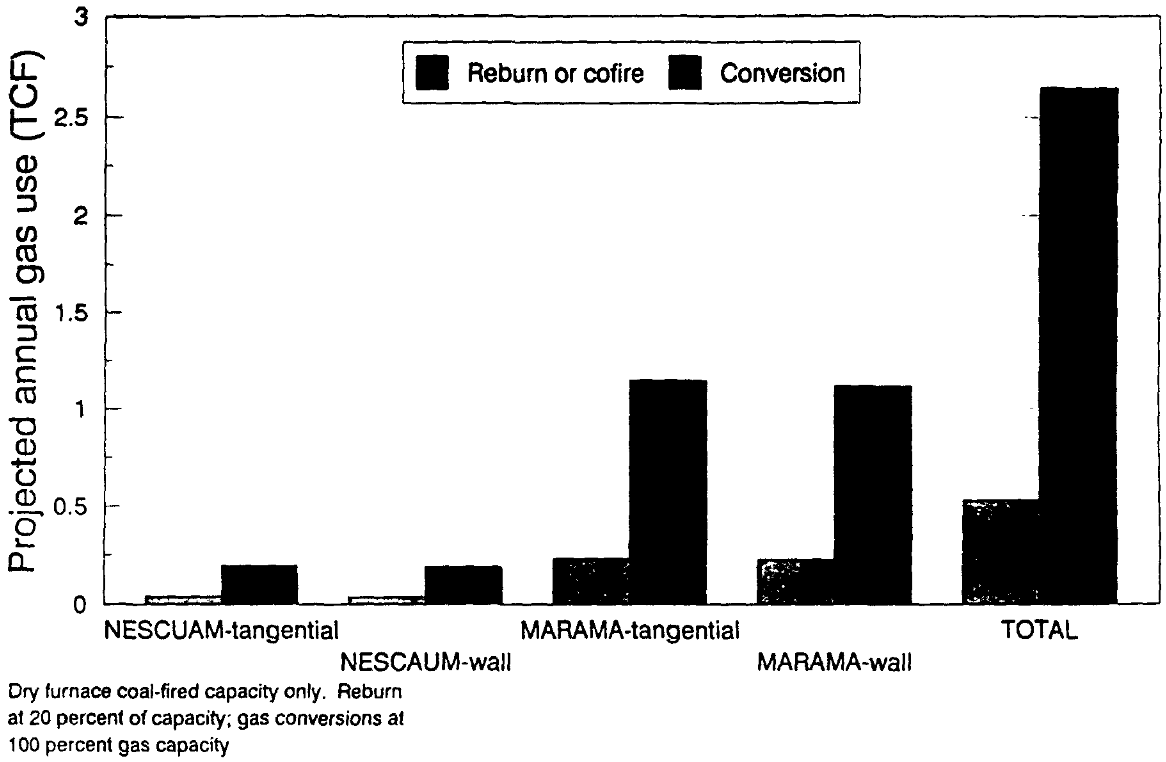


Figure 3-4. Estimates of natural gas required for widespread reburn or conversions of coal-fired boilers

currently used by the utilities if these controls were widespread. The more realistic scenario indicates that approximately 0.5 TCF of gas will be needed for the reburn or cofire technologies for all the coal dry furnace boilers in both NESCAUM and MARAMA. This total amount of natural gas translates to approximately 1,400 MMcfd, considering year around operation with these controls. A recent study on natural gas availability estimates that the gas capacity available for NO_x control purposes in the OTR in the year 1997 is 3,490 MMcfd for the period from April to October following a cold winter (EEA Inc., 1994). This capacity would be reduced to 2,830 by the year 2,000. Therefore, this study would suggest that gas will be available to implement the reburning and cofiring techniques, should these be considered by the utilities for their NO_x reduction compliance strategies. Although gas supplies are projected to be capable of satisfying even the full gas conversion of all dry furnace PC-fired boilers, this scenario is very unlikely considering the economic impact.

The second consideration is one of gas access. A recent study sponsored by the Coalition for Gas Based Environmental Solutions, Inc. revealed that only about 9 percent (14 out of 155 units) of the total coal-fired generating capacity in the OTR is currently equipped to burn any amount of natural gas (EVA Inc., 1994). Most of these plants with dual-fuel firing capability only have access to sufficient natural gas for ignition, warm up, and for flame stabilization which require relatively small amounts of gas. Therefore, to adapt these units to either reburning or cofiring with a maximum of 20 percent gas use, it would require installation of new pipelines and burner equipment. The study went on to reveal that, although few power stations have any gas firing capability, nearly half are located less than 5 miles from an existing natural gas pipeline. For oil-fired utility boilers, 39 percent of the existing capacity has gas service, and 20 percent are fully dual fuel boilers capable of supplying full capacity on either oil or gas. Many of the oil-fired boilers are also located within 5 miles of a gas pipeline.

Because NO_x reduction efficiencies may be marginal beyond the 50 to 60 percent obtained by LNB+OFA, gas reburning may not be able to achieve deep NO_x reductions as a retrofit option on boilers already retrofit with LNB. In fact, test results summarized above, point to lower NO_x reduction efficiencies with lower primary zone NO_x. For example, NO_x reduction on uncontrolled boilers have been reported as high as 72 percent on a short-term basis. When applied to LNB-equipped boilers, the NO_x reduction of gas reburning can fall as low as 30 percent for wall fired units and percent for tangential-fired boilers. Utilities have also expressed little incentive for reburn retrofit on older boilers when LNBs have nearly similar NO_x reduction performance.

The EVA Inc. study also evaluated the price for natural gas to project the competitiveness of gas against coal for base loaded utility boilers. The study revealed that the break even fuel differential cost between gas and coal was at \$1.65/MMBtu. Higher differential cost will not make natural gas attractive as a utility boiler fuel in existing coal-based powerplants. Between increased projected demand for gas and higher wellhead prices, increased fuel differential costs will make coal-based power generation technologies more attractive in the future limiting gas role in existing powerplants, according to EVA Inc.

All the demonstrations of reburning to date have focused on smaller-scale utility boiler furnaces. With the exception of the KP&L Lawrence Unit 5, the sizes of boilers retrofit with gas reburn range between 33 and 185 MWe. Because of various technical issues centering on mixing and residence time primarily, larger utility boiler demonstrations are needed to confirm that performance is not hindered. Larger-scale demos are being sought to address commercialization concerns and demonstration thus far limited to smaller units. Some utilities and boiler vendors have also concerns with the safety of gas reburning. These concerns stem from some designs that use wall injectors rather than burners with flame scanners and other safety controls. These concerns do not seem to be borne by any negative experience with gas reburning, however. Finally, because of reduced NO_x reduction performance with lower loads, gas reburning is seen principally as a technology best suited for base loaded units.

Many additional developments are underway aimed at improving on the gas reburning process for utility applications. Among the newest research being sponsored by the Gas Research Institute (GRI) are (Freedman, et al., 1994):

- Improved gas injection mechanisms to maximize the mixing and possibly reduce the amount of gas required.
- Improved OFA port designs to achieve more complete and rapid burnout
- Advanced reburning techniques that combine conventional gas reburn with selective noncatalytic reduction (SNCR)
- Integration of gas reburning into the operation of pulverized coal-fired burners for enhanced NO_x reduction.

Many of the recent demonstrations have utilized flue gas recirculation (FGR) to increase the momentum of the gas entering the furnace and, thus improve the mixing with coal combustion products leaving the main burner zone. The objective of improved gas injection ports is to eliminate the need for FGR, thus reducing cost and simplifying its operation. OFA ports are also being optimized for improved burnout. The combination of reburning with SNCR has some intrinsic advantages that enhance the performance of either control when used separately, thus achieving high overall NO_x emissions reductions. Advanced gas reburning technologies will be discussed in Section 3.4.1. The potential for improved LNB operation with the addition of some natural gas into the burner itself has initially been demonstrated by pilot-scale tests at the International Flame Research Foundation (IFRF) (Freedman, et al., 1994).

Coal reburning is being actively investigated by boiler OEMs as a potential technology that might be incorporated into future low-NO_x burner systems for new boilers. However, because coal contains its own fuel-bound nitrogen, its use as a reburning fuel may lead in additional NO_x being formed. Therefore, retrofit on LNB controlled boilers in NESCAUM and MARAMA is questionable at this time because these units have managed already to reduce NO_x in the primary combustion zone and the addition of coal as a reburning fuel would likely be less effective that natural gas.

3.2 COAL REBURNING

The only demonstration of coal reburning to date has taken place at the Nelson Dewey Station of WP&L. The 110 MWe Unit 2 cyclone boiler was retrofit with coal reburning under a DOE Clean Coal II Demonstration program. For safety, the B&W retrofit uses coal burners with their own primary and secondary air. Two coals were tested during this demonstration: a medium sulfur Illinois Basin (Lamar) bituminous coal and a low sulfur western Power River Basin (PRB) subbituminous coal. Table 3-10 lists the NO_x reduction results obtained, and Table 3-8 lists the measured impacts.

The short-term tests showed that NO_x reductions ranged from 36 to 52 percent over the load range for the bituminous coal to NO_x levels between 0.39 to 0.44 lb/MMBtu. Using more volatile western coal, the NO_x reductions were maximized to a range between 53 and 62 percent, corresponding to controlled NO_x levels of 0.28 to 0.30 lb/MMBtu. The NO_x reduction performance

Table 3-10. Reburn NO_x emissions as a percent reduction from baseline versus load (Coal Reburning at Nelson Dewey Station)

Load (MWe)	Percent Reduction and Controlled Level with Lamar Coal as Reburning Fuel	Percent Reduction and Controlled Level with Reburn PRB Coal[a]	Percent Reduction and Controlled Level with Optimized Reburn PRB Coal
110	52 Percent (0.39 lb/MMBtu)	58 percent (0.32 lb/MMBtu)	62 percent (0.28 lb/MMBtu)
82	47 Percent (0.39 lb/MMBtu)	51 Percent (0.32 lb/MMBtu)	55 Percent (0.29 lb/MMBtu)
60	36 Percent (0.44 lb/MMBtu)	50 Percent (0.332 lb/MMBtu)	53 Percent (0.30 lb/MMBtu)

[a]PRB = Power River Basin.
Source: Farzan, et al., 1993.

decreases with load because more burner air is introduced at the reburner zone to maintain flame stability. This addition air increases reburner stoichiometry, increasing NO_x. As indicated in Table 3-11, coal reburning generally caused only minor changes in boiler performance. In general, the use of more reactive western coal has the least effect on unburned carbon in the flyash, FEGT, and steam temperatures. Also, the Nelson Dewey boiler did not suffer any derate as a result of switching to the PRB coal. This is because B&W was able to increase coal feedrate to 30 percent above normal to compensate for the lower heating value of the western coal. Therefore, for boilers required to switch to a lower sulfur western coal switching to meet SO_2 emission levels under Title IV, coal reburning may be an attractive option provided the boiler furnace is large enough to accommodate reburn (Farzan, et al., 1993).

The selection of the coal type for reburning is very important to its performance and retrofit feasibility. Ideally, the reburning coal should be most reactive, meaning that it must contain high percent of volatile matter. Reactive coals will burn faster and hotter thus minimizing the requirements for large burnout zone and potential increase in unburned carbon in the flyash. Also, reactive coals will release more of the fuel nitrogen with the volatile matter reducing the potential for high NO_x generation in the burnout zone from oxidation of char nitrogen. For this reason, western subbituminous coals are most likely candidates as reburning coals. Eastern utility plants that currently burn bituminous coals would have to maintain separate western coal inventories for

Table 3-11. Coal reburning effects on general boiler operation (Nelson Dewey)

Parameter	Anticipated Results	Actual results with Lamar Coal	Actual Results with PRB Coal[a]
Slagging/fouling	No change	No change	No change
Header/tube temperature	25 to 50 °F higher	No increase from base	No increase from base
SSH and RH spray flows	30 percent higher	75 percent lower	25 percent lower
Opacity	5 to 10 percent higher	No increase from base	No increase from base
Furnace corrosion	No change	No change	No change
UBCL (full to low load)	Would increase	0.1 to 1.5 percent	0 to 0.3 percent
FEGT at full load	Would increase	Decrease 100 to 150°F	Decrease 25 to 50°F

[a]PRB = Power River Basin.
Source: Farzan, et al., 1993.

their reburning fuels. Use of less reactive bituminous coal for reburning will likely require that it be finely ground, as in micronized coal, to minimize increases in unburned carbon or lower NO_x reduction efficiencies.

A demonstration of coal reburning using micronized coal is planned at the Tennessee Valley Authority's (TVA) Shawnee Station 175 MWe Unit 6 (Bradshaw, et al., 1991). This project is being sponsored under DOE's Clean Coal Technology IV. Micronized coal characteristics and benefits are summarized in Figure 3-5. Under this project, up to 30 percent of the coal will be micronized (80 percent less than 325 mesh, corresponding to approximately 43 micron or smaller). Today, most coals are pulverized only to about 80 percent through 200 mesh. The micronized coal will be injected into the upper furnace, above the four levels of existing circular burners, to create a reburn zone with 0.80 to 0.90 percent stoichiometry. High velocity overfire air will be injected to bring the overall stoichiometry bach to about 1.15 prior to the gases exiting the furnace. The NO_x reduction goal for the demonstration is set at 50 to 60 percent from uncontrolled levels. The retrofit of this technology, although theoretically applicable to most existing pulverized coal-fired boilers and cyclones, will require the installation of a MicroMill System and burners. Feasibility and benefits

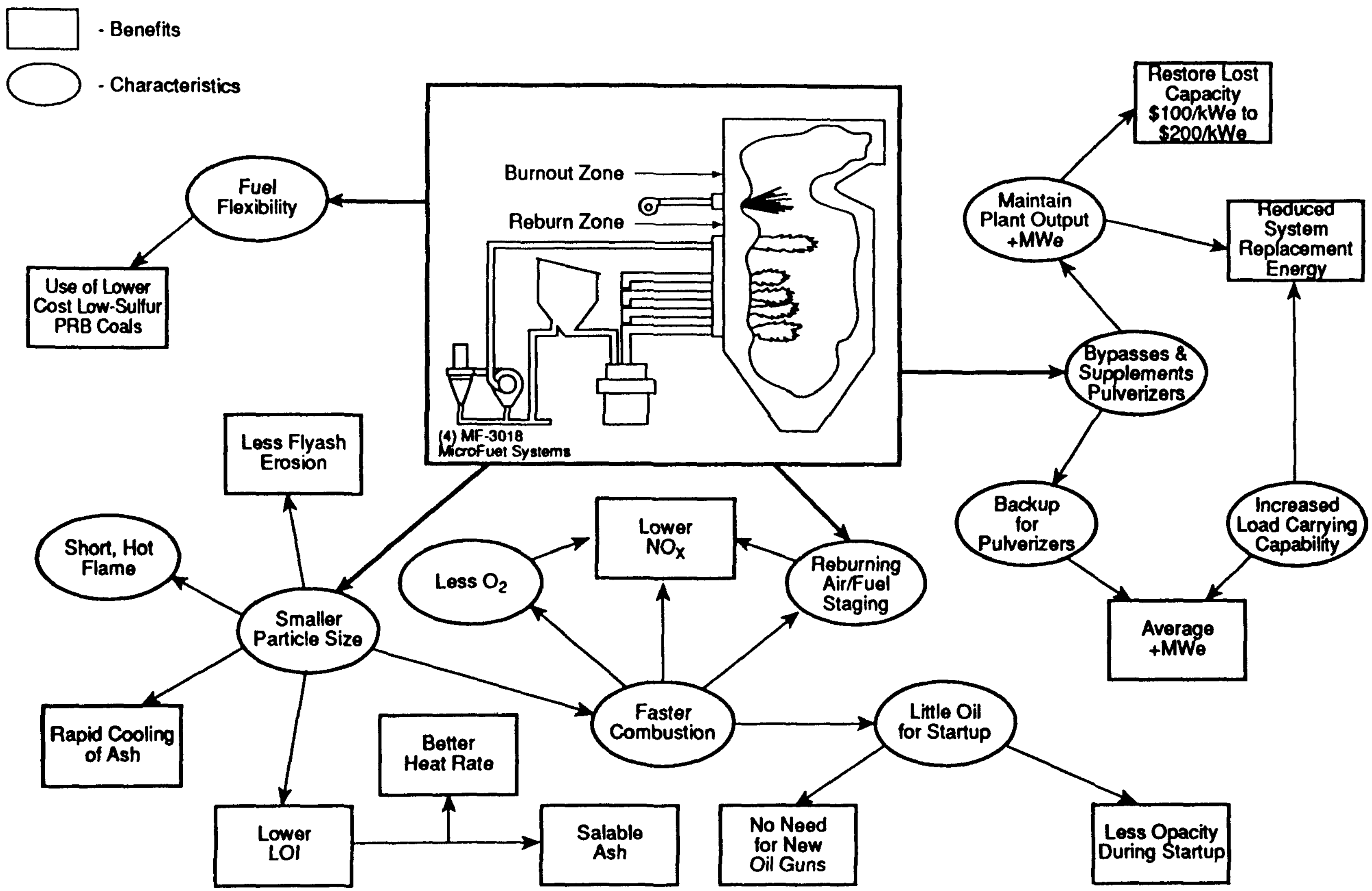


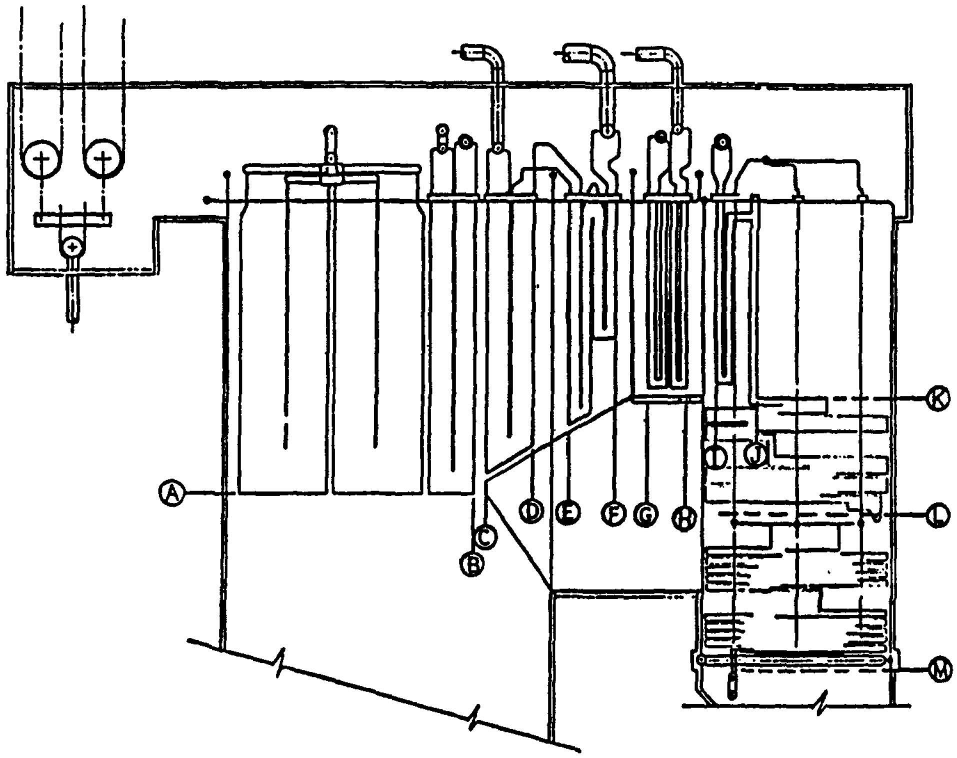
Figure 3-5. Micronized coal reburn characteristics and benefits (Bradshaw, et al., 1991)

of this technology must be weighed when the demonstration results are made available at the completion of the project.

3.3 NONCATALYTIC FLUE GAS TREATMENT CONTROLS

Selective noncatalytic reduction (SNCR) is a process that uses ammonia-based reagents to selectively reduce NO_x to nitrogen and water without the presence of a catalyst. The principal attractive feature of this technology is that it does not rely on any catalyst surface and, therefore, can be implemented at much lower costs compared to catalyst based technologies. The ability to do away with the need for a catalyst, however, requires that the reagent be injected where the flue gas temperature is optimal to promote the reaction with the minimal amount of unreacted ammonia. This optimum temperature window is in the range of 870° to 1,150°C (1,600° to 2,100°F). Higher injection temperatures are possible by proper design and operational settings of SNCR systems. Selected vendors of SNCR-based technologies offer proprietary additives aimed at broadening this temperature window and, thus making the efficiency of the process and ammonia slip requirements somewhat less sensitive to flue gas temperature swings (Rini, et al., 1993 and Lin, et al., 1994).

In a utility boiler operating at full steam load, this temperature window occurs in a zone starting approximately at the furnace exit plane and extending just passed the first convective superheater and reheater tube banks. Figure 3-6 illustrates the approximate temperature profile in the upper furnace of a typical pulverized coal-fired boiler. The SNCR temperature window shifts toward the burner zone when boiler load is reduced. The inserted table illustrates how the average flue gas temperature at each plane varies with load. Equally important to the process, is the fact that the flue gas temperature across the furnace plane in this location is also not uniform and subject to rapid cooling as heat continues to be absorbed. Furthermore, gas velocities and NO_x concentrations are also not uniform. This nonuniformity of temperature, velocity, and NO_x concentration coupled with relatively short residence times are major challenges for this technology



Load, % MCR	100	75	60
Net heat input, 10^6 Btu/hr	3,405	2,550	2,035
Gas weight, 10^3 lb/hr	3,213,000	2,425,000	2,088,000
Air preheat, °F (secondary)	550	510	480
Flue gas temperature °F (average)			
Plane A	2,400	2,400	2,285
Plane B	1,910	1,810	1,710
Plane C	1,900	1,800	1,700
Plane D	1,720	1,610	1,520
Plane E	1,700	1,590	1,500
Plane F	1,465	1,365	1,295
Plane G	1,440	1,340	1,260
Plane H	1,340	1,250	1,190
Plane I	1,310	1,230	1,170
Plane J	1,195	1,115	1,075
Plane K	1,180	1,100	1,055
Plane L	935	885	855
Plane M	640	580	550
NO_x – lb/NO_2/MMBtu	0.60	0.50	0.45
Oxygen content, % by dry Vol.	3.5	3.5	4.9

Figure 3-6. Flue gas convective path and temperature profile — 350 MWe bituminous coal-fired (Source: ABB-CE)

and often limit the NO_x reduction performance of SNCR to maintain ammonia slip below acceptable levels.

Ammonia slip is caused by excessive use of reagent, insufficient mixing of reagent with flue gas, and low flue gas temperatures. When using ammonia-based reagents in a boiler burning sulfur bearing fuels, such as coal or residual oil, the amount of ammonia slip must be particularly controlled to minimize plugging of air heater and cold end corrosion caused by ammonia sulfates and bisulfates compounds formed by the reaction between NH_3 and SO_2/SO_3 in the flue gas. Furthermore, excessive ammonia is also trapped in the flyash often precluding the continued sale of this commodity for cement manufacturing. At least one vendor, however, offers additives to an aqueous urea reagent mix that has proven to minimize NH_3 slip under well controlled and supervised SNCR operation (Shore, et al., 1993).

The two principal reagents used in the SNCR process are aqueous ammonia (NH_4OH) and urea (NH_2CONH_2). Anhydrous ammonia can also be used but it is generally not considered for SNCR applications because of safety and better process operation with aqueous reagents. Urea is procured and delivered to the plant in a water solution containing appropriate grade urea with or without proprietary additives, depending on the vendor of the SNCR process. These additives are used as corrosion inhibitors to facilitate onsite storage, transport, and injection in the furnace, and for performance enhancement. Large onsite storage tanks with recirculation capability, and heating if necessary, are needed to maintain a supply of reagent usually containing 30 to 50 percent water. Additional water is then mixed prior to injection into the furnace from wall injectors. Because flue gas temperatures are not uniform and because SNCR must often perform over some boiler load range, several injection locations are necessary, each capable of distributing the reagent-containing droplets over the effective area to ensure maximum reagent utilization. Controls to monitor and change the amount of reagent injected, the droplet size, and the velocity of injection are also part of the SNCR process needed to maximize its performance.

A permanent SNCR installation will require several process modules. The following is a list of these process modules prepared for the 321 MWe coal/gas-fired Mercer Unit 2 with four level of reagent wall injectors, as defined by Nalco Fuel Tech (Gibbons, et al., 1994):

A. One storage tank of 250,000 gallon capacity and stainless steel construction with heat tracing, insulation, level transmitter and accessories.

B. One Circulation Module for the continuous circulation and heating of the NO_xOUT® reagent. This module is equipped with redundant pumps, strainer, electrical heater, flow sensor, and a local control panel

C. One Transfer Module for boosting reagent and water pressures to 150 PSI. This module includes redundant pumps, flow meters, pressure control valves, and a local control panel

D. The Metering Modules, one for each furnace (dual-furnace boilers) and one common spare. These modules provide flow and pressure control for both the NO_xOUT reagent and dilution water. These modules also distribute water chemical mixture selectively to all levels of injectors. Each module is equipped with flow meters, flow control valves, pressure controls, static mixers, and a local control panel.

E. Eight Distribution Modules for control of flow of water/chemical mixture and atomizing air for each level of injectors at each furnace. Each free-standing four-circuit (for four levels of injectors) module includes flow and pressure indication, valves and manifolding

F. 32 Injector assemblies with cooling shield, tip, and flex hoses with disconnects.

G. 32 Injector Retract Mechanisms for the proper positioning of the injector into the furnace during operation and retraction into the cooler zone when not in operation.

H. Two Injector Retract Control Panels for local or automatic operation/selection of Injectors, with indication

I. One Master Control Module for complete automation control of the NO_xOUT system modules and collection of operating data. This module includes a PLC system, PC, color monitor, printer, cabinetry, input terminal for plant operating signals, and software.

The amount of urea or ammonia injected in the furnace varies with the NO_x reduction target. As a minimum, the full conversion of NO_x to nitrogen and water will require a stoichiometric amount of NH_2. For ammonia, it is one mole of ammonia for each mole of NO. For urea, it is 0.5 moles of urea for each mole of NO because of the two nitrogens in one mole of urea. However, all full-scale test have shown that more than the stoichiometric quantity is often needed to maximize the performance of the process. This is because of the mass transport limitations imposed by imperfect mixing of reagent with flue gas at optimum reaction temperature. Therefore, most of the excess reagent either reacts to form NO or degrades to nitrogen and carbon dioxide. The quantity of reagent used in the SNCR process is often reported using the Normalized Stoichiometric Ratio (NSR), defined as:

$$NSR = \frac{\dfrac{Actual\ Moles\ of\ Reagent}{Moles\ of\ Inlet\ NO_x}}{\dfrac{Stoichiometric\ Molar\ Ratio\ of\ Reagent}{Moles\ of\ Inlet\ NO_x}} \tag{3-3}$$

where the denominator is 1.0 for ammonia and 2.0 for urea reagents. The amount of reagent utilized is given by the ratio of measured NO_x reduction (in percent) and the calculated NSR.

Table 3-12 lists the NO_x reduction performance data reported on seven permanent and demonstration coal-fired utility boiler SNCR installations. The list include nearly 1,000 MWe of demonstration and commercial SNCR capacity with a range in NO_x emission rate before reagent injection between 0.90 to 1.54 lb/MMBtu at full load. The boiler types include cyclones and wet-bottom wall-fired units as well as one roof-fired boiler. All these boilers were retrofit with the NO_xOUT Process commercially available from Nalco Fuel Tech of Naperville, IL. In addition to these units, other NO_xOUT SNCR installations are planned and they include the 150 MWe Milliken Unit 2 of New York State Electric and Gas Company and one of the two cyclones at Merrimack Station of Public Service of New Hampshire. The SNCR demonstration at the Mercer Station was recently converted to a commercial installation servicing the entire generating capacity of the plant.

The average NO_x reduction for these facilities ranges between 30 and 66 percent at full load with 75 percent NO_x reduction peaks measured on a short-term basis. For any one boiler and injection configuration, the NO_x reduction efficiency of SNCR is linked principally to the level of NH_3 slip that can be tolerated. For example, NO_x reductions at the Mercer Station were limited to a range of 32 to 38 percent over the load range when the NH_3 slip was maintained below 5 ppm. When the NH_3 slip limits were relaxed to 15 ppm, the NO_x reduction efficiency was slightly

Table 3-12. SNCR experience on coal-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Controls	NO_x Emission Rate Before SNCR (lb/MMBtu)	NO_x Emission Rate After SNCR[a] (lb/MMBtu)	Average Performance and Measured Impacts
Atlantic Electric B.L. England Unit 1	138 MWe cyclone	None	0.90 to 1.3 (low to full load) Highly variable emissions	0.61 to 0.90 over the load range tested depending on injection configuration. Short term	30-40 percent NO_x reduction with less than 10 ppm NH_3, N_2O and CO emissions. No operational impacts with 30 percent reduction and NH_3 less than 10 ppm (Cunningham, et al., 1994; Himes, 1995)
Public Service Electric & Gas Company Mercer Unit 2	321 MO wet bottom wall fired twin furnace burning low sulfur/ash coal	With and without fuel bias	Uncontrolled: 0.52-1.54 (low-full load) With fuel bias: 1.22 at full load	W/O combustion controls: 0.35 to 0.97 (low to full load) Short term	32 to 38 percent reduction over load range (36 percent average) with less than 5 ppm NH_3 slip. 37 to 46 percent reduction when combined with fuel bias and 15 ppm NH_3 slip. No impacts with low NH_3 slip. Performance equal or less than OFA (Gibbons et a., 1994; Himes, 1995)
New England Power Company Salem Harbor Unit 1	84 MO dry bottom wall fired	None	0.9 to 1.1 (full load)	0.31 to 0.37 over the load range. Short term tests	66 percent reduction with NH_3 slip in the 10 to 20 ppm range (ICAC, 1994)
New England Power Company Salem Harbor Unit 2	84 MO dry bottom wall fired	None	0.90 to 1.1 (full load)	0.31 to 0.37 over the load range. Short term tests	66 percent reduction with NH_3 slip in the 10 to 20 ppm range (Hofmann, et al., 1993; ICAC, 1994)
New England Power Company Salem Harbor Unit 3	156 MWe dry bottom wall fired	None	0.90 to 1.1 (full load)	0.31 to 0.37 over the load range. Short term tests	66 percent reduction with NH_3 slip in the 10 to 20 ppm range (ICAC, 1994)
Wisconsin Electric Power Company Valley Plant Unit 4	70 MWe dry bottom wall fired	None	1.33 (full load)	0.53 at full load. Short term tests	60 percent reduction with less than 5 ppm NH_3 slip (ICAC, 1994)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

Table 3-12. SNCR experience on coal-fired utility boilers (concluded)

Boiler Site	Boiler Type and Gross Capacity	Combustion Controls	NO_x Emission Rate Before SNCR (lb/MMBtu)	NO_x Emission Rate After SNCR[a] (lb/MMBtu)	Average Performance and Measured Impacts
Public Service Co. of Colorado; Arapahoe Unit 4	100 MWe roof fired	LNB	W/O LNB+OFA Control: 1.15 (full load) W/LNB+OFA Control: 0.30 to 0.40 (over load range)	W/O LNB controls: 0.81 at full load. W/ LNB+OFA controls: 0.19 to 0.28 over load range Short term tests	30 percent at full load and only 10 percent at low load with acceptable ammonia slip (ICAC, 1994; Hunt, 1993; Jones, 1995)
Public Service of New Hampshire; Merrimack Unit 1	120 MWe cyclone	None	1.25 at full load	0.90 at full load. Short term.	30 percent reduction at full load. Preliminary tests (Jones, 1995).
Montana Electric Company; Somerset Unit 8	120 MWe tangential	Mills out of service[b]	0.60 to 0.90 (w/o SOFA) over load range 0.42 to 0.85 (with SOFA)	0.30 to 0.35 over load range with 4 injection levels. Short term.	45 to 55 percent reduction with NH_3 slip less than 10 ppm. Short term experience shows good load following capability (Staudt, 1995)

[b]Simulated overfire air by taking top burner level out of service.

increased to a range of 32 to 46 percent over the load range. Similar results showing the dependence of NO_x reduction performance on NH_3 slip are apparent in many parametric demonstration tests on full scale boilers (Cunningham, 1994; Himes, 1995; Staubt, 1995). Figure 3-7 illustrates other test results showing the increase in NH_3 slip beyond 10 ppm for NO_x reduction in excess of 45 percent. Excessive NH_3 slip is particularly a concern when burning high sulfur fuels because of sulfate deposits that cause corrosion and plugging of air heaters. Typically, NH_3 levels are maintained below 10 ppm for all flue gas treatment technologies that use ammonia-based reagents.

Although the retrofits of SNCR on coal units to date have included furnaces with maximum generating capacity of 160 MWe (Mercer Unit 2 is a twin furnace 321 MWe boiler), the technology is considered equally applicable to larger furnaces. For larger furnaces, however, it may be

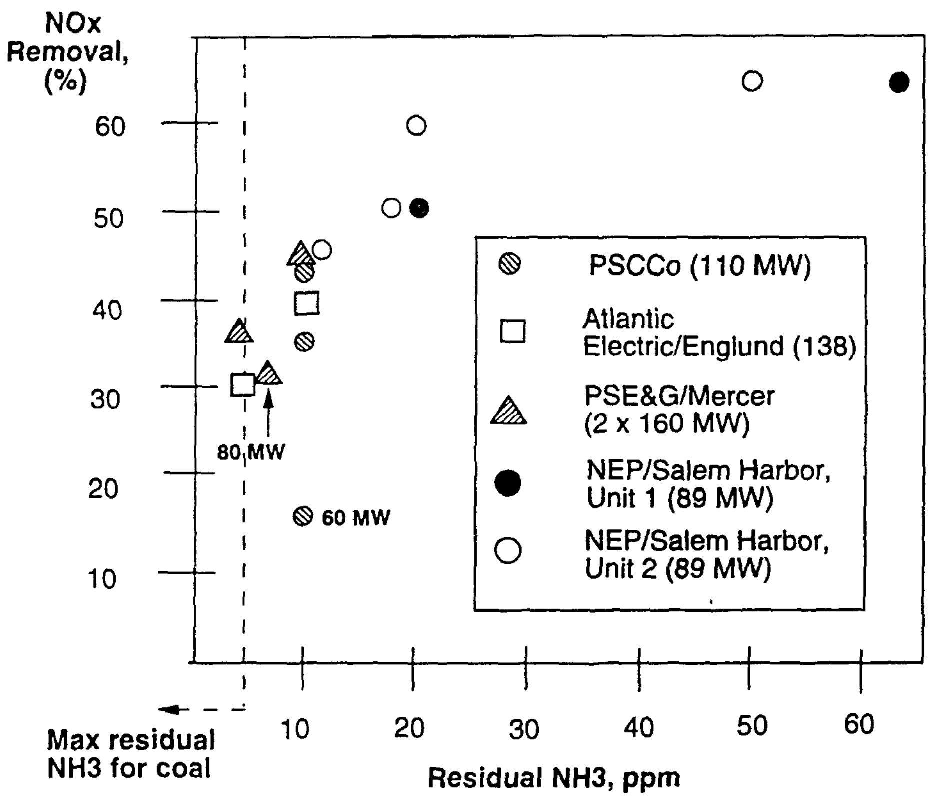


Figure 3-7. NO_x removal versus residual NH_3: SNCR on coal (Reference UARG, 1995)

necessary to add more injectors to maintain NO_x reduction performance and minimize NH_3 slip. These considerations could result in higher cost and increased operational complexity. In general, experience with retrofit on larger furnaces is necessary to document hardware requirements and performance.

It is also important to keep in mind that all these tests were performed on generally uncontrolled coal-fired boilers with relatively high NO_x levels. Application of SNCR on combustion controlled units with lower initial NO_x levels could result in somewhat lower average NO_x reductions efficiencies than those reported here. The dependence of SNCR performance on changes in initial NO_x levels is perhaps best illustrated by comparing these coal-fired results with results obtained with gas fired boilers.

Table 3-13 lists SNCR performance results obtained on demonstration and commercial oil/gas-fired utility boilers. Average NO_x reduction performance of this technology ranges between 7 to 50 percent reduction, lower than coal-fired results. The lowest NO_x reduction efficiencies are reported for gas-fired combustion controlled boilers in Southern California with an initial baseline level of 0.05 to 0.10 lb/MMBtu. One of the gas-fired installations is the hybrid SNCR+SCR demonstration at the Encina Station in California. The NO_x reduction efficiencies attributed to SNCR alone cannot be interpreted to be performance levels if SNCR were the only control in place. This is because the NSRs used with hybrid control are much higher than 1.0 and are only possible when SCR reactors are in place to further react the excess NH_3. However, the results at Encina show that with higher baseline levels of 0.19 lb/MMBtu, the SNCR NO_x reduction performance was approximately 60 percent. When burners out of service (BOOS), biased firing, and FGR combustion controls were in operation, the performance of the SNCR diminished to a range of 20 to 40 percent depending on load. Although temperature profiles are affected with implementation of combustion controls, these results tend to support the conclusion that lower NO_x reduction efficiencies are likely with lower initial NO_x levels.

Table 3-13. SNCR experience on oil/gas-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Control Types	NO_x Emission Rate Before SNCR (lb/MMBtu)	NO_x Emission Rate After SNCR[a] (lb/MMBtu)	Average Performance and Measured Impacts
Long Island Lighting Company Port Jefferson Unit 3	Coal-designed 185 MWe dry bottom corner fired	None	0.27 to 0.34 over the load range and long-term testing	0.10 to 0.22 long term. Average emission limit of 0.18.	40 to 50 percent NO_x reduction with less than 15 ppm NH_3 slip; 25 to 30 percent reduction when NH_3 is maintained below 10 ppm. Air heater plugging occurred as part of the tests (Shore, et al., 1993)
Niagara Mohawk Oswego Unit 1	Oil fired 850 MWe dry bottom wall fired	None	NA	450 ppm (full load) Short term	50 percent reduction (ICAC, 1994)
Pacific Gas and Electric Morro Bay Unit 1	Gas-fired 345 MWe wall fired	FGR	0.19 to 0.31 lb/MMBtu over load range	0.14 to 0.19 lb/MMBtu Short term	23 to 45 percent reduction over the load range with NH_3 slip as high as 110 ppm. Both urea and ammonia tried (EPA, 1994; Teixeira, et al., 1993)
San Diego Gas & Electric Encina Unit 2	Gas-fired 110 MWe wall fired	BOOS, Bias firing and FGR	W/o BOOS controls: 0.19 max load With BOOS controls: 0.11 to 0.15 lb/MMBtu over load range	W/o BOOS controls: 0.08 to 0.1 lb/MMBtu W/ BOOS controls: 0.09 to 0.11 lb/MMBtu over load range (short) term	Tested in tandem with SCR. 40 percent average reduction is attributed to SNCR. Results should be interpreted with caution (Krimont, et al., 1993)
Southern California Edison Etiwanda Unit 3	Gas-fired 333 MWe corner fired	FGR and OFA	0.05 to 0.12 lb/MMBtu over load range	0.03 to 0.07 lb/MMBtu over load range Short term results	30 to 42 percent reduction with no reported NH_3 slip (Springer, 1992; ICAC, 1994)
Southern California Edison Etiwanda Unit 4	333 MWe corner fired	FGR and OFA	0.05 to 0.08 lb/MMBtu over load range	0.03 to 0.06 lb/MMBtu over load range Short term results	20 to 40 percent reduction with no reported NH_3 slip (Springer, 1992; ICAC, 1994)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

Table 3-13. SNCR experience on oil/gas-fired utility boilers (continued)

Boiler Site	Boiler Type and Gross Capacity	Combustion Control Types	NO_x Emission Rate Before SNCR (lb/MMBtu)	NO_x Emission Rate After SNCR[a] (lb/MMBtu)	Average Performance and Measured Impacts
Southern California Edison Alamitos Unit 4	Gas-fired 333 MWe corner fired		0.05 to 0.09 lb/MMBtu over load range	0.04 to 0.07 lb/MMBtu over load range Short term results	7 to 14 percent with up to 7 ppm NH_3 slip (Springer, 1992; ICAC, 1994)
Los Angeles Department of Water and Power Scattergood Unit 1	180 MWe wall fired	FGR	0.04 to 0.11 lb/MMBtu over load range	0.03 to 0.07 lb/MMBtu over load range Long term	22 to 33 percent NO_x reduction with 20 ppm NJ_3 slip (Kwan, et al., 1993)
Southern California Edison El Segundo Unit 3	342 MWe corner fired		0.05 to 0.10 lb/MMBtu over load range	0.04 to 0.06 lb/MMBtu over load range Short term	23 to 36 percent reduction in NO_x with up to 17 ppm NH_3 slip (Springer, 1994; ICAC, 1994)
Southern California Edison El Segundo Unit 4	Gas-fired 342 MWe corner fired		0.07 to 0.08 lb/MMBtu over load range	0.05 to 0.06 lb/MMBtu over load range Short term	25 to 33 percent reduction with no reported NH_3 slip (Springer, 1992; ICAC, 1994)
Southern California Edison El Segundo Unit 1	Gas-fired 156 MWe wall fired		0.04 to 0.11 lb/MMBtu over load range	0.03 to 0.08 lb/MMBtu over load range Short term	26 to 41 percent NO_x reduction with up to 18 ppm NH_3 slip (Springer, 1992; ICAC, 1994)
Southern California Edison El Segundo unit 2	156 MWe wall fired		0.08 to 0.10 lb/MMBtu over the load range	0.05 to 0/07 lb/MMBtu over the load range Short term	30 to 50 percent NO_x reduction wi no reported NH_3 slip (Springer, 1992; ICIAC, 1994)
Southern California Edison Alamitos Unit 3	333 MWe corner fired		0.03 to 0.09 lb/MMBtu over load range	0.03 to 0.08 lb/MMBtu over load range Short term	zero to 20 percent reduction with up to 20 ppm NH_3 slip (Springer, 1992; ICAC, 1994)

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

Table 3-13. SNCR experience on oil/gas-fired utility boilers (concluded)

Boiler Site	Boiler Type and Gross Capacity	Combustion Control Types	NO_x Emission Rate Before SNCR (lb/MMBtu)	NO_x Emission Rate After SNCR[a] (lb/MMBtu)	Average Performance and Measured Impacts
Public Service Electric & Gas Mercer Unit 2	Coal-designed 321 MWe high heat release slagging unit	Simulated OFA (Fuel Bias)	0.27 to 0.89 lb/MMBtu low to full load w/o combustion modifications	0.17 to 0.54 lb/MMBtu low to full load without combustion modifications. Short term	36 to 42 percent reduction from low to full load with 5.4 ppm maximum NH_3 slip. Performance equal or lower than simulated OFA (Gibbons, et al., 1994)
Los Angeles Department of Water and Power · Scattergood Unit 1	Gas-fired 180 MWe corner fired	BOOS and FGR (steam Control)	0.17 lb/MMBtu with BOOS operation	0.035 to 0.075 lb/MMBtu over the load range. Long-term	22 to 38 percent NO_x reduction under load following conditions with less that 20 ppm NH_3 slip (Kwan, et al., 1993)
Totals	2,040 MWe corner fired 1,797 MWe wall fired		0.03 to 0.12 for corner 0.04 to 0.11 for wall	0.03 to 0.07 for corner 0.03 to 0.08 for wall	0 to 40 percent reduction for combustion controlled corner fired boiler 23 to 45 percent reduction for combustion controlled wall fired boiler 40 to 50 percent reduction for uncontrolled boilers

[a]Short-term data indicate results obtained under supervised, well-controlled operation over a period of time spanning a few hours to several days, generally less than 1 month in duration.

In general, SNCR is a low-cost gas treatment option for post-RACT NO_x reduction. The retrofit experience gathered to date on utility boilers would indicate that NO_x reduction levels are limited to a range of 25 to 65 percent for coal-fired boilers and from less than 10 to 50 percent for oil/gas-fired boilers, depending on boiler load and NO_x level. Uncertainties with SNCR performance on larger size boilers, excessive NH_3 slip, load following capability, and potential for reduced NO_x reduction performance when SNCR is implemented on combustion-controlled boilers may limit the attractiveness of SNCR only controls for post-RACT compliance. Lower performance levels of SNCR might be further aggravated when the controls are applied to large gas-fired utility boilers with variable dispatch loads. Because of the strong dependence on gas temperature and mixing, it is likely that optimum NO_x reduction performance for SNCR will come from retrofit on smaller, base loaded, coal-fired utility boilers with high inlet NO_x levels. Currently these candidate boilers include wet bottom and cyclone units and several lower capacity dry bottom units.

Reported operational impacts have been minimum for the most part. This is due principally to the ability of most installations to maintain NH_3 slip at low levels, between <5 to 20 ppm in most cases. Although many of these tests were performed on a short-term basis, long-term operational impacts have also been minimal. Ammonia slip levels below 5 ppm would likely have little effect on the salability of the flyash or air heater pluggage and cold-end corrosion. Long-term tests are planned at some facilities to explore these issues (Cunningham, et al., 1994). Other byproducts of the SNCR reaction, especially with urea-based reagents, are N_2O and CO emissions. N_2O is a greenhouse gas not currently regulated. Typically N_2O emissions are a function of the reaction temperature and tend to range between 10 to 15 percent of the total NO_x reduced (Hofmann, et al., 1993). Because of the quantities of water injected into the furnace to provide adequate dispersion of the reagent, a decline in boiler efficiency of 0.5 to 1 percent has been reported (Gibbons, et al., 1994).

3.4 CATALYTIC FLUE GAS TREATMENT CONTROLS

Interest in SCR for NO_x reductions on a variety of combustion sources has grown substantially in recent years. The technology has been commercially available on gas turbines, industrial boilers, reciprocating engines, process heaters, and utility boilers in the U.S. and abroad for several years. Because it can reach NO_x reductions in excess of 90 percent, in some cases, the SCR technology is often seen as the ultimate solution is reducing NO_x in combustion sources. Little or no additional NO_x reduction seems warranted once SCR is in place. In light of recent commercial installations in the United States, the applicability of SCR to gas, oil and coal-fired boilers is all about certain.

SCR installations on utility boilers are many, principally in Germany and Japan as illustrated in Table 3-14. This recent inventory, prepared by the Institute of Clean Air Companies, puts the total SCR installations on overseas utility coal-fired boilers at 213 for a total of 56 GW. Many of these installations are retrofits and have been in place since early to mid-1980s. Of the total capacity, a minimum of 36 GW is coal-fired capacity (Baldwin, 1991). Considering all combustion equipment categories, SCR is installed on about 200 combustion processes in this country and 500

Table 3-14. Overseas SCR installations on coal-fired powerplants (ICAC, 1994)

Country	Number	Retrofits	New	Power (GW)	Percent NO_x Reduction
Germany	137	127	10	30	70 to 90
Japan	40	29	11	12	25 to 90
Italy	29	19	10	12	80
Austria	3	2	1	0.9	80
Netherlands	3	1	—	0.13	80
Sweden	2	2	—	0.08	84
Finland	1	1	—	0.56	70
Total	213	181	32	56	25 to 90

abroad (ICAC, 1994). In the U.S., SCR is installed on 12 gas-fired utility boilers in California ranging in size from 230 to 750 MWe with nearly as many units planned for retrofit, and also operating or planned on a combined 1,390-MWe utility coal-fired boilers in New Jersey, Florida, and New Hampshire. Recent NO_x reduction rules for utility power plants promulgated in Southern California are being met with SCR retrofits. The SCR installation capacity, in place and planned, on utility boilers in the U.S. now totals about 5,000 MWe with approximately 2,400 MWe more scheduled to be in place in the next few years. The successful application of SCR control systems on utility boilers in Southern California was possible because of design improvements that utilize smaller catalyst volumes while retaining high NO_x reduction performance.

The SCR process is based on the selective reduction of NO_x by NH_3 over a catalyst at a temperature in the range of approximately 260° to 480°C (500° to 900°F). Contrary to the SNCR process, both NO and NO_2, the two principal forms of NO_x from powerplants, are both reduced. In the SNCR process only NO is affected. Also, N_2O is not a byproduct of the SCR reaction, whereas N_2O can be as much as 25 percent of the NO reduced in the SNCR process. The overall SCR reactions that occur in the flue gas of utility boilers are (Bosh and Janssen, 1987):

$$4NH_3 + 4NO + O_2 \rightarrow 4N2 = 6H_2O \tag{3-4}$$

$$8NH_3 = 6NO_2 \rightarrow 7N_2 + 12H_2O \tag{3-5}$$

Ammonia is injected in either in its anhydrous form or in an aqueous solution. The amount of NH_3 injected is nearly the stoichiometric amount required, or 17 pounds of ammonia for each 46 pounds of NO_x as NO_2. The optimum reaction temperature is based on the catalyst formulation. Many of the formulation use vanadium pentoxide (V_2O_5) supported on titanium dioxide (TiO_2) with an operating temperature window of 300° to 400°C (570° to 750°F). Zeolites and other rare earth materials are also effective catalysts, but their operating temperatures tend to be higher making them more suitable for applications on cogeneration or simple cycle gas-turbine plants. Catalysts and substrates are shaped in either parallel or honeycomb modules that are stacked together into a reactor that must then be placed in the appropriate location where gas temperature matches the catalyst peak performance temperature. In a utility boiler, this temperature normally corresponds to the inlet air heater when the boiler is at or near full load. At lower boiler loads, the temperature at the air heater inlet drops sufficiently that some amount of economizer bypass may be required to maintain the catalyst at the optimum temperature. This bypass inflicts a thermal efficiency loss that is attributed to the operation of the SCR process.

Besides temperature, other factors that affect the performance of SCR catalysts are (Rosenberg and Oxley, 1993):

- SO_2 content of the flue gas
- Flyash content in the flue gas
- Molar feed ratio of NH_3 to NO
- Catalyst space velocity
- NH_3 distribution
- Trace metals in the flyash

Application of SCR in high sulfur and dust flue gas represents a particular challenge for SCR catalysts. This is because the catalysts performance can: (1) deteriorate from the erosion effect of the flyash, especially when gas velocities are high; (2) become plugged or fouled because of sticky deposits; (3) become poisoned from certain trace metals and alkaline components in the flyash such as arsenic, CaO, and MgO; and (4) cause oxidation of SO_2 to SO_3 that can result in higher flue gas dew point with potential for cold end corrosion due to ammonium sulfate deposits. If neglected, these conditions can reduce the catalyst life, and make the SCR very expensive to operate. By considering the effects of sulfur content and dust loading on catalyst performance in the design of each unit, system and catalyst suppliers have been able to install SCR on numerous boilers here and abroad.

The space velocity is the volumetric flow rate of the flue gas under standard conditions divided by the volume of the catalyst, in units of 1/hr. The smaller the space velocity, the larger is the catalyst volume. Large catalyst volumes offer greater NO_x reduction capability and lower emissions of unreacted NH_3. With some catalyst formulations, SO_2 oxidation increases with larger catalyst volumes (lower space velocities). To put this term into perspective, a space velocity of 100 to 220 1/hr would mean an SCR catalyst the size of the boiler furnace. Fortunately, catalyst volumes are on the order of 2,400 to 4,000 1/hr (about 20 times smaller than a boiler furnace) for high performance SCR units on coal-fired powerplants. However, reactor housing the catalyst in full-scale SCR systems can be as much as 5 times larger that the catalyst it contains to permit maintenance, sootblowing, and gas flow control. The catalyst space velocities for some of the in-duct SCR applications in Southern California gas-fired utility boilers are on the order of 33,000 1/hr.

The volume of the catalyst at the Merrimack Unit 2 will initially consist of two layers of catalyst module for a total space velocity estimated at about 7,500 1/hr for 65 percent NO_x reduction. Anticipated deterioration of the catalyst performance over the first 5 years of operation and planned increase in NO_x removal efficiency of the system from 65 to 91 percent will require two additional layers of catalyst bringing the final space velocity to about 3,750 1/hr (700 m^3 of catalyst), similar to catalyst space velocities used on the new coal plant in New Jersey (Philbrick, 1995).

As in the case of SNCR, the injection of NH_3 must also be accomplished with the outmost mixing efficiency with the flue gas. This requires the careful mapping of the flue gas velocities, NO_x distribution and temperatures at the plane of NH_3 injection. Also, the mixing requires the installation of an injection grid that takes into consideration the results of the flue gas mapping. The optimization of the injection and mixing is particularly important when the volume of the catalyst is minimized to permit retrofit in existing ducting and air preheater baskets. Often, flow straighteners must be installed in the inlet flue gas to maximize the uniformity of the gas flow across the catalyst inlet plane. Economizer bypass provisions are also necessary in the retrofit to ensure that SCR inlet temperatures are maintained with decreasing boiler loads.

Improvements in process design and catalyst formulations have alleviated many of the potential problems discussed above. For example, downflow reactors with plate and honeycomb catalysts and dummy catalyst layers acting as flow straighteners and operating at the higher end of the temperature window are often used in coal-fired boilers to combat the effects of high dust loadings. Catalyst formulations more resistant to SO_2 to SO_3 conversions have been developed for applications in flue gas with high SO_2 loadings. Concerns regarding sulfur limits with SCR have diminished somewhat as new and planned SCR installation in the U.S. and Europe have guaranteed NO_x reduction performance with sulfur level as high as 2.5 percent (Philbrick, 1995). With high sulfur levels and NO_x reduction performance (large catalyst volumes), NH_3 slip must be maintained to a minimum. Flow straighteners with accurate NH_3 distribution are used to minimize NH_3 slip and maximize performance. Many of these retrofit considerations and improvements have important effects on the feasibility of retrofit, performance, operational impact, and cost. This dependence is illustrated in Table 3-15.

For the most part, installations already in place in the U.S. are relatively new and experience is limited. However, many of the initial reports indicate that SCR installations are operating satisfactorily and meeting or exceeding performance guarantees. Because catalyst cost can be a large fraction of the total operating cost, one especially important guarantee is the life (performance period) of the catalyst material. Over time, the catalyst activation will decrease due to erosion, blinding, or poisoning of the catalytic surface. Along with this deactivation, SO_2 to SO_3 conversion can increase and lead to corrosion problems in load cycling plants. Long-term pilot tests at TVA Shawnee Station with coal firing and Niagara Mohawk Oswego Station with oil firing conclude that deposition of flyash and fuel oil additives (MgO) can result in significant deactivation and pluggage of the catalyst. For the hot-side, high-dust SCR test at Shawnee, activity loss was the result of masking of the catalyst surface by sulfate flyash and not by arsenic deposition. Catalyst activity loss ranged from 25 to 50 percent, depending on catalyst formulation, after 8,000 of operation (Mechtenberg, 1995).

Table 3-15. **Major design factors affecting costs**

Design Factors	Capital Cost Considerations	Operating Costs Considerations
Fuel Type (Flue gas composition: fly ash, SO_2 content)	• Catalyst volume, geometry, pitch, orientation • Reactor volume • Catalyst composition • Reactor design (conventional vs. in-duct) • Cleaning provisions • Catalyst replacement • Ammonia consumption	• Catalyst replacement • Ammonia consumption
Initial NO_x Concentration	• Catalyst volume • Reactor volume	• Catalyst replacement • Ammonia consumption
Environmental Performance (NO_x removal/residual NH_3) control	• Catalyst volume • Reactor volume	• Catalyst replacement • Ammonia consumption
Catalyst Management Strategy	• Catalyst volume • Initial catalyst inventory	• Catalyst replacement

Source: Chicanowicz, E., et al., 1993.

Once performance cannot be maintained it becomes imperative to add or replace several catalyst modules to retain performance and minimize the potential for NH_3 breakthrough. Recent reports have shown that catalyst life has exceeded vendor guarantees. SCR systems are operating without catalyst additions or replacements for 4 to 5 years for coal applications and more than 10 years for gas applications (ICAC, 1994). Utility SCR experience in the United States although limited, is represented well by experience in Japan and Germany when catalyst for coal-fired boilers can be expected to operate without addition or replacement for over 4 years.

The SCR catalyst can be installed in various configurations. The most popular arrangements are the following:

- Air preheater catalysts
- In-duct catalysts

- Combination of air preheater and in-duct catalysts used in tandem
- Full-scale reactor catalysts

In coal fired applications, full-scale SCR reactors have been most common. The following subsections highlight the performance results of these types of SCR configurations at specific sites. Tables 3-16 and 3-17 list the available data on the performance of these SCR utility boiler installations.

3.4.1 In-duct SCR Systems

Figure 3-8 illustrates the in-duct arrangement of SCR catalyst modules retrofitted on Southern California Edison's Alamitos 5 and 6 480 MWe utility boilers firing natural gas. The approach is to squeeze as much catalyst as possible within the existing duct space between the economizer and the air heater without having to move any of this equipment. The amount of catalyst is limited, however, not only by access but also by excessive pressure drop. Because the volume of catalyst is small compared to full reactor systems, the resulting space velocities have are as high as about 33,000 1/hr. Nonetheless, in-duct SCR retrofits on gas-fired Southern California utility boilers are recording NO_x reduction efficiencies as high as 93 percent from combustion-controlled NO_x levels. Other installations in Southern California have required moving of the air heater to permit the installation of the catalyst volume necessary for the target NO_x reduction levels. For example, the two largest SCR retrofits in the country on the Ormond Beach 750 MWe each Units 1 and 2, required some equipment rearrangement for the installation of the "in-duct" catalyst. Porous plates were also necessary to "straighten" the gas flow. Detailed cold flow modeling of the flow was used to optimize the installation and maintain the total pressure drop within the design point. The target NO_x levels with these SCR systems in place are 0.10 lb/MW-hr for gas-firing at all loads and 0.33 lb/MW-hr for oil-firing at all load, corresponding to about 0.01 and 0.03 lb/MMBtu respectively (Johnson, 1993). New Source Review (NSR) permits issued with installation of SCR in Southern California often limit NH_3 slip to 10 ppm or less to mitigate potential health hazards. The installation of this amount of catalyst requires detailed engineering evaluations and,

Table 3-16. SCR experience on domestic coal-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Control Types	NO_x Emission Rate Without SCR (lb/MMBtu)	NO_x Emission Rate With SCR (lb/MMBtu)	Overall Performance and Measured Impacts
Orlando Utilities New Stanton	460 MWe, 2.5 percent sulfur coal	Low NO_x burners	NA	NA	Expected online late 1995. Originally designed for 47 percent reduction with provision to add more catalysts
DuPont Chambers Works Cogeneration Chambers Unit 1	143 MWe, Foster Wheeler wall-fired burning 2 percent Appalachian coal	Low NO_x burners with advanced overfire air	0.27 lb/MMBtu expected with combustion controls	0.10 target design for NO_x removal by SCR with 5 ppm NH_3 slip	Designed for 70 percent reduction. Catalyst supplied by IHI Industries of Japan. Complete catalyst replacement in 10 years System in operation for 9 months (Cho, Dubow 1993)
DuPont Chambers Works Cogeneration Chambers Unit 2	143 MWe, Foster Wheeler wall-fired	Low NO_x burners with advanced overfire air	0.27 lb/MMBtu expected with combustion controls	0.10 target design for NO_x removal by SCR with 5 ppm NH_3 slip	Designed for 70 percent reduction. Catalyst supplied by IHI Industries of Japan. Complete catalyst replacement in 10 years. System in operation for 9 months (Cho, Dubow 1993)
Atlantic Electric Keystone	230 MWe, Foster Wheeler wall-fired	Low NO_x burners	NA	NA	New facility scheduled for startup in 4th qtr 1994. NO performance data available
Public Service Electric and Gas Mercer Unit 2	321 MWe slagging wall-fired burning lower sulfur (0.85%) coal[a]	None	0.52 to 1.54 low to full load	Full load 0.15 to 0.35 low load 0.20	60 to 95 percent NO_x reduction with new catalyst and CAT-AH downstream of SCR. First ever horizontal SCR installation on coal (Wallace, Gibbons, 1995).
Public Service of New Hampshire Merrimack Unit 2	338 MWe, cyclone	None	2.6 at full load	SCR designed for 65 percent reduction to a RACT level of 0.90 lb/MMBtu	Retrofit recently completed and operating satisfactorily (Philbrick, 1995)

[a]Only 1/4 of boiler capacity retrofit with SCR.

Table 3-17. SCR experience on domestic gas-fired utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Control Types	NO_x Emission Rate without SCR	NO_x Emission Rate with SCR	Overall Performance and Operational Impacts
Southern California Edison (SCE) Ormond Beach Unit 1	750 MWe Opposed Fired (principally gas fueled)	BOOS and FGR	0.15 to 0.27 lb/MMBtu (est.)	0.01 lb/MMBtu (0.10 lb/MWh) for gas firing 0.04 lb/MMBtu (0.33 lb/MWh) for oil firing	Designed for 87 to 95 percent reduction. In-duct SCR system is sensitive to NO_x, temperature and gas flow distribution (Johnson, et al, 1993)
Southern California Edison (SCE) Ormond Beach Unit 2	750 MWe Opposed Fired (principally gas fueled)	Flue gas recirculation	0.15 to 0.27 lb/MMBtu (est.)	0.01 lb/MMBtu (0.10 lb/MWh) for gas firing 0.04 lb/MMBtu (0.33 lb/MWh) for oil firing	Designed for 87 to 95 percent reduction. In-duct SCR system is sensitive to NO_x, temperature and gas flow distribution (Johnson, et al., 1993)
Southern California Edison (SCE) Redondo Beach Unit 8	Gas-fired 480 MWe wall	BOOS and FGR	0.15 to 0.27 lb/MMBtu (est.)	0.10 lb/MWhr (est.)	Online since December 1993. Performs according to specifications (ICAC, 1994
Southern California Edison (SCE) Alamitos Unit 6	Gas-fired 480 MWe wall	BOOS and FGR	0.15 to 0.27 lb/MMBtu (est.)	0.10 lb/MWhr (est.)	Design performance of 87 percent. Online since December 1993. Performs according to specifications
LA Department of Water & Power Haynes Unit 1	Gas-fired 230 MWe, wall	BOOS and FGR	0.15 to 0.27 lb/MMBtu (est.)	0.10 lb/MWhr (est.)	82 percent NO_x reduction targeted with less than 10 ppm NH_3 slip and 3 year catalyst guarantee (ICAC, 1994)
LA Department of Water & Power Haynes Unit 2	Gas-fired 230 MWe wall	BOOS and FGR	0.15 to 0.27 lb/MMBtu (est.)	0.10 lb/MWhr (est.)	82 percent NO_x reduction targeted with less than 10 ppm NH_3 slip and 3 year catalyst guarantee (ICAC, 1994)

Note: To convert lb/MWh to lb/MMBtu, divide by 10. The conversion is approximate because it varies with the heat rate of the plant.

Table 3-17. SCR experience on domestic gas-fired utility boilers (concluded)

Boiler Site	Boiler Type and Gross Capacity	Combustion Control Types	NO_x Emission Rate Without SCR	NO_x Emission Rate With SCR	Overall Performance and Operational Impacts
LA Department of Water & Power Haynes Units 5	Gas-fired 330 MWe wall	BOOS and FGR	0.15 to 0.27 lb/MMBtu	0.10 lb/MWh performance specification	Design performance of 92 percent NO_x reduction. Meeting performance specifications (ICAC, 1994).
LA Department of Water & Power Haynes Unit 6	Gas-fired 330 MWe wall fired	BOOS and FGR	NA	0.10 lb/MWh performance specification	Scheduled for commissioning in March 1997
Southern California Edison[a] Mandalay Unit 2	Gas-fired 215 MWe wall fired	BOOS	Without BOOS: 0.18 lb/MMBtu full load With BOOS: 0.13 lb/MMBtu full load	Without BOOS: 0.09 lb/MMBtu With BOOS: 0.04 lb/MMBtu	Catalyst air heater (CAT-AH) showed average efficiency of 50 percent without BOOS and 70 percent with BOOS. Higher efficiency with lower inlet NO_x (Reese, 1992)
Southern California Edison Alamitos Unit 5	Gas-fired 480 MWe wall	BOOS and FGR	Without BOOS: 0.18 lb/MMBtu full load With BOOS: 0.13 lb/MMBtu full load	0.10 lb/MWh performance specifications	Design performance of 87 percent NO_x reduction. Meeting performance specifications (ICAC, 1994)

[a]Mandalay Units 1 and 2 are scheduled for commissioning with in-duct SCR in 1996.
Note: To convert lb/MWh to lb/MMBtu, divide by 10. The conversion is approximate because it varies with the heat rate of the plant.

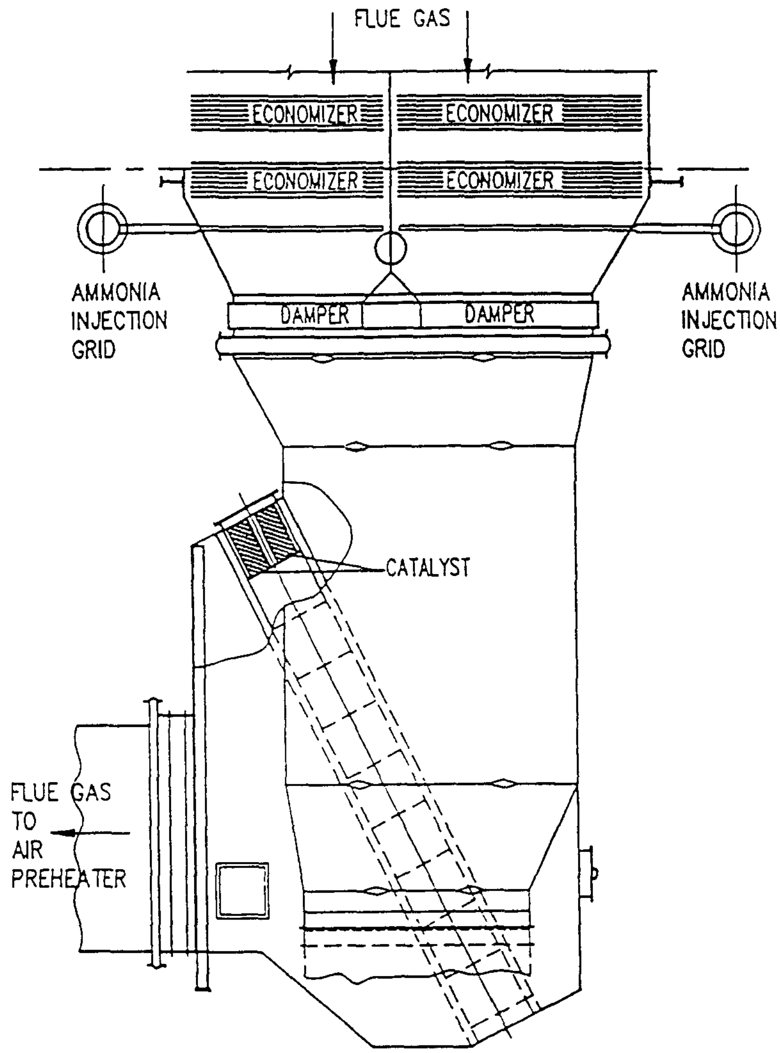


Figure 3-8. In-duct SCR system — SCE Alamitos Power Station Unit 6

as mentioned above, straightening of the flue gas flow to maintain gas velocity uniformity across the catalyst inlet plane.

3.4.2 AH-SCR Systems

The air heater SCR technology was first introduced by Rothemuhle and Siemens of Germany. Rothemuhle is an international manufacturer of regenerative air heaters for powerplants. Siemens is a major European supplier of catalysts for NO_x reductions from all major combustion sources. The retrofit of this technology will require replacing the existing enamel-coated air heater elements of a rotating Ljungstrom air heater with catalyst-coated ones on the hot end of the rotating elements and installations of NH_3 injection and control system. The applications of air heater SCR catalyst also result in low pressure drop that translate in fan power savings. Because the air heater is at the ideal temperature for NO_x reduction, the doubling of this device as an SCR reactor in addition to its heat transfer duties, provides an opportunity for SCR-type NO_x reductions without major modifications to the existing ductwork. Additionally, AH-SCR acts as scrubber for NH_3 slip with hybrid systems, such as the one demonstrated at PSE&G Mercer station. The added benefit of an NH_3 scrubber downstream of an SNCR or in-duct SCR provides greater operational flexibility and enhanced NO_x performance. Traditionally, the technology has been developed primarily for difficult retrofit cases where installation of a full-scale SCR catalytic reactor is made difficult by poor access or insufficient space.

In Europe, AH-SCR has been installed on two 200 MWe pulverized coal-fired plants in the Netherlands with reported NO_x reductions in the range of 30 to 50 percent and less than 5 ppm ammonia slip (Takeshita, 1994). In the U.S., catalyst air heater (CAT-AH) technology is distributed by ABB Air Preheater, Inc. (API). Because of its limitations on NO_x reduction performance and NH_3 slip when used alone, this technology is perhaps best applied in tandem with in-duct catalyst SCR and SNCR hybrids with overall NO_x reduction performance equalling that of a full-scale SCR reactor applications of this technology are now under evaluation at the Mercer Power Station.

The first utility boiler retrofit evaluation of this technology in the U.S was performed at the Mandalay Generating Station's 215 MWe Unit 2 (Reese, 1993). This demonstration showed a NO_x reduction capability of 50 to 64 percent from BOOS-controlled emission levels of 0.18 lb/MMBtu. Also, it was observed that the NO_x reduction performance of this technology increases with lower inlet emission levels, making it particularly useful for application on combustion controlled boilers. A study performed by Pacific Gas and Electric (PG&E) Company of San Francisco on the feasibility of CAT-AH for oil- and gas-fired boilers in their system concluded that a maximum 40 percent NO_x reduction was possible with this technology (Holliday, et al., 1993). The level of NO_x reduction, although not sufficient to attain the most stringent NO_x control regulations, would nevertheless decrease the requirements for an integrated NO_x control system capable of achieving up to 90 percent NO_x reduction levels. The feasibility of retrofit and long-term performance of this technology on oil- and coal-fired boilers remains to be demonstrated. In particular, the ability of the catalyst material to withstand thermal cycling along with plugging and masking in high dust and sulfur environments needs to be evaluated.

3.4.3 Full-Scale SCR Systems

For utility boilers burning sulfur and ash bearing fuels such as residual oil and coal, SCR installation almost exclusively requires full-scale SCR reactors containing layers of catalyst. Figure 3-9 illustrates the three possible arrangements to place an SCR reactor within the existing

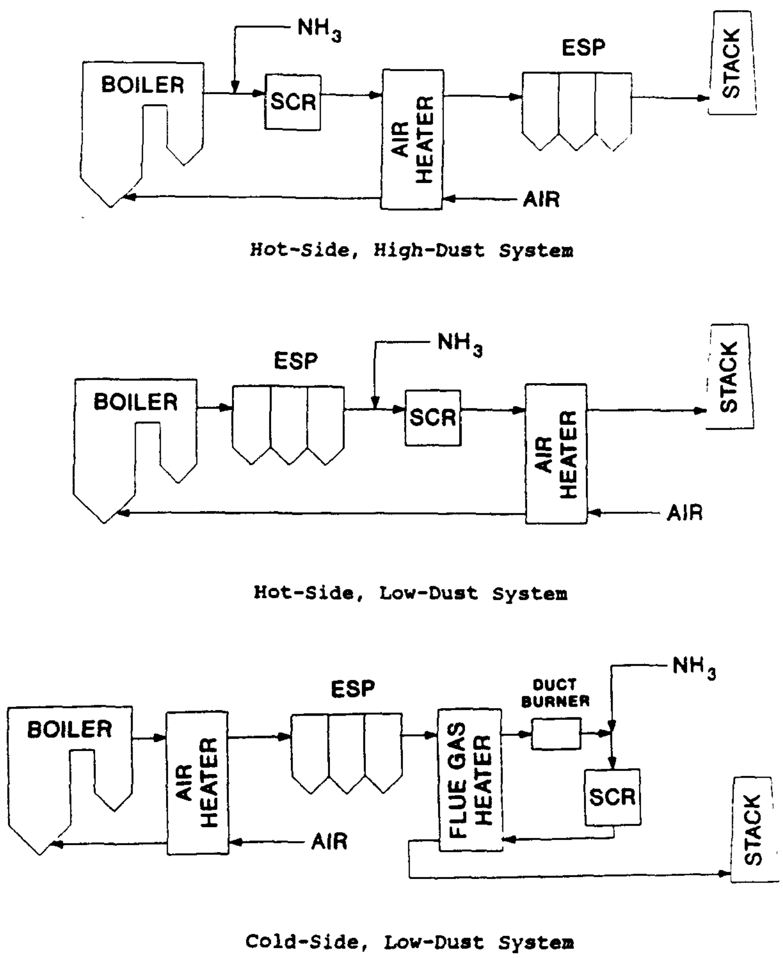


Figure 3-9. Possible SCR arrangements (Rao, et al., 1994)

equipment layout of a steam generator. The most popular arrangement, both in the U.S. and abroad, is the hot side, high dust setup where the reactor is placed ahead of the air heater and cold-side ESP. Although the SCR catalyst is exposed to the full dust loading leaving the boiler, this arrangement often represents the most economical operation, provided that the catalyst can survive in the high dust environment for sufficient time before requiring replacement. The other hot-side arrangement requires the installation of a hot-ESP which is not popular in U.S. powerplants. Therefore, this arrangement would require replacing the current ESP in addition to making room for the SCR reactor.

These full-scale reactors are generally arranged for downward flow to minimize ash deposition and they are sufficiently large to reduce flue gas velocities as low as 20 ft/sec to minimize erosion from ash and to provide sufficient space to add active catalyst layers. Figure 3-10 illustrates a typical SCR reactor for a coal-fired installation. The space velocities of these reactors are as low as 2,500 1/hr with as much as 10 times the catalyst volume found in some in-duct SCR applications. The overall pressure drop is on the order of 3 to 4 inches of water, often higher than the in-duct SCR and CAT-AH systems used in gas-fired applications. The catalyst modules are arranged in a minimum of three layers with occasionally a layer of dummy catalyst to take the brunt of the erosion from moving flyash. Additional space is also engineered in the reactor to add a fresh new layer of catalyst when the NO_x removal efficiency decreases below required levels and/or ammonia slip exceeds design values. Eventually, all the layers of catalyst must be replaced to compensate for the aging effect.

Obviously, the retrofit of a full-scale SCR reactor into an existing powerplant will require much more equipment modifications than some of the in-duct systems so successfully retrofitted on gas-fired boilers in California. The catalyst volume of one of these full-scale systems can be as large as 1/10th the size of the boiler furnace and the reactor required to house it can require a volume much larger than the active catalyst. Inevitably, significant engineering must be done to evaluate not only the rearrangement of existing equipment but also to calculate the necessary upgrades in

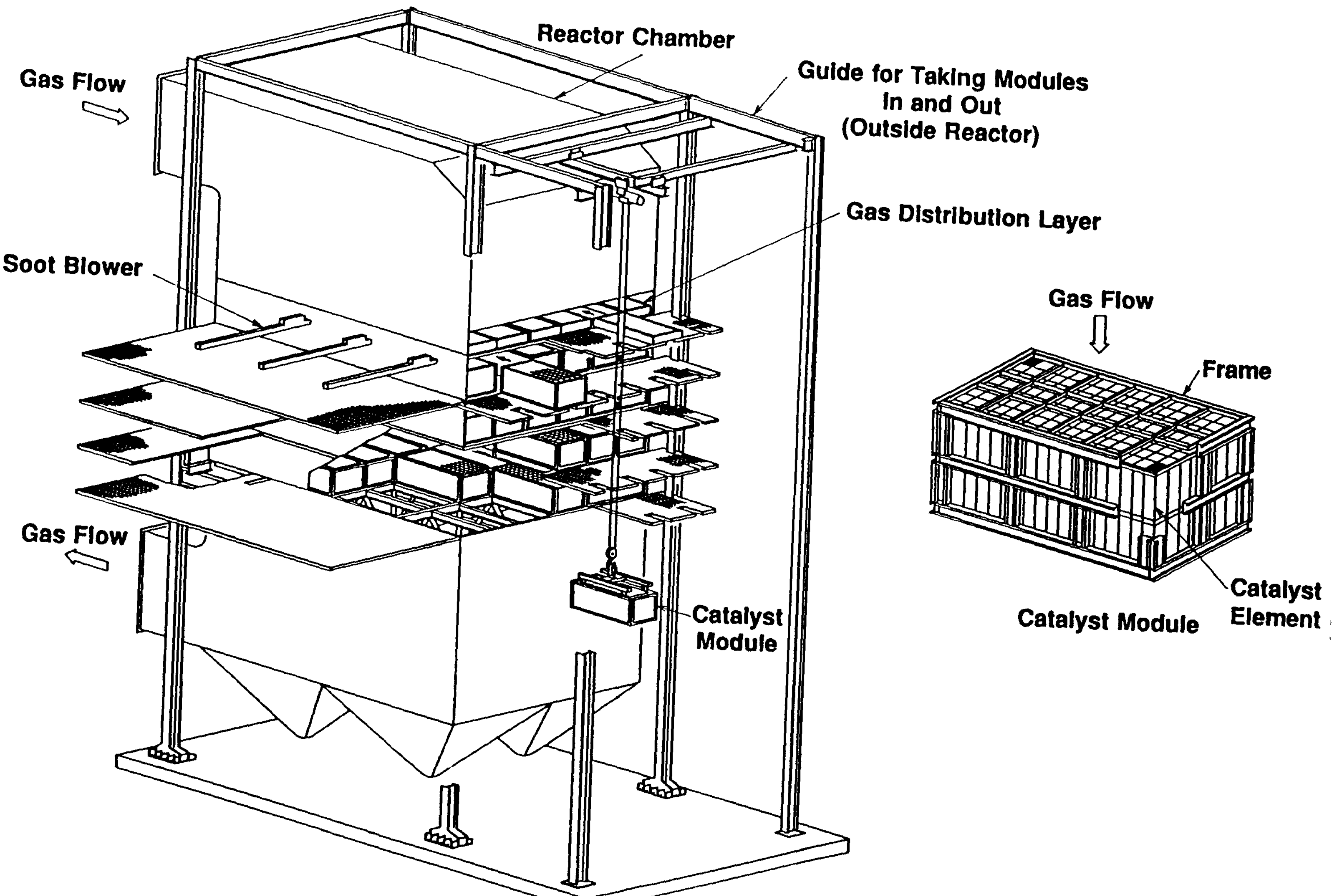


Figure 3-10. Reactor for SCR on a coal-fired utility boiler (Rosenberg and Oxley, 1993)

fan power and air heater washing to compensate for greater pressure drop and possible increased plugging rates of the air heater. As is the case with SNCR and all other SCR arrangements, the level of NH_3 slip is of considerable importance from an operational point of view, if not from an environmental one. However, the level of NH_3 slip is often lower with full-scale SCR systems because of larger catalyst volumes which permit higher NO_x reduction efficiencies and, therefore, higher reagent utilization.

Table 3-16 lists the domestic experience of SCR systems on coal-fired utility boilers. The only performance data available to date is limited to the Cogeneration Chambers Plant in New Jersey where the SCR reactor volume was designed to reduce inlet NO_x by 70 percent to a level of 0.1 lb/MMBtu with less than 5 ppm NH_3 slip (Cho and Dubow, 1993). The plant has been operating satisfactorily for the past 9 months with a 2 percent sulfur coal and a planned complete catalyst replacement period of 10 years. The Keystone facility will shortly be on line. The SCR arrangement there is also the hot-side high-dust for a 1.1 percent sulfur coal, and is designed for 70 percent reduction in inlet NO_x, also to 0.1 lb/MMBtu (Cho and Snapp, 1994). Both the Chambers and Keystone plants were designed by Foster Wheeler with IHI catalyst for Chambers and Siemens catalyst for Keystone.

The first full-scale SCR reactor retrofit at the Merrimack cyclone Unit 2 in New Hampshire, was completed in mid 1995, in time to meet the NO_x RACT deadline. The cyclone is one of the highest boiler NO_x emitter because of the arrangement and size of the cyclone furnaces. Its uncontrolled baseline level at full load is 2.66 lb/MMBtu. The design of the SCR reactor permits 65 percent reduction in NO_x to 35 tons/day (RACT limit) while burning 2.5 percent sulfur coal. The slagging furnace design exposes the catalyst to lower flyash loadings than in a comparable dry bottom unit. Catalyst life is projected up to 12 years, that is the entire initial catalyst charge (installed over a period of 5 years) will be replaced in a 12-year span. Catalyst resistance to poison such as arsenic in the coal flyash, remains to be validated. Catalyst resistance to masking and deactivation due to deposition of sulfated flyash and poisons such as arsenic, vanadium, and other inorganic compounds remains to be validated. Ongoing tests suggest, however, that optimization of physical catalyst properties, such as pitch, and countermeasures, such as sootblowing, have the potential to increase catalyst resistance to high dust and high sulfur environments. Undoubtedly, the success of this retrofit, once demonstrated, will propel SCR technology to the forefront of the commercial controls available for large NO_x reductions from coal plants.

3.5 COMBINED TECHNOLOGIES

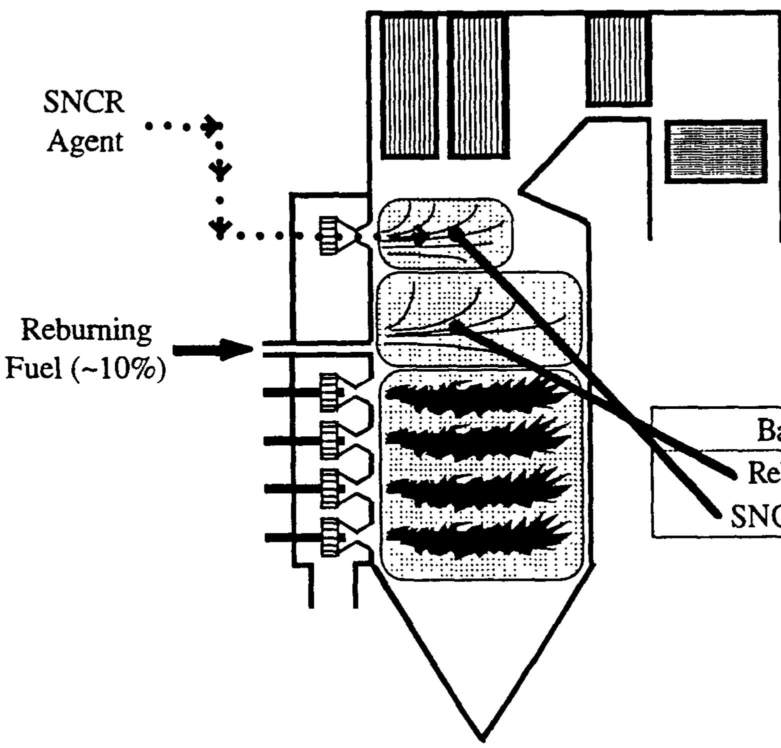
Combining two or more control technologies can be a cost effective approach to large NO_x reductions without major equipment modifications. Recently, several combinations of controls have been proposed, researched, and patented in an effort to attain NO_x reduction efficiencies of 80 percent and more without the need for large-scale SCR reactors. In addition to these combined technologies that target NO_x reduction only, other gas treatment controls for simultaneous SO_2 and NO_x reductions are being demonstrated under DOE's Clean Coal Program. These technologies will likely play a significant role in controlling emissions from new coal-fueled powerplant installations and may, in the future, offer feasible alternatives to traditionally separate NO_x and SO_2 controls strategies when both SO_2 and NO_x emissions reductions are required.

The following subsections review these technologies and their current commercialization status. Generally, hybrid controls have a much smaller experience base for coal- and oil-fired plants than for gas-fired boilers. However, the recent reported success of the SNCR+SCR+AH-SCR at Mercer certainly points to the commercial feasibility of this control approach for coal-fired boilers as well.

3.5.1 Advanced Gas Reburning

The integration of gas reburning with SNCR is referred to as advanced gas reburning (AGR). This process is considered by EER Corporation, the patent holder, to be an improvement over either the gas reburning and SNCR technologies used separately because of synergism between the two technologies (Sanyal, et al., 1993). AGR uses reburning with natural gas to enhance the SNCR process, broadening and deepening the SNCR temperature window for greater overall NO_x

reduction (Folsom, et al., 1995) The preferred arrangement for natural gas and SNCR agent injection is illustrated in Figure 3-11. The reburn zone stoichiometry is adjusted to near stoichiometric conditions, instead of the reburn optimum setting of 0.90. Normally, this would require only 10 percent gas use instead of the 18 percent used in conventional reburning, thus lowering the cost of the technology. Urea or ammonia agents are injected along with the overfire air, reducing the complexity of another separate injection location. Pilot-scale test results showed a peak overall NO_x reduction of 90 percent from uncontrolled levels of 890 ppm (about 1.2 lb/MMBtu). The increased CO and OH^- radicals from the reburn zone produced higher SNCR efficiencies over a broader temperature window than would otherwise be possible with conventional SNCR (Chen, 1991). Full-scale utility boiler demonstration of this technology is being planned (Freedman, 1994). Because the process uses a combination of gas reburning and SNCR, reliable operation in large (>200 MWe) boilers and load-following capability as well as gas supply and differential fuel costs remain principal concerns for full-scale retrofits.



	NOx Reduction (%) Incremental	NOx Reduction (%) Total	Remaining NOx (%)
Baseline	--	--	100
Reburning	45	45	55
SNCR agent	73	85	15

Figure 3-11. Advanced reburning (AR) with synergism (Folsom, et al., 1995)

A variation of the Advanced Gas Reburning (AGR) Process is the CombiNO$_x$ Process (Sanyal, et al., 1993). This process combines AGR with downstream methanol injection and NO_2 scrubbing. The methanol is injected downstream of the SNCR process at a molar ration of about 1.5 to oxidize the NO to NO_2. Pilot-scale tests have shown overall NO_x reductions of 85 percent (Pont, et al., 1993 and Sanyal et al., 1993). Additional combinations of controls explored by EER Corporation have included switching the location of urea injection upstream of the OFA. In this approach, the reburn stoichiometry is maintained near 1.0 with a minimum of natural gas, typically 10 percent. The objective of the process is to increase the concentration of NO_x reducing radicals available in the reburning zone. In pilot-scale tests, high concentrations of CO in the reburning zone with urea injection at a stoichiometry of 1.02 produced NO_x reductions as high as 80 percent at a urea injection temperature of approximately 1,850 °F (Pont, et al., 1993).

Application of these technologies on full-scale utility boilers is only speculative at this time. There are several practical considerations that will require field evaluation of this technology with initial exploratory tests on full-scale boilers.

3.5.2 SNCR and SCR

The principal objective of combining SNCR and SCR in tandem is to reduce the volume of catalyst needed, thus permitting the installation of SCR with the minimum of modifications to the existing ductwork and heat transfer equipment downstream of the economizer. The synergism between SNCR and SCR also permits more flexibility in the operation of the SNCR. For example, the presence of SCR catalyst downstream of the SNCR allows for greater NSR levels because the catalyst will use the unreacted NH_3 leaving the SNCR temperature window to further reduce NO_x. In addition, hybrid SNCR is designed for a different temperature window than commercial stand-alone SNCR. Stand-along SNCR is commercially designed for operation at higher temperature than ideal for NO_x reduction in order to keep NH_3 slip at the user guarantee level. With hybrid, instead, SNCR is allowed to be engineered for the maximum SNCR NO_x reduction because the concern for ammonia slip is greatly diminished. In other words, NO_x reduction is greater at the same NSR because of latitude allowed in the NH_3 slip level. The greater reagent utilization has a beneficial effect on lifecycle O&M costs relative to stand-alone SNCR. Additionally, NSR can be increased to provide a higher yet slip level to feed the SCR in accordance with catalyst size. Therefore, a double positive effect relative to NO_x reduction accounts for the attractiveness of this concept.

In summary, the combination of higher NSR in the SNCR zone with downstream SCR can permit high NO_x reduction efficiencies, in theory approaching the 90 percent level only possible with full-scale SCR, with greater assurances of low NH_3 slip and at lower balance of plant cost.

There are several combinations of SNCR and SCR controls. These are:

- SNCR with full-scale SCR reactor
- SNCR with catalyst air heater (CAT-AH)
- SNCR with in-duct SCR
  - Existing duct
  - Expanded duct
- SNCR with in-duct SCR and CAT-AH in series

The first of these combinations is the least likely and the most costly of retrofits because it does not take advantage of the combination of controls to minimize retrofit capital requirement. To date, retrofit demonstrations have focused on the last three arrangement options using in-duct and AH-SCR catalysts. At least two vendors are actively pursuing installations of these combined systems. Wahlco Environmental Systems, Inc. in California has demonstrated the efficiency of the Staged NO_x Reduction (SNR) process at the San Diego Gas and Electric Encina Power Plant and is active in evaluating this approach for coal applications at the Public Service Electric and Gas Mercer Unit 2. Nalco Fuel Tech, the major vendor of SNCR systems using urea, has tested the hybrid technology in a pilot-scale program where 85 percent NO_x reduction with 6 ppm or lower NH_3 slip was recorded on a short-term basis (Graff, 1995). The patented process is under the trade mark NOxOUT CASCADE®.

As indicated, the in-duct SCR systems can be distinguished between two major applications. Those whose catalyst is made to fit within the existing ductwork, and those whose catalyst volume requires an enlargement of the ductwork. The former truly in-duct systems have appeared only in gas-fired boiler applications in California. For various reasons, including the small NO_x reductions, catalyst volumes for dedicated gas-fired boilers have been sufficiently small to fit in existing ductwork with the aide of gas flow control devices. However, these true in-duct systems are considered least likely for coal- or oil-fired boilers because NO_x reductions goals are typically larger, excessive gas inlet velocities cannot be tolerated, and maintenance requirements increase.

Table 3-18 lists performance data obtained on three demonstration sites: the gas-fired Encina plant and the Mandalay plant in California and the coal-fired boiler at the Mercer Station in New Jersey. The Encina retrofit relied on an in-duct catalyst with a space velocity of 33,800 hr^{-1} and a hot-end catalyst in the air heater with a space velocity of 22,800 hr^{-1}. The demonstration of this technology was started in 1992 and showed an average NO_x reduction of greater than 50 percent. Plans to add more catalyst in the existing duct are projected to boost the overall efficiency of the SNR to a range of 88 to 97 percent (Krimont, et al., 1993).

A similar combination of controls was recently demonstrated at the Mercer Unit 2. The 80 MWe demonstration at Mercer was not only the first SNCR+in-duct SCR+CAT-AH demonstration on a coal unit, but it was also the first application of a horizontal catalyst arrangement for a coal unit anywhere in the world. This type of retrofit installation was possible because of low ash and sulfur loading. The coal is a high quality low sulfur and ash coal and the boiler uses slagging twin furnaces reducing the amount of ash reaching the catalyst. Preliminary concerns with potential plugging of the in-duct catalyst modules were dispelled and the system operator with a maximum pressure drop of 5 in. H_2O. The major findings of this demonstration point to the technical feasibility of hybrid controls for low sulfur coal units with NO_x reductions exceeding 90 percent and acceptable NH_3 slip levels. The long-term operating performance of the hybrid control must be evaluated. Also, the feasibility for high-sulfur and high ash plants remains

Table 3-18. SNCR plus SCR experience on domestic utility boilers

Boiler Site	Boiler Type and Gross Capacity	Combustion Control Types	NO_x Emission Rate Before SNCR + SCR (lb/MMBtu)	NO_x Emission Rate After SNCR + SCR (lb/MMBtu)	Overall Performance and Operational Impacts
Southern California Edison Mandalay Unit 2	215 MWe wall fired (principally gas fueled)	Burners out of service (BOOS)	0.12 with BOOS in place	0.03 with BOOS, SNCR and catalytic air heater Short-term	79 percent average NO_x reduction efficiency was reported with retrofit of urea injection and CAT-AH of two regenerative air heaters (Reese, 1992)
San Diego Gas & Electric (SDG&E) Encina Unit 2	110 MWe Wall fired (principally gas fueled)	Burners out of service (BOOS)	0.15 (125 ppm @ 3% O_2) with combustion controls at full load	0.03 (25 ppm) at full load; 0.02 (17 ppm) at 64 percent load; and 0.01 lb/MMBtu (8 ppm) at 20 percent capacity Short-term	Recorded 23 to 36 ppm ammonia slip (Krimont, et al., 1993)
Public Service Electric & Gas (PSE&G) Mercer Unit 2	321 MWe wall-fired wet bottom (principally fired with low sulfur coal)	With and without fuel bias	Uncontrolled: 0.52 to 1.54 (low to full load) 1.22 full load with fuel bias	0.1 to 0.15 over load range	Retrofit of 80 MWe only. Overall NO_x reduction performance 80 to 94 percent with <5 ppm NH_3 slip similar performance with gas firing (Wallace and Gibbons, 1995).

to be demonstrated. However, in light of these promising results, commercial retrofit of this technology on both PSE&G units at Mercer is being planned to permit attainment of the company's NO_x reduction goals.

3.5.3 Combined NO_x/SO_x

When regulations call for significant reductions in both SO_2 and NO_x from coal-fired powerplants, the retrofit of processes that can combine the reduction of both pollutants with efficiencies reaching 90 percent may prove to be the most cost-effective approach. In Europe, combined SO_2/NO_x removal systems are currently installed on 2.9 GWe of coal-based generation capacity in Denmark, Germany, Italy and the USA (IEA Coal Research, 1994). These European installations tend to prefer catalytic and activated carbon combined SO_2/NO_x removal systems. All the installations in the US are part of the U.S. DOE Clean Coal Demonstration program and tend to be based on sorbent injection systems. Perhaps, the most advanced of these processes are the B&W's SO_x-NO_x-RO_x-Box (SNRB) and The Netherland's Haldor Topsoe SNOX process. The B&W's SNRB process uses a hot catalytic baghouse injected with dry calcium or sodium. NO_x is removed by NH_3 injection all in the same reactor. The process is being demonstrated on a 5-MWe slip stream at the Ohio Edison's R.E. Burger Station. With an NH_3/NO molar ratio of 0.9, the NO_x reduction efficiency of the SNBR process has been shown to exceed 90 percent routinely (DOE, 1994). The SNOX process uses a Haldor Topsoe NO_x reducing catalyst followed by catalytic oxidation of SO_2 to SO_3, which is in turn hydrated to make concentrated and salable sulfuric acid. This process has been demonstrated at the Ohio Edison's Niles Station Unit 2 with 2 consecutive months of 94 percent NO_x reduction performance (DOE, 1994). This process is particularly attractive because it minimizes solid waste discharge. At least one 300 MWe powerplant in Europe is currently equipped with the SNOX process.

Many of the retrofit issues that accompany full-scale SCR reactor retrofits at existing powerplants would apply even more so in the case of these combined NO_x/SO_x processes. These technologies are for the most part still in the demonstration stage, and their most cost-effective applications may be for new powerplants where site layout can include provisions for these systems.

3.6 SEASONAL CONTROLS

This section highlights the feasibility and benefits of NO_x controls used on a seasonal basis to achieve reductions in emissions when ambient ozone levels are highest. From a practical viewpoint, all control options discussed above can operate either on a year-around basis or during the ozone season which typically spans between April and October. Because NO_x control is costly, the use of controls for a reduced amount of time brings about obvious economic benefits. However, coupled with lower operating costs, seasonal controls also have overall lower yearly NO_x reductions. The amount of NO_x reduced during the ozone season compared to a year-around basis will likely be in proportion to the percent time that the control is in operation. If the dispatch load and capacity factor are higher during the ozone season (i.e., scheduled boiler outage is in late fall), the NO_x reduction would benefit from a seasonal NO_x reduction strategy.

3.6.1 Seasonal Gas Use

The price of natural gas can vary dramatically from one location to the next. It is not unusual, for example, for natural gas to be very economically priced with coal and oil in one location but much less competitive in another. This spot pricing and availability of natural gas make it difficult to make broad generalization about the application of this fuel for utility boilers as an emission control option. However, it is reasonable to assume that because the availability of natural gas as a boiler fuel typically peaks in the summer season, when residential and commercial heating demand is lowest, natural gas for utilities is most competitively priced during the summer months. Coincidently, the summer season is also the period when ground level ozone peaks and exceedances of federal standards are recorded. The seasonality of the ozone problem and the concurrent availability of natural gas points to some obvious benefits of seasonal gas use as a way to reduce the NO_x emission inventory. The selected use of natural gas over a short ozone season, rather than throughout the year, can be used to mitigate the economic disadvantage of higher fuel cost while providing, perhaps, the greatest benefit to the ozone attainment effort.

Seasonal gas use can be implemented via cofiring, reburning, and full gas conversions. Considering that the NO_x reduction is typically higher with reburning methods, it stands to reason that peak reductions in NO_x per unit of gas heat input will be achieved with gas reburning. Regardless of the method of seasonal gas use chosen, however, access to a gas pipeline and boiler modifications discussed above will be necessary even for a reduced number of months of gas firing. Figure 3-12 illustrates the potential scenarios for seasonal gas using cofire, reburn, and 100 percent gas firing versus similar gas uses on a year around basis. On a MWe output basis, seasonal gas use in a reburning scenario for a tangentially coal-fired boiler would produce on the order of 3 to 17 tons a year of NO_x reduction. The low end of this estimate is based on reburning with LNB

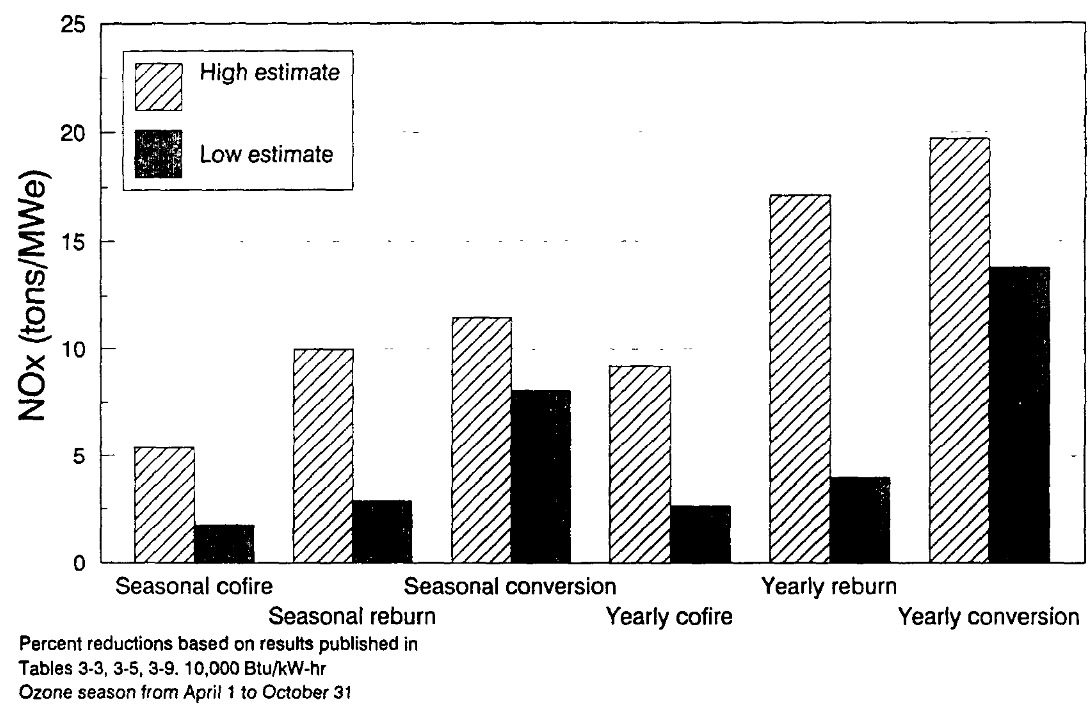


Figure 3-12. NO_x reductions on a seasonal versus a yearly basis for coal-fired tangential boilers

technology in place, as the case would be for post-RACT retrofit. The high estimate is based on reburning being in place on an uncontrolled tangentially fired boiler. The experience available with gas reburn on an LNB-controlled tangential coal-fired boiler is limited to the Lawrence station of KP&L. Close coupled reburning and cofiring for tangential boilers produced similar NO_x reduction levels. With an uncontrolled boiler, however, this estimate of NO_x reduction is more than if the same boiler were to operate with cofire on a year around basis. Also noticeable, is the small difference between NO_x levels from reburning and full conversions for uncontrolled boilers. However, when combustion controls are applied to a gas-converted boiler, NO_x reductions are much higher than a coal unit using reburning and LNB. The benefits of seasonal gas use may be greater if dispatch loads are lower in the ozone season because of the improved operational performance of gas firing at lower boiler loads.

3.6.2 Seasonal Flue Gas Treatment

All flue gas treatment controls can be used to reduce NO_x all year around (i.e., whenever the boiler is operating within its normal dispatch range) or for a fraction of that time. Among the three major control options (NSCR, SCR, or hybrid combinations), SNCR is perhaps the most adapt to a seasonal use. This is because SNCR does not employ any catalyst and can be readily turned off or on without consideration to continuous deterioration of equipment. In addition, because SNCR would be used only during the warmer months, it may be possible to reduce or eliminate insulation and heat tracing of reagent lines, reducing the initial capital investment.

The seasonal use of SCR controls may require the ability to by pass the catalyst section to avoid continued exposure of catalyst material to flue gas without the benefits of continuous NO_x reduction. This may be particularly desirable for SCR installation on coal-fired boilers where catalyst erosion and pressure drop due to high dust loading are of particular concern. In most cases, the bypass of the catalyst section or reactor may not be possible or even warranted considering the space and investment necessary to provide the additional duct-work. Removal of the catalyst from the gas stream to extend its life may also not prove feasible because reinstallation would require a second boiler outage.

Compared to SCR-only controls, hybrid systems such as SNCR with in-duct SCR catalyst, may provide greater flexibility to modulate NO_x reduction with seasonal needs. In the hybrid controls, the use of reagent in the upstream SNCR can be reduced or eliminated and the downstream catalyst can be operated at lower reduction efficiency with its own supply of reagent. Also, because the downstream catalyst is likely to be an in-duct design, smaller quantities of catalyst may be exposed to the gas stream than, perhaps, in full-scale SCR applications.

3.7 SUMMARY

Several NO_x control technologies are commercially available to reduce NO_x from the population of RACT-controlled utility boilers in NESCAUM and MARAMA. The reasonableness of each application hinges on many factors. Only a few factors have been considered in this study. Others are, for the most part, site specific and cannot be fully weighed in the context of this study. For example, the application of gas-based controls, whether seasonally or year around, hinges on the availability of gas supplies, primary fuel choice, RACT-controlled NO_x levels, and above all, fuel prices. Many of these gas-based controls may contribute only marginally to attainment of very low NO_x emission targets. Among the various gas-based options available, reburning is likely to provide the largest NO_x reduction on a gas heat input basis. The NO_x reduction potential of cofiring has not been fully explored, especially when used in combination with LNB technologies. Its application on post-RACT units remains doubtful except as a technique to trim NO_x emissions from selected boilers.

The applicability of ammonia-based controls, whether catalytic or noncatalytic, hinges on several factors such as fuel choice, boiler load dispatch, retrofit access, age of unit, and others. Yet, these controls installed by themselves or in combination may provide the only feasible approach to deep reduction in NO_x from post-RACT levels. Although experience is growing at a rapid pace, widespread reliance on both non-catalytic and catalytic controls will be more likely once long term performance has been ascertained and operational impacts and costs fully realized. SCR, especially, must be evaluated on high sulfur units, coal and oil, to be considered commercially feasible for plants that burn high sulfur fuels. The recent retrofit at Merrimack will provide one such demonstration. In the interim, further technical improvements and demonstrations of commercial and novel technologies will likely improve the retrofit potential of many of the controls evaluated in this study.

Tables 3-19 and 3-20 list estimates of NO_x reduction efficiencies for utility boilers in NESCAUM and MARAMA. These results are based for the most part on performance of controls reported to date and estimates based on factors impacting performance. These estimates are made irrespective of the retrofit feasibility of these controls on specific boilers. For example, it is recognized that retrofit of SCR may not be considered feasible because of space limitation coupled with high sulfur fuel. Also shown are the NO_x emissions for uncontrolled and RACT-controlled boilers. Reduction efficiencies estimates are the result of performance data documented in this chapter.

For RACT-controlled coal-fired boilers, the application of gas-based technologies, with a maximum heat input of 20 percent, will likely add NO_x reductions in the range of 30 to 50 percent. For uncontrolled units, reburning can result in a maximum of 65 percent reduction. Most of the uncontrolled coal-fired boilers are presently located in the MARAMA states of Maryland and North Carolina, where access to natural gas supplies for powerplants must be evaluated. Full conversions of LNB-controlled coal-fired boilers to gas firing are not likely considering the impact on operating costs and the marginal benefit of this approach in reducing NO_x compared to reburning. To illustrate this point, Table 3-21 compares the NO_x reduction in lb/MMBtu of gas used. Clearly, in all cases, reburning offers the greater NO_x reduction potential on unit of gas than either cofiring or conversions.

SNCR, by itself, for either coal- or oil/gas-fired plants already controlled with RACT, is likely to be able to reduce NO_x in the range of 10 to 40 percent depending on initial NO_x levels,

Table 3-19. Summary of NO_x reduction efficiencies for coal-fired boilers

Control Type	Wall-fired Boilers		Tangentially-fired Boilers		Cyclone and Slagging Furnaces
	Uncontrolled 0.90 lb/MMBtu	LNB-Controlled 0.50 lb/MMBtu	Uncontrolled 0.6 lb/MMBtu	LNB-Controlled 0.45 lb/MMBtu	Uncontrolled 1.2 lb/MMBtu
Cofire	25 to 40	ND	10 to 35	25 to 40	NA
Reburn	40 to 65	30 to 50	65	15 to 40	45 to 60
Conversion	40 to 70	35	70 to 75	ND	45 to 50
SNCR[a]	30 to 65	30 to 40	30 to 50 (est.)	30 to 35 (est.)	30 to 40
SCR	60 to 90	60 to 90	60 to 90	60 to 90	60 to 90
Hybrids: SNCR+SCR[b]	80 to 95	80 to 95	80 to 95	80 to 95	80 to 95
AGR	80 to 85 (est)	80 to 85 (est)	80 to 85 (est)	80 to 85 (est)	80 to 85 (est)
NO_x/SO_x	80 to 85	80 to 85	80 to 85	80 to 85	80 to 85

NA = Not applicable.
[a]SNCR NO_x reduction efficiencies based on maximum of 10 ppm NH_3 slip.
[b]*Estimated based on recent demonstration successes at Mercer Station*
[c]Advanced gas reburn (GR+SNCR). Not yet demonstrated on full-scale boilers.

Table 3-20. Summary of NO_x reduction efficiencies for oil/gas-fired boilers

Control Type	Wall-fired Boilers		Tangentially-fired Boilers		Cyclone and Slagging Furnaces
	Uncontrolled 0.50 lb/MMBtu	RACT-Controlled 0.35 lb/MMBtu	Uncontrolled 0.30 lb/MMBtu	RACT-Controlled 0.25 lb/MMBtu	Uncontrolled 0.52 lb/MMBtu
Cofire	20 to 30 (est.)	20 to 30 (est.)	20 to 30 (est.)	20 to 30 (est.)	ND
Reburn	50 to 60	50 to 60	50 to 60	30 to 40	ND
Conversion (oil to gas)	30 to 40	40 to 50 (est.)	30 to 40	40 to 50 (est.)	10 to 20 (est.)
SNCR[a]	25 to 40	10 to 40	25 to 40	10 to 40	ND
SCR[b]	80 to 95	80 to 95	80 to 95	80 to 95	ND
Hybrids: (SNCR+SCR)[b]	70 to 90	70 to 90	70 to 90	70 to 90	ND

ND = Not commercially demonstrated, although theoretically feasible.
[a]SNCR results based on maximum NH_3 slip of 10 ppm.
[b]Data for SCR and hybrids are for gas-fired boilers only.

Table 3-21. Documented NO_x reductions for gas-based controls on PC-fired boilers[a]

	Wall-fired Boilers		Tangentially-fired Boilers		Cyclone and Slagging Furnaces
Control Type	Uncontrolled 0.90 lb/MMBtu	LNB-Controlled 0.50 lb/MMBtu	Uncontrolled 0.6 lb/MMBtu	LNB-Controlled 0.45 lb/MMBtu	Uncontrolled 1.2 lb/MMBtu
Cofire	0.90 to 2.8	NA	0.75 to 1.2	0.56 to 0.90	NA
Reburn	2.5 to 3.4	1.0 to 1.6	2.2	0.56 to 0.90	3.4 to 4.0
Conversion	0.41 to 0.68	0.35	0.42 to 0.45	NA	0.54 to 0.64

NA = Not applicable. Technology not tested or not considered likely for that application.
[a]*All units are in lb of NO_2 reduced per MMBtu of gas used in the control technology.* Cofiring gas use less than 8 to 35 percent; reburning 16 to 20 percent; conversion 100 percent gas firing.

the size of the boiler, and its load dispatch characteristics. Higher NO_x reduction levels up to 65 percent with SNCR are possible for small MWe, base-loaded uncontrolled boilers. SCR and hybrid technologies offer the potential to exceed 80 percent NO_x reduction in all installations, whether RACT-controlled or not. The overall range in NO_x reduction of 70 to 95 percent reflects the flexibility of hybrids to deliver moderate to high percent reduction efficiencies depending on the volume of catalyst used, as required to meet regulations. SCR by itself can achieve 60 to 95 percent control or more for most applications, including boilers with low inlet NO_x levels, as demonstrated in California. Therefore, their applications are particularly suitable for retrofit on RACT-controlled boilers. NO_x reduction of 90 percent or more may not be feasible with some high sulfur fuel applications, however, due to the potential for excessive SO_2 to SO_3 conversion and subsequent maintenance requirements of sulfate deposits. Although the technical and experience gains of recent years on the use of SCR and SNCR+SCR hybrids are obvious, greater experience is necessary to fully document the long-term performance of these novel control approaches, especially on high sulfur-fueled boilers. Furthermore, the feasibility of retrofitting SCR or SNCR+SCR must be evaluated on a case-by-case basis because of the equipment, fuel, and layout constraints that are particular to each installation.

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CHAPTER 4

COST OF POST-RACT CONTROLS

The cost to modify existing boiler equipment at power plants for the purpose of installing NO_x controls vary from plant to plant. Although the vendor's equipment may be the same, additional costs incurred because of site-specific factors and balance of plant modifications often determine the final cost of any one technology. For example, the overall capital cost can be much higher than the average when the installation requires more extensive modifications for needed equipment upgrades in aging plants, incompatible fuel type and quality, or poor retrofit access. Also, the operating cost can change because of site specific labor costs and operational impacts such as heat rates and ash disposal costs.

Control costs are also influenced by market competition and technology advances. For example, the rapid development of the NO_x retrofit market has intensified competitiveness among various suppliers creating a downward trend in the cost of some NO_x controls. Ongoing technological advances, principally in SCR and SNCR+SCR hybrids, have contributed to recent retrofit successes in certain applications at much lower costs than projected just a few years ago. Whether this trend in declining costs is likely to continue will depend on the growth of the retrofit market and the level of competition.

Table 4-1 lists major factors that will influence the cost of four post-RACT control options available to utilities. The factors that influence the capital cost of gas reburn, for example, include the gas pipeline supply (proximity to the plant and capacity), the size and firing configuration of the boiler and its current burner configuration. Retrofit requirements will vary whether the boiler is firing with low NO_x tangential or wall burners. For example, because tangential LNCFS systems

Table 4-1. Factors that influence capital and operating costs of post-RACT retrofit controls

Cost Components	Natural Gas Reburn	SNCR	SCR	Hybrids
Capital Cost Components:				
Process Capital	Pipeline gas supply Boiler size Primary fuel type Reburn burner type Firing configuration	Boiler size Primary fuel type Royalty allowance Load dispatch schedule NO_x level	Boiler size Fuel type SO_2 and fly ash loadings Inlet NO_x concentration NO_x emission target NH_3 slip target Catalyst configuration/composition Catalyst face velocity Catalyst space velocity Reactor volume/geometry	Boiler size Fuel type SO_2 and fly ash loading Inlet NO_x concentration NO_x emission target NH_3 slip target Catalyst configuration Catalyst face velocity Catalyst space velocity Reactor volume/geometry
Balance of Plant	Physical conditions Spray attemperation Boiler metals Economizer capacity Fans capacity		Plant layout Economizer to inlet ducting Reactor pressure drop Flue gas flow distribution	Plant layout Economizer to inlet ducting Reactor pressure drop Flow distribution
Levelized Capital	Remaining life of plant Boiler capacity factor Interest on capital	Remaining life of plant Boiler capacity factor Interest on capital Load dispatch schedule	Remaining life of plant Boiler capacity factor Interest on capital Load dispatch	Remaining life of plant Boiler capacity factor Interest on capital Load dispatch
O&M Cost Components:				
Fixed	Gas price differential Current heat rate Load dispatch cycle	Required NO_x reduction Efficiency loss Reagent type and cost	Required NO_x reduction Catalyst life Catalyst disposal	Catalyst life Required NO_x reduction Catalyst disposal Load dispatch cycle
Variable	Furnace slagging pattern Furnace exit temperature SO_2 allowance Capacity recovery	Fuel type and SO_2/SO_3 loading	Load dispatch cycle Reactor pressure drop	Reactor pressure drop Reagent type and cost Efficiency loss Fuel type and SO_2/SO_3 level

are likely to have SOFA ports already in place and can use the top burner level for injection of natural gas, firebox penetration is often unnecessary for retrofit of gas reburn. Installation of OFA ports and gas injectors is necessary, however, for wall-fired boilers retrofitted with gas reburn. Additional capital costs can arise from other plant modifications needed because of poor operating condition of existing boiler equipment, superheater spray improvements, reheat and superheat tube metal upgrades, etc. These modifications may especially be necessary when 100 percent gas firing capability is desired as in gas conversions. The major recurring costs for gas reburn is the fuel price differential. Additional site specific costs can result in either loss or improvement in heat rate[1] and any changes in furnace slagging or fouling patterns. Some sites will benefit from reduced SO_2 emissions when coal or high sulfur oil is displaced, and when lost boiler load capacity is recovered, translating to SO_2 allowance and capacity recovery credits. Lost boiler load capacity can result when the coal is switched from a low ash, high heating value eastern bituminous coal to a low sulfur, lower heating value subbituminous coal.

SNCR capital costs are principally influenced by the boiler's size, primary fuel, and load dispatch schedule. Aside from the effects of economies of scale, larger boiler furnaces often dictate improved reagent coverage with more injectors to compensate for broad temperatures and gas velocity unevenness. Changing loads will also dictate more than one injection location, increased operational complexity and control systems. Primary fuel influences the initial NO_x level and sets limits on allowable NH_3 slip to minimize problems with air heater fouling and contamination of fly ash. For example, high sulfur coal-fired boilers may permit only 5 ppm NH_3 slip because of operational concerns, whereas gas-fired units can allow 10 ppm NH_3 slip to limit potential health hazards associated with these hazardous emissions. Boiler size and initial NO_x level also define the requirements for reagent storage. From an operational point of view, reagent cost is the highest

[1] Boiler efficiency loss is the direct result of higher moisture in the flue gas from increased hydrogen in the fuel. An efficiency improvement can result from other combustion air balance modifications that can reduce the overall combustion excess air.

of the recurring costs for SNCR. Other operational costs can result from increased maintenance of downstream equipment, such as air preheaters and from some thermal efficiency loss due to the use of water with the reagent.

Many more factors can influence the capital cost for SCR. This is because various configurations are possible depending on the fuel, boiler size, inlet NO_x level and target NO_x reduction, plant layout, etc. Fuel type is a dominant cost consideration because it often implies the level of SO_2, fly ash, and trace contaminants reaching the catalyst. Coupled with other design considerations, fuel type often dictates the catalyst composition, configuration, and volume required for a specific installation. Inlet and target NO_x levels and NH_3 slip that can be tolerated also play key roles in the volume of catalyst required. In-duct and air heater applications are likely to have a lower capital cost because as little as 1/10 of the catalyst needed for coal units, for example, may be sufficient to meet the NO_x target in a gas-fired boiler.

The installation of SCR is also subject to the greatest uncertainties with respect to balance of plant costs. This is because the installation of the catalyst requires access to economizer outlet. Modifications to the ductwork and downstream equipment are often in proportion to the volume of catalyst installed, which in turn also affects the pressure drop. If the pressure drop exceeds the capacity of the fans, costly fan upgrades may also be necessary. The existing equipment layout, availability of space and ease of access, and configuration of the air heater will influence the final retrofit design and layout. Because several configurations are possible, costs are often misleading and do not consider these effects. Various types of flow distribution and temperature control mechanisms are also site-specific costs incurred because of the need to optimize inlet flow conditions to the catalyst. The O&M costs of SCR are dominated by the catalyst replacement schedule and amount of reagent. Additional site specific factors that influence recurring variable O&M costs are associated with heat rate losses and increased fan power to overcome the added pressure drop of the catalyst. The costs of hybrid controls are influenced by a combination of factors that affect SNCR and SCR costs.

Finally, how the capital cost is amortized also influences the overall costs and cost effectiveness. Factors that influence how capital is amortized include the remaining life of the boiler, the average capacity factor over that period of time, the interest on capital, and the rate of inflation on recurring costs. Low capital cost controls, such as SNCR and possibly gas reburning on T-fired boilers, are least affected by the remaining life of the boiler or by the capacity factor.

This section provides a brief overview of the costs reported to date and arrives at some general guidelines on expected costs of NO_x control for retrofit on most utility boilers. Although actual costs are expected to vary from plant to plant, estimates developed in this study are representative of costs anticipated for most retrofit scenarios. These estimates are supported by recent retrofit experiences, vendor estimates, and vendor guarantees.

Table 4-2 lists the cost cases evaluated in this chapter. The technologies selected for cost evaluations are those that have either commercial or full-scale demonstrated experience. Each of the entries in Table 4-2 represents the level of NO_x reduction in lb/MMBtu from post-RACT emission levels listed in the column headings. These emission levels reflect data presented in Chapter 2. For coal-fired plants equipped with LNB, the post-RACT technologies include gas reburning, SNCR, and SCR. Full gas conversions are considered only for dry-bottom coal units and oil-fired boilers with gas already available onsite. For gas reburning, a distinction is made for plants that already have access to adequate supply of gas and those that must install a pipeline to a maximum distance of 10 miles to ensure adequate gas supply. Performance data for hybrid combinations of SNCR and SCR are based on recent tests on at least one slagging furnace.

For example, gas reburning on LNB-retrofitted coal-fired boilers with controlled levels in the range of 0.38 to 0.75 lb/MMBtu (see Chapter 2) is likely to reduce NO_x by 0.10 to 0.40 lb/MMBtu according to estimates developed in this study from full-scale experience. These estimates predict NO_x reduction performance in the range of 30 to 50 percent for boilers in this NO_x emission range. The NO_x reductions for uncontrolled slagging furnaces are much higher based on higher NO_x levels and NO_x reduction performance for reburn as high as 65 percent. Similarly,

Table 4-2. List of cost cases

Control Technology	NO$_x$ Reduction (lb/MMBtu)		
	LNB-controlled Coal-fired Boiler (0.38 to 0.75 lb/MMBtu)	**Combustion-controlled Gas/Oil-fired Boiler (0.30 to 0.45 lb/MMBtu)**	**Uncontrolled Cyclone Boiler (0.9 to 2.4 lb/MMBtu)**
Gas reburning (NGR)	0.10 to 0.40	0.15 to 0.20	0.55 to 1.20
Gas Conversion (NGC)	0.25 to 0.50	0.15 to 0.25	0.35 to 1.0[a]
SNCR	0.10 to 0.30	0.10 to 0.20	0.30 to 0.90
SCR (in-duct)	NA	0.20 to 0.35[b]	NA
SCR (air heater)	—[c]	0.05 to 0.20[b]	—[c]
SCR (full-scale)	0.25 to 0.60	0.25 to 0.40	0.60 to 1.7
Hybrid (SNCR+SCR)	0.30 to 0.60	0.25 to 0.40	NA

[a]Not considered applicable or likely retrofit option.
[b]Most likely application is on gas- and low sulfur oil-fired units.
[c]Not a likely stand-alone NO$_x$ control for coal or oil-fired boilers.
NA = Data not available. But, if proven feasible, NO$_x$ reductions similar to SCR (80 to 95 percent) levels are anticipated with smaller catalyst volumes.

air heater SCR (CAT-AH) will likely be applied to boilers principally in combination with other gas treatment controls because, by itself, NO$_x$ reductions are on the order of 10 to 40 percent. This reduction efficiency translates to a net NO$_x$ reduction of 0.05 to 0.20 lb/MMBtu from post-RACT levels in the range of 0.30 to 0.45 lb/MMBtu. In-duct and full-scale SCR systems will generate reductions of 0.20 to 0.35 lb/MMBtu for gas/oil-fired boilers and 0.25 to 0.60 lb/MMBtu for dry bottom coal units and up to 1.7 lb/MMBtu for uncontrolled slagging furnaces. The high estimate of 1.7 lb/MMBtu is unusual because it refers to the Merrimack Unit 2 with a very high uncontrolled level of 2.66 lb/MMBtu.

Table 4-3 lists the various elements of the capital and operating costs that make up the total cost at any retrofit installation. Detailed estimates of these costs are not always available on recent retrofit experiences. Therefore, the cost evaluation in this chapter often deals with the total reported cost. Major cost elements for gas reburning include the pipeline hookup, furnace

Table 4-3. Required capital and operating cost components

Cost Component	Natural Gas Reburn	SNCR	SCR	Hybrids
Capital Cost Components:	Buried and plant piping Burner and piping valves Gas nozzles, spuds, manifold Gas control system FGR fan and ducting Multiclone and cooling fan FGR controls and insulation Tubewalls OFA cooling fan and ducting OFA fan, control, insulation Labor and engineering Indirect costs Contingencies	Reagent storage tank Reagent circulation system Reagent flow control system Redundant pump systems Injectors and distribution Injectors control panel System master control Labor and engineering Indirect costs Contingencies	Reactor vessel (full-scale) Foundation Ducting and insulation Catalyst NH_3 storage tank & evaporator NH_3 carrier fan or pump NH_3 piping, pump and control *NH_3 injection grid and mixing* Process control and instruments Structural support Combustion fan upgrades Labor and engineering Indirect costs Boiler outage Contingencies	Reagent storage tank Reagent circulation system Reagent flow control system Redundant pump systems Injectors and distribution Injectors control panel System master control *Ducting and insulation* Reagent/gas mixing equipment Reactor and catalyst Foundation & structural Process control & instruments Labor and engineering Boiler outage Indirect costs Contingencies
O&M Cost Components:	Natural gas differential cost Current heat rate Load dispatch cycle Maintenance labor	Reagent Heat rate loss Maintenance labor Pump and fan power	Reagent Catalyst addition/replacement Heat rate loss Fan power consumption Maintenance labor	Reagent Catalyst addition/replacement Heat rate loss Fan, pump power consumption Maintenance labor

waterwall modifications for OFA ports, ducting and FGR fan. Because the installation and operation of an FGR system is expensive, attempts to operate gas reburning without FGR have also been investigated. ABB has pioneered the use of gas reburning without FGR. When this is possible, cost savings of about 30 percent can be realized (La Flesh and Borio, 1993). One NGR vendor has reported a second generation reburning technology that uses high velocity gas jets thus eliminating the need to use FGR. The result of eliminating FGR is to reduce the capital cost of retrofit to $15/kW for a 300 MWe boiler (Folsom, et al., 1995). Gas-coal price differential and any changes in heat rate that result from changes in boiler efficiency and reduced power for auxiliary equipment constitute the major operating costs for any type of gas reburn retrofit. Compared to other post-RACT control approaches, the capital cost of SNCR is often much lower. The principal elements of the SNCR capital cost are associated with the reagent storage, transport, and injection and their associated control system. The reagent cost dominates the O&M cost for SNCR. The initial investment for SCR retrofit is perhaps the most variable. It depends on whether the installation is for an in-duct, air heater, or full-scale reactor system. In-duct systems also have variable costs, whether they require expanded ductwork or the catalyst volume is sufficient small to fit in existing duct dimensions. Independent of this, capital costs include catalyst, reagent storage and injection grid systems, ducting and flue gas mixing aides, process control. Reagent and frequency of catalyst additions and replacement are the major elements of O&M cost.

4.1 COST OF GAS-BASED CONTROLS

The cost of natural gas-based controls is generally dominated by the cost differential between the price of natural gas and the displaced fuel. For example, bituminous coal in the MARAMA and NESCAUM regions ranges between $1.30/MMBtu and $1.90/MMBtu, equivalent to about $34 to $48/ton. The price of natural gas is highly variable based on location and availability. For example, in few instances, the price of delivered natural gas to the utilities has been as low as that of coal, especially during high-availability summer months. However, it is very unlikely that on a year around basis, natural gas can be as competitive as coal. In general, in the

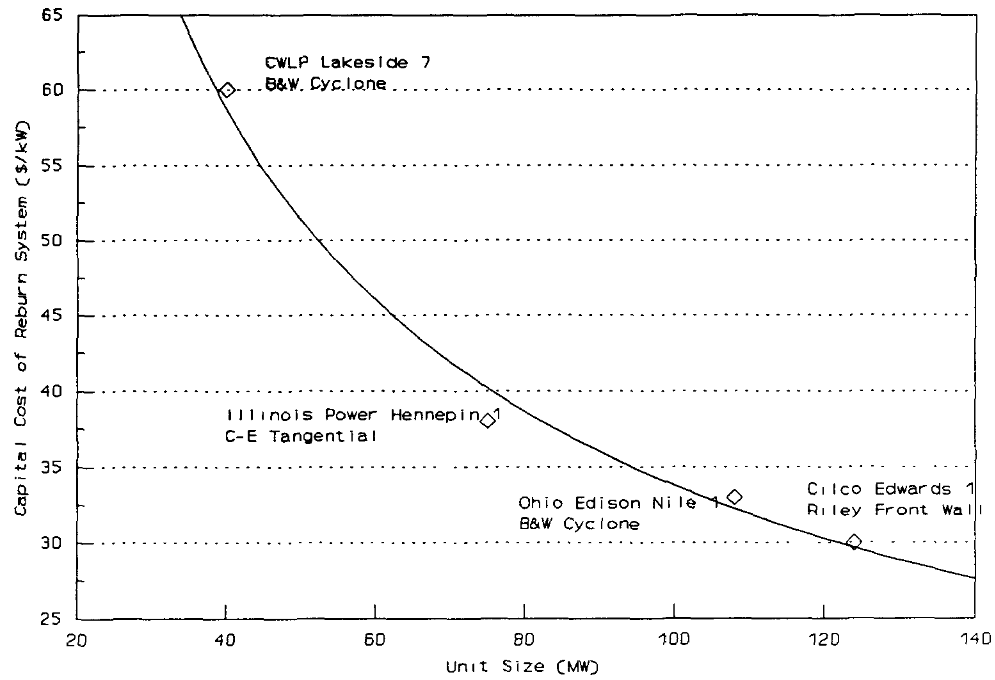
Northeast, natural gas cost delivered to the utilities ranges between \$2.50 and \$2.70/MMBtu. The approximate average cost differential of \$1/MMBtu between the two fuels translates to about 10 mills/kWh for a full conversion to natural gas and an incremental fuel cost of 2 mills/kWh for about 20 percent gas reburning. The range of 2 to 10 mills/kWh is equivalent to a capital cost of about \$60/kW to \$300/kW, levelized over 20 years for a boiler operating at 60 percent capacity. This range is much higher than any capital cost reported for gas-based controls. Clearly, the fuel differential cost is the dominant factor in evaluating the cost effectiveness of gas-based controls for utilities.

The following sections present 1995 costs estimated for gas reburning and full gas conversions for coal boilers.

4.1.1 Cost of Natural Gas Reburning

Figure 4-1 illustrates the total capital cost for installation of gas reburning on four utility boilers where gas reburning was retrofitted and tested. These boilers range in size from about 40 MWe to 130 MWe. The reported capital cost ranges from about \$30 to \$60/kW. The cost for the three smaller units include long-term testing and engineering evaluations because they were part of DOE's Clean Coal Demonstration projects. For most retrofit boilers, the cost of gas reburning installations, including the cost of pipeline hookup, is estimated to fall in the range of \$30 to \$35/kW for conventional NGR retrofits that use FGR to enhance mixing (GRI, 1993; Harding, 1994; DOE, 1993). As indicated earlier, NGR is now offered without FGR at a much reduced cost (Folsom, et al., 1995). The cost of pipeline hookup for most of the coal units in the OTR was estimated by the Coalition for Gas-Based Solutions to be less than \$10/kW, or approximately \$1/kW-mile (Vaszily, 1994).

Figure 4-2 illustrates the estimated range in cost effectiveness of gas reburning for a 200 MWe coal-fired utility boiler as a function of the NO_x reduction achieved. The band in the cost is the result of a range in gas-coal differential price from \$0/MMBtu to \$1.5/MMBtu. The estimates were developed using a capital cost of \$20/kW, recently claimed by one vendor and



Source Harding, et al, 1994

Figure 4-1. Reburn system cost versus unit size

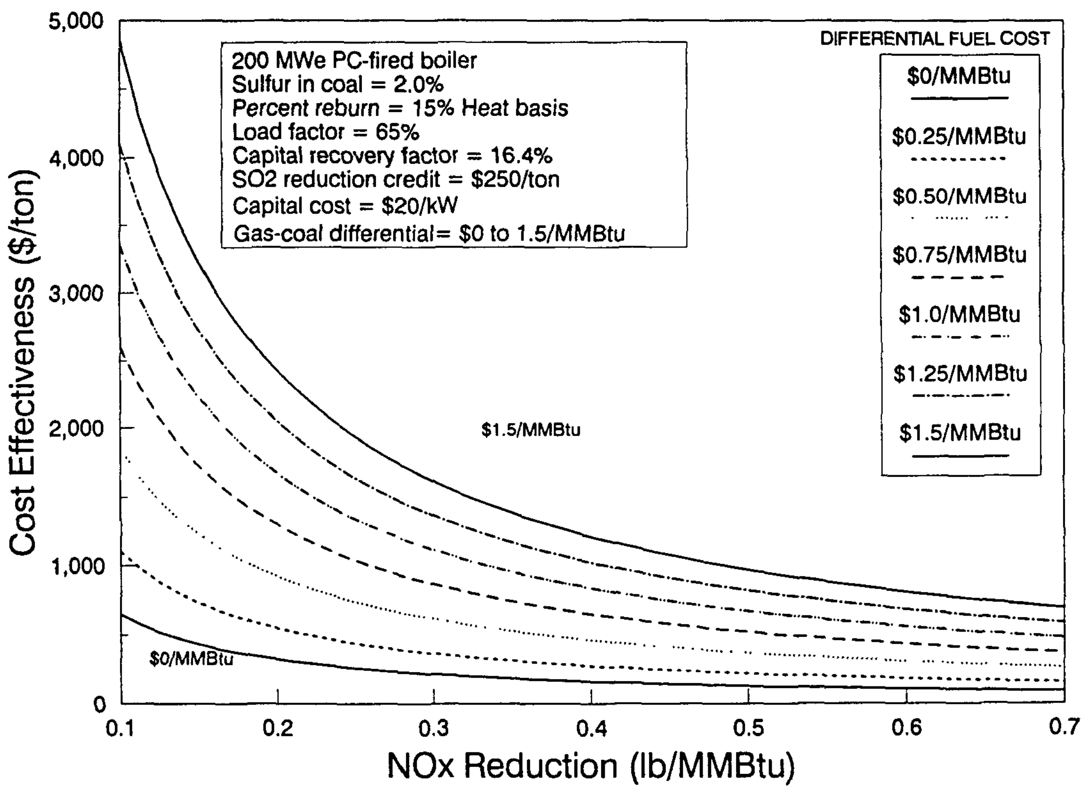


Figure 4-2. Estimated cost of gas reburn for coal-fired boilers

escalated to 200 MWe boiler, and with assumption of SO_2 credit of $250/ton. The range in cost effectiveness illustrates the dominant effects of fuel price differential and NO_x reduction. In the few cases when the price of natural gas is equivalent to that of coal, the operational benefits of gas use are such that many of the costs of retrofits are offset and the cost effectiveness is reduced below about $250/ton for most NO_x reduction ranges. When the fuel price differential is as large as $1.5/MMBtu, the cost effectiveness of NGR increases above $1,000/ton for all cases, except when NO_x reduction are large (e.g., from uncontrolled cyclones and slagging furnaces).

As indicated, Figure 4-2 is based on a capital retrofit cost of $20/kW. This is lower than actual experience but is based on recent estimates of lower cost by avoiding the use of FGR. An increase in capital requirement to $35/kW for a conventional NGR retrofit with FGR would translate to increase of about $200 to $400/ton of NO_x reduced, depending on the fuel price differential and the initial NO_x emission level.

When gas reburning is used on uncontrolled dry bottom boilers, reductions in NO_x on the order of 0.5 to 0.6 lb/MMBtu are possible, resulting in a cost effectiveness in the range of $150/ton for a zero differential fuel price to about $1,000/ton for $1.5/MMBtu price differential. When gas reburning is retrofitted on LNB-controlled units, the cost per ton of NO_x removed will be logically higher because NO_x reductions will be smaller from lower baseline levels. For example, a NO_x reduction in the range of 0.10 to 0.40 lb/MMBtu from LNB-controlled levels of 0.38 to 0.75 lb/MMBtu for wall fired boiler could cost as much as $3,000/ton to as little as $800/ton with a fuel price differential of $1.0/MMBtu to $2,300/ton. When reburning is applied to wet bottom furnaces, the cost effectiveness improves because of the larger NO_x reductions that can be achieved. The effect of additional capital cost of $10/kWe for installation of a 10 mile pipeline, in the worst case retrofit, will only add about $100 to $200 per ton to the cost effectiveness range illustrated in Figure 4-2.

4.1.2 Cost of Gas Conversions

The initial capital required to convert a coal-fired boiler to gas firing is estimated by GRI to range between \$10/kW to \$20/kW (GRI, 1993). This is approximately half of the cost reported for conventional gas reburning, but almost equivalent to second-generation reburning, on the assumption that major modifications are not required such as retrofit of new burners, installation of OFA ports, or upgrade of steam tube material to compensate for increased peak and furnace exit gas temperatures. The upper range in capital cost for gas conversions can be much higher than the \$20/kW reported by GRI because some sites will include these upgrades. For example, the conversion of the New England Power 430 MWe Brayton Point Unit 4 included many of these modifications and equipment upgrades and the added cost to access a pipeline with sufficient capacity. For this site, the cost for the retrofit exceeded \$90/kW but was reported to include costs other than those associated with gas conversion (Harding, 1994).

For the cost effectiveness analysis, the lower cost of gas conversion was set at \$15/kW for sites with onsite gas availability and no upgrades and \$25/kW for retrofits requiring pipeline access. Still higher costs are likely when burners are replaced, for example on oil-fired boilers to permit low-NO_x operation without some of the existing combustion controls such as FGR and BOOS. Figure 4-3 illustrates the annualized capital and O&M cost of gas conversion for differential fuel prices of \$1.0 and \$1.5/MMBtu. Both debits and credits are shown. Clearly, the fuel differential cost of \$1-1.5/MMBtu makes up the largest fraction of the total annualized cost. The SO_2 reduction credit translates to about \$0.42/MMBtu for a displaced 2.5 percent sulfur fuel. The loss in boiler efficiency is estimated to be about \$0.17/MMBtu. The net annualized cost, taking into account the potential credits, is about \$0.70/MMBtu when the fuel differential cost is \$1/MMBtu and \$1.7/MMBtu when the fuel differential cost is \$1.5/MMBtu.

Figure 4-4 illustrates how this total annualized cost translates into cost effectiveness for various levels of NO_x reduction. For NO_x reductions on the order of 0.6 lb/MMBtu from uncontrolled coal-fired boilers, the cost effectiveness of gas conversions is on the order of \$2,200

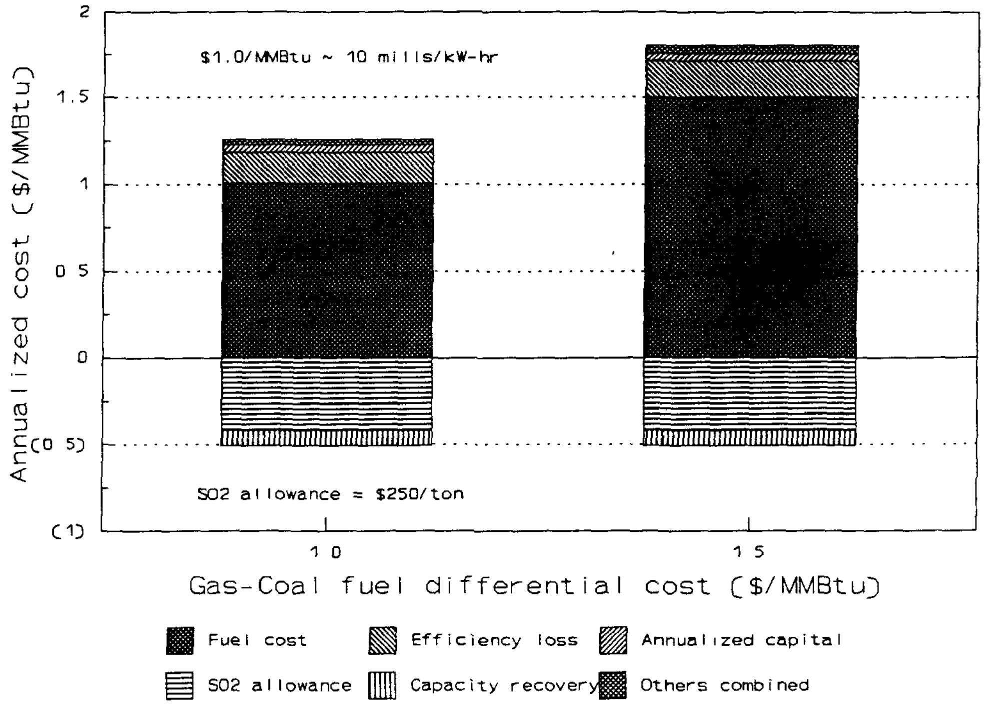


Figure 4-3. Estimated annual cost of coal to gas conversion

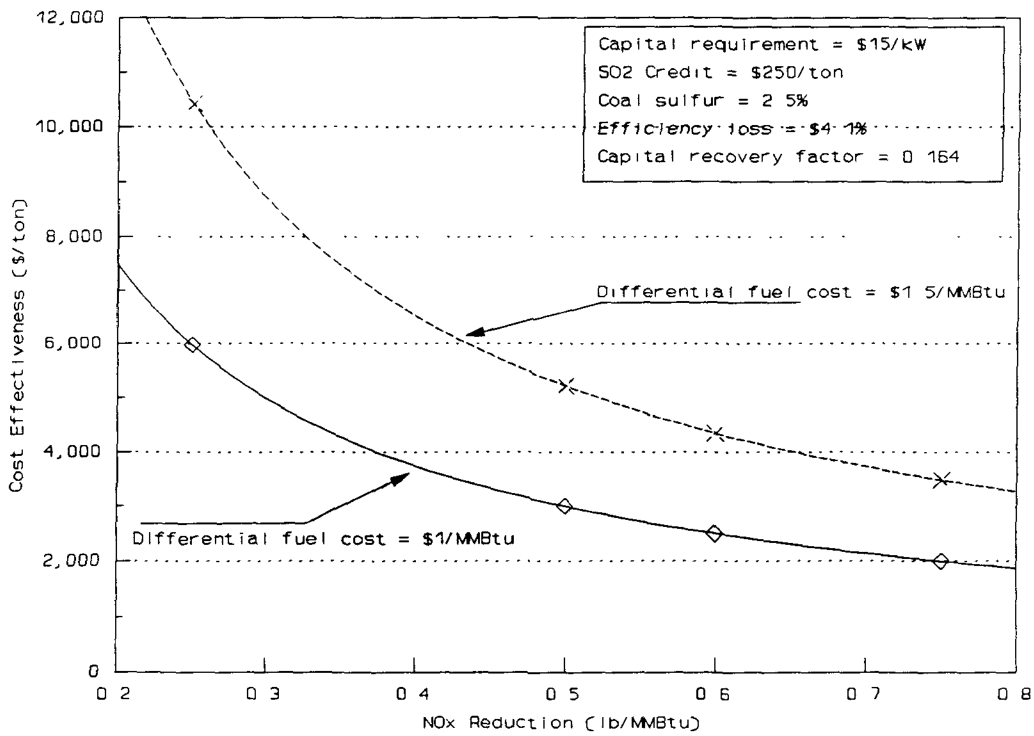


Figure 4-4. Estimated cost effectiveness for coal to gas conversions

to \$4,200/ton. The conversion of LNB-controlled coal units becomes even less attractive as the gains in NO_x reductions diminish. For example, for a NO_x reduction of 0.4 lb/MMBtu, the cost effectiveness is well in the range of \$4,000 to \$6,000/ton.

For similar fuel price differentials, conversion of oil-fired boilers, already controlled to a RACT level of 0.3 lb/MMBtu, will result in even higher dollars per ton because net NO_x reductions from these controlled levels are on the order of 0.15 to 0.25 lb/MMBtu depending on the firing configuration (i.e., tangential versus wall-fired), the burner area heat release rate, and the use of combustion controls such as FGR or BOOS. However, generally natural gas is much more competitive with fuel oil than with coal. In fact, recent price differentials vary between \$0 and \$0.50/MMBtu. Natural gas may even show a price advantage over oil during the summer ozone season. The 1994 average price of oil delivered to utilities in the New England and with Atlantic regions ranged between \$2.1/MMBtu for high sulfur oil (up to 1 percent) to about \$2.9/MMBtu for low sulfur oil, exclusive of Pennsylvania where the price reached \$3.77/MMBtu (EIA, 1994).

4.2 COST OF SNCR

Nalco Fuel Tech (NFT), the major vendor of urea-based SNCR controls for utilities and industrial boilers, estimates that the cost to retrofit Mercer 320 Unit 2 as a commercial installation would be approximately \$3,400,000, or \$10.6/kW (Gibbons, et al., 1994). This estimate is about at the half point in the range of \$5 to \$15/kW quoted by several sources (ICAC, 1994; Kaplan, 1993). A more recently reported cost estimate is at \$14/kW for this dual furnace unit (Wallace and Gibbons, 1995). On an annualized basis, the capital cost translates to a range of about 0.15 to 0.47 mills/kW-hr.

The reagent cost, which represents by far the largest fraction of the O&M cost for SNCR, was estimated to be about \$3,000,000 for the Mercer installation when burning coal and \$1,400,000 when burning natural gas (Gibbons, et al., 1994). These O&M costs translate to about 1.8 to 0.83 mills/kW-hr, for coal and gas respectively. Kaplan (1993) estimated that the levelized costs of SNCR range between 1.7 and 2.4 mills/kW-hr. The bulk of this O&M cost is in the use of the urea reagent, efficiency loss of about 0.5 to 1 percent because of the water injection, and power consumption for reagent feed. No additional costs will be incurred, if NH_3 slip from the SNCR process can be maintained to a minimum, generally less than 10 ppm, depending on sulfur content of the fuel. No additional costs have been reported from recent commercial applications of SNCR on utility boilers. However, some installations have experienced air heater fouling during initial evaluations (Himes, 1995; Shore, 1993).

Because SNCR has a relatively low capital investment compared to other technologies and because its operating cost rests primarily with the use of the reagent, its retrofit application becomes particularly attractive when the boilers have already reduced NO_x to the extent possible with combustion modifications. This is because lower operating costs will be incurred with lower inlet NO_x levels. Also SNCR can be used to trim NO_x levels at relatively low cost or to reduce NO_x on a seasonal basis. Low cost per ton of NO_x reduced is more likely when NH_3 slip can be maintained at very low levels as in the case when NO_x reductions are moderate or when SNCR is used in tandem with SCR catalyst as in the hybrid retrofit at the Mercer Plant.

Figure 4-5 illustrates the range in cost effectiveness for urea-based SNCR process on a 200-MWe coal-fired utility boiler. Three retrofit scenarios are presented for different types of boilers, each with a different post-RACT NO_x level. All costs within anticipated ranges in NO_x reduction are based on the average capital cost of \$11/kW to \$14/kW and a range in O&M cost of 1.1 to 2.4 mills/kWh for coal units and 0.45 to 0.75 mills/kWh for oil/gas-fired units. These O&M costs do not include adverse operational impacts from loss of ash sale, forced outages, and increased maintenance because of excessive NH_3 slip. This scenario is most likely because SNCR performance on any retrofit will be limited by the necessity to avoid operational impacts from NH_3 slip. Lower NO_x reductions at some site will always be preferred over excessive NH_3 slip that occur when the process is pushed to its technological limits. However, at least one reported experience with SNCR at a 240 MWe coal-fired cogeneration facility in Virginia has shown an increase of 40 percent in the cost of SNCR operation due to excessive blinding of downstream baghouse. The

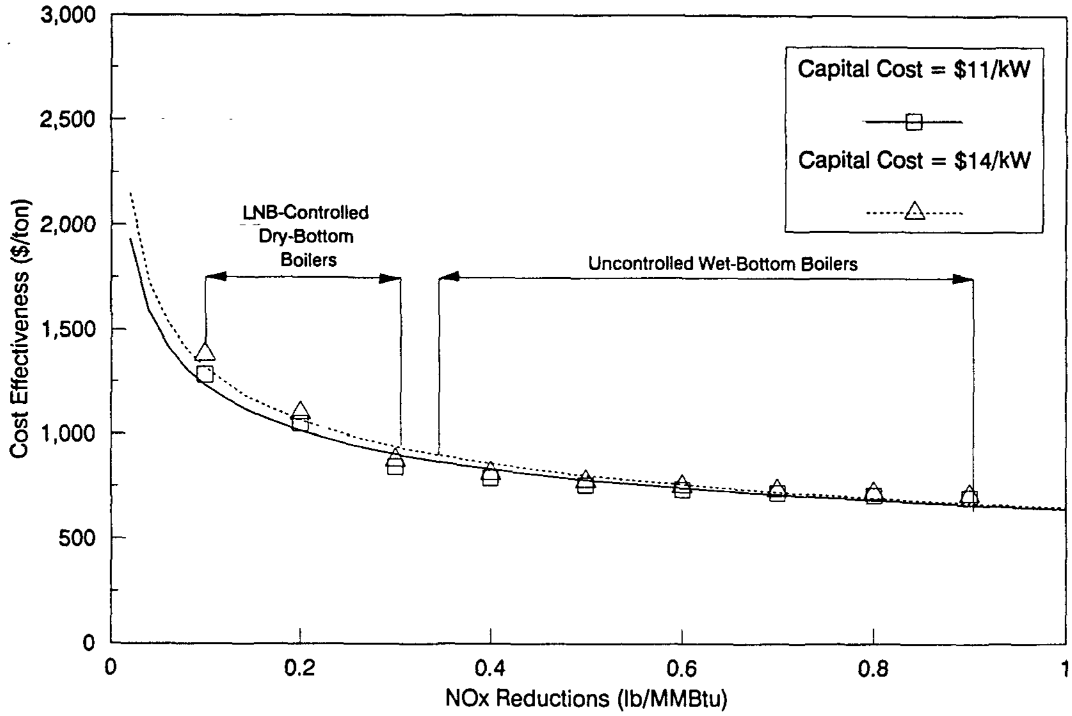


Figure 4-5. Cost effectiveness of urea-based SNCR

bag blinding was attributed to ammonia salts from excessive ammonia slip and increased gas moisture (ICAC, 1994). Improved design and process monitoring are expected to eliminate these problems.

Without adverse operational impacts, the range in cost effectiveness is in range of $850 to $1,280/ton for coal-fired boilers equipped with LNB and $1,000 to $1,400/ton for oil and gas units equipped with combustion controls for lower NO_x emissions. Also notable is the slower rate of increase in cost effectiveness of SNCR with decreasing NO_x reductions. This is the result of lower reagent use with lower NO_x reductions and inlet NO_x levels.

4.3 COST OF SCR

The installation of catalyst in existing power plants can be adapted to the existing ductwork in any one of a number of ways. As discussed in Chapter 3, SCR catalysts are often tailored to each particular application with the specific goal to minimize installation cost, simplify operation, while meeting present and projected performance targets. For example, where fuel type allows it, SCR catalyst volumes can sometimes be minimized without having to compromise on the NO_x reduction performance. This is often the case for boilers dedicated to natural gas burning, as experienced in the Southern California experience. However, when the fuel is coal or another high sulfur and ash content fuel such as residual oil, such cost saving measures are often not possible resulting in large escalations in both capital and operating costs. Furthermore, the SCR configuration can be readily adapted to a broad range of NO_x reductions in tandem with other control types.

The various types of SCR configurations make it difficult to report a "representative" retrofit cost for this technology. In fact, much of the wide range in reported costs for SCR can be attributed to dissimilar installations, boiler fuels, inlet NO_x levels, NO_x reduction performance, and other retrofit factors (Cichanowicz, et al., 1993). Certainly, the retrofit of smaller quantities of catalyst in existing ductwork of gas-fired boiler is a much different application than one with larger quantities of catalyst needed in full-scale reactors for coal-fired boilers. Therefore, when developing cost estimates it is important to treat these types of SCR configurations separately as much as possible to reflect the broad differences in both installation and operating costs that can occur from one retrofit site to another. This suggests that the retrofit SCR experience in capital cost reported in Southern California is not applicable to the NESCAUM and MARAMA, with the exception of boilers that exclusively fire natural gas.

The following subsections present estimates of the cost and cost-effectiveness for the three major SCR configuration in use today: (1) in-duct SCR considered practicable at this stage mainly on in boilers with fuels such as natural gas; (2) air heater SCR (CAT-AH) also considered principally a technology with most promise for gas/oil-fired boilers; and (3) full-scale SCR where the fuel and NO_x reduction levels are such that larger catalyst volumes, installed in separate structure reactors, are needed to meet design specifications on space and face velocities, SO_2 conversion efficiency, NO_x reduction efficiency, and NH_3 slip.

4.3.1 Cost of In-duct SCR

The bulk of the experience in the use of in-duct SCR system is in Southern California. Retrofits of small volumes of catalyst, up to 1/6 of the volume often needed for coal plants, in the existing ductwork of gas-fired utility boilers has proven effective in achieving NO_x reductions in excess of 90 percent from combustion-controlled levels. Because of smaller catalyst quantities and other factors, these reductions have been achieved at significantly lower costs than projected just a few years ago by Southern California Edison (SCE) and Los Angeles Department of Water and Power (LADWP). In fact, recent costs of these installations were quoted by SCE to be in the range of \$25 to \$35/kW (ICAC, 1994), far below estimates that often exceeded the \$100/kW mark as late as 1991 (Johnson, 1991). These large reductions in retrofit cost for the Southern California installations have come about principally because the technology has improved so that a much lower quantity of catalyst is needed to attain the high NO_x reductions targets. Consequently, the feasibility of inserting the catalyst in the existing ductwork became an option, voiding the much costlier modifications, such as moving and replacing fans and stacks, that were originally anticipated. Projections of catalyst life have also been upgraded. Current estimates put the catalyst replacement schedule for gas firing at a minimum of 6 years for upgrade and a total of 12 years of complete replacement. Although experience is still too limited to validate these claims, catalysts have performed satisfactorily.

Figure 4-6 illustrates the estimated range in cost effectiveness for in-duct SCR systems on gas- and light oil-fired boilers as a function of NO_x reduction. These estimates are based on a capital cost of \$25 to \$30/kW, average range for the California installations and an average first year O&M cost of 0.87 to 1.1 mills/kWh, comprised of about 10 percent catalyst replacement, 20 percent NH_4OH reagent use, and 70 percent other fixed and variable costs. The total busbar cost of 1.4 to 1.8 mills/kWh translates to a cost effectiveness range of about \$1,200 to \$1,700 /ton for a NO_x reduction in the range of 0.20 to 0.35 lb/MMBtu. The range in NO_x reduction has an upper limit of 0.35 lb/MMBtu because in-duct SCR is likely to find applications only on dedicated

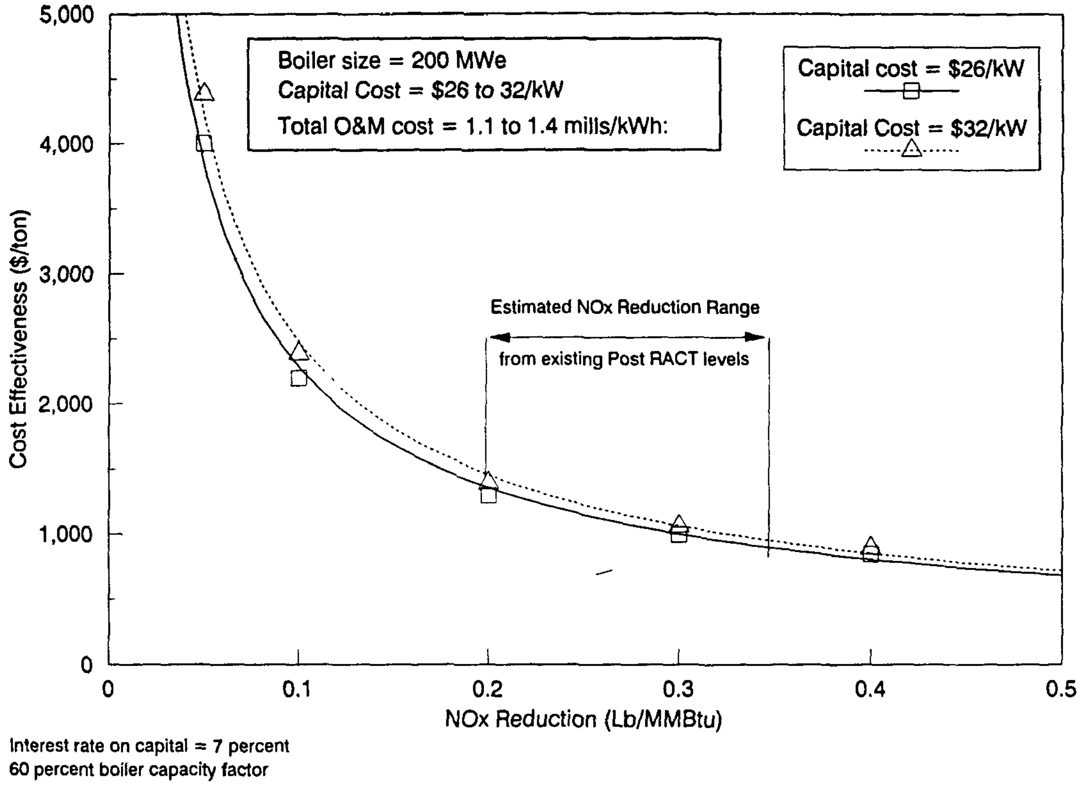


Figure 4-6. Estimated cost effectiveness of in-duct SCR systems on gas-fired utility boilers

gas-fired units where NO_x levels are typically lower than those from other fuels and, consequently, NO_x reductions in lb/MMBtu will also be lower. When gas-fired boilers are controlled to levels of 0.2 lb/MMBtu possible with combustion modifications, SCR cost effectiveness would become less attractive as indicated by the steep rise in Figure 4-6.

The estimates shown in Figure 4-6 consider a catalyst cost of $\$350/ft^3$ incremented by an additional $\$15/ft^3$ to account for labor and spent catalyst disposal costs associated with the replacement of the catalyst. The catalyst cost of $\$350/ft^3$ are supported by recent retrofit projects (ICAC, 1994). Estimates of 12 years catalyst life were used for gas only applications. This is not unreasonable for gas-fired boilers, as projected data from Southern California would suggest.

In-duct SCR for coal-fired plants has been recently demonstrated at the Mercer plant. With new catalyst installed and ammonia injection, the NO_x reduction were in the 85 to 90 percent range and NH_3 slip were between 2 and 31 ppm. Although further evaluations are needed and planned, in-duct SCR for coal plants may prove to be a viable option for boilers with low ash and sulfur loadings in the flue gas. As is the case for the Mercer Station, these retrofits of enlarged in-duct SCR on low ash and sulfur units can be an option especially for retrofits with difficult access and lack of space to install a self-supported reactor. Retrofit cost estimates for the full retrofit of in-duct SCR followed by one layer of CAT-SCR baskets on two 321 MWe at the Mercer Station were in the $90 to $95/kWe. For a conservative 1-year catalyst life and NO_x reductions in the 85 to 90 percent range, PSE&G estimates the overall cost effectiveness in the range of $1,400 to 1,700/ton (Wallace and Gibbons, 1995). For 3-year catalyst life, the cost effectiveness would improve to a range between $1,200 and $1,400/ton (Huhmann, 1995).

4.3.2 Cost of CAT-AH

There are presently no installations of CAT-AH as a stand-alone flue gas treatment control. Therefore, any cost representation is considered speculative and, to some extent, academic because the technology is not likely to be considered in applications other than hybrid systems. However, Pacific Gas & Electric (PG&E) Company conducted an evaluation in the potential use and cost of the CAT-AH technology on several utility boilers burning primarily natural gas. The evaluation was undertaken to determine the potential savings associated with the use of in-duct SCR. Table 4-4 lists the various cost elements determined by PG&E for hypothetical installations on five utility boilers in size range from 210 to 750 MWe. The budgetary costs include 10 and 25 percent process and total project contingencies with catalyst replacement every six years. The data illustrate that the catalyst replacement accounts for about two thirds of the total annualized cost. Capital annualization contributes another 30 percent. O&M, including NH_3 reagent use, is minimal compared to these costs.

Figure 4-7 illustrates these data as a function of the boiler size. The data suggests that for a 200 MWe gas-fired boiler in NESCAUM or MARAMA, the capital cost would be on the order of $25/kW with a total annual cost of about 3 mills/kWh. Figure 4-8 illustrates the calculated cost effectiveness of this technology. The cost effectiveness is shown over a range in NO_x reductions

Table 4-4. Levelized CAT-AH operating costs

	Pittsburgh Unit 6	Morro Bay Unit 3	Potrero Unit 3	Moss Landing Unit 6
Plant Output, MW	329	345	210	750
Estimated Capacity Factor	45%	45%	50%	65%
Total Capital Requirement	18.7	16.3	25	11.7
NO_x with gas fuel before CAT-AH, ppm	140	115	132	154
NO_x with oil fuel before CAT-AH, ppm	255	253	229	179
Percent reduction with gas firing	41	32	47	20
Percent reduction with oil firing	18	16	25	7
20-Year Levelized Revenue Requirement:				
Capital Carrying Costs, $/kW-yr	2.71	2.36	3.63	1.70
Replacement Catalyst Elements, $/kW-yr	6.04	4.84	7.54	3.75
Fixed O&M Costs, $/kW-yr	0.24	0.23	0.36	0.14
Power Costs, $/kW-yr	0.08	0.09	0.13	0.11
NH_3 Costs, $/kW-yr	0.15	0.11	0.17	0.11
Total, $/kW-yr	9.22	7.63	11.83	5.81
Total, mills/kWh	2.34	1.94	2.7	1.02

Notes:

1. 20-year levelized capital carrying charge (0.145) based on 10.5% discount rate, 5% inflation. 30-year book life and 15 yr tax recovery preference. See EPRI TAG.
2. Levelized factor (1.484) based on 10.5% discount and 5% inflation.
3. NH_3 cost at $100/ton of solution.
4. Power costs at $0.0516/kWh.
5. Fixed O&M cost include cost of new air preheater elements.

Source, Holliday, et al., 1993.

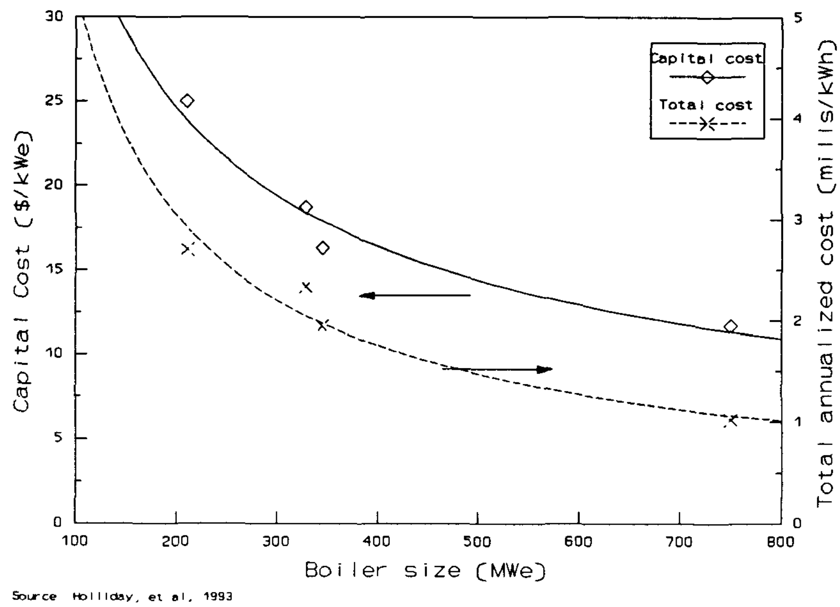


Figure 4-7. Capital and annualized costs for catalytic air heater on gas/oil-fired boilers

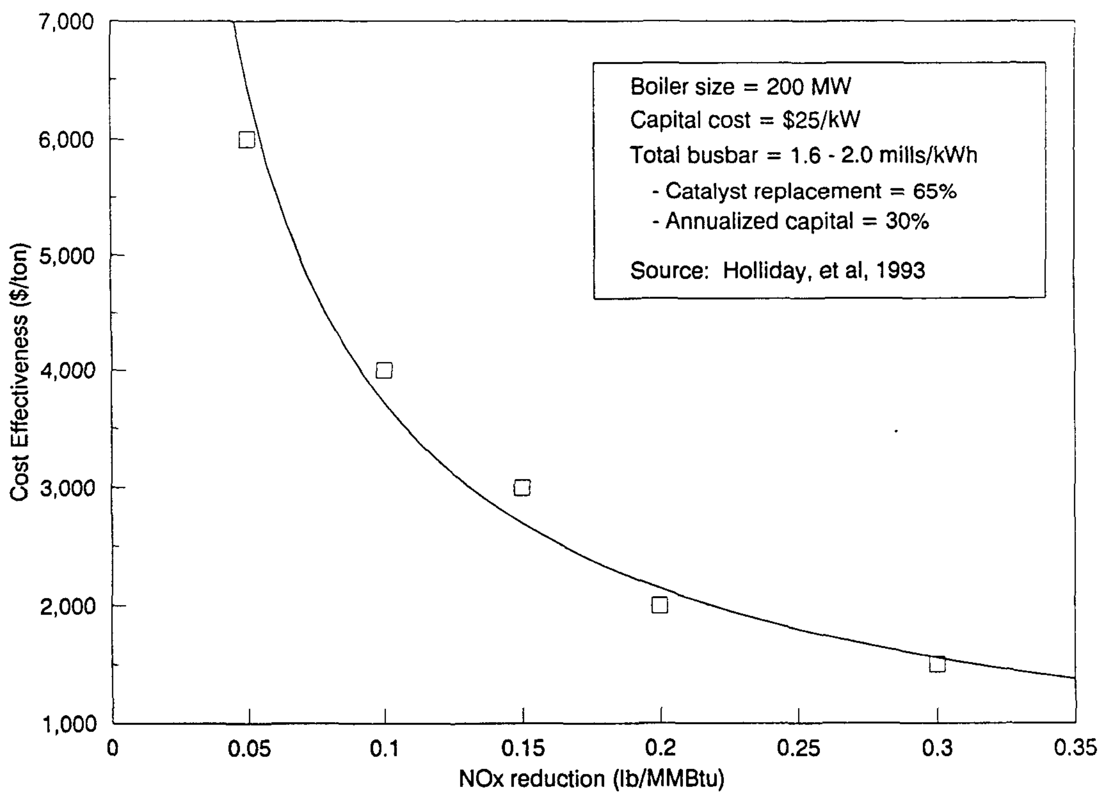


Figure 4-8. Cost effectiveness of CAT-AH on gas-fired utility boilers

from 0.10 to 0.30 lb/MMBtu, which is representative of gas-fired boilers and 40 percent average NO_x reduction capability for oil firing. The data shows that CAT-AH cost effectiveness will likely be in the range of $2,000 to $6,000/ton for NO_x reductions in the range of 0.05 to 0.2 lb/MMBtu.

The catalytic air heater used in the hybrid control system at Mercer does not imply that this technology can be implemented or stand-alone control for coal plants. Although the catalytic surface in the air heater enhances the performance of the in-duct SCR by permitting higher NH_3/NO molar ratios, by itself the technology would not be able to reach SCR performance. Therefore, no cost analysis is warranted at this stage for either coal- or high-sulfur oil-fired plants.

4.3.3 Cost of Full-scale SCR

The installation of full-scale SCR reactors is most likely when large (greater than 60 percent) NO_x reductions are targeted with less than 5 ppm NH_3 slip on boilers burning either coal or high sulfur oil. This is because catalyst volumes larger than those possible for in-duct of air heater configurations are necessary to compensate for the higher inlet NO_x levels and counter the deleterious effects of high ash loadings and SO_2 concentrations entering the catalyst. Full-scale reactors are also selected to permit the gradual addition of catalyst volume for improved catalyst life and to increase the NO_x reduction performance as regulations require it.

The costs presented here reflect two types of retrofit installations, one that is targeted for 60 to 70 percent reduction and one that targets more than 80 percent reduction. This is an important distinction because the volume of the catalyst needed is sufficiently different to have important effects on the degree of plant modifications needed and the required equipment upgrades. Figure 4-9 illustrates the relationship of catalyst space velocity with percent NO_x reduction. The curve was developed using the algorithm presented for a Foster Wheeler Corporations SCR installation on a new coal-boiler at the Keystone Cogeneration Facility (Cho and Snapp, 1993). The calculations assume a near stoichiometric NH_3/NO molar ratio to account for the need to maintain NH_3 slip in check even with larger catalyst volumes. The curve illustrates, for example, that an increase in catalyst volume of about 50 percent would be required when the target

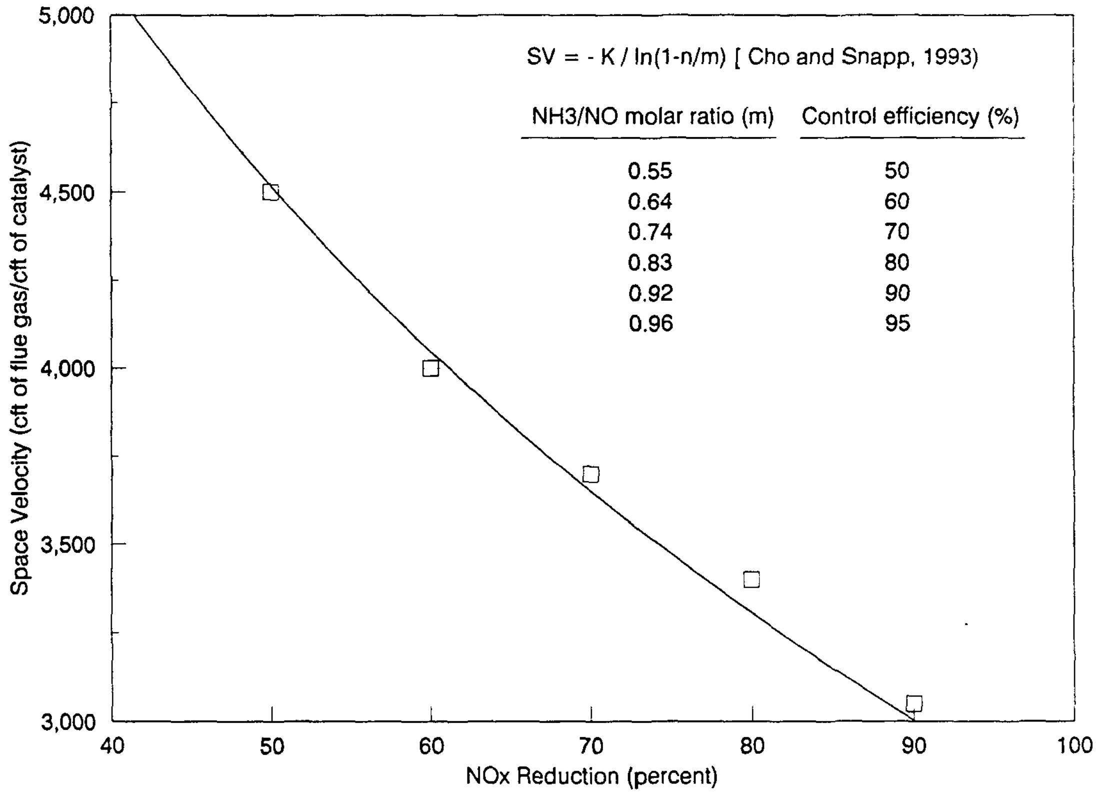


Figure 4-9. Decrease in catalyst space velocity with increasing demand on NO_x reduction efficiency

NO_x reduction is 80 percent rather than 50 percent. Considering that the cost of the catalyst and the reactor are nearly 60 percent of the total purchased equipment cost and 40 percent of the total process capital cost according to ICAC cost estimates (ICAC, 1994), the NO_x reduction performance is an important design criteria affecting the final cost of the retrofit. One must also consider that with increasing catalyst volumes there is also an increase in pressure drop that can have costly consequences on fan power requirements and maintenance as well as increased likelihood of major equipment modification to "fit-in" the reactor and all auxiliaries.

Tables 4-5 and 4-6 summarized actual costs and cost estimates for SCR installations on new and retrofit coal-fired boilers in the United States. Although not directly applicable to the study of retrofit cost estimates, the data for new plants are included for reference to illustrate the possible difference between a retrofit and a greenfield application of the technology.

Table 4-5. Utility boiler SCR costs — application of full-scale reactors on new boilers

Cost Estimating Basis	U.S. Generating Plants[a]	Orlando Utilities Stanton Unit 2	Hypothetical (DOE)	Hypothetical EPRI	Hypothetical USEPA
Fuel Type	Low to Medium Sulfur Coal	Medium Sulfur Coal	High Sulfur Coal	High Sulfur Coal	High Sulfur Coal
Generating Capacity, MWe	2x140 Chambers 230 Keystone 320 Indiantown	460	200	500	500
Initial NO_x, lb/MMBtu	0.4-0.6 (est)	0.30	1.0	0.60	1.0
Target NO_x Reduction, percent	65	50	80	80	80
Type of SCR Installation	Conventional Vertical	Conventional Vertical	Conventional Vertical	Conventional Vertical	Conventiona l Vertical
Catalyst Supplier and Installer	IHI, Siemens Foster Wheeler	Siemens	—	Grid Type Catalyst	—
Catalyst Space Velocity (1/hr)	3250 (est)	3,500	3250	2800	2500
Catalyst Bypass	Yes	—	No	No	No
Capital Cost ($/kW)	$50-$60 (est)	$55	$75	$60	97
Catalyst Management and Life Estimate	10 yr total design life 3-yr increments	6 years life	4 years	4 years	4 years
Measured NH3 slip, ppm	5 (est)	5	5	5	5
Status	Operational	1996	Hypothetical	Hypothetical	Hypothetical

[a]The Chambers, Keystone, and Indiantown plants. No actual costs attributable to SCR have been reported because of difficulty in separating out these costs from all plant costs. Therefore, data reported are estimates.

Table 4-6. Utility boiler SCR costs — retrofit of full-scale or expanded in-duct reactors on existing boilers

Cost Estimating Basis	PSNH Merrimack Unit 2	PSE&G Mercer Unit 1	Hypothetical Retrofit (ICAC Estimate)	Hypothetical (EPRI Estimate)	Hypothetical (DOE Estimate)
Fuel Type	Medium Sulfur Coal	Low Sulfur Coal	Medium Sulfur Coal	High Sulfur Coal	High Sulfur Coal
Generating Capacity, MWe	320	80	200	500	500
Initial NO_x, lb/MMBtu at full load	2.6	1.8	1.0	0.70	1.0
Target NO_x Reduction, percent	65	80	75	80	80
Type of SCR Installation	Conventional Vertical	Enlarged in-duct	Conventional Vertical	Conventional Vertical	Conventional Vertical
Catalyst Supplier and Installer	Siemens Noell, Inc	Siemens Wahlco	BHK Babcock and Wilcox	Grid Type Catalyst	—
Catalyst Space Velocity (1/hr)	6,000 (est)	5,000	4,000	2800	2,500
Balance of Plant Requirements	Ductwork and Structural Steel	Significant relocation of existing equipment	Ductwork and structural	Ductwork, fan upgrade and Air heater modifications	—
Catalyst Bypass	Yes	No	No	No	No
Capital Cost ($/kW)	$65	$100	$65	$80	125
Catalyst Management and Life Estimate	Expected life = 3yrs	Unknown	4 years	4 years	4 years
Measured NH3 slip, ppm	5 (est)	5	5	5	5
Status	Operational	Operated as 8 months demonstration	Hypothetical	Hypothetical	Hypothetical

[a]The Chambers, Keystone, and Indiantown plants. No actual costs attributable to SCR have been reported because of difficulty in separating out these costs from all plant costs. Therefore, data reported are estimates.

The new coal-fired installations are the three U.S. Generating Plants at Chambers, Keystone, and Indiantown and the Stanton Plant in Florida, estimated to be operational sometime in 1996. As indicated, the cost of SCR for these new plants is difficult to differentiate from the total cost of the plant. This is because there are many equipment upgrades, such as fan horsepower, control, ductwork, that are attributable to the placement of SCR, but are normally not separated out for the purpose of defining the actual cost of the NO_x control system. Estimates for these new plants put the installed cost of SCR in the range of $50 to $60/kW. Other costing estimates, prepared by the Electric Power Research Institute, DOE, and U.S. EPA, for hypothetical plants range between $60 and $97/kW. The estimates for these hypothetical plants are somewhat higher than the costs for the actual units, in part because of greater inlet NO_x concentrations, greater NO_x reduction efficiencies, and larger catalysts.

The experience with SCR retrofits on coal plants is also small. In fact, only two data points are available, and of these, only one involves a full-scale reactor. The Merrimack plant is also not entirely representative of the SCR retrofit costs for dry bottom plants because of the it represents a low dust application and reduced NO_x reduction performance. The reduced NO_x reduction of 65 percent is translated into a smaller catalyst as suggested by the space velocity of 6,000 l/hr. therefore, the capital cost of $65/kW for Merrimack is considered at the low end of the "average cost of retrofitting a dry bottom boiler with requirements for 80 percent reduction. Engineering estimates prepared by EPRI, ICAC, and DOE put the retrofit cost of SCR between $65 to $125/kW for catalyst space velocities in the range of 2,500 to 4,000 l/hr and NO_x reduction efficiencies in the range of 75 to 80 percent.

Table 4-7 lists estimates developed in this study for retrofit of SCR on a 200 MWe coal plant. These estimates are developed based on U.S. DOE updated IAPCS4 code[2] with costs escalated to reflect estimates for a 200 MWe boiler rather than a 500 MWe unit, using the

[2] U.S. DOE document titled "Evaluation of NO_x Removal Technologies - Volume 1 - Selective Catalytic Reduction — Revision 2," September 1994.

Table 4-7. Estimates for SCR total capital requirement for 200 MWe coal boiler

Capital Cost Item	Total Capital Requirement ($/kW)	
Ducting	11	11
Fan Upgrade/Replace	1.6	1.6
Structural	2.7	2.7
Ammonia Storage & Distribution	2.4	2.4
Reactor/Catalyst	17.3	21
Controls	incl.	incl.
Air Heater	2.4	2.4
Purchased Equipment Cost	37	41
Direct Installation	19	20
Total Process Capital	56	62
Indirect Costs & Contingencies	22	25
Total Plant Cost	78	87
AFUDC	0	0
Total Capital Requirement	78	87

expression: $ for 200 MWe = $ for 500 MWe * $(200/500)^{0.6}$. The table shows estimates for two SCR installation types differing only in NO_x reduction efficiency target.

For a 65 percent SCR reduction system with a catalyst space velocity of 4,000 hr^{-1}, the total capital requirement is approximately $78/kW. This estimate includes 40 percent for indirect costs and contingencies but does not include any funds for downtime during construction. An 80 percent reduction system would have larger catalyst volume and therefore higher initial cost, here estimated to reach $87/kW. Aside from the catalyst cost, the cost of other retrofit equipment will likely not vary because installations with smaller catalyst volumes will have design provisions that allow catalyst addition for more cost effective catalyst management and future demand for higher NO_x reduction efficiencies.

Figure 4-10 illustrates the calculated cost effectiveness of SCR retrofitted on a 200 MWe coal-fired boiler according to percent NO_x reduction. For SCR installations on dry bottom coal-fired boilers, the anticipated NO_x reduction is on the order of 0.25 to 0.6 lb/MMBtu from RACT-

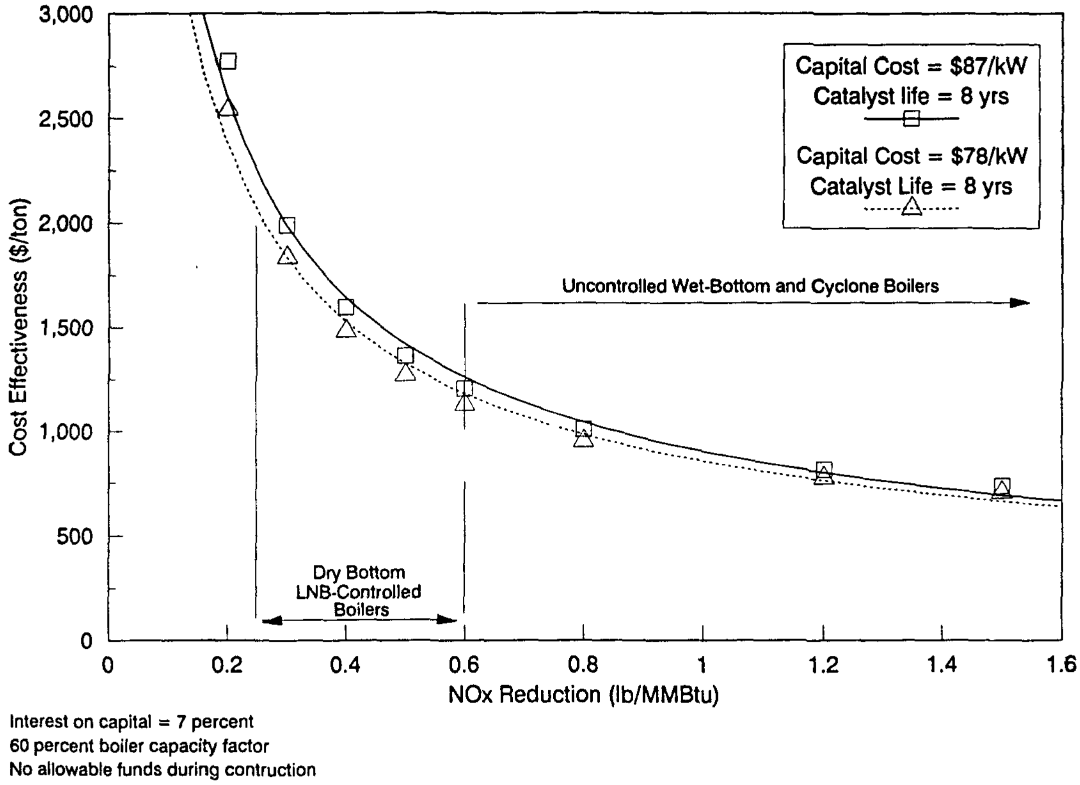


Figure 4-10. Cost effectiveness of full-scale SCR reactors retrofitted on 200 MWe coal-fired boiler

controlled levels and the corresponding SCR cost effectiveness is anticipated to range between \$1,200 and \$2,300/ton. When SCR is applied to uncontrolled cyclone and slagging furnaces, the cost effectiveness is anticipated to range between \$600 and \$1,200/ton with NO_x reductions reaching 0.90 lb/MMBtu as in the case of the planned SCR retrofit at the Merrimack Station.

4.4 COST OF HYBRID CONTROLS

Hybrid controls can be cost effective alternatives to full-scale SCR control systems. For example, the combination of gas reburning and SNCR can achieve NO_x reduction levels that would only be possible with full-scale SCR systems. Also, the combination of SNCR and in-duct and/or air heater catalysts can be designed to achieve NO_x reductions higher than those possible with SNCR alone at lower cost especially for retrofit cases where SCR access is difficult. Estimates of the cost of advanced gas reburn (AGR) were developed by EERC (Evans, et al., 1993). The cost for AGR retrofit on a 500 MWe coal-fired boiler was estimated to be \$35/kW, including 36 percent contingency. The corresponding cost effectiveness was calculated to be about \$250/ton with SO_2

credit of \$300/ton. Estimates developed in this study, put the total capital requirement for gas reburning at \$25 for an average retrofit and for SNCR at \$11 for a 200 MWe boiler. Additionally, \$10/kW was added to account for access to a natural gas pipeline to represent the upper range of the overall retrofit cost. Consequently, the combined cost of these technologies will likely result in a retrofit cost in the range of \$36 to \$46/kW. These costs are somewhat speculative because, as of this writing, there is no commercial or demonstrated experience of AGR on a full-scale utility boiler.

Figure 4-11 illustrates the range in established cost effectiveness of AGR as a function of NO_x reduction. The O&M cost is based on 10 percent natural gas heat input coupled with ammonia reagent rate with an NSR of 1.4. Because the NO_x reduction associated with AGR is in the range of 0.30 to 0.60 lb/MMBtu, the cost effectiveness of this technology is estimated to fall in

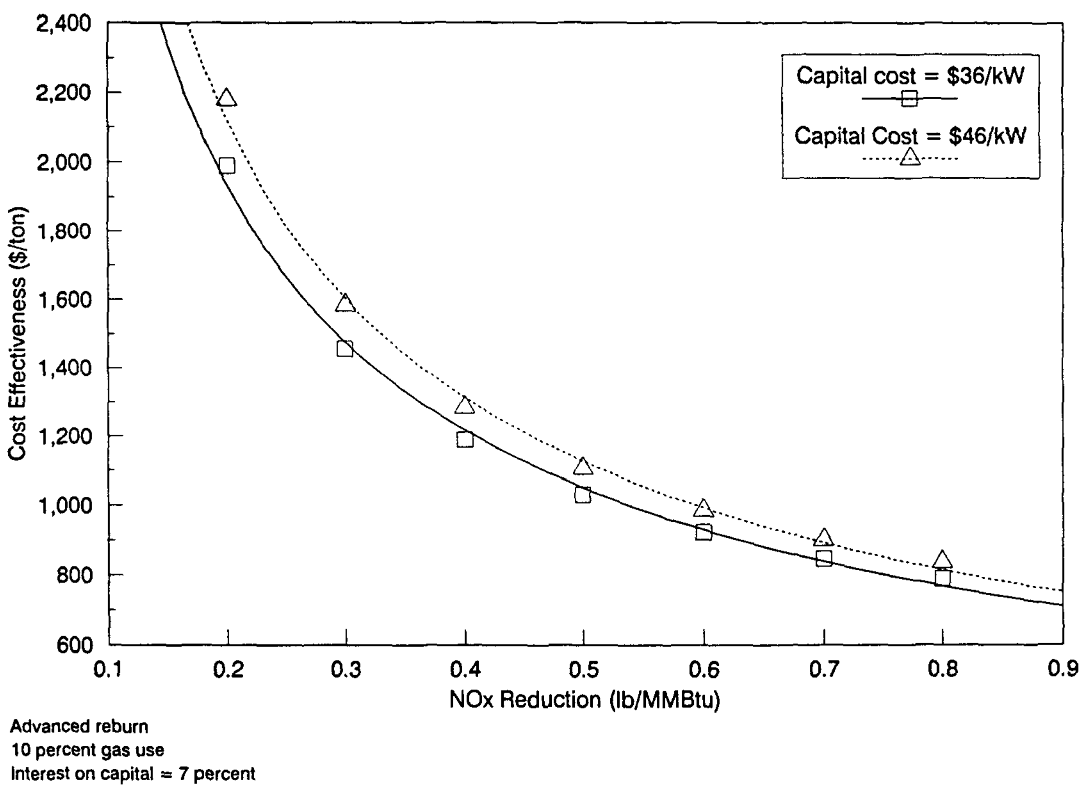


Figure 4-11. Cost effectiveness of AGR (Advanced Gas Reburn) retrofitted in 200 MWe coal-fired boiler

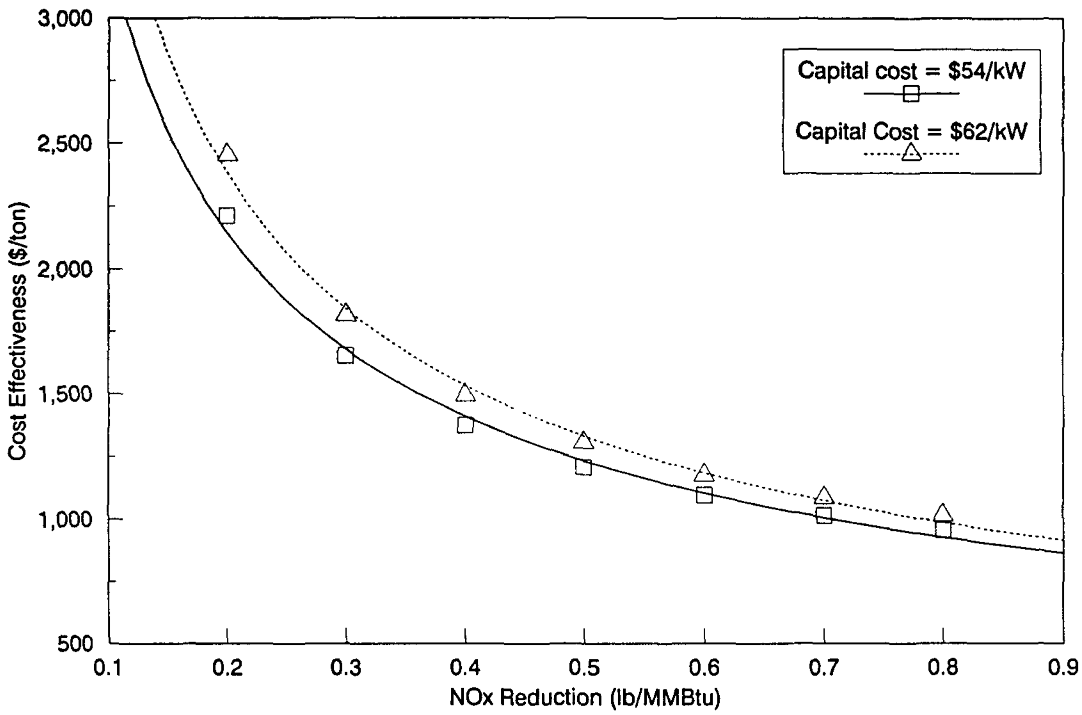
the range of \$900/ton to \$1,600/ton. This cost effectiveness is based on a \$1.50/MMBtu differential fuel price between gas and coal. If the price disadvantage for gas is reduced to \$0.70/MMBtu, for example, the cost effectiveness of AGR improver to the \$800 to \$1,300/ton range for a favorable capital cost of \$36/kW.

Estimates provided by NFT for their proprietary SNCR+SCR combined process (known as NOxOUT CASCADE™) are for a capital investment of \$22/kW with a busbar cost of 1.8 mills/kWh and a corresponding cost effectiveness of \$1,900/ton (NFT, undated). These SNCR+SCR hybrid controls are currently commercially available only for gas-fired installations, although some tests are underway to evaluate its feasibility on coal units. Reported retrofit costs for in-duct SCR alone were reported in the range of \$25 to \$35/kW (Johnson, 1991). When coupled with the cost of SNCR which is in the range of \$11 to \$14/kW, the anticipated capital requirement is in the range of \$36 to \$50/kWe for gas-fired boilers. For coal-fired boilers, the capital cost is likely to be higher because true in-duct SCR systems may not be possible because of excessive face velocities and flyash loading. For coal-fired retrofits, the capital cost was estimated to fall in the range of \$54 to \$62/kW. Higher retrofit costs are possible as indicated by the PSE&G retrofit of \$100/kW for the Mercer 80 MWe equivalent system.

Figure 4-12 illustrates the estimates of the cost effectiveness for SNCR+in-duct SCR hybrid for a 200 MWe coal-fired boiler. The total busbar cost for each of these hybrid controls is estimated to be in the range of about 2.5 to 3.5 mills/kWh. For oil/gas-fired boilers, the combination of SNCR and in-duct SCR will likely result in NO_x reductions in the range of 0.25 to 0.40 lb/MMBtu at a cost of about \$1,200 to \$1,600/ton.

4.5 COST OF SEASONAL CONTROLS

The application of NO_x controls on a seasonal basis will result in cost savings and reduced annual NO_x reductions. Gas-based control technologies such as reburn and gas conversion (i.e., switching fuels to 100 percent gas from either coal or oil), in particular, may attain the greatest economic benefit. Substantial savings in the annual cost of gas-based technologies is likely in some



Catalyst SV = 6000 cft; Catalyst life = 6 years
Catalyst cost = $370/cft
Interest on capital = 7 percent

Figure 4-12. Estimate of SNCR + SCR cost effectiveness for retrofit on a 200 MWe coal-fired boiler

cases because the price of natural gas tends to be lower during the summer, ozone season. Considering that the fuel differential cost is by far the main cost of natural gas-based technologies, it stands to reason that any cost savings in fuel during the ozone months will reflect in reduced annual cost for these technologies and make their application more competitive for post-RACT NO_x reductions.

This section explores the changes in annual cost and cost effectiveness for the various post-RACT control technologies when controls are applied on a seasonal basis rather than year-around. The analysis is based on the premise that:

- Ozone season spans 5 months out of the year
- Boiler capacity factor remains unchanged at 60 percent during the ozone season
- The useful life of SCR catalysts remains unchanged as for year-around applications

- Seasonal cost savings are principally the result of reduced fuel, reagent and energy associated with the operation of the control
- Maintenance and labor costs remain unchanged, especially for capital intensive controls such as SCR and hybrids

Except for gas based controls, the cost effectiveness of seasonal controls is expected to be higher than similar applications operating on a year-around basis. This is because the only savings associated with seasonal control are for the most part operating costs, whereas the total annualized cost includes the annualization of capital. Capital intensive controls, such as SCR for coal plants, for example, may have a dramatic increase in dollars per ton removed when operation is limited to only a few months of the year.

Table 4-8 lists the annual cost and cost effectiveness calculated for post-RACT controls on a 200 MWe coal-fired boiler equipped with RACT controls such as LNB. Because slagging furnaces, including cyclones, are largely uncontrolled, a comparison of annual and seasonal SCR use on these units was also included. The table shows the average NO_x reductions that each control was credited with in the analysis. For gas reburn, four differential prices between natural gas and coal were considered ranging from \$0.25 to \$1.0/MMBtu. Lower price differentials are more likely during the summer months. Conversely, higher gas prices are more likely for year-around applications (un-interruptable supply), especially in the case of fuel switching. Two SCR retrofit scenarios were considered in the analysis. For both cases, SCR capital cost are in the range \$78 to \$87/kWe. The first scenario is for a dry bottom coal-fired unit. The second scenario is for a similar retrofit but on an uncontrolled cyclone or slagging unit resulting in a much higher NO_x reduction of 1.1 lb/MMBtu compared to an average of 0.45 lb/MMBtu for a dry bottom boiler.

The results indicate that, form an annual cost point of view, the least expensive controls are NGR and SNCR. Average difficulty retrofits of SCR and hybrid controls have annualized costs in the range of 3.0 to 4.8 mills/kWh. When viewed on a seasonal basis, the relative ranking of controls remains much the same. Largest savings are for gas conversion because of gas use is reduced the

Table 4-8. Comparison of year-around and seasonal costs for post-RACT NO_x control technologies — 200 MWe coal-fired boiler

Control	Average Amount of NO_x Reducted (lb/MMBtu)	Fuel Differential Cost ($/MMBtu)	Capital Cost ($/kWe)	Year Around		Seasonal	
				mills/kWh	$/ton	mills/kWh	$/ton
NGR	0.25	0.25	20-35	0.55-0.85	440-850	0.40-0.77	320-620
		0.50		0.93-1.2	740-1,200	0.60-0.92	480-740
		0.75		1.3-1.6	1,000-1,300	0.70-1.1	1,000-1,300
		1.00		1.7-2.0	1,300-1,600	0.81-1.3	1,400-1,600
SNCR	0.20	—	11-14	0.77-1.3	850-1,280	0.47-0.66	1,100-1,900
SCR-Avg (dry bottom)	0.45	—	78-87	3.0-3.3	1,300-1,500	3.1-3.7	3,400-4,400
SCR-Avg (wet bottom)	1.10	—	78-87	4.5-4.8	820-850	3.7-4.4	1,700-1,900
Hybrid (SNCR+SCR)	0.45	—	54-62	2.9-3.2	1,300-1,400	2.0-2.3	2,200-2,500

Notes: 60 percent capacity factor.
Seasonal = 5 months/yr.
No increase in life of catalyst due to seasonal use.
No reduction in capital cost of SCR due to seasonal use.
Average NO_x reduction for the range shown in Chapter 3 rounded to the nearest 0.05 lb/MMBtu

most with this strategy. In fact, favorable gas prices that result in low fuel differential cost between coal and gas, would make NGC relatively attractive compared to other controls. As indicated earlier, the dollars per ton of NO_x for seasonal use of these controls is higher than if the controls were used year around. The least increase in cost effectiveness is recorded for SNCR and gas reburn.

Figures 4-13 and 4-14 illustrate cost effectiveness of yearly and seasonal controls plotted against the gas-coal fuel price differential. The two sloped lines represent the best and worst cost effectiveness for NGR based on the amount of NO_x reduced. Gas conversions, not included in the analysis, would be less competitive than NGR on a year around or seasonal basis. The lowest dollar per ton of NO_x removed, when controls are compared on a year-around basis, is for SNCR except for NGR when fuel price differential is at a minimum and NO_x reductions are high. The cost effectiveness of SCR and hybrid controls (SNCR + SCR) overlap and are shown to be in the range

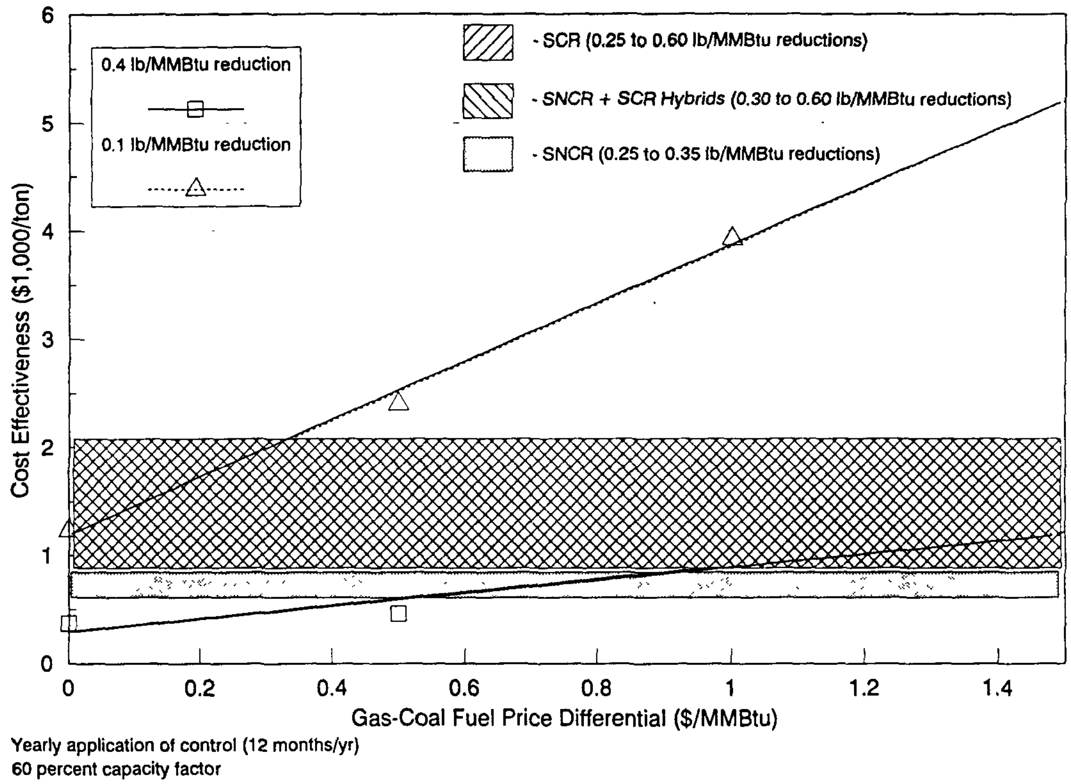


Figure 4-13. Cost effectiveness of controls used all year-around

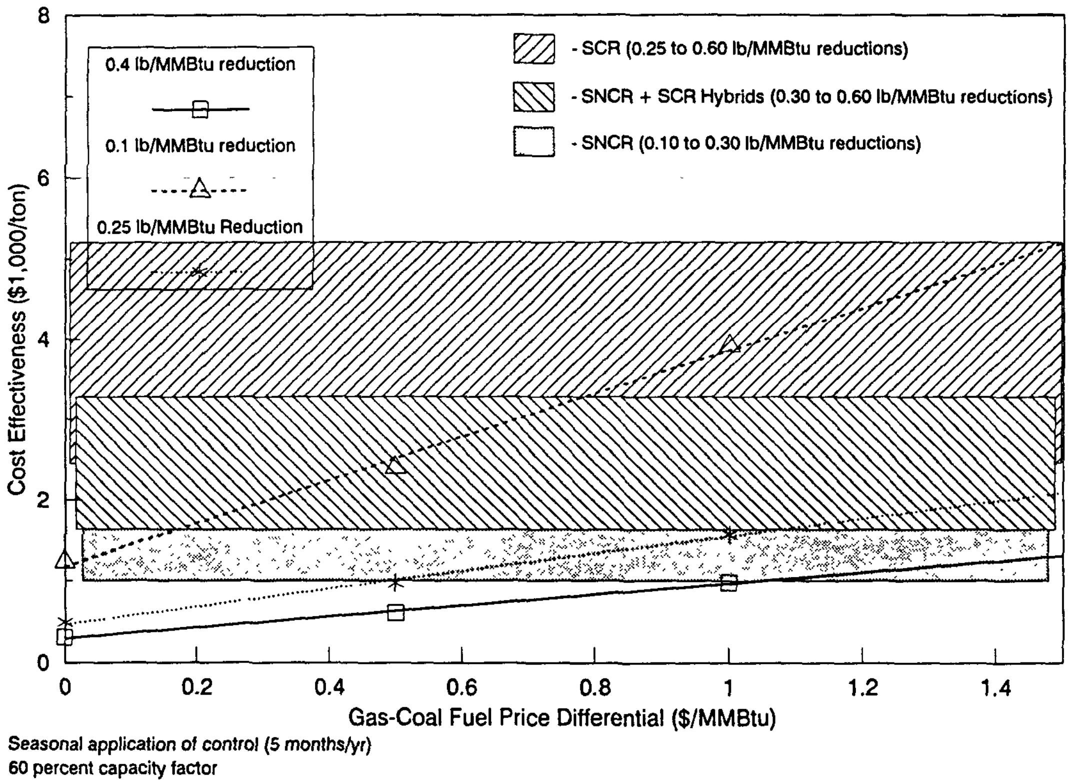


Figure 4-14. Cost effectiveness of controls used on a seasonal basis

of about \$900 to \$2,000/ton. The cost effectiveness band for SNCR is lower, in the range of \$850 to \$1,300/ton. As indicated, in Figure 1-5, NGR can be most competitive when both the NO_x reduction achieved is highest, estimated in this report to be about 0.40 lb/MMBtu, and the fuel price differential is below \$0.5/MMBtu. This level of NO_x reduction is more representative of NGR control performance on uncontrolled coal-fired boilers rather than LNG-controlled units. When NO_x reductions for NGR are minimal, perhaps as low as 0.1 lb/MMBtu from well controlled tangential-fired units, NGR promises to be less cost competitive on a year-around application basis.

The conclusions differ somewhat when controls cost effectiveness are viewed on seasonal use basis. Here, gas-based NGR controls can be less costly or equally competitive with most gas treatment ammonia-based controls up to a fuel price differential of \$0.50/MMBtu and the amount of NO_x reduction achieved is 0.25 lb/MMBtu. If the NO_x resolution is large, e.g., approaching 0.4 lb/MMBtu, NGR on a seasonal basis is the most cost-effective approach as long as fuel-price differentials are lower than about \$1.0/MMBtu. For seasonal use of controls, cost effectiveness generally rises because the capital cost is amortized over fewer kW-hr. For example, the cost effectiveness of SNCR worsens from about \$850 to \$1,300/ton on a yearly basis to about \$1,000 to \$1,900/ton on a seasonal basis depending on the level of NO_x achieved. SCR, with the most intensive capital investment has the largest increase in dollars spent per ton of NO_x reduced when going from a yearly use to a seasonal use. These results assume that the catalyst life does not improve with seasonal use of SCR control, a probability of the catalyst cannot be bypassed or removed from the gas stream.

4.6 SUMMARY

Table 4-9 summarizes the capital and operating costs and cost effectiveness for control options available to utilities to further reduce NO_x from post-RACT NO_x emission levels. These estimates were developed for a nominal 200 MWe capacity boiler, corresponding to the average unit size in the entire NESCAUM and MARAMA Regions. The control list includes NGR and full-scale conversions to gas firing, as well as a variety of ammonia- or urea-based flue gas treatment

Table 4-3. Summary of costs for retrofit of a 200-MWe boiler

Post-RACT Control	Capital Cost ($/kW)	Coal-fired Boilers			Oil-fired Boilers			Gas-fired Boilers		
		Amount of NO_x Reduced (lb/MMBtu)[a]	Busbar (mill/kWh)	Cost Effectiveness ($/ton)	Amount of NO_x Reduced (lb/MMBtu)[a]	Busbar (mills/kWh)	Cost Effectiveness ($/ton)	Amount of NO_x Reduced (lb/MMBtu)[a]	Busbar (mills/kWh)	Cost Effectiveness ($/ton)
NGR	20-30	0.10 - 0.40	0.93 - 2.0	460 - 3,900	0.15 - 0.20	0.33 - 1.2	320 - 1,800	0.15 - 0.20	0.33 - 0.61	320 - 1,200
NGR[b]	25-35	0.10 - 0.40	1.2 - 2.1	610 - 4,200	0.15 - 0.20	0.47 - 1.4	470 - 2,100	NA	NA	NA
NGC	10-20	0.25 - 0.50	8.2 - 8.3	3,300 - 6,600	0.15 - 0.25	2.5 - 2.7	2,000 - 4,100	NA	NA	NA
NGC[b]	20-30	0.25 - 0.50	8.4 - 8.6	3,400 - 6,900	0.15 - 0.25	2.7 - 2.8	2,200 - 4,200	NA	NA	NA
SNCR	11-14	0.30-0.90[c] 0.10-0.30[d]	1.3 - 3.1 0.77 - 1.3	700 - 880[c] 850 - 1,300[d]	0.10 - 0.20	0.77 to 1.0	1,000 - 1,400	0.10 - 0.20	0.77 to 1.0	1,000 - 1,400
SCR (in-duct)	26-32	NA	NA	NA	0.20 - 0.35	1.5 - 1.6	900 - 1,500	0.20 - 0.35	1.5 - 1.6	900 - 1,500
SCR-AH	25	NA	NA	NA	0.05 - 0.20	1.6 - 2.0	2,000 - 3,200	0.05 - 0.20	1.6 - 2.0	2,000 - 6,000
SCR	78-87	0.60 - 1.7[c] 0.25 - 0.60[d]	3.4 - 5.8 2.6 - 3.4	500 - 1,200[c] 1,200 - 2,800[d]	0.25 - 0.40	2.6 - 3.2	1,600 - 2,000	NA	NA	NA
SNCR + SCR	54-62	0.30 - 0.60	2.5 - 3.5	1,100 - 1,800	NA	NA	NA	0.25 - 0.40	1.8 - 2.0	1,400 - 2,200
AGR	36-46	0.30 - 0.60	2.4 - 2.7	900 - 1,600	NA	NA	NA	NA	NA	NA

[a]NO_x reductions in lb/MMBtu from ranges of post-RACT implementation levels on NESCAUM and MARAMA utility boilers. Calculated from LNB-controlled levels for dry bottom coal-fired boilers and combustion-controlled levels from gas/oil-fired boilers (see Chapter 2 for details of post-RACT levels).
[b]Additional capital cost for access to pipeline.
[c]Cost effectiveness and NO_x reductions for uncontrolled cyclone and wet bottom furnaces.
[d]Cost effectiveness and NO_x reductions for LNB-controlled dry bottom furnaces.
[e]Combination of SNCR, in-duct SCR, or CAT-AH.

Notes: For reburn: Coal-gas fuel price differential = $0.5 to 1.0/MMBtu; Oil-gas price differential = $0.0 to 0.50/MMBtu; no price differential for gas-gas reburn.
For conversion: coal-gas fuel price differential = $1.0/MMBtu; oil-gas price differential = $0.50/MMBtu.
NA = Not applicable or not a probable control option.
Boiler capacity factor = 60 percent in all cases.

options using controls alone or in reasonable combinations. The cost effectiveness results are calculated based on the busbar cost (total annualized cost) and listed NO_x reductions from existing LNB-controlled or combustion controlled levels. Cost algorithms and additional detail can be found in Appendix C. For SNCR and SCR controls, estimates were also developed for control of cyclone and wet-bottom boilers, which remain largely uncontrolled. Many site-specific factors will influence the actual retrofit cost. Therefore, it is possible that some sites will show retrofit costs, either capital, operating or cost effectiveness that may fall outside these calculated ranges. Further, because the commercial experience in this country for many of these controls is relatively new, or nonexistent in some cases, there continues to be considerable doubt as to the actual and long-term costs for many applications.

The capital cost of gas-based controls is estimated to range between \$10 and \$35/kW with NO_x reduction levels for post-RACT controlled boilers in the range of 0.10 to 0.50 lb/MMBtu. The low end of the NO_x reduction can be associated with NGR control effectiveness for LNB-controlled coal-fired tangential boilers, whose current NO_x levels are as low as 0.38 lb/MMBtu. The high end of the NO_x reduction range can be attributed to currently uncontrolled coal-fired boilers or LNB-controlled units with a level of 0.75 lb/MMBtu, reported in the data base. The busbar cost of gas-based controls is dominated by the fuel price differential. The cost effectiveness of gas controls is dominated by the fuel price differential and by the amount of NO_x reduced. The calculations used for Table 4-9 are based on \$0.50 to \$1.0/MMBtu fuel price differential between coal and gas, lower for oil-fired units. In some locations, natural gas can be more competitive than assumed here, especially on a seasonal basis. In some areas, the price of gas can be lower than imported oil prices, especially when sulfur emission limits are required. The range in cost effectiveness for NGR is calculated to be \$460 to \$4,200/ton for retrofit on coal-fired units, lower for oil- and gas-fired boilers. The difference between the low and the high cost effectiveness values is primarily the result of fuel price differential and amount of NO_x reduced.

SNCR has an estimated capital cost of $11 to $14/kW for a 200 MWe boiler, the lowest of any of the applicable control options. The range in calculated cost effectiveness for LNB-controlled coal-fired boilers is $820 to $1,100/ton. The cost per ton of NO_x removed improves when applied on uncontrolled cyclones or wet bottom boilers. However, SNCR is limited in NO_x reduction performance to a range of 0.20 to 0.35 lb/MMBtu for LNB-controlled coal-fired boilers, based on the current levels in the NESCAUM and MARAMA inventory. The cost-effectiveness of SNCR is dominated, for the most part, by the cost of the reagent. The amount of NO_x reduced from dry bottom boilers is estimated to improve to levels as high as 0.6 lb/MMBtu for SCR, SNCR+SCR or AGR. SCR and the hybrid combination of SNCR+SCR are the only two control options with commercial experience. AGR, on the contrary, has yet to be demonstrated on full-scale boilers, so the estimates remain speculative. The cost per ton of NO_x removed from dry bottom coal-fired boilers already equipped with LNB, ranges between about $1,000 and nearly $3,000/ton, depending on the level of NO_x removed and the capital cost of the installation. When SCR can be applied to cyclone or wet bottom boilers, which are largely uncontrolled, the cost effectiveness can readily improve to below the $1,000/ton mark, the result of large NO_x reductions from very high uncontrolled levels. The first commercial examples of this cost effective way of reducing NO_x from these types of boilers are given by the Merrimack and Mercer retrofit experiences of full-scale SCR and hybrid systems, respectively.

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APPENDIX A

OTC MEMORANDUM OF UNDERSTANDING

MEMORANDUM OF UNDERSTANDING
AMONG THE STATES OF THE OZONE TRANSPORT COMMISSION
ON DEVELOPMENT OF A REGIONAL STRATEGY CONCERNING THE CONTROL OF STATIONARY SOURCE NITROGEN OXIDE EMISSIONS

WHEREAS, the States of the Ozone Transport Commission (OTC) face a pervasive problem in their efforts to attain the National Ambient Air Quality Standard (NAAQS) for ozone; and

WHEREAS, a 1991 National Academy of Sciences study on ground-level ozone indicates that a combination of reductions in emissions of volatile organic compounds (VOCs) and nitrogen oxides (NOx) will be necessary to bring the entire Ozone Transport Region (OTR) into attainment by the statutory attainment dates; and

WHEREAS, modeling and other studies confirm that NOx emission reductions are effective in reducing ozone formation and help to reduce ozone transport; and

WHEREAS, the States of the OTC are requiring major stationary sources of NOx to implement reasonably available control technology (RACT); and

WHEREAS, by November 15, 1994, the States must submit attainment demonstrations to EPA as State Implementation Plan (SIP) revisions; and

WHEREAS, the implementation of RACT for the control of NOx emissions will not be sufficient to enable all States in the OTR to reach attainment; and

WHEREAS, the undersigned States seek to develop an effective regional program to reduce NOx emissions, which would be implemented in conjunction with other measures to control ozone precursors (including state-specific measures, regional measures and Federal measures required under the Clean Air Act); and

WHEREAS, these measures together may enable EPA to approve the States' SIPs and refrain from imposing sanctions that could restrict economic growth throughout the OTR; and

WHEREAS, information that the States have collected in their emissions inventories shows that large boilers and other large indirect heat exchangers are the source of a substantial portion of the NOx emissions in the States, and will continue to be so after they implement RACT;

WHEREAS, the States intend to complete a reevaluation of stationary source controls for 2003 and beyond in 1997, based on results of EPA-approved models and other relevant technical data;

THEREFORE, the undersigned member States hereby agree to propose regulations and/or legislation for the control of NOx emission from boilers and other indirect heat exchangers with a maximum gross heat input rate of at least 250 million BTU per hour; and

FURTHERMORE, that the States agree to propose regulations that reflect the difference in conditions in (i) the OTR's "Northern Zone" consisting of the northern portion of the OTR; (ii) the OTR's "Inner Zone" consisting of the central eastern portion of the OTR; and (iii) the OTR's "Outer Zone" consisting of the remainder of the OTR; and

FURTHERMORE, that to establish a credible emissions budget, the States agree to propose regulations that require enforceable specific reductions in NOx emissions from the actual 1990 emissions set forth in each State's 1990 inventory submitted to EPA in compliance with § 182(a) (1) of the Clean Air Act or in a similar emissions inventory prepared for each attainment area (provided that for exceptional circumstances that a more representative base year may be applied to individual sources in a manner acceptable to EPA) subject to public notice; and

FURTHERMORE, that the States agree to develop a budget in a manner acceptable to EPA based on the principles above no later than March 1, 1995; and

FURTHERMORE, if such a budget is not developed by March 1, 1995, that the 1990 interim inventory used by EPA in its Regional Oxidant Model simulations for the 1994 OTC Fall Meeting will be used for the budget; and

FURTHERMORE, that the States agree to propose regulations that require subject sources in the Inner Zone to reduce their rate of NOx emissions by 65 percent from base year levels by May 1, 1999, or to emit NOx at a rate no greater than 0.2 pounds per million BTU; and

FURTHERMORE, that the States agree to propose regulations that require subject sources in the Outer Zone to reduce their rate of NOx emissions by 55 percent from base year levels by May 1, 1999, or to emit NOx at a rate no greater than 0.2 pounds per million BTU; and

FURTHERMORE, that the States agree to propose regulations that require sources in the Inner Zone and the Outer Zone to reduce their rate of NOx emissions by 75 percent from base year levels by May 1, 2003, or to emit NOx at a rate no greater than 0.15 pounds per million BTU; and

FURTHERMORE, that the States agree to propose regulations that require subject sources in the Northern Zone to reduce their rate of NOx emissions by 55 percent from base year levels by May 1, 2003, or to emit NOx at a rate no greater than 0.2 pounds per million BTU; and

FURTHERMORE, that the States agree to develop a regionwide trading mechanism in consultation with EPA; and

FURTHERMORE, that in lieu of proposing the regulations described above, a State may propose regulations that achieve an equivalent reduction in stationary source NOx emissions in an equitable manner; and

FURTHERMORE, that the regulations for May 1, 2003 described above may be modified if (i) additional modeling and other scientific analysis shows that the regulations as modified, together with regulations governing VOC emissions, will achieve attainment of the ozone NAAQS across the OTR, and (ii) this Memorandum of Understanding is modified to reflect those modeling results and other analysis no later than December 31, 1998; and

FURTHERMORE, that the States agree to propose regulations that are otherwise consistent with the attached recommendations of the OTC's Stationary/Area Source Committee; and

FURTHERMORE, that the undersigned States agree to request that the EPA Administrator determine whether the SIPs of States outside the OTR contain adequate provisions to prohibit the emission of air pollutants in amounts that will contribute significantly to nonattainment of a National Ambient Air Quality Standard (NAAQS) within the OTR, as required under 42 U.S.C. Section 110(a)(2)(D).

Figure 1

Northeast Ozone Transport Region
Ozone Nonattainment Areas

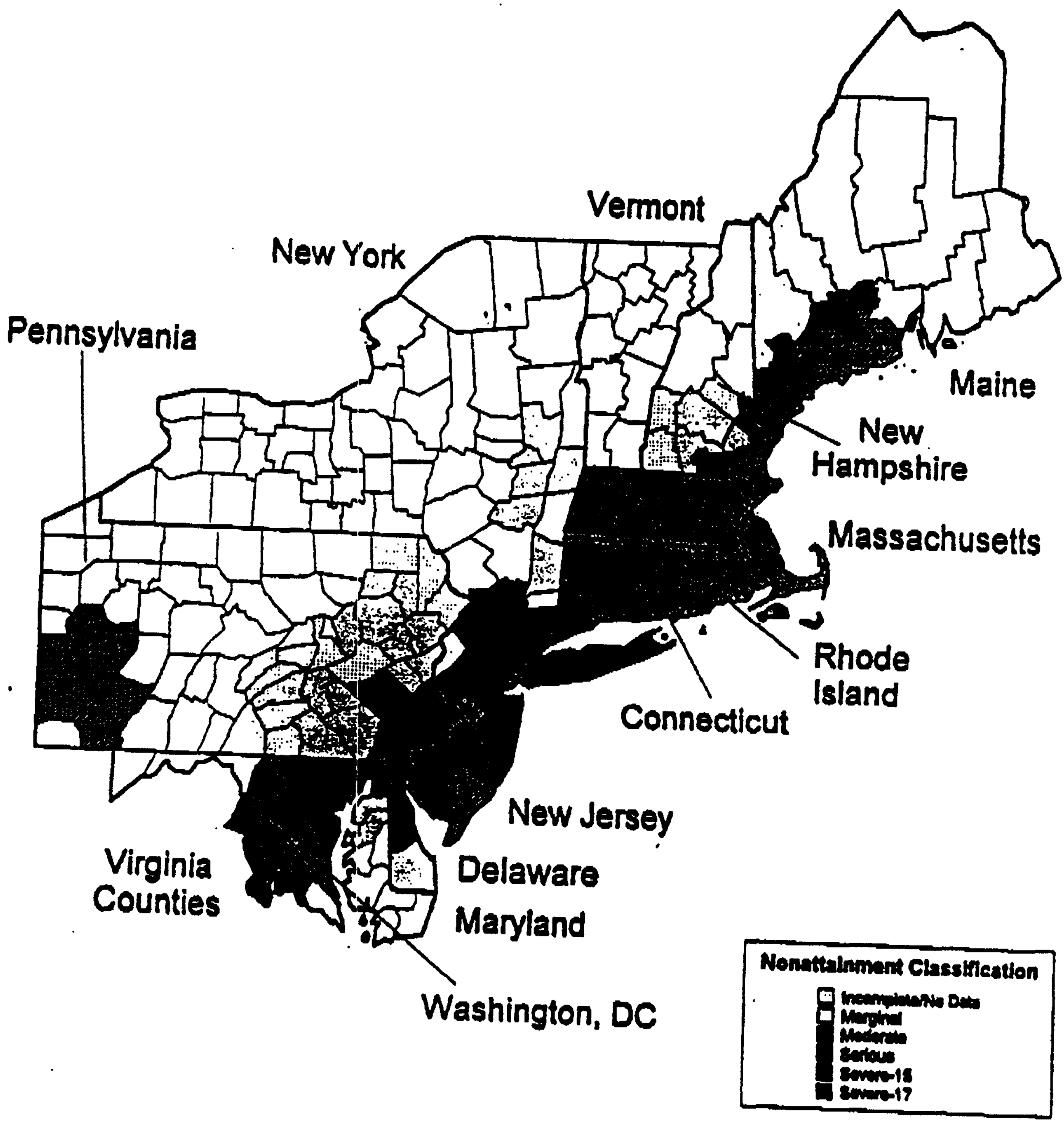
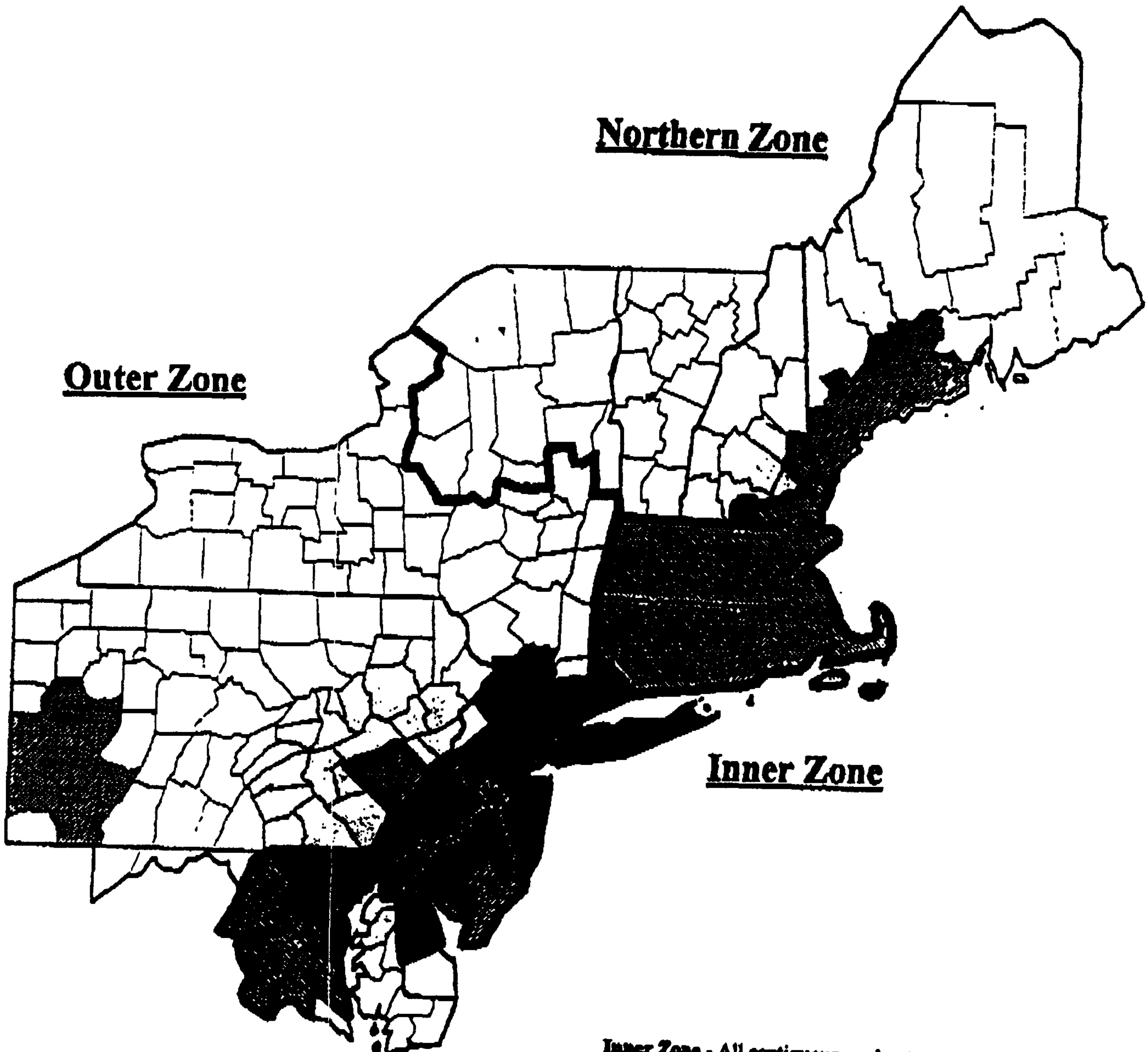


Figure 2

Northeast Ozone Transport Region
Zones for Proposed
Regional NOx Stationary Source Strategy



Inner Zone - All contiguous moderate and above nonattainment areas except those located in Maine #

Outer Zone - Remainder of the OTR except the northern zone

Northern Zone - Maine, Vermont and New Hampshire (except for its moderate and above nonattainment areas), and the northeastern attainment portion of New York

The Inner Zone includes Merrimack County, New Hampshire.

*The inner zone is based on existing attainment designations. If an area is redesignated attainment, it remains in the inner zone. However, if contiguous marginal areas are "bumped up" to moderate status, they become a part of the inner zone.

Signed this 27th day of September, 1994 by the following:

CONNECTICUT: ____________________

DELAWARE: ____________________

DISTRICT OF COLUMBIA: ____________________

MAINE: ____________________

MARYLAND: ____________________

MASSACHUSETTS: ____________________

NEW HAMPSHIRE: ____________________

NEW JERSEY: ____________________

NEW YORK: ____________________

PENNSYLVANIA: ____________________

RHODE ISLAND: ____________________

VERMONT: ____________________

VIRGINIA: ____________________

APPENDIX B

POST-RACT NESCAUM UTILITY BOILER AND NO_x INVENTORY

TABLE A - 1

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr) pres yr for age 1995
CT	UNITED ILLUMINATING CO	BRIDGEPORT HBR	3	385	24	Coal	Dry	Tangential	not reported	0.38	99.4%	6,372		10,000
CT	CONNECTICUT LT & PWR	DEVON	7	104	41	Resid	Dry	Tangential	STAGED COMBUST	0.25	53.8%	650		10,600
CT	CONNECTICUT LT & PWR	DEVON	8	104	37	Resid	Dry	Tangential	STAGED COMBUST	0.25	44.6%	538		10,600
CT	CONNECTICUT LT & PWR	MONTVILLE	5	85	41	Resid	Dry	Tangential	STAGED COMBUST	0.25	6.0%	67		11,900
CT	CONNECTICUT LT & PWR	MONTVILLE	6	415	24	Resid	Dry	Tangential	STAGED COMBUST	0.25	2.2%	118		11,700
CT	CONNECTICUT LT & PWR	NORWALK HARBOR	1	163	35	Resid	Dry	Tangential	GAS RECIRC - OFA	0.25	51.1%	957		10,500
CT	CONNECTICUT LT & PWR	NORWALK HARBOR	2	172	32	Resid	Dry	Tangential	GAS RECIRC - OFA	0.25	58.8%	1,097		9,900
CT	UNITED ILLUMINATING CO	NEW HAVEN HRBR	1	465	20	Resid	Dry	Tangential	GAS RECIRC - OFA	0.25	59.0%	3,005		10,000
CT	UNITED ILLUMINATING CO	ENGLISH	7	35	47	Resid	Dry	Vertical	not reported	0.43	2.5%	22		13,200
CT	UNITED ILLUMINATING CO	ENGLISH	8	37	42	Resid	Dry	Vertical	not reported	0.43	3.6%	31		12,200
CT	CONNECTICUT LT & PWR	DEVON	3	66	44	Resid	Dry	Wall	not reported	0.25	7.9%	65		11,400
CT	CONNECTICUT LT & PWR	DEVON	4	48		Resid	Dry	Wall	not reported	0.25	10.8%	72		12,700
CT	UNITED ILLUMINATING CO	BRIDGEPORT HBR	1	82	38	Resid	Wet	Cyclone	not reported	0.43	51.4%	810		10,200
CT	UNITED ILLUMINATING CO	BRIDGEPORT HBR	2	170	34	Resid	Wet	Cyclone	not reported	0.43	43.5%	1,406		10,100
CT	CONNECTICUT LT & PWR	MIDDLETOWN	1	69	41	Resid	Wet	Wall	not reported	0.25	93.5%	883		12,500
CT	CONNECTICUT LT & PWR	MIDDLETOWN	2	114	37	Resid	Wet	Wall	STAGED COMBUST	0.25	39.2%	558		11,400
CT	CONNECTICUT LT & PWR	MIDDLETOWN	3	239	31	Resid	Wet	Wall	STAGED COMBUST	0.25	86.0%	2,813		12,500
CT	CONNECTICUT LT & PWR	MIDDLETOWN	4	415	22	Resid	Wet	Wall	STAGED COMBUST	0.25	8.3%	473		12,500
MA	MONTAUP ELECTRIC CO	SOMERSET	6	105	36	Coal	Dry	Tangential	SNCR	0.38	68.4%	1,195		10,000
MA	NEW ENGLAND POWER CO	BRAYTON POINT	1	231	32	Coal	Dry	Tangential	LNB - OFA	0.38	91.4%	3,535		10,065
MA	NEW ENGLAND POWER CO	BRAYTON POINT	2	250	31	Coal	Dry	Tangential	not reported	0.38	93.3%	3,611		9,300
MA	NEW ENGLAND POWER CO	BRAYTON POINT	3	606	27	Coal	Dry	Wall	SCR - OFA	0.45	76.0%	9,072		10,000
MA	NEW ENGLAND POWER CO	SALEM HARBOR	1	85	43	Coal	Dry	Wall	SNCR	0.33	92.2%	1,174		10,361
MA	NEW ENGLAND POWER CO	SALEM HARBOR	2	80	43	Coal	Dry	Wall	SNCR	0.33	86.8%	1,079		10,750
MA	NEW ENGLAND POWER CO	SALEM HARBOR	3	153	37	Coal	Dry	Wall	SNCR	0.33	92.2%	1,972		9,667
MA	NORTHEAST UTILITIES	HWP MOUNT TOM	1	147	35	Coal	Dry	Wall	STAGED CONBUST	0.45	97.7%	2,713		9,589
MA	MONTAUP ELECTRIC CO	SOMERSET	5	89	44	Coal	Wet	Tangential	RETIRED	0.38	0.0%	0		10,708
MA	BOSTON EDISON CO	MYSTIC	4	135	38	Oil	Dry	Tangential	not reported	0.25	34.7%	568		11,074
MA	BOSTON EDISON CO	MYSTIC	5	135	36	Oil	Dry	Tangential	not reported	0.25	15.2%	249		11,074
MA	BOSTON EDISON CO	MYSTIC	6	149	34	Oil	Dry	Tangential	not reported	0.25	47.7%	877		11,255
MA	BOSTON EDISON CO	MYSTIC	7	585	20	Oil/Gas	Dry	Tangential	not reported	0.20	57.5%	2,991		10,150
MA	WESTERN MASS ELEC CO	WEST SPRINGFLD	1	46	43	Oil	Dry	Tangential	RETIRED	0.25	0.0%	0		10,280

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TABLE A - 1

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	pres yr for age 1995 Heat Rate (Btu/kW-hr)
MA	WESTERN MASS ELEC CO	WEST SPRINGFLD	2	50	43	Oil	Dry	Tangential	RETIRED	0.25	0.0%	0		12,800
MA	WESTERN MASS ELEC CO	WEST SPRINGFLD	3	107	38	Oil/Gas	Dry	Tangential	STAGED COMBUST	0.24	44.5%	549		11,000
MA	BOSTON EDISON CO	NEW BOSTON	1	380	30	Gas	Dry	Wall	GAS ONLY	0.20	72.7%	2,343		9,682
MA	BOSTON EDISON CO	NEW BOSTON	2	380	28	Gas	Dry	Wall	GAS ONLY	0.20	36.9%	1,189		9,682
MA	CAMBRIDGE ELECT LT CO	BLACKSTONE ST	5	3	30	Oil/Gas	Dry	Wall	not reported	0.28	9.8%	4		10,000
MA	CAMBRIDGE ELECT LT CO	BLACKSTONE ST	6	3	28	Oil/Gas	Dry	Wall	not reported	0.28	7.6%	3		10,000
MA	CAMBRIDGE ELECT LT CO	BLACKSTONE ST	11	6	34	Oil/Gas	Dry	Wall	not reported	0.28	15.2%	11		10,000
MA	CAMBRIDGE ELECT LT CO	BLACKSTONE ST	12	6	20	Oil/Gas	Dry	Wall	not reported	0.28	16.3%	11		10,000
MA	CAMBRIDGE ELECT LT CO	KENDALL SQUARE	1	18	13	Oil/Gas	Dry	Wall	not reported	0.28	22.8%	76		15,167
MA	CAMBRIDGE ELECT LT CO	KENDALL SQUARE	2	19	13	Oil/Gas	Dry	Wall	not reported	0.28	27.1%	63		10,000
MA	CAMBRIDGE ELECT LT CO	KENDALL SQUARE	3	26	38	Oil/Gas	Dry	Wall	not reported	0.28	54.4%	273		15,731
MA	COMMONWEALTH ELECTRIC	CANAL	1	569	27	Oil	Dry	Wall	not reported	0.28	76.0%	4,564		8,612
MA	COMMONWEALTH ELECTRIC	CANAL	2	581	20	Oil	Dry	Wall	OFA	0.28	74.9%	4,499		8,434
MA	COMMONWEALTH ELECTRIC	CANNON STREET	1	25	48	Oil/Gas	Dry	Wall	RETIRED	0.25	0.0%	0		10,000
MA	COMMONWEALTH ELECTRIC	CANNON STREET	2	25	45	Oil/Gas	Dry	Wall	RETIRED	0.25	0.0%	0		10,000
MA	COMMONWEALTH ELECTRIC	CANNON STREET	3	34	13	Oil/Gas	Dry	Wall	RETIRED	0.25	0.0%	0		10,000
MA	NEW ENGLAND POWER CO	BRAYTON POINT	4	432	21	Oil/Gas	Dry	Wall	GAS RECRC/OS FIR	0.23	48.8%	2,263		10,700
MA	NEW ENGLAND POWER CO	SALEM HARBOR	4	446	23	Oil	Dry	Wall	LNB	0.28	47.7%	2,810		10,762
MA	TAUNTON MUNI LIGHT	CLEARY FLOOD	8	25	20	Oil	Dry	Wall	not reported	0.28	6.5%	27		13,600
MA	TAUNTON MUNI LIGHT	CLEARY FLOOD	9	87	15	Oil/Gas	Dry	Wall	not reported	0.28	15.2%	192		11,851
ME	CENTRAL MAINE POWER CO	WILLIAM F WYMAN	3	114	30	Oil	Dry	Tangential	COMBUSTION EVAL	0.40	38.0%	759		10,000
ME	BANGOR HYDRO-ELECTRIC	GRAHAM STATION	4	18	38	Oil	Dry	Wall	COLD RESERVE	0.70	0.0%	0	em?	10,000
ME	BANGOR HYDRO-ELECTRIC	GRAHAM STATION	5	27	31	Oil	Dry	Wall	COLD RESERVE	0.70	0.0%	0	em?	10,000
ME	CENTRAL MAINE POWER CO	WILLIAM F WYMAN	1	50	38	Oil	Dry	Wall	LNB	0.40	8.5%	74		10,000
ME	CENTRAL MAINE POWER CO	WILLIAM F WYMAN	2	50	37	Oil	Dry	Wall	not reported	0.40	10.7%	94		10,000
ME	CENTRAL MAINE POWER CO	WILLIAM F WYMAN	4	632	17	Oil	Dry	Wall	not reported	0.30	3.9%	324		10,000
NH	PUBLIC SERVICE OF NH	SCHILLER	4	50	43	Coal	Dry	Wall	LNB + CONTROLS	0.50	47.4%	519		10,000
NH	PUBLIC SERVICE OF NH	SCHILLER	5	50	40	Coal	Dry	Wall	LNB + CONTROLS	0.50	43.0%	471		10,000
NH	PUBLIC SERVICE OF NH	SCHILLER	6	50	38	Coal	Dry	Wall	LNB + CONTROLS	0.50	64.4%	705		10,000
														10,000
NH	PUBLIC SERVICE OF NH	MERRIMACK	1	120	35	Coal	Wet	Cyclone	SNCR	0.92	70.2%	3,396		10,000
NH	PUBLIC SERVICE OF NH	MERRIMACK	2	338	27	Coal	Wet	Cyclone	SCR	1.40	70.8%	14,677		10,000
NH	PUBLIC SERVICE OF NH	NEWINGTON	1	425	23	Oil	Dry	Tangential	GAS COFIRE	0.25	38.8%	1,966		10,900
NH	PUBLIC SERVICE OF NH	SCHILLER	3	25	46	Oil/Gas	Dry	Wall	RETIRED	0.43	0.0%	0		12,000

10/17/94

TABLE A - 1

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
NJ	ATLANTIC CITY ELECTRIC	DEEPWATER	8	80	41	Coal	Dry	Wall	LNB	0.45	51.8%	817		10,000
NJ	PUBLIC SERVICE EL&GAS	HUDSON	2	660	24	Coal	Dry	Wall	not reported	0.50	50.0%	7,227	*	10,000
														10,000
NJ	ATLANTIC CITY ELECTRIC	B L ENGLAND	1	136	33	Coal	Wet	Cyclone	SNCR	0.90	63.4%	3,399		10,000
NJ	ATLANTIC CITY ELECTRIC	B L ENGLAND	2	163	31	Coal	Wet	Cyclone	SNCR	1.30	50.9%	4,724		10,000
														10,000
NJ	PUBLIC SERVICE EL&GAS	MERCER	1	326	32	Coal	Wet	Wall	not reported	0.50	48.9%	3,491	*	10,000
NJ	PUBLIC SERVICE EL&GAS	MERCER	2	326	31	Coal	Wet	Wall	SNCR+SCR	0.50	39.9%	2,849	*	10,000
														10,000
NJ	ATLANTIC CITY ELECTRIC	B L ENGLAND	3	160	21	Oil	Dry	Tangential	SNCR	0.22	14.1%	222		10,000
NJ	JERSEY CENTRAL P & L	GILBERT	3	72	46	Nat Gas	Dry	Tangential	NAT GAS ONLY	0.50	21.5%	415		12,252
NJ	PUBLIC SERVICE EL&GAS	KEARNY	7	157	42	Oil	Dry	Tangential	not reported	0.23	3.5%	85	*	15,234
NJ	PUBLIC SERVICE EL&GAS	KEARNY	8	157	42	Oil/Gas	Dry	Tangential	not reported	0.23	7.5%	160	*	13,511
NJ	PUBLIC SERVICE EL&GAS	SEWAREN	1	111	47	Oil/Gas	Dry	Tangential	not reported	0.19	5.5%	77	*	15,279
NJ	PUBLIC SERVICE EL&GAS	SEWAREN	2	108	47	Oil/Gas	Dry	Tangential	not reported	0.19	19.9%	235	*	13,134
NJ	PUBLIC SERVICE EL&GAS	SEWAREN	3	116	46	Oil/Gas	Dry	Tangential	not reported	0.19	12.0%	163	*	14,091
NJ	PUBLIC SERVICE EL&GAS	SEWAREN	4	127	44	Oil/Gas	Dry	Tangential	not reported	0.19	24.0%	311	*	12,280
NJ	ATLANTIC CITY ELECTRIC	DEEPWATER	7	26	50	Resid	Dry	Vertical	RETIRED	0.42	0.0%	0		10,000
NJ	JERSEY CENTRAL P & L	SAYREVILLE	4	29	46	Oil/Gas	Dry	Vertical	RETIRED	0.22	0.0%	0		10,000
														10,000
NJ	ATLANTIC CITY ELECTRIC	DEEPWATER	9	26	35	Resid	Dry	Wall	RETIRED	0.42	0.0%	0		10,000
NJ	JERSEY CENTRAL P & L	GILBERT	1	45	65	Nat Gas	Dry	Wall	NATGAS ONLY	0.35	3.5%	36		14,771
NJ	JERSEY CENTRAL P & L	GILBERT	2	45	65	Nat Gas	Dry	Wall	NATGAS ONLY	0.35	4.2%	43		14,771
NJ	JERSEY CENTRAL P & L	SAYREVILLE	2	18	65	Oil/Gas	Dry	Wall	RETIRE		0.0%	0		12,252
NJ	JERSEY CENTRAL P & L	SAYREVILLE	3	18	65	Oil/Gas	Dry	Wall	RETIRE		0.0%	0		15,334
NJ	JERSEY CENTRAL P & L	SAYREVILLE	5	25	40	Oil/Gas	Dry	Wall	RETIRE		0.0%	0		15,334
NJ	JERSEY CENTRAL P & L	SAYREVILLE	6	25	40	Oil/Gas	Dry	Wall	RETIRE		0.0%	0		15,334
NJ	PUBLIC SERVICE EL&GAS	BERGEN	1	325	36	Oil/Gas	Dry	Wall	GTURB + HRSG	0.47	44.2%	3,129	*	10,580
NJ	PUBLIC SERVICE EL&GAS	BERGEN	2	325	35	Oil/Gas	Dry	Wall	GTURB + HRSG	0.47	34.5%	2,487	*	10,776
NJ	PUBLIC SERVICE EL&GAS	BURLINGTON	7	205	40	Oil	Dry	Wall	GTURB + HRSG	0.47	10.0%	516	*	12,228
NJ	PUBLIC SERVICE EL&GAS	LINDEN	2	260	38	Oil	Dry	Wall	not reported	0.44	11.8%	707	*	12,019
NJ	PUBLIC SERVICE EL&GAS	LINDEN	4	93	23	Oil	Dry	Wall	not reported	0.44	15.0%	302	*	11,240
NJ	PUBLIC SERVICE EL&GAS	LINDEN	11	87	38	Oil	Dry	Wall	not reported	0.44	22.0%	415	*	11,240
NJ	PUBLIC SERVICE EL&GAS	LINDEN	12	87	38	Oil	Dry	Wall	not reported	0.44	12.0%	226	*	11,240
NJ	PUBLIC SERVICE EL&GAS	LINDEN	13	87		Oil	Dry	Wall	not reported	0.44	27.0%	509	*	11,240
NJ	VINELAND CITY OF	HOWARD DOWN	1	25	22	Resid	Dry	Wall	RETIRE	0.50	0.0%	0		10,000
NJ	VINELAND CITY OF	HOWARD DOWN	7	8	43	Oil	Dry	Wall	LNB	0.28	6.4%	9		14,500
NJ	VINELAND CITY OF	HOWARD DOWN	8	11	41	Oil	Dry	Wall	LNB	0.28	12.9%	23		13,500
NJ	VINELAND CITY OF	HOWARD DOWN	9	17	35	Oil	Dry	Wall	LNB	0.28	10.4%	30		13,900
NJ	VINELAND CITY OF	HOWARD DOWN	10	25	26	Oil	Dry	Wall	LNB	0.45	19.6%	111		11,500

TABLE A - 1

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
NJ	VINELAND CITY OF	OLD PLANT	-	7	50	Oil	Dry	Wall	LNB	0.42	1.4%	3		16,000
NJ	ATLANTIC CITY ELECTRIC	DEEPWATER	1	86	37	Oil/Gas	Wet	Cyclone	TUNING	0.43	10.0%	162		10,000
NJ	JERSEY CENTRAL P & L	SAYREVILLE	7	108	40	Oil	Wet	Cyclone	OIL/ EM AVG	0.35	0.14	230		10,000
NJ	JERSEY CENTRAL P & L	SAYREVILLE	8	112	37	Oil	Wet	Cyclone	OIL/ EM AVG	0.35	0.13	231		10,000
NJ	JERSEY CENTRAL P & L	WERNER	4	58	42	Oil	Wet	Cyclone	OIL/ EM AVG	0.50	0.11	145		10,000
NJ	PUBLIC SERVICE EL&GAS	HUDSON	1	455	31	Oil/Gas	Wet	Cyclone	not reported	0.68	21.3%	3,395	*	11,713
NY	NY STATE ELEC & GAS	HICKLING	1	37	46	Coal	Dry	Stoker	NONE	0.40	50.0%	521		16,079
NY	NY STATE ELEC & GAS	HICKLING	2	50	42	Coal	Dry	Stoker	NONE	0.40	49.0%	637		14,851
NY	NY STATE ELEC & GAS	JENNISON	1	33	49	Coal	Dry	Stoker	NONE	0.40	34.0%	325		16,552
NY	NY STATE ELEC & GAS	JENNISON	2	38	44	Coal	Dry	Stoker	NONE	0.40	31.0%	335		16,252
NY	CENTRAL HUDSON GAS&EL	DANSKAMMER	3	134	37	Coal	Dry	Tangential	SOFA	0.42	45.8%	1,075		9,522
NY	CENTRAL HUDSON GAS&EL	DANSKAMMER	4	235	29	Coal	Dry	Tangential	SOFA	0.42	42.7%	1,823		9,878
NY	NIAGARA MOHAWK POWER	C R HUNTLEY	67	185	37	Coal	Dry	Tangential	CONTROLS & AVG	0.42	64.0%	2,111		9,693
NY	NIAGARA MOHAWK POWER	C R HUNTLEY	68	190	36	Coal	Dry	Tangential	CONTROLS & AVG	0.42	76.0%	2,649		9,973
NY	NIAGARA MOHAWK POWER	DUNKIRK	1	90	44	Coal	Dry	Tangential	CONTROLS & AVG	0.42	77.0%	1,316		10,325
NY	NIAGARA MOHAWK POWER	DUNKIRK	2	90	44	Coal	Dry	Tangential	CONTROLS & AVG	0.42	78.0%	1,349		10,447
NY	NIAGARA MOHAWK POWER	DUNKIRK	3	195	35	Coal	Dry	Tangential	CONTROLS & AVG	0.42	81.0%	2,831		9,742
NY	NIAGARA MOHAWK POWER	DUNKIRK	4	195	34	Coal	Dry	Tangential	CONTROLS & AVG	0.42	82.0%	2,858		9,717
NY	NY STATE ELEC & GAS	GOUDEY	8	85	44	Coal	Dry	Tangential	BOOS, DERATE	0.42	78.0%	1,235		10,127
NY	NY STATE ELEC & GAS	GREENIDGE	4	108	41	Coal	Dry	Tangential	BOOS, DERATE	0.42	70.0%	1,385		9,957
NY	NY STATE ELEC & GAS	MILLIKEN	1	157	39	Coal	Dry	Tangential	LNB, SNCR DEMO	0.42	86.0%	2,314		9,318
NY	NY STATE ELEC & GAS	MILLIKEN	2	161	36	Coal	Dry	Tangential	LNB	0.42	82.0%	2,300		9,470
NY	ROCHESTER GAS & ELEC	RUSSELL	1	47	46	Coal	Dry	Tangential	MOTHBALL	0.42	0.0%	0		11,749
NY	ROCHESTER GAS & ELEC	RUSSELL	2	65	44	Coal	Dry	Tangential	SEASONAL BOOS	0.42	62.0%	774		10,446
NY	ROCHESTER GAS & ELEC	RUSSELL	3	65	41	Coal	Dry	Tangential	LNB & OFA	0.42	63.0%	785		10,421
NY	ROCHESTER GAS & ELEC	RUSSELL	4	80	37	Coal	Dry	Tangential	LNB & OFA	0.42	70.0%	1,021		9,914
NY	JAMESTOWN CITY OF	S A CARLSON	6	50	24	Coal	Dry	Wall	not reported	0.45	68.9%	679	*	10,000
NY	NY STATE ELEC & GAS	GOUDEY	7	45	43	Coal	Dry	Wall	MOTHBALL	0.45	0.0%	0		12,868
NY	NY STATE ELEC & GAS	GREENIDGE	3	55	44	Coal	Dry	Wall	MOTHBALL	0.45	0.0%	0		12,732
NY	NY STATE ELEC & GAS	KINTIGH	1	691	10	Coal	Dry	Wall	CONTROLS	0.45	86.0%	10,802		9,222
NY	ORANGE & ROCKLAND UTIL	LOVETT	4	181	28	Coal	Dry	Wall	LNB, OFA	0.45	56.0%	2,169		10,858
NY	ORANGE & ROCKLAND UTIL	LOVETT	5	200	25	Coal	Dry	Wall	LNB, OFA	0.45	66.0%	2,757		10,598
NY	ROCHESTER GAS & ELEC	BEEBEE	12	80	35	Coal	Dry	Wall	SEASONAL BOOS	0.45	72.0%	1,128		9,940
NY	NIAGARA MOHAWK POWER	C R HUNTLEY	63	85	52	Coal	Wet	Vertical	CONTROLS & AVG	1.00	75.0%	3,351		12,002
NY	NIAGARA MOHAWK POWER	C R HUNTLEY	64	85	46	Coal	Wet	Vertical	CONTROLS & AVG	1.00	73.0%	3,127		11,506
NY	NIAGARA MOHAWK POWER	C R HUNTLEY	65	85	41	Coal	Wet	Vertical	CONTROLS & AVG	1.00	75.0%	3,071		10,999
NY	NIAGARA MOHAWK POWER	C R HUNTLEY	66	85	40	Coal	Wet	Vertical	CONTROLS & AVG	1.00	73.0%	2,865		10,542

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UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr) pres yr for age 1995
NY	CENTRAL HUDSON GAS&EL	DANSKAMMER	1	60	44	Oil/Gas	Dry	Tangential	OP ADJ & AVG	0.25	1.2%	10		12,195
NY	CENTRAL HUDSON GAS&EL	DANSKAMMER	2	60	41	Oil/Gas	Dry	Tangential	OP ADJ & AVG	0.25	4.8%	36		11,413
NY	CENTRAL HUDSON GAS&EL	ROSETON	1	600	21	Oil	Dry	Tangential	BOOS, FGR, AVG	0.25	16.4%	1,265		11,743
NY	CENTRAL HUDSON GAS&EL	ROSETON	2	540	21	Oil	Dry	Tangential	BOOS, FGR, AVG	0.25	16.4%	1,027		10,594
NY	CONSOLIDATED EDISON NY	59TH STREET	115	73	28	Oil	Dry	Tangential	BOOS	0.25	21.0%	209		12,470
NY	CONSOLIDATED EDISON NY	74TH STREET	120	46	36	Oil	Dry	Tangential	BOOS	0.25	7.0%	36		10,260
NY	CONSOLIDATED EDISON NY	74TH STREET	121	46	39	Oil	Dry	Tangential	BOOS	0.25	6.0%	31		10,260
NY	CONSOLIDATED EDISON NY	74TH STREET	122	46	33	Oil	Dry	Tangential	BOOS	0.25	24.0%	124		10,260
NY	CONSOLIDATED EDISON NY	ARTHUR KILL	30	501	26	Oil/Gas	Dry	Tangential	BOOS	0.25	20.0%	1,148		10,465
NY	CONSOLIDATED EDISON NY	ASTORIA	40	375	34	Oil/Gas	Dry	Tangential	BOOS	0.25	28.0%	1,270		11,046
NY	CONSOLIDATED EDISON NY	ASTORIA	50	375	33	Oil/Gas	Dry	Tangential	BOOS	0.25	25.0%	1,136		11,067
NY	CONSOLIDATED EDISON NY	RAVENSWOOD	10	390	32	Oil/Gas	Dry	Tangential	BOOS	0.25	28.0%	1,249		10,443
NY	CONSOLIDATED EDISON NY	RAVENSWOOD	20	390	32	Oil/Gas	Dry	Tangential	BOOS, LNB	0.25	39.0%	1,769		10,624
NY	CONSOLIDATED EDISON NY	RAVENSWOOD	30	972	30	Oil/Gas	Dry	Tangential	BOOS, LNB	0.25	37.0%	4,029		10,232
NY	CONSOLIDATED EDISON NY	WATERSIDE	41	48	47	Oil/Gas	Dry	Tangential	RETIRED	0.25	0.0%	0		10,000
NY	CONSOLIDATED EDISON NY	WATERSIDE	42	48	46	Oil/Gas	Dry	Tangential	RETIRED	0.25	0.0%	0		10,000
NY	CONSOLIDATED EDISON NY	WATERSIDE	51	42	57	Oil/Gas	Dry	Tangential	BOOS	0.25	25.0%	115		10,000
NY	CONSOLIDATED EDISON NY	WATERSIDE	52	42	57	Oil/Gas	Dry	Tangential	BOOS	0.25	25.0%	115		10,000
NY	CONSOLIDATED EDISON NY	WATERSIDE	61	36	54	Oil/Gas	Dry	Tangential	TURB REPWR	0.25	30.0%	118		10,000
NY	CONSOLIDATED EDISON NY	WATERSIDE	62	36	54	Oil/Gas	Dry	Tangential	TURB REPWR	0.25	33.0%	130		10,000
NY	CONSOLIDATED EDISON NY	WATERSIDE	80	113	46	Oil/Gas	Dry	Tangential	BOOS	0.25	13.0%	165		10,230
NY	CONSOLIDATED EDISON NY	WATERSIDE	90	106	46	Oil/Gas	Dry	Tangential	BOOS	0.25	47.0%	549		10,070
NY	LONG ISLAND LIGHTING	E F BARRETT	1	185	39	Oil/Gas	Dry	Tangential	ALREADY COMPL	0.25	67.0%	1,397		10,291
NY	LONG ISLAND LIGHTING	E F BARRETT	2	185	32	Oil/Gas	Dry	Tangential	NG REBURN, CCOFA	0.25	70.0%	1,496		10,552
NY	LONG ISLAND LIGHTING	FAR ROCKAWAY	4	100	42	Oil/Gas	Dry	Tangential	ALREADY COMPL	0.25	45.0%	548		11,112
NY	LONG ISLAND LIGHTING	GLENWOOD	4	118	43	Oil/Gas	Dry	Tangential	ALREADY COMPL	0.25	33.0%	523		12,259
NY	LONG ISLAND LIGHTING	GLENWOOD	5	118	41	Oil/Gas	Dry	Tangential	ALREADY COMPL	0.25	27.0%	409		11,724
NY	LONG ISLAND LIGHTING	NORTHPORT	1	375	28	Oil	Dry	Tangential	CCOFA	0.25	44.0%	1,875		10,378
NY	LONG ISLAND LIGHTING	NORTHPORT	2	375	27	Oil	Dry	Tangential	CCOFA, ADD GAS	0.25	45.0%	1,933		10,461
NY	LONG ISLAND LIGHTING	NORTHPORT	3	375	23	Oil	Dry	Tangential	CCOFA	0.25	56.0%	2,335		10,154
NY	LONG ISLAND LIGHTING	NORTHPORT	4	375	18	Oil	Dry	Tangential	CCOFA	0.25	38.0%	1,620		10,380
NY	LONG ISLAND LIGHTING	PORT JEFFERSON	1	45	47	Oil	Dry	Tangential	ALREADY COMPL	0.25	4.0%	28		14,297
NY	LONG ISLAND LIGHTING	PORT JEFFERSON	2	45	45	Oil	Dry	Tangential	ALREADY COMPL	0.25	4.0%	28		14,297
NY	LONG ISLAND LIGHTING	PORT JEFFERSON	3	185	37	Oil	Dry	Tangential	CCOFA	0.25	45.0%	957		10,501
NY	LONG ISLAND LIGHTING	PORT JEFFERSON	4	185	35	Oil	Dry	Tangential	CCOFA	0.25	55.0%	1,152		10,341
NY	NIAGARA MOHAWK POWER	ALBANY	1	100	43	Oil/Gas	Dry	Tangential	CONTROLS & AVG	0.25	56.0%	652		10,635
NY	NIAGARA MOHAWK POWER	ALBANY	2	100	43	Oil/Gas	Dry	Tangential	CONTROLS & AVG	0.25	62.0%	736		10,834
NY	NIAGARA MOHAWK POWER	ALBANY	3	100	42	Oil/Gas	Dry	Tangential	CONTROLS & AVG	0.25	54.0%	663		11,220
NY	NIAGARA MOHAWK POWER	ALBANY	4	100	41	Oil/Gas	Dry	Tangential	CONTROLS & AVG	0.25	63.0%	746		10,814
NY	ORANGE & ROCKLAND UTIL	BOWLINE POINT	1	600	22	Oil/Gas	Dry	Tangential	BOOS	0.25	32.0%	2,177		10,357
NY	ORANGE & ROCKLAND UTIL	LOVETT	3	69	40	Oil/Gas	Dry	Tangential	NO PLAN	0.25	19.0%	186		12,935
NY	NIAGARA MOHAWK POWER	OSWEGO	3	80	47	Nat Gas	Dry	Vertical	CONTROLS & AVG	0.20	18.0%	167		13,206

TABLE A - 1

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
NY	NIAGARA MOHAWK POWER	OSWEGO	4	90	44	Oil	Dry	Vertical	CONTROLS & AVG	0.25	18.0%	214		12,056
NY	CONSOLIDATED EDISON NY	59TH STREET	110	72	43	Oil	Dry	Wall	RETIRED	0.25	0.0%	0		9,650
NY	CONSOLIDATED EDISON NY	59TH STREET	111	50	45	Oil	Dry	Wall	RETIRED	0.25	0.0%	0		9,650
NY	CONSOLIDATED EDISON NY	59TH STREET	112	38		Oil	Dry	Wall	RETIRED	0.25	0.0%	0		10,779
NY	CONSOLIDATED EDISON NY	59TH STREET	113	47		Oil	Dry	Wall	RETIRED	0.25	0.0%	0		9,650
NY	CONSOLIDATED EDISON NY	59TH STREET	114	73	34	Oil	Dry	Wall	BOOS	0.25	24.0%	239		12,470
NY	CONSOLIDATED EDISON NY	ARTHUR KILL	20	350	36	Oil/Gas	Dry	Wall	BOOS	0.25	22.0%	1,047		12,418
NY	CONSOLIDATED EDISON NY	ASTORIA	10	175	42	Oil/Gas	Dry	Wall	RETIRED	0.25	0.0%	0		11,232
NY	CONSOLIDATED EDISON NY	ASTORIA	20	173	41	Oil/Gas	Dry	Wall	RETIRED	0.25	0.0%	0		10,711
NY	CONSOLIDATED EDISON NY	ASTORIA	30	361	37	Oil/Gas	Dry	Wall	BOOS, LNB, FGR	0.25	17.0%	761		11,322
NY	CONSOLIDATED EDISON NY	EAST RIVER	50	130	44	Oil/Gas	Dry	Wall	BOOS	0.25	29.0%	531		12,862
NY	CONSOLIDATED EDISON NY	EAST RIVER	60	130	44	Oil/Gas	Dry	Wall	BOOS	0.25	30.0%	564		13,203
NY	CONSOLIDATED EDISON NY	EAST RIVER	70	175	40	Oil/Gas	Dry	Wall	BOOS	0.25	32.0%	695		11,330
NY	CONSOLIDATED EDISON NY	HUDSON AVENUE	100	152	44	Oil	Dry	Wall	BOOS	0.25	23.0%	297		7,764
NY	NIAGARA MOHAWK POWER	OSWEGO	5	850	20	Oil/Gas	Dry	Wall	CONTROLS & AVG	0.25	28.0%	2,715		10,418
NY	NIAGARA MOHAWK POWER	OSWEGO	6	850	15	Oil/Gas	Dry	Wall	CONTROLS & AVG	0.25	13.0%	1,440		11,902
NY	ORANGE & ROCKLAND UTIL	BOWLINE POINT	2	600	22	Oil/Gas	Dry	Wall	BOOS, OFA, FGR	0.25	48.0%	3,327		10,550
NY	ORANGE & ROCKLAND UTIL	LOVETT	1	20	45	Oil	Dry	Wall	NO PLAN	0.25	0.0%	0		10,000
NY	ORANGE & ROCKLAND UTIL	LOVETT	2	20	43	Oil/Gas	Dry	Wall	NO PLAN	0.25	0.0%	0		10,000
NY	POWER AUTH OF STATE NY	CHARLES POLETTI	1	825	18	Oil/Gas	Dry	Wall	CONTROLS	0.25	35.0%	3,419		10,812
RI	NARRAGANSETT ELEC	SOUTH STREET	121	55	41	none	Dry	Wall	RETIRE	0.45	0.0%	0		10,000
RI	NARRAGANSETT ELEC	SOUTH STREET	122	55	41	none	Dry	Wall	RETIRE	0.45	0.0%	0		10,000
RI	NARRAGANSETT ELEC	MANCHESTER ST	6	50	51	Nat gas	Dry	Wall	CONSTR GTRB+HRSG	0.04	0.0%	0		10,000
RI	NARRAGANSETT ELEC	MANCHESTER ST	7	50	55	Nat gas	Dry	Wall	CONSTR GTRB+HRSG	0.04	0.0%	0		10,000
RI	NARRAGANSETT ELEC	MANCHESTER ST	12	50	51	Nat gas	Dry	Wall	CONSTR GTRB+HRSG	0.04	0.0%	0		10,000
VT	BURLINGTON ELEC DEPT	J. C. MCNEIL	1	52	11	Wood	Dry	Wall/Stok	LNB+FGR	0.25	32.0%	182		10,000
VT	RYEGATE ASSOCIATES	EAST RYEGATE	1	20	6	Wood	Dry	Stoker	SNCR	0.15	92.0%	121		10,000
CONNECTICUT		SUBTOTALS	1	385		Coal	Dry	Tangential		0.38	99.4%	6,372		
		SUBTOTALS	7	1,508		Oil/Gas	Dry	Tangential		0.25	38.2%	6,432		
		SUBTOTALS	2	72		Oil/Gas	Dry	Vertical		0.43	3.1%	53		
		SUBTOTALS	2	114		Oil/Gas	Dry	Wall		0.25	9.1%	137		
		SUBTOTALS	2	252		Oil/Gas	Wet	Cyclone		0.43	46.1%	2,216		

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UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
		SUBTOTALS	4	837		Oil/Gas	Wet	Wall		0.25	41.7%	4,727		
TOTAL CONNECTICUT		==================	18	3,168						0.28	45.3%	19,937		
MASSACHUSETTS		SUBTOTALS	3	586		Coal	Dry	Tangential		0.38	88.1%	8,341		
		SUBTOTALS	5	1,071		Coal	Dry	Wall		0.41	83.4%	16,009		
		SUBTOTALS	1	89		Coal	Wet	Tangential		0.38	0.0%	0		
		SUBTOTALS	7	1,207		Oil/Gas	Dry	Tangential		0.22	43.3%	5,234		
		SUBTOTALS	18	3,065		Oil/Gas	Dry	Wall		0.25	57.0%	18,329		
TOTAL MASSACHUSETTS		==================	34	6,018						0.29	61.1%	47,913		
MAINE		SUBTOTALS	1	114		Oil/Gas	Dry	Tangential		0.40	38.0%	759		
		SUBTOTALS	5	777		Oil/Gas	Dry	Wall		0.34	4.4%	492		
TOTAL MAINE		==================	6	891						0.34	8.7%	1,251		
NEW HAMPSHIRE		SUBTOTALS	3	150		Coal	Dry	Wall		0.50	51.6%	1,694		
		SUBTOTALS	2	458		Coal	Wet	Cyclone		1.27	70.7%	18,074		
		SUBTOTALS	1	425		Oil/Gas	Dry	Tangential		0.25	38.8%	1,966		
		SUBTOTALS	0	25		Oil/Gas	Dry	Wall		0.43	0.0%	0		
TOTAL NEW HAMPSHIRE		==================	6	1,058						0.73	53.5%	21,734		
NEW JERSEY		SUBTOTALS	2	740		Coal	Dry	Wall		0.49	50.2%	8,044		
		SUBTOTALS	2	299		Coal	Wet	Cyclone		1.12	56.6%	8,123		
		SUBTOTALS	2	652		Coal	Wet	Wall		0.50	44.4%	6,340		
		SUBTOTALS	8	1,008		Oil/Gas	Dry	Tangential		0.23	12.6%	1,668		
		SUBTOTALS	2	55		Oil/Gas	Dry	Vertical		0.31	0.0%	0		
		SUBTOTALS	21	1,764		Oil/Gas	Dry	Wall		0.43	21.9%	8,545		

TABLE A - 1

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
		SUBTOTALS	5	819		Oil/Gas	Wet	Cyclone		0.55	17.4%	4,163		
TOTAL NEW JERSEY		==================	42	5,337						0.46	27.8%	36,883		
NEW YORK		SUBTOTALS	4	158		Coal	Dry	Stoker		0.40	41.8%	1,819		
		SUBTOTALS	16	2,082		Coal	Dry	Tangential		0.42	68.6%	25,828		
		SUBTOTALS	7	1,302		Coal	Dry	Wall		0.45	70.6%	17,536		
		SUBTOTALS	4	340		Coal	Wet	Vertical		1.00	74.0%	12,415		
		SUBTOTALS	41	8,680		Oil/Gas	Dry	Tangential		0.25	33.8%	33,993		
		SUBTOTALS	2	170		Oil/Gas	Dry	Vertical		0.23	18.0%	380		
		SUBTOTALS	19	5,091		Oil/Gas	Dry	Wall		0.25	24.5%	15,034		
TOTAL NEW YORK		==================	93	17,823						0.30	38.6%	107,006		
RHODE ISLAND		SUBTOTALS	5	260		Oil/Gas	Dry	Wall		0.22	0.0%	0		
TOTAL RHODE ISLAND		==================	5	260						0.22	0.0%	0		
VERMONT		SUBTOTALS	2	72		Wood	Dry	Stoker		0.22	48.7%	303		
TOTAL VERMONT		==================	2	72						0.22	48.7%	303		
SUBTOTALS ---NESCAUM			4	158		Coal	Dry	Stoker		0.40	41.8%	1,819		
			20	3,053		Coal	Dry	Tangential		0.41	76.2%	40,541		
			17	3,263		Coal	Dry	Wall		0.45	69.3%	43,282		
			4	757		Coal	Wet	Cyclone		1.21	65.1%	26,197		
			1	89		Coal	Wet	Tangential		0.38	0.0%	0		
			4	340		Coal	Wet	Vertical		1.00	74.0%	12,415		
			2	652		Coal	Wet	Wall		0.50	44.4%	6,340		
			2	72		Wood	Dry	Stoker		0.22	48.7%	303		

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TABLE A - 1

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
			65	12,942		Oil/Gas	Dry	Tangential		0.25	33.8%	50,053		
			6	297		Oil/Gas	Dry	Vertical		0.29	11.1%	433		
			70	11,096		Oil/Gas	Dry	Wall		0.28	30.9%	42,537		
			7	1,071		Oil/Gas	Wet	Cyclone		0.52	24.1%	6,379		
			4	837		Oil/Gas	Wet	Wall		0.25	41.7%	4,727		
TOTAL NESCAUM			206	34,627				All types		0.34	40.9%	235,026		

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TABLE A - 1

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
NESCAUM SPREADSHEET SUMMARY DATA														
			41	6,474		Coal	Dry					85,643		
			11	1,838		Coal	Wet					44,951		
			52	8,312		Coal		All types				130,594		
			143	24,407		Oil/Gas	Dry					93,326		
			11	1,908		Oil/Gas	Wet					11,106		
			154	26,315		Oil/Gas		All types				104,432		
BY STATE:														
CT			1	385		Coal						6,372		
			17	2,783		Oil/Gas						13,565		
MA			9	1,746		Coal						24,350		
			25	4,272		Oil/Gas						23,563		
ME			0	0		Coal						0		
			6	891		Oil/Gas						1,251		
NH			5	608		Coal						19,767		
			1	450		Oil/Gas						1,966		
NJ			6	1,691		Coal						22,507		
			36	3,646		Oil/Gas						14,376		
NY			31	3,882		Coal						57,598		
			62	13,941		Oil/Gas						49,408		
RI			0	0		Coal						0		
			5	260		Oil/Gas						0		
VT			0	0		Coal						0		
			2	72		Wood						303		
TOTALS			206	34,627								235,026		

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UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

NESCAUM.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)

MISCELLANEOUS

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Fuel	Furnac	Firing Type	NOx RACT Control	NOx (lb/MBtu)	CF (%)	TOTAL NOx	no dt	Heat Rate (Btu/KW-hr)
MISCELLANEOUS														
CT	UNITED ILLUMINATING CO	STEEL POINT	9	30	1941		Dry	Opposed		0.00	0.0%		*	10,000
CT	UNITED ILLUMINATING CO	STEEL POINT	11	35	1950		Dry	Opposed		0.00	0.0%		*	10,000
MA	MASS MUN WHOLES EL CO	STONY BROOK	ST1	67	1981		Dry	Tangential		0.00	0.0%		*	10,000
MA	MASS MUN WHOLES EL CO	STONY BROOK	ST2	68	1981		Dry	Tangential		0.00	0.0%		*	10,000
MA	TAUNTON CITY OF	CLEARY FLOOD	*9 CB	47	1975	Oil/Gas	Gas	Turbine		0.36	55.9%		*	10,000
ME	BANGOR HYDRO-ELECTRIC	GRAHAM STATION	* 3	163	1964	Coal	N/R	N/R		1.45	0.5%		*	10,000

10/17/94

UTILITY BOILERS IN THE

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CTR: COMB CONTROLS, LEA,FGR, BOOS, CTRL
RPW: REPOWER
UNC: UNCONTROLLED
FSW: FUEL SWITCHING
NRP: NOT REPORTED

/WCS5~{RIGHT}

State	Fuel	Furn. Type	Firing Type	# UNITS	LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MWe PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	TONS/YEAR NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
CONNE	Coal	Dry	Tangential	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	385	0	0	0	0	0	0	0	6,372
	Oil/Gas	Dry	Tangential	7	0	3	0	4	0	0	0	0	0	800	0	708	0	0	0	0	0	5,059	0	1,373	0	0	0	0
	Oil/Gas	Dry	Vertical	2	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	72	0	0	0	0	0	0	0	53
	Oil/Gas	Dry	Wall	2	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	114	0	0	0	0	0	0	0	137
	Oil/Gas	Wet	Cyclone	2	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	252	0	0	0	0	0	0	0	2,216
	Oil/Gas	Wet	Wall	4	0	0	0	3	0	0	0	1	0	0	0	768	0	0	0	69	0	0	0	3,844	0	0	0	883
TOTAL CONNECTICUT				18	0	3	0	7	0	0	0	8	0	800	0	1,476	0	0	0	892	0	5,059	0	5,217	0	0	0	9,661
MASSA	Coal	Dry	Tangential	3	1	0	0	0	0	0	0	2	231	0	0	0	0	0	0	355	3535	0	0	0	0	0	0	4805
	Coal	Dry	Wall	5	0	4	0	1	0	0	0	0	0	924	0	147	0	0	0	0	0	13296	0	2713	0	0	0	0
	Coal	Wet	Tangential	1	0	0	1	0	0	0	0	0	0	0	89	0	0	0	0	0	0	0	0	0	0	0	0	0
	Oil/Gas	Dry	Tangential	7	0	0	2	1	0	0	0	4	0	0	96	107	0	0	0	1004	0	0	0	549	0	0	0	4685
	Oil/Gas	Dry	Wall	18	1	1	0	1	0	0	2	13	446	432	0	581	0	0	760	846	2810	2263	0	4499	0	0	3532	5225
TOTAL MASSACHUSETTS				34	2	5	3	3	0	0	2	19	677	1356	185	835	0	0	760	2205	6346	15559	0	7761	0	0	3532	14715
MAINE	Oil/Gas	Dry	Tangential	1	0	0	0	1	0	0	0	0	0	0	0	114	0	0	0	0	0	0	0	759	0	0	0	0
	Oil/Gas	Dry	Wall	5	1	0	2	0	0	0	0	2	50	0	45	0	0	0	0	682	74	0	0	0	0	0	0	418
TOTAL MAINE				6	1	0	2	1	0	0	0	2	50	0	45	114	0	0	0	682	74	0	0	759	0	0	0	418
NEW H	Coal	Dry	Wall	3	3	0	0	0	0	0	0	0	150	0	0	0	0	0	0	0	1694	0	0	0	0	0	0	0
	Coal	Wet	Cyclone	2	0	2	0	0	0	0	0	0	0	458	0	0	0	0	0	0	0	18074	0	0	0	0	0	0
	Oil/Gas	Dry	Tangential	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	425	0	0	0	0	0	0	0	1966	0
	Oil/Gas	Dry	Wall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL NEW HAMPSHIRE				6	3	2	0	0	0	0	1	0	150	458	0	0	0	0	425	0	1694	18074	0	0	0	0	1966	0

10/17/94

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RPW: REPOWER
UNC: UNCONTROLLED
FSW: FUEL SWITCHING
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/WCS5~(RIGHT)

State	Fuel	Furn. Type	Firing Type	# UNITS	LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MWe PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	TONS/YEAR NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
NEW J	Coal	Dry	Wall	2	1	0	0	0	0	0	0	1	80	0	0	0	0	0	0	660	817	0	0	0	0	0	0	7227
	Coal	Wet	Cyclone	2	0	2	0	0	0	0	0	0	0	299	0	0	0	0	0	0	0	8123	0	0	0	0	0	0
	Coal	Wet	Wall	2	0	1	0	0	0	0	0	1	0	326	0	0	0	0	0	326	0	2849	0	0	0	0	0	3491
	Oil/Gas	Dry	Tangential	8	0	1	0	0	0	0	1	6	0	160	0	0	0	0	72	776	0	222	0	0	0	0	415	1031
	Oil/Gas	Dry	Vertical	2	0	0	2	0	0	0	0	0	0	0	55	0	0	0	0	0	0	0	0	0	0	0	0	0
	Oil/Gas	Dry	Wall	21	5	0	6	0	3	0	2	5	68	0	137	0	855	0	90	614	176	0	0	0	6132	0	78	2159
	Oil/Gas	Wet	Cyclone	5	0	0	0	1	0	0	3	1	0	0	0	86	0	0	278	455	0	0	0	162	0	0	605	3395
TOTAL NEW JERSEY				42	6	4	8	1	3	0	6	14	148	785	192	86	855	0	440	2,831	993	11,194	0	162	6,132	0	1,099	17,303
NEW Y	Coal	Dry	Stoker	4	0	0	0	0	0	4	0	0	0	0	0	0	0	158	0	0	0	0	0	0	0	1819	0	0
	Coal	Dry	Tangential	16	5	1	1	9	0	0	0	0	675	157	47	1203	0	0	0	0	7005	2314	0	16509	0	0	0	0
	Coal	Dry	Wall	7	2	0	1	3	0	0	0	1	381	0	55	816	0	0	0	50	4927	0	0	11930	0	0	0	679
	Coal	Wet	Vertical	4	0	0	0	4	0	0	0	0	0	0	0	340	0	0	0	0	0	0	0	12415	0	0	0	0
	Oil/Gas	Dry	Tangential	41	0	0	2	29	2	7	1	0	0	0	96	7457	72	680	375	0	0	0	0	28694	248	3118	1933	0
	Oil/Gas	Dry	Vertical	2	0	0	0	2	0	0	0	0	0	0	0	170	0	0	0	0	0	0	0	380	0	0	0	0
	Oil/Gas	Dry	Wall	19	0	0	6	11	0	2	0	0	0	0	555	4496	0	40	0	0	0	0	0	15034	0	0	0	0
TOTAL NEW YORK				93	7	1	10	58	2	13	1	1	1056	157	753	14482	72	878	375	50	11931	2314	0	84962	248	4937	1933	679
RHODE	Oil/Gas	Dry	Wall	5	0	0	2	0	3	0	0	0	0	0	110	0	150	0	0	0	0	0	0	0	0	0	0	0
TOTAL RHODE ISLAND				5	0	0	2	0	3	0	0	0	0	0	110	0	150	0	0	0	0	0	0	0	0	0	0	0
VERMO	Wood	Dry	Stoker	2	1	1	0	0	0	0	0	0	52	20	0	0	0	0	0	0	182	121	0	0	0	0	0	0
TOTAL VERMONT				2	1	1	0	0	0	0	0	0	52	20	0	0	0	0	0	0	182	121	0	0	0	0	0	0
SUBTO	Coal	Dry	Stoker	4	0	0	0	0	0	4	0	0	0	0	0	0	0	158	0	0	0	0	0	0	0	1819	0	0
	Coal	Dry	Tangential	20	6	1	1	9	0	0	0	3	906	157	47	1203	0	0	0	740	10540	2314	0	16509	0	0	0	11177

10/17/94

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/WCS5~{RIGHT}

State Fuel	Furn. Type	Firing Type	# UNITS	LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MWe PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	TONS/YEAR NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
Coal	Dry	Wall	17	6	4	1	4	0	0	0	2	611	924	55	963	0	0	0	710	7437	13296	0	14643	0	0	0	7906
Coal	Wet	Cyclone	4	0	4	0	0	0	0	0	0	0	757	0	0	0	0	0	0	0	26197	0	0	0	0	0	0
Coal	Wet	Tangential	1	0	0	1	0	0	0	0	0	0	0	89	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	Wet	Vertical	4	0	0	0	4	0	0	0	0	0	0	0	340	0	0	0	0	0	0	0	12415	0	0	0	0
Coal	Wet	Wall	2	0	1	0	0	0	0	0	1	0	326	0	0	0	0	0	326	0	2849	0	0	0	0	0	3491
Wood	Dry	Stoker	2	1	1	0	0	0	0	0	0	52	20	0	0	0	0	0	0	182	121	0	0	0	0	0	0
Oil/Gas	Dry	Tangential	65	0	4	4	35	2	7	3	10	0	960	192	8386	72	680	872	1780	0	5281	0	31375	248	3118	4314	5716
Oil/Gas	Dry	Vertical	6	0	0	2	2	0	0	0	2	0	0	55	170	0	0	0	72	0	0	0	380	0	0	0	53
Oil/Gas	Dry	Wall	70	7	1	16	12	6	2	4	22	564	432	847	5077	1005	40	850	2256	3061	2263	0	19533	6132	0	3610	7938
Oil/Gas	Wet	Cyclone	7	0	0	0	1	0	0	3	3	0	0	0	86	0	0	278	707	0	0	0	162	0	0	605	5611
Oil/Gas	Wet	Wall	4	0	0	0	3	0	0	0	1	0	0	0	768	0	0	0	69	0	0	0	3,844	0	0	0	883
TOTAL NESCAUM		All types	206	20	16	25	70	8	13	10	44	2133	3576	1285	16993	1077	878	2000	6660	21220	52321	0	98861	6380	4937	8530	42775

10/17/94

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/WCS5~{RIGHT}

State	Fuel	Furn. Type	Firing Type	# UNITS	LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MWe PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	TONS/YEAR NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
NESCAUM SPREADSHEET SUMMARY DATA																												
	Coal	Dry		41	12	5	2	13	0	4	0	5	1517	1081	102	2166	0	158	0	1450	17977	15611	0	31152	0	1819	0	19083
	Coal	Wet		11	0	5	1	4	0	0	0	1	0	1083	89	340	0	0	0	326	0	29045	0	12415	0	0	0	3491
	Coal		All types	52	12	10	3	17	0	4	0	6	1517	2164	191	2506	0	158	0	1776	17977	44656	0	43567	0	1819	0	22575
	Oil/Gas	Dry		143	8	6	22	49	8	9	7	34	616	1412	1094	13633	1077	720	1722	4108	3243	7665	0	51288	6380	3118	7925	13706
	Oil/Gas	Wet		11	0	0	0	4	0	0	3	4	0	0	0	854	0	0	278	776	0	0	0	4006	0	0	605	6494
	Oil/Gas		All types	154	8	6	22	53	8	9	10	38	616	1412	1094	14487	1077	720	2000	4884	3243	7665	0	55294	6380	3118	8530	20201
BY STATE:																												
CT	Coal			1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	385	0	0	0	0	0	0	0	6372
	Oil/Gas			17	0	3	0	7	0	0	0	7	0	800	0	1476	0	0	0	507	0	5059	0	5217	0	0	0	3289
MA	Coal			9	1	4	1	1	0	0	0	2	231	924	89	147	0	0	0	355	3535	13296	0	2713	0	0	0	4805
	Oil/Gas			25	1	1	2	2	0	0	2	17	446	432	96	688	0	0	760	1850	2810	2263	0	5048	0	0	3532	9909
ME	Coal			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Oil/Gas			6	1	0	2	1	0	0	0	2	50	0	45	114	0	0	0	682	74	0	0	759	0	0	0	418
NH	Coal			5	3	2	0	0	0	0	0	0	150	458	0	0	0	0	0	0	1694	18074	0	0	0	0	0	0
	Oil/Gas			1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	425	0	0	0	0	0	0	0	1966	0
NJ	Coal			6	1	3	0	0	0	0	0	2	80	625	0	0	0	0	0	986	817	10972	0	0	0	0	0	10718
	Oil/Gas			36	5	1	8	1	3	0	6	12	68	160	192	86	855	0	440	1,845	176	222	0	162	6,132	0	1,099	6,585
NY	Coal			31	7	1	2	16	0	4	0	1	1056	157	102	2359	0	158	0	50	11931	2314	0	40854	0	1819	0	679
	Oil/Gas			62	0	0	8	42	2	9	1	0	0	0	651	12123	72	720	375	0	0	0	0	44108	248	3118	1933	0
RI	Coal			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Oil/Gas			5	0	0	2	0	3	0	0	0	0	0	110	0	150	0	0	0	0	0	0	0	0	0	0	0
VT	Coal			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Wood			2	1	1	0	0	0	0	0	0	52	20	0	0	0	0	0	0	182	121	0	0	0	0	0	0
TOTALS				206	20	16	25	70	8	13	10	44	2133	3576	1285	16993	1077	878	2000	6660	21220	52321	0	98861	6380	4937	8530	42775

10/17/94

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/WCS5~(RIGHT)

State	Fuel	Furn. Type	Firing Type	# UNITS	LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MWe PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	TONS/YEAR NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP

MISCELLANEOUS

State	Furnac	Firing Type

MISCELLANEOUS

State	Fuel	Furn. Type	Firing Type
CT		Dry	Opposed
CT		Dry	Opposed
MA		Dry	Tangential
MA		Dry	Tangential
MA	Oil/Gas	Gas	Turbine
ME	Coal	N/R	N/R

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
CONNE	Coal	Dry	Tangential	1								0.38
	Oil/Gas	Dry	Tangential	7		0.25		0.25				
	Oil/Gas	Dry	Vertical	2								0.43
	Oil/Gas	Dry	Wall	2								0.25
	Oil/Gas	Wet	Cyclone	2								0.43
	Oil/Gas	Wet	Wall	4				0.25				0.25
TOTAL CONNECTICUT				18		0.25		0.25				0.37
MASSA	Coal	Dry	Tangential	3	0.38							0.38
	Coal	Dry	Wall	5		0.41		0.45				
	Coal	Wet	Tangential	1			0.38					
	Oil/Gas	Dry	Tangential	7			0.25	0.24				0.22
	Oil/Gas	Dry	Wall	18	0.28	0.23		0.28			0.20	0.28
TOTAL MASSACHUSETTS				34	0.31	0.35	0.31	0.30			0.20	0.27
MAINE	Oil/Gas	Dry	Tangential	1				0.40				
	Oil/Gas	Dry	Wall	5	0.40		0.70					0.31
TOTAL MAINE				6	0.40		0.70	0.40				0.31
NEW H	Coal	Dry	Wall	3	0.50							
	Coal	Wet	Cyclone	2		1.27						
	Oil/Gas	Dry	Tangential	1							0.25	
	Oil/Gas	Dry	Wall	0								
TOTAL NEW HAMPSHIRE				6	0.50	1.27					0.25	

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
NEW J	Coal	Dry	Wall	2	0.45							0.50
	Coal	Wet	Cyclone	2		1.12						
	Coal	Wet	Wall	2		0.50						0.50
	Oil/Gas	Dry	Tangential	8		0.22					0.50	0.21
	Oil/Gas	Dry	Vertical	2			0.31					
	Oil/Gas	Dry	Wall	21	0.36		0.17		0.47		0.35	0.44
	Oil/Gas	Wet	Cyclone	5				0.43			0.38	0.68
TOTAL NEW JERSEY				42	0.41	0.68	0.21	0.43	0.47		0.39	0.44
NEW Y	Coal	Dry	Stoker	4						0.40		
	Coal	Dry	Tangential	16	0.42	0.42	0.42	0.42				
	Coal	Dry	Wall	7	0.45		0.45	0.45				0.45
	Coal	Wet	Vertical	4				1.00				
	Oil/Gas	Dry	Tangential	41			0.25	0.25	0.25	0.25	0.25	
	Oil/Gas	Dry	Vertical	2				0.23				
	Oil/Gas	Dry	Wall	19			0.25	0.25		0.25		
TOTAL NEW YORK				93	0.43	0.42	0.28	0.29	0.25	0.28	0.25	0.45
RHODE	Oil/Gas	Dry	Wall	5			0.45		0.04			
TOTAL RHODE ISLAND				5			0.45		0.04			
VERMO	Wood	Dry	Stoker	2	0.25	0.15						
TOTAL VERMONT				2	0.25	0.15						
SUBTO	Coal	Dry	Stoker	4						0.40		
	Coal	Dry	Tangential	20	0.41	0.42	0.42	0.42				0.38

10/17/94

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State Fuel	Furn. Type	Firing Type	# UNITS	LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
Coal	Dry	Wall	17	0.46	0.41	0.45	0.45				0.50
Coal	Wet	Cyclone	4		1.21						
Coal	Wet	Tangential	1			0.38					
Coal	Wet	Vertical	4				1.00				
Coal	Wet	Wall	2		0.50						0.50
Wood	Dry	Stoker	2	0.25	0.15						
Oil/Gas	Dry	Tangential	65		0.25	0.25	0.25	0.25	0.25	0.27	0.21
Oil/Gas	Dry	Vertical	6			0.31	0.23				0.43
Oil/Gas	Dry	Wall	70	0.30	0.23	0.29	0.25	0.41	0.25	0.22	0.33
Oil/Gas	Wet	Cyclone	7				0.43			0.38	0.59
Oil/Gas	Wet	Wall	4				0.25				0.25
TOTAL NESCAUM		All types	206	0.39	0.52	0.30	0.29	0.40	0.28	0.26	0.36

10/17/94

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
NESCAUM SPREADSHEET SUMMARY DATA												
	Coal	Dry		41	0.43	0.41	0.44	0.43		0.40		0.44
	Coal	Wet		11		1.00	0.38	1.00				0.50
	Coal		All types	52	0.43	0.70	0.41	0.51		0.40		0.45
	Oil/Gas	Dry		143	0.30	0.24	0.28	0.25	0.40	0.25	0.24	0.28
	Oil/Gas	Wet		11				0.27			0.38	0.56
	Oil/Gas		All types	154	0.30	0.24	0.28	0.25	0.40	0.25	0.26	0.33
BY STATE:												
CT	Coal			1								0.38
	Oil/Gas			17		0.25		0.25				0.37
MA	Coal			9	0.38	0.41	0.38	0.45				0.38
	Oil/Gas			25	0.28	0.23	0.25	0.27			0.20	0.25
ME	Coal			0								
	Oil/Gas			6	0.40		0.70	0.40				0.31
NH	Coal			5	0.50	1.27						
	Oil/Gas			1							0.25	
NJ	Coal			6	0.45	0.80						0.50
	Oil/Gas			36	0.36	0.22	0.21	0.43	0.47		0.39	0.40
NY	Coal			31	0.43	0.42	0.44	0.51		0.40		0.45
	Oil/Gas			62			0.25	0.25	0.25	0.25	0.25	
RI	Coal			0								
	Oil/Gas			5			0.45		0.04			
VT	Coal			0								
	Wood			2	0.25	0.15						
TOTALS				206	0.39	0.52	0.30	0.29	0.40	0.28	0.26	0.36

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP

MISCELLANEOUS

State	Furnac	Firing Type

MISCELLANEOUS

CT		Dry	Opposed
CT		Dry	Opposed
MA		Dry	Tangential
MA		Dry	Tangential
MA	Oil/Gas	Gas	Turbine
ME	Coal	N/R	N/R

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	MAXIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MINIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
					0.00 INDICATES NO DATA								99.99 INDICATES NO DATA							
CONNE	Coal	Dry	Tangential	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	99.99	99.99	99.99	99.99	99.99	99.99	99.99	0.38
	Oil/Gas	Dry	Tangential	7	0.00	0.25	0.00	0.25	0.00	0.00	0.00	0.00	99.99	0.25	99.99	0.25	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Vertical	2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.43	99.99	99.99	99.99	99.99	99.99	99.99	99.99	0.43
	Oil/Gas	Dry	Wall	2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25	99.99	99.99	99.99	99.99	99.99	99.99	99.99	0.25
	Oil/Gas	Wet	Cyclone	2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.43	99.99	99.99	99.99	99.99	99.99	99.99	99.99	0.43
	Oil/Gas	Wet	Wall	4	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.25	99.99	99.99	99.99	0.25	99.99	99.99	99.99	0.25
TOTAL CONNECTICUT				18	0.00	0.25	0.00	0.25	0.00	0.00	0.00	0.43	99.99	0.25	99.99	0.25	99.99	99.99	99.99	0.25
MASSA	Coal	Dry	Tangential	3	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.38	99.99	99.99	99.99	99.99	99.99	99.99	0.38
	Coal	Dry	Wall	5	0.00	0.45	0.00	0.45	0.00	0.00	0.00	0.00	99.99	0.33	99.99	0.45	99.99	99.99	99.99	99.99
	Coal	Wet	Tangential	1	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.00	99.99	99.99	0.38	99.99	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Tangential	7	0.00	0.00	0.25	0.24	0.00	0.00	0.00	0.25	99.99	99.99	0.25	0.24	99.99	99.99	99.99	0.20
	Oil/Gas	Dry	Wall	18	0.28	0.23	0.00	0.28	0.00	0.00	0.20	0.28	0.28	0.23	99.99	0.28	99.99	99.99	0.20	0.25
TOTAL MASSACHUSETTS				34	0.38	0.45	0.38	0.45	0.00	0.00	0.20	0.38	0.28	0.23	0.25	0.24	99.99	99.99	0.20	0.20
MAINE	Oil/Gas	Dry	Tangential	1	0.00	0.00	0.00	0.40	0.00	0.00	0.00	0.00	99.99	99.99	99.99	0.40	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Wall	5	0.40	0.00	0.70	0.00	0.00	0.00	0.00	0.40	0.40	99.99	0.70	99.99	99.99	99.99	99.99	0.30
TOTAL MAINE				6	0.40	0.00	0.70	0.40	0.00	0.00	0.00	0.40	0.40	99.99	0.70	0.40	99.99	99.99	99.99	0.30
NEW H	Coal	Dry	Wall	3	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	99.99	99.99	99.99	99.99	99.99	99.99	99.99
	Coal	Wet	Cyclone	2	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	99.99	0.92	99.99	99.99	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Tangential	1	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.00	99.99	99.99	99.99	99.99	99.99	99.99	0.25	99.99
	Oil/Gas	Dry	Wall	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	99.99	99.99	99.99	99.99	99.99	99.99	99.99	99.99
TOTAL NEW HAMPSHIRE				6	0.50	1.40	0.00	0.00	0.00	0.00	0.25	0.00	0.50	0.92	99.99	99.99	99.99	99.99	0.25	99.99

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	MAXIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MINIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
NEW J	Coal	Dry	Wall	2	0.45	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.45	99.99	99.99	99.99	99.99	99.99	99.99	0.50
	Coal	Wet	Cyclone	2	0.00	1.30	0.00	0.00	0.00	0.00	0.00	0.00	99.99	0.90	99.99	99.99	99.99	99.99	99.99	99.99
	Coal	Wet	Wall	2	0.00	0.50	0.00	0.00	0.00	0.00	0.00	0.50	99.99	0.50	99.99	99.99	99.99	99.99	99.99	0.50
	Oil/Gas	Dry	Tangential	8	0.00	0.22	0.00	0.00	0.00	0.00	0.50	0.23	99.99	0.22	99.99	99.99	99.99	99.99	0.50	0.19
	Oil/Gas	Dry	Vertical	2	0.00	0.00	0.42	0.00	0.00	0.00	0.00	0.00	99.99	99.99	0.22	99.99	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Wall	21	0.45	0.00	0.50	0.00	0.47	0.00	0.35	0.44	0.28	99.99	0.42	99.99	0.47	99.99	0.35	0.44
	Oil/Gas	Wet	Cyclone	5	0.00	0.00	0.00	0.43	0.00	0.00	0.50	0.68	99.99	99.99	99.99	0.43	99.99	99.99	0.35	0.68
TOTAL NEW JERSEY				42	0.45	1.30	0.50	0.43	0.47	0.00	0.50	0.68	0.28	0.22	0.22	0.43	0.47	99.99	0.35	0.19
NEW Y	Coal	Dry	Stoker	4	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	99.99	99.99	99.99	99.99	99.99	0.40	99.99	99.99
	Coal	Dry	Tangential	16	0.42	0.42	0.42	0.42	0.00	0.00	0.00	0.00	0.42	0.42	0.42	0.42	99.99	99.99	99.99	99.99
	Coal	Dry	Wall	7	0.45	0.00	0.45	0.45	0.00	0.00	0.00	0.45	0.45	99.99	0.45	0.45	99.99	99.99	99.99	0.45
	Coal	Wet	Vertical	4	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	99.99	99.99	99.99	1.00	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Tangential	41	0.00	0.00	0.25	0.25	0.25	0.25	0.25	0.00	99.99	99.99	0.25	0.25	0.25	0.25	0.25	99.99
	Oil/Gas	Dry	Vertical	2	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.00	99.99	99.99	99.99	0.20	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Wall	19	0.00	0.00	0.25	0.25	0.00	0.25	0.00	0.00	99.99	99.99	0.25	0.25	99.99	0.25	99.99	99.99
TOTAL NEW YORK				93	0.45	0.42	0.45	1.00	0.25	0.40	0.25	0.45	0.42	0.42	0.25	0.20	0.25	0.25	0.25	0.45
RHODE	Oil/Gas	Dry	Wall	5	0.00	0.00	0.45	0.00	0.04	0.00	0.00	0.00	99.99	99.99	0.45	99.99	0.04	99.99	99.99	99.99
TOTAL RHODE ISLAND				5	0.00	0.00	0.45	0.00	0.04	0.00	0.00	0.00	99.99	99.99	0.45	99.99	0.04	99.99	99.99	99.99
VERMO	Wood	Dry	Stoker	2	0.25	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.15	99.99	99.99	99.99	99.99	99.99	99.99
TOTAL VERMONT				2	0.25	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.15	99.99	99.99	99.99	99.99	99.99	99.99
SUBTO	Coal	Dry	Stoker	4	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	99.99	99.99	99.99	99.99	99.99	0.40	99.99	99.99
	Coal	Dry	Tangential	20	0.42	0.42	0.42	0.42	0.00	0.00	0.00	0.38	0.38	0.42	0.42	0.42	99.99	99.99	99.99	0.38

10/17/94

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State				MAXIMUM LB/MMBTU NOx PER:								MINIMUM LB/MMBTU NOx PER:							
Fuel	Furn. Type	Firing Type	# UNITS	LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
Coal	Dry	Wall	17	0.50	0.45	0.45	0.45	0.00	0.00	0.00	0.50	0.45	0.33	0.45	0.45	99.99	99.99	99.99	0.45
Coal	Wet	Cyclone	4	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	99.99	0.90	99.99	99.99	99.99	99.99	99.99	99.99
Coal	Wet	Tangential	1	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.00	99.99	99.99	0.38	99.99	99.99	99.99	99.99	99.99
Coal	Wet	Vertical	4	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	99.99	99.99	99.99	1.00	99.99	99.99	99.99	99.99
Coal	Wet	Wall	2	0.00	0.50	0.00	0.00	0.00	0.00	0.00	0.50	99.99	0.50	99.99	99.99	99.99	99.99	99.99	0.50
Wood	Dry	Stoker	2	0.25	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.15	99.99	99.99	99.99	99.99	99.99	99.99
Oil/Gas	Dry	Tangential	65	0.00	0.25	0.25	0.40	0.25	0.25	0.50	0.25	99.99	0.22	0.25	0.24	0.25	0.25	0.25	0.19
Oil/Gas	Dry	Vertical	6	0.00	0.00	0.42	0.25	0.00	0.00	0.00	0.43	99.99	99.99	0.22	0.20	99.99	99.99	99.99	0.43
Oil/Gas	Dry	Wall	70	0.45	0.23	0.70	0.28	0.47	0.25	0.35	0.44	0.28	0.23	0.25	0.25	0.04	0.25	0.20	0.25
Oil/Gas	Wet	Cyclone	7	0.00	0.00	0.00	0.43	0.00	0.00	0.50	0.68	99.99	99.99	99.99	0.43	99.99	99.99	0.35	0.43
Oil/Gas	Wet	Wall	4	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.25	99.99	99.99	99.99	0.25	99.99	99.99	99.99	0.25
TOTAL NESCAUM		All types	206	0.50	1.40	0.70	1.00	0.47	0.40	0.50	0.68	0.25	0.15	0.22	0.20	0.04	0.25	0.20	0.19

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	MAXIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MINIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
NESCAUM SPREADSHEET SUMMARY DATA																				
	Coal	Dry		41	0.50	0.45	0.45	0.45	0.00	0.40	0.00	0.50								
	Coal	Wet		11	0.00	1.40	0.38	1.00	0.00	0.00	0.00	0.50								
	Coal		All types	52	0.50	1.40	0.45	1.00	0.00	0.40	0.00	0.50								
	Oil/Gas	Dry		143	0.45	0.25	0.70	0.40	0.47	0.25	0.50	0.44								
	Oil/Gas	Wet		11	0.00	0.00	0.00	0.43	0.00	0.00	0.50	0.68								
	Oil/Gas		All types	154	0.45	0.25	0.70	0.43	0.47	0.25	0.50	0.68								
BY STATE:																				
CT	Coal			1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38								
	Oil/Gas			17	0.00	0.25	0.00	0.25	0.00	0.00	0.00	0.43								
MA	Coal			9	0.38	0.45	0.38	0.45	0.00	0.00	0.00	0.38								
	Oil/Gas			25	0.28	0.23	0.25	0.28	0.00	0.00	0.20	0.28								
ME	Coal			0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00								
	Oil/Gas			6	0.40	0.00	0.70	0.40	0.00	0.00	0.00	0.40								
NH	Coal			5	0.50	1.40	0.00	0.00	0.00	0.00	0.00	0.00								
	Oil/Gas			1	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.00								
NJ	Coal			6	0.45	1.30	0.00	0.00	0.00	0.00	0.00	0.50								
	Oil/Gas			36	0.45	0.22	0.50	0.43	0.47	0.00	0.50	0.68								
NY	Coal			31	0.45	0.42	0.45	1.00	0.00	0.40	0.00	0.45								
	Oil/Gas			62	0.00	0.00	0.25	0.25	0.25	0.25	0.25	0.00								
RI	Coal			0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00								
	Oil/Gas			5	0.00	0.00	0.45	0.00	0.04	0.00	0.00	0.00								
VT	Coal			0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00								
	Wood			2	0.25	0.15	0.00	0.00	0.00	0.00	0.00	0.00								
TOTALS				206	0.50	1.40	0.70	1.00	0.47	0.40	0.50	0.68								

UTILITY BOILERS IN THE NESCAUM REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	MAXIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MINIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
MISCELLANEOUS																				
CT		Dry	Opposed																	
CT		Dry	Opposed																	
MA		Dry	Tangential																	
MA		Dry	Tangential																	
MA	Oil/Gas	Gas	Turbine																	
ME	Coal	N/R	N/R																	

MISCELLANEOUS

State	Furnac	Firing Type

APPENDIX C

09/06/95

TABLE A - 1

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

MARAMA.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
DE	DELMARVA POWER & LIGHT	EDGE MOOR	3	84	41	Coal	Dry	Tangential	NO CONTROLS	0.54	58.7%	1,166		10,000
DE	DELMARVA POWER & LIGHT	EDGE MOOR	4	167	29	Coal	Dry	Tangential	LNB w/ OFA	0.67	64.5%	3,138		10,000
DE	DELMARVA POWER & LIGHT	INDIAN RIVER	1	89	38	Coal	Dry	Wall	RETIR ~2000	0.67	61.7%	1,610		10,000
DE	DELMARVA POWER & LIGHT	INDIAN RIVER	2	82	37	Coal	Dry	Wall	RETIR ~2000	0.81	55.9%	1,617		10,000
DE	DELMARVA POWER & LIGHT	INDIAN RIVER	3	162	25	Coal	Dry	Wall	LNB	0.34	72.7%	1,753		10,000
DE	DELMARVA POWER & LIGHT	INDIAN RIVER	4	424	15	Coal	Dry	Wall	LNB	0.42	48.4%	3,773		10,000
DE	DELMARVA POWER & LIGHT	EDGE MOOR	2	67		Oil	Dry	Tangential	not reported	0.56	64.2%	1,041		10,000
DE	DELMARVA POWER & LIGHT	EDGE MOOR	5	444	22	Oil	Dry	Tangential	LNB w/ OFA	0.37	45.5%	3,273		10,000
DE	DELMARVA POWER & LIGHT	DELAWARE CITY	1	56		Oil/Gas	Dry	Wall	not reported	0.49	31.6%	374		10,000
DE	DELMARVA POWER & LIGHT	DELAWARE CITY	2	56		Oil/Gas	Dry	Wall	not reported	0.49	31.6%	374		10,000
DE	DELMARVA POWER & LIGHT	DELAWARE CITY	3	12		Oil/Gas	Dry	Wall	not reported	0.49	31.6%	82		10,000
DE	DOVER CITY	MCKEE RUN	1	18	33	Oil/Gas	Dry	Wall	not reported	0.53	21.2%	90		10,000
DE	DOVER CITY	MCKEE RUN	2	18	33	Oil/Gas	Dry	Wall	not reported	0.53	13.5%	57		10,000
DE	DOVER CITY	MCKEE RUN	3	87	20	Oil/Gas	Dry	Wall	not reported	0.49	59.6%	1,109		10,000
DC	POTOMAC ELECTRIC	BENNING	15	290	27	Oil	Dry	Tangential	TUNING BURNERS	0.25	3.4%	115		10,761
DC	POTOMAC ELECTRIC	BENNING	16	290	23	Oil	Dry	Tangential	TUNING BURNERS	0.25	4.4%	154		10,979
MD	ALLEGHENY/POTOMAC EDISON	R.P. SMITH	4	90	37	Coal	Dry	Tangential	LNB w/ SOFA	0.45	71.0%	1,259		10,000
MD	POTOMAC ELECTRIC	DICKERSON	1	196	36	Coal	Dry	Tangential	AVG CREDIT	0.65	80.0%	4,464		10,000
MD	POTOMAC ELECTRIC	DICKERSON	2	196	35	Coal	Dry	Tangential	AVG CREDIT	0.70	85.0%	5,108		10,000
MD	POTOMAC ELECTRIC	DICKERSON	3	196	33	Coal	Dry	Tangential	AVG CREDIT	0.70	85.0%	5,108		10,000
MD	POTOMAC ELECTRIC	MORGANTOWN	1	626	25	Coal	Dry	Tangential	LNB w/ SOFA	0.76	74.0%	15,420		10,000
MD	POTOMAC ELECTRIC	MORGANTOWN	2	626	24	Coal	Dry	Tangential	LNB w/ SOFA	0.76	77.0%	16,045		10,000
MD	ALLEGHENY/POTOMAC EDISON	R.P. SMITH	3	27	48	Coal	Dry	Wall	IMPROVED O&M	0.55	16.0%	104		10,000
MD	BALTIMORE GAS & ELECT.	BRANDON SHORES	1	642	11	Coal	Dry	Wall	CURRENT LNB	0.42	79.0%	9,330		10,000
MD	BALTIMORE GAS & ELECT.	BRANDON SHORES	2	642	4	Coal	Dry	Wall	CURRENT LNB	0.48	79.0%	10,663		10,000
MD	BALTIMORE GAS & ELECT.	HERBERT WAGNER	2	136	37	Coal	Dry	Wall	LNB	0.39	74.0%	1,719		10,000
MD	BALTIMORE GAS & ELECT.	HERBERT WAGNER	3	359	29	Coal	Dry	Wall	NO RACT	1.18	78.0%	14,473		10,000
MD	POTOMAC ELECTRIC	CHALK POINT	1	364	31	Coal	Dry	Wall	LNB	0.46	87.0%	6,380		10,000
MD	POTOMAC ELECTRIC	CHALK POINT	2	364	30	Coal	Dry	Wall	LNB	0.46	77.0%	5,647		10,000
MD	BALTIMORE GAS & ELECT.	CHARLES CRANE	1	188	34	Coal	Wet	Cyclone	LOW SULFUR COAL	1.10	65.0%	5,888		10,000
MD	BALTIMORE GAS & ELECT.	CHARLES CRANE	2	188	33	Coal	Wet	Cyclone	LOW SULFUR COAL	1.23	65.0%	6,583		10,000

09/06/95

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UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

MARAMA.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
MD	POTOMAC ELECTRIC	CHALK POINT	3	640	20	Oil/Gas	Dry	Tangential	AVG CREDIT	0.29	50.0%	4,065		10,000
MD	POTOMAC ELECTRIC	CHALK POINT	4	640	14	Oil/Gas	Dry	Tangential	AVG CREDIT	0.29	39.0%	3,170		10,000
MD	BALTIMORE GAS & ELECT.	GOULD STREET	3	103	43	Oil/Gas	Dry	Wall	NO RACT	0.30	8.0%	108		10,000
MD	BALTIMORE GAS & ELECT.	HERBERT WAGNER	1	137	39	Oil/Gas	Dry	Wall	70% NAT GAS	0.25	12.0%	180		10,000
MD	BALTIMORE GAS & ELECT.	HERBERT WAGNER	4	398	23	Oil/Gas	Dry	Wall	NO RACT	0.55	9.0%	863		10,000
MD	BALTIMORE GAS & ELECT.	RIVERSIDE	1	64		Oil/Gas	Dry	Wall	SHUTDOWN	0.45	0.0%	0		10,000
MD	BALTIMORE GAS & ELECT.	RIVERSIDE	2	64		Oil/Gas	Dry	Wall	SHUTDOWN	0.45	0.0%	0		10,000
MD	BALTIMORE GAS & ELECT.	RIVERSIDE	3	67		Oil/Gas	Dry	Wall	SHUTDOWN	0.53	0.0%	0		10,000
MD	BALTIMORE GAS & ELECT.	RIVERSIDE	4	76	44	Oil/Gas	Dry	Wall	100% NAT GAS	0.20	6.0%	40		10,000
MD	BALTIMORE GAS & ELECT.	RIVERSIDE	5	76		Oil/Gas	Dry	Wall	SHUTDOWN	0.45	0.0%	0		10,000
MD	BALTIMORE GAS & ELECT.	WESTPORT	3	58		Oil/Gas	Dry	Wall	SHUTDOWN	0.28	0.0%	0		10,000
MD	BALTIMORE GAS & ELECT.	WESTPORT	4	68		Oil/Gas	Dry	Wall	SHUTDOWN	0.55	0.0%	0		10,000
MD	DELMARVA POWER & LIGHT	VIENNA	8	156	24	Oil	Wet	Tangential	IMPROVED O&M	0.39	33.0%	879		10,000
NC	CAROLINA POWER & LIGHT	CAPE FEAR	5	111	39	Coal	Dry	Tangential	n/a (phase II)	0.60	53.0%	1,514		9,780
NC	CAROLINA POWER & LIGHT	CAPE FEAR	6	140	37	Coal	Dry	Tangential	n/a (phase II)	0.60	48.0%	1,739		9,846
NC	CAROLINA POWER & LIGHT	H.F. LEE	1	61	43	Coal	Dry	Tangential	n/a (phase II)	0.60	27.0%	367		11,537
NC	CAROLINA POWER & LIGHT	L.V. SUTTON	1	106	41	Coal	Dry	Tangential	n/a (phase II)	0.60	34.0%	488		11,964
NC	CAROLINA POWER & LIGHT	ROXBORO	2	657	27	Coal	Dry	Tangential	n/a (phase II)	0.60	61.0%	13,202		9,724
NC	CAROLINA POWER & LIGHT	WEATHERSPOON	3	61	43	Coal	Dry	Tangential	n/a (phase II)	0.60	29.0%	663		11,038
NC	DUKE POWER	ALLEN	1	165	38	Coal	Dry	Tangential	LNB	0.45	49.0%	1,594		10,000
NC	DUKE POWER	ALLEN	2	165	38	Coal	Dry	Tangential	LNB	0.45	35.0%	1,138		10,000
NC	DUKE POWER	ALLEN	3	275	36	Coal	Dry	Tangential	LNB	0.45	47.0%	2,028		10,000
NC	DUKE POWER	ALLEN	4	275	35	Coal	Dry	Tangential	LNB	0.45	31.0%	2,257		10,000
NC	DUKE POWER	ALLEN	5	275	34	Coal	Dry	Tangential	LNB	0.45	55.0%	2,225		10,000
NC	DUKE POWER	BUCK	5	40	54	Coal	Dry	Tangential	n/a (phase II)	0.60	5.0%	53		10,000
NC	DUKE POWER	BUCK	6	40	53	Coal	Dry	Tangential	n/a (phase II)	0.60	5.0%	53		10,000
NC	DUKE POWER	BUCK	7	40	53	Coal	Dry	Tangential	n/a (phase II)	0.60	7.0%	74		10,000
NC	DUKE POWER	BUCK	8	125	42	Coal	Dry	Tangential	n/a (phase II)	0.60	14.0%	460		10,000
NC	DUKE POWER	BUCK	9	125	42	Coal	Dry	Tangential	n/a (phase II)	0.60	15.0%	493		10,000
NC	DUKE POWER	CLIFFSIDE	1	40	55	Coal	Dry	Tangential	n/a (phase II)	0.60	5.0%	53		10,000
NC	DUKE POWER	CLIFFSIDE	2	40	55	Coal	Dry	Tangential	n/a (phase II)	0.60	7.0%	74		10,000
NC	DUKE POWER	CLIFFSIDE	3	65	47	Coal	Dry	Tangential	n/a (phase II)	0.60	10.0%	171		10,000
NC	DUKE POWER	CLIFFSIDE	4	65	47	Coal	Dry	Tangential	n/a (phase II)	0.60	11.0%	188		10,000
NC	DUKE POWER	CLIFFSIDE	5	570	23	Coal	Dry	Tangential	n/a (phase II)	0.60	36.0%	5,393		10,000
NC	DUKE POWER	DAN RIVER	1	70	46	Coal	Dry	Tangential	n/a (phase II)	0.60	8.0%	147		10,000
NC	DUKE POWER	DAN RIVER	2	70	45	Coal	Dry	Tangential	n/a (phase II)	0.60	6.0%	110		10,000
NC	DUKE POWER	DAN RIVER	3	150	40	Coal	Dry	Tangential	n/a (phase II)	0.60	20.0%	788		10,000
NC	DUKE POWER	MARSHALL	1	350	30	Coal	Dry	Tangential	n/a (phase II)	0.60	69.0%	6,347		10,000
NC	DUKE POWER	MARSHALL	2	350	29	Coal	Dry	Tangential	n/a (phase II)	0.60	67.0%	6,163		10,000

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UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

MARAMA.WK1 — pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
NC	DUKE POWER	MARSHALL	3	648	26	Coal	Dry	Tangential	n/a (phase II)	0.60	57.0%	9,707		10,000
NC	DUKE POWER	MARSHALL	4	648	25	Coal	Dry	Tangential	n/a (phase II)	0.60	74.0%	12,602		10,000
NC	DUKE POWER	RIVERBEND	6	100	43	Coal	Dry	Tangential	LNB	0.45	23.0%	453		10,000
NC	DUKE POWER	RIVERBEND	7	100	43	Coal	Dry	Tangential	LNB	0.45	8.0%	158		10,000
NC	DUKE POWER	RIVERBEND	8	133	41	Coal	Dry	Tangential	LNB	0.45	39.0%	1,022		10,000
NC	DUKE POWER	RIVERBEND	9	133	41	Coal	Dry	Tangential	LNB	0.45	33.0%	865		10,000
NC	CAROLINA POWER & LIGHT	ASHEVILLE	1	146	31	Coal	Dry	Wall	n/a (phase II)	0.84	72.0%	3,761		9,754
NC	CAROLINA POWER & LIGHT	ASHEVILLE	2	153	24	Coal	Dry	Wall	n/a (phase II)	0.84	73.0%	4,049		9,846
NC	CAROLINA POWER & LIGHT	CAPE FEAR	3	32	53	Coal	Dry	Wall	n/a (phase II)	1.20	30.0%	505	*	10,000
NC	CAROLINA POWER & LIGHT	CAPE FEAR	4	32	52	Coal	Dry	Wall	n/a (phase II)	1.20	30.0%	505	*	10,000
NC	CAROLINA POWER & LIGHT	H.F. LEE	2	72	44	Coal	Dry	Wall	n/a (phase II)	0.84	30.0%	598		11,520
NC	CAROLINA POWER & LIGHT	H.F. LEE	3	189	33	Coal	Dry	Wall	n/a (phase II)	0.84	40.0%	3,978		9,944
NC	CAROLINA POWER & LIGHT	L.V. SUTTON	2	86	40	Coal	Dry	Wall	n/a (phase II)	0.84	28.0%	980		11,038
NC	CAROLINA POWER & LIGHT	L.V. SUTTON	3	380	23	Coal	Dry	Wall	n/a (phase II)	0.84	35.0%	4,069		10,265
NC	CAROLINA POWER & LIGHT	MAYO	1	650	12	Coal	Dry	Wall	LNB- STAGED COMB	0.50	68.0%	9,719		10,040
NC	CAROLINA POWER & LIGHT	ROXBORO	1	393	29	Coal	Dry	Wall	n/a (phase II)	0.84	70.0%	7,423		9,585
NC	CAROLINA POWER & LIGHT	ROXBORO	3	731	22	Coal	Dry	Wall	n/a (phase II)	0.84	71.0%	18,870		9,882
NC	CAROLINA POWER & LIGHT	ROXBORO	4	718	15	Coal	Dry	Wall	LNB	0.68	66.0%	14,197		10,059
NC	CAROLINA POWER & LIGHT	WEATHERSPOON	1	47	46	Coal	Dry	Wall	n/a (phase II)	0.84	26.0%	560		12,395
NC	CAROLINA POWER & LIGHT	WEATHERSPOON	2	47	45	Coal	Dry	Wall	n/a (phase II)	0.84	26.0%	564		12,492
NC	DUKE POWER	BELEWS CREEK	1	1,080	21	Coal	Dry	Wall	n/a (phase II)	1.20	71.0%	40,303		10,000
NC	DUKE POWER	BELEWS CREEK	2	1,120	20	Coal	Dry	Wall	n/a (phase II)	1.20	76.0%	44,739		10,000
PA	DUQUESNE LIGHT CO.	CHESWICK	1	570	25	Coal	Dry	Tangential	LNB + SOFA	0.45	72.2%	8,058		9,934
PA	METROPOLITAN EDISON CO	PORTLAND	1	158	37	Coal	Dry	Tangential	LNB + SOFA	0.37	55.0%	1,408		10,000
PA	METROPOLITAN EDISON CO	PORTLAND	2	243	33	Coal	Dry	Tangential	LNB + SOFA	0.43	50.0%	2,288		10,000
PA	METROPOLITAN EDISON CO	TITUS	1	80	44	Coal	Dry	Tangential	LNB + SOFA	0.40	51.0%	715		10,000
PA	METROPOLITAN EDISON CO	TITUS	2	80	44	Coal	Dry	Tangential	LNB + SOFA	0.40	40.0%	561		10,000
PA	METROPOLITAN EDISON CO	TITUS	3	80	42	Coal	Dry	Tangential	LNB + SOFA	0.40	48.0%	673		10,000
PA	PENN POWER & LIGHT CO.	BRUNNER ISLAND	1	334	34	Coal	Dry	Tangential	LNB + SOFA	0.45	75.1%	4,944		10,000
PA	PENN POWER & LIGHT CO.	BRUNNER ISLAND	2	390	30	Coal	Dry	Tangential	LNB + SOFA	0.45	69.4%	5,335		10,000
PA	PENN POWER & LIGHT CO.	BRUNNER ISLAND	3	745	27	Coal	Dry	Tangential	LNB + SOFA	0.45	71.6%	10,514		10,000
PA	PENN POWER & LIGHT CO.	MONTOUR	1	765	24	Coal	Dry	Tangential	LNB + SOFA	0.50	75.4%	12,632		10,000
PA	PENN POWER & LIGHT CO.	MONTOUR	2	750	22	Coal	Dry	Tangential	LNB + SOFA	0.50	91.7%	15,062		10,000
PA	PENNSYLVANIA ELECTRIC	CONEMAUGH	1	893	25	Coal	Dry	Tangential	LNB + SOFA	0.45	72.0%	12,673		10,000
PA	PENNSYLVANIA ELECTRIC	CONEMAUGH	2	893	24	Coal	Dry	Tangential	LNB + SOFA	0.45	88.0%	15,489		10,000
PA	PENNSYLVANIA ELECTRIC	KEYSTONE	1	893	28	Coal	Dry	Tangential	LNB + SOFA	0.45	88.0%	15,489		10,000
PA	PENNSYLVANIA ELECTRIC	KEYSTONE	2	893	27	Coal	Dry	Tangential	LNB + SOFA	0.45	71.0%	12,497		10,000
PA	PENNSYLVANIA ELECTRIC	SEWARD	15	134		Coal	Dry	Tangential	LNB + SOFA	0.50	75.0%	2,201		10,000
PA	PENNSYLVANIA ELECTRIC	SHAWVILLE	3	191	36	Coal	Dry	Tangential	APPL N RECVD	0.45	65.0%	2,447	*	10,000
PA	PENNSYLVANIA ELECTRIC	SHAWVILLE	4	191	35	Coal	Dry	Tangential	APPL N RECVD	0.45	65.0%	2,447	*	10,000

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UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

MARAMA.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
PA	PHILADELPHIA ELECTRIC	EDDYSTONE	1	279	36	Coal	Dry	Tangential	LNB + SOFA	0.50	50.0%	3,055		10,000
PA	PHILADELPHIA ELECTRIC	EDDYSTONE	2	302	35	Coal	Dry	Tangential	LNB + SOFA	0.50	50.0%	3,307		10,000
PA	WEST PENN POWER CO.	MITCHELL	33	284		Coal	Dry	Tangential	LNB + SOFA	0.40	62.2%	3,095		10,000
														10,000
PA	DUQUESNE LIGHT CO.	ELRAMA	1	100	43	Coal	Dry	Vertical	LNB	0.50	65.0%	1,424		10,000
PA	DUQUESNE LIGHT CO.	ELRAMA	2	100	42	Coal	Dry	Vertical	LNB	0.50	65.0%	1,424		10,000
PA	DUQUESNE LIGHT CO.	ELRAMA	3	112	41	Coal	Dry	Vertical	LNB	0.50	65.0%	1,594		10,000
PA	DUQUESNE LIGHT CO.	PHILLIPS	3	58	53	Coal	Dry	Vertical	APPL N RECVD	0.50	65.0%	826	*	10,000
PA	DUQUESNE LIGHT CO.	PHILLIPS	4	58	46	Coal	Dry	Vertical	APPL N RECVD	0.50	65.0%	826	*	10,000
PA	DUQUESNE LIGHT CO.	PHILLIPS	5	58	45	Coal	Dry	Vertical	APPL N RECVD	0.50	65.0%	826	*	10,000
PA	DUQUESNE LIGHT CO.	PHILLIPS	6	134	39	Coal	Dry	Vertical	APPL N RECVD	0.50	65.0%	1,907	*	10,000
PA	PENN POWER & LIGHT CO.	HOLTWOOD	17	73	41	Coal	Dry	Vertical	NONE PROPOSED	0.50	88.2%	1,410	sq?	10,000
PA	DUQUESNE LIGHT CO.	ELRAMA	4	175	35	Coal	Dry	Wall	LNB	0.50	65.0%	2,491		10,000
PA	PENN POWER & LIGHT CO.	SUNBURY	1A	75	46	Coal	Dry	Wall	NONE PROPOSED	0.50	73.5%	1,207	sq?	10,000
PA	PENN POWER & LIGHT CO.	SUNBURY	1B	75	46	Coal	Dry	Wall	NONE PROPOSED	0.50	73.5%	1,207	sq?	10,000
PA	PENN POWER & LIGHT CO.	SUNBURY	2A	75	46	Coal	Dry	Wall	NONE PROPOSED	0.50	73.5%	1,207	sq?	10,000
PA	PENN POWER & LIGHT CO.	SUNBURY	2B	75	46	Coal	Dry	Wall	NONE PROPOSED	0.50	73.5%	1,207	sq?	10,000
PA	PENN POWER & LIGHT CO.	MARTINS CREEK	1	150	41	Coal	Dry	Wall	LNB	0.50	55.2%	1,813		10,000
PA	PENN POWER & LIGHT CO.	MARTINS CREEK	2	150	39	Coal	Dry	Wall	LNB	0.50	45.1%	1,482		10,000
PA	PENN POWER & LIGHT CO.	SUNBURY	3	103	44	Coal	Dry	Wall	NONE PROPOSED	0.50	73.5%	1,658	sq?	10,000
PA	PENN POWER & LIGHT CO.	SUNBURY	4	134	42	Coal	Dry	Wall	NONE PROPOSED	0.50	68.3%	2,004	sq?	10,000
PA	PENNSYLVANIA ELECTRIC	HOMER CITY	1	662	26	Coal	Dry	Wall	LNB	0.50	68.0%	9,859		10,000
PA	PENNSYLVANIA ELECTRIC	HOMER CITY	2	650	26	Coal	Dry	Wall	LNB	0.50	74.0%	10,534		10,000
PA	PENNSYLVANIA ELECTRIC	HOMER CITY	3	682	18	Coal	Dry	Wall	LNB	0.50	83.0%	12,397		10,000
PA	PENNSYLVANIA ELECTRIC	SEWARD	12	40		Coal	Dry	Wall	LNB COFIRE	0.50	61.0%	534		10,000
PA	PENNSYLVANIA ELECTRIC	SEWARD	14	40		Coal	Dry	Wall	LNB COFIRE	0.50	61.0%	534		10,000
PA	PENNSYLVANIA ELECTRIC	SHAWVILLE	1	138	41	Coal	Dry	Wall	LNB	0.50	76.0%	2,297		10,000
PA	PENNSYLVANIA ELECTRIC	SHAWVILLE	2	138	41	Coal	Dry	Wall	LNB	0.50	48.0%	1,451		10,000
PA	PENNSYLVANIA ELECTRIC	WARREN	1	24	47	Coal	Dry	Wall	APPL N RECVD	0.50	53.0%	273	*	10,000
PA	PENNSYLVANIA ELECTRIC	WARREN	2	24	46	Coal	Dry	Wall	APPL N RECVD	0.50	53.0%	273	*	10,000
PA	PENNSYLVANIA ELECTRIC	WARREN	3	24		Coal	Dry	Wall	APPL N RECVD	0.50	53.0%	273	*	10,000
PA	PENNSYLVANIA ELECTRIC	WARREN	4	24		Coal	Dry	Wall	APPL N RECVD	0.50	53.0%	273	*	10,000
PA	PENNSYLVANIA POWER	BRUCE MANSFIELD	1	780	20	Coal	Dry	Wall	LNB	0.50	68.0%	11,616		10,000
PA	PENNSYLVANIA POWER	BRUCE MANSFIELD	2	780	18	Coal	Dry	Wall	LNB	0.50	69.0%	11,787		10,000
PA	PENNSYLVANIA POWER	BRUCE MANSFIELD	3	800	15	Coal	Dry	Wall	LNB	0.50	72.0%	12,614		10,000
PA	PENNSYLVANIA POWER	NEW CASTLE	3	98	43	Coal	Dry	Wall	NONE PROPOSED	0.79	42.0%	1,424		10,000
PA	PENNSYLVANIA POWER	NEW CASTLE	4	98	37	Coal	Dry	Wall	NONE PROPOSED	0.70	40.0%	1,202		10,000
PA	PENNSYLVANIA POWER	NEW CASTLE	5	137	31	Coal	Dry	Wall	NONE PROPOSED	0.97	67.0%	3,900		10,000
PA	WEST PENN POWER CO.	HATFIELDS FERRY	1	555	26	Coal	Dry	Wall	LNCB	0.58	70.3%	9,912		10,000
PA	WEST PENN POWER CO.	HATFIELDS FERRY	2	555	25	Coal	Dry	Wall	LNCB	0.58	73.5%	10,363		10,000
PA	WEST PENN POWER CO.	HATFIELDS FERRY	3	555	24	Coal	Dry	Wall	LNCB	0.58	75.8%	10,687		10,000
PA	WEST PENN POWER CO.	ARMSTRONG	1	176	37	Coal	Dry	Wall	LNB	0.50	76.1%	2,933		10,000
PA	WEST PENN POWER CO.	ARMSTRONG	2	176	36	Coal	Dry	Wall	LNB	0.50	70.0%	2,698		10,000

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UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

MARAMA.WK1

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	pres yr for age 1995 Heat Rate (Btu/kW-hr)
PA	U.G.I. UTILITIES	HUNLOCK POWER	6	50	36	Coal	Wet	Vertical	APPL N RECVD	0.50	76.0%	831	*	10,000
PA	PHILADELPHIA ELECTRIC	CROMBY	1	144	41	Coal	Wet	Wall	LNB	0.50	50.0%	1,577		10,000
PA	PENN POWER & LIGHT CO.	MARTINS CREEK	3	820	20	Oil	Dry	Tangential	LNB w/ OFA	0.50	7.0%	1,257		10,000
PA	PENN POWER & LIGHT CO.	MARTINS CREEK	4	820	18	Oil	Dry	Tangential	LNB w/ OFA	0.50	7.7%	1,383		10,000
PA	PHILADELPHIA ELECTRIC	CROMBY	2	201	40	Oil	Dry	Tangential	AIR BIASING	0.26	20.0%	458		10,000
PA	PHILADELPHIA ELECTRIC	EDDYSTONE	3	380	21	Oil	Dry	Tangential	OFA REHAB	0.28	20.0%	932		10,000
PA	PHILADELPHIA ELECTRIC	EDDYSTONE	4	380	19	Oil	Dry	Tangential	OFA REHAB	0.33	20.0%	1,099		10,000
PA	PHILADELPHIA ELECTRIC	SCHUYLKILL	1	166	37	Oil	Dry	Tangential	LNB + SOFA	0.31	30.0%	673		9,950
PA	TRIGEN (PHILA. THERMAL)	SCHUYLKILL	23	88	57	Oil	Dry	Tangential	LNB + SOFA	0.28	25.0%	232		8,550
PA	TRIGEN (PHILA. THERMAL)	SCHUYLKILL	24	88	57	Oil	Dry	Tangential	LNB + SOFA	0.28	25.0%	265		9,800
PA	PHILADELPHIA ELECTRIC	DELAWARE	7	126	42	Oil	Dry	Wall	LNB + SOFA	0.47	30.0%	645		8,290
PA	PHILADELPHIA ELECTRIC	DELAWARE	8	124	42	Oil	Dry	Wall	LNB + SOFA	0.44	30.0%	595		8,300
PA	TRIGEN (PHILA. THERMAL)	SCHUYLKILL	26	85	23	Oil	Dry	Wall	GAS + LNB	0.45	25.0%	458		11,000
PA	TRIGEN (PHILA. THERMAL)	EDISON	1	283	38	Oil	Dry	Wall	FUEL LIMIT /YR	0.45	1.8%	102		10,000
PA	TRIGEN (PHILA. THERMAL)	EDISON	2	283	38	Oil	Dry	Wall	FUEL LIMIT /YR	0.45	1.8%	102		10,000
PA	TRIGEN (PHILA. THERMAL)	EDISON	3	335	26	Oil	Dry	Wall	FUEL LIMIT /YR	0.45	1.8%	121		10,000
PA	TRIGEN (PHILA. THERMAL)	EDISON	4	335	26	Oil	Dry	Wall	FUEL LIMIT /YR	0.45	1.8%	121		10,000
PA	WEST PENN POWER CO.	MITCHELL	1	51	47	Oil/Gas	Dry	Wall	(COLD RESERVE)	0.50	0.0%	0	em?	10,000
PA	WEST PENN POWER CO.	MITCHELL	2	51	46	Oil/Gas	Dry	Wall	(COLD RESERVE)	0.50	0.0%	0	em?	10,000
PA	WEST PENN POWER CO.	MITCHELL	3	51	32	Oil/Gas	Dry	Wall	(COLD RESERVE)	0.50	0.0%	0	em?	10,000
PA	WEST PENN POWER CO.	SPRINGDALE	7	86	50	Oil/Gas	Dry	Wall	(COLD RESERVE)	0.50	0.0%	0	em?	
PA	WEST PENN POWER CO.	SPRINGDALE	8	121	41	Oil/Gas	Dry	Wall	(COLD RESERVE)	0.50	0.0%	0	em?	
VA	APPALACHIAN POWER CO	GLEN LYN	5	100	51	Coal	Dry	Tangential	n/a (phase II)	0.45	24.4%	481	*	10,000
VA	POTOMAC ELECTRIC	POTOMAC RIVER	1	93	46	Coal	Dry	Tangential	AVG/NO CTRL	0.55	68.0%	1,682		11,043
VA	POTOMAC ELECTRIC	POTOMAC RIVER	2	93	45	Coal	Dry	Tangential	AVG/NO CTRL	0.55	75.0%	1,819		10,828
VA	POTOMAC ELECTRIC	POTOMAC RIVER	3	108	41	Coal	Dry	Tangential	AVG/NO CTRL	0.62	90.0%	2,368		8,972
VA	POTOMAC ELECTRIC	POTOMAC RIVER	4	108	39	Coal	Dry	Tangential	AVG/NO CTRL	0.62	92.0%	2,451		9,083
VA	POTOMAC ELECTRIC	POTOMAC RIVER	5	108	38	Coal	Dry	Tangential	AVG/NO CTRL	0.62	93.0%	2,498		9,157
VA	VIRGINIA POWER	CHESAPEAKE	1	113	42	Coal	Dry	Tangential	n/a (phase II)	0.45	38.0%	843	*	10,000
VA	VIRGINIA POWER	CHESAPEAKE	2	113	41	Coal	Dry	Tangential	n/a (phase II)	0.45	38.0%	843	*	10,000
VA	VIRGINIA POWER	CHESAPEAKE	4	239	33	Coal	Dry	Tangential	n/a (phase II)	0.45	54.0%	2,548	*	10,000
VA	VIRGINIA POWER	CHESTERFIELD	1	83		Coal	Dry	Tangential	n/a (phase II)	0.45	54.0%	887	*	10,000
VA	VIRGINIA POWER	CHESTERFIELD	2	133		Coal	Dry	Tangential	n/a (phase II)	0.45	54.0%	1,419	*	10,000
VA	VIRGINIA POWER	CHESTERFIELD	3	113	43	Coal	Dry	Tangential	n/a (phase II)	0.45	38.5%	853	*	10,000
VA	VIRGINIA POWER	CHESTERFIELD	4	188	35	Coal	Dry	Tangential	n/a (phase II)	0.45	54.4%	2,011	*	10,000
VA	VIRGINIA POWER	CHESTERFIELD	5	359	31	Coal	Dry	Tangential	n/a (phase II)	0.45	50.9%	3,600	*	10,000
VA	VIRGINIA POWER	CHESTERFIELD	6	694	26	Coal	Dry	Tangential	n/a (phase II)	0.45	46.9%	6,416	*	10,000

TABLE A - 1

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

MARAMA.WK1

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	pres yr for age 1995 Heat Rate (Btu/kW-hr)
VA	VIRGINIA POWER	POSSUM POINT	3	106	39	Coal	Dry	Tangential	COMPUTER CTRL	0.47	59.0%	1,371		10,651
VA	VIRGINIA POWER	POSSUM POINT	4	230	33	Coal	Dry	Tangential	LNB + COMPUTR	0.37	95.0%	3,590		10,139
VA	VIRGINIA POWER	YORKTOWN POWER	1	188	38	Coal	Dry	Tangential	n/a (phase II)	0.45	41.2%	1,524	*	10,000
VA	VIRGINIA POWER	YORKTOWN POWER	2	188	37	Coal	Dry	Tangential	n/a (phase II)	0.45	20.0%	737	*	10,000
VA	APPALACHIAN POWER CO	CLINCH RIVER	1	238	37	Coal	Dry	Wall	n/a (phase II)	0.50	46.4%	2,412	*	10,000
VA	APPALACHIAN POWER CO	CLINCH RIVER	2	238	37	Coal	Dry	Wall	n/a (phase II)	0.50	52.0%	2,707	*	10,000
VA	APPALACHIAN POWER CO	CLINCH RIVER	3	238	34	Coal	Dry	Wall	n/a (phase II)	0.50	66.6%	3,465	*	10,000
VA	APPALACHIAN POWER CO	GLEN LYN	6	238	38	Coal	Dry	Wall	n/a (phase II)	0.50	54.2%	2,819	*	10,000
VA	VIRGINIA POWER	BREMO BLUFF	3	69	45	Coal	Dry	Wall	n/a (phase II)	0.50	52.0%	786	*	10,000
VA	VIRGINIA POWER	BREMO BLUFF	4	185	37	Coal	Dry	Wall	n/a (phase II)	0.50	52.4%	2,125	*	10,000
VA	VIRGINIA POWER	CHESAPEAKE	3	185	36	Coal	Dry	Wall	n/a (phase II)	0.50	52.0%	2,110	*	10,000
VA	VIRGINIA POWER	POSSUM POINT	1	78	48	Oil	Dry	Tangential	EXEMPT CF<5%	0.29	0.0%	0		11,859
VA	VIRGINIA POWER	POSSUM POINT	2	72	46	Oil	Dry	Tangential	EXEMPT CF<5%	0.29	0.0%	0		12,644
VA	VIRGINIA POWER	POSSUM POINT	5	649	20	Oil	Dry	Tangential	NONE NEEDED	0.24	2.9%	191		9,664
VA	VIRGINIA POWER	YORKTOWN POWER	3	649	21	Oil	Dry	Tangential	n/a (phase II)	0.45	5.8%	740	*	10,000
DELAWARE		SUBTOTALS	2	251		Coal	Dry	Tangential		0.62	62.6%	4,304		
		SUBTOTALS	4	757		Coal	Dry	Wall		0.47	55.9%	8,754		
		SUBTOTALS	2	511		Oil/Gas	Dry	Tangential		0.39	47.9%	4,314		
		SUBTOTALS	6	247		Oil/Gas	Dry	Wall		0.49	39.4%	2,086		
TOTAL DELAWARE		====================	14	1,766						0.47	52.2%	19,458		
DISTRICT OF COLUMBIA		SUBTOTALS	2	580		Oil/Gas	Dry	Tangential		0.25	3.9%	268		
TOTAL DISTRICT OF COLUMBIA		====================	2	580						0.25	3.9%	268		
MARYLAND		SUBTOTALS	6	1,930		Coal	Dry	Tangential		0.72	77.7%	47,405		
		SUBTOTALS	7	2,534		Coal	Dry	Wall		0.55	78.8%	48,316		
		SUBTOTALS	2	376		Coal	Wet	Cyclone		1.17	65.0%	12,471		
		SUBTOTALS	2	1,280		Oil/Gas	Dry	Tangential		0.29	44.5%	7,235		
		SUBTOTALS	10	1,111		Oil/Gas	Dry	Wall		0.43	5.9%	1,191		

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TABLE A - 1

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

MARAMA.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
		SUBTOTALS	1	156		Oil/Gas	Wet	Tangential		0.39	33.0%	879		
TOTAL MARYLAND		===================	28	7,387						0.56	59.9%	117,498		
NORTH CAROLINA		SUBTOTALS	32	6,193		Coal	Dry	Tangential		0.56	46.2%	72,585		
		SUBTOTALS	16	5,876		Coal	Dry	Wall		0.92	65.4%	154,819		
TOTAL NORTH CAROLINA		===================	48	12,069						0.74	55.5%	227,405		
PENNSYLVANIA		SUBTOTALS	21	9,148		Coal	Dry	Tangential		0.46	73.4%	134,888		
		SUBTOTALS	8	693		Coal	Dry	Vertical		0.50	67.4%	10,236		
		SUBTOTALS	31	8,166		Coal	Dry	Wall		0.53	69.9%	132,109		
		SUBTOTALS	1	50		Coal	Wet	Vertical		0.50	76.0%	831		
		SUBTOTALS	1	144		Coal	Wet	Wall		0.50	50.0%	1,577		
		SUBTOTALS	8	2,944		Oil/Gas	Dry	Tangential		0.41	13.8%	6,298		
		SUBTOTALS	12	1,932		Oil/Gas	Dry	Wall		0.46	6.2%	2,145		
TOTAL PENNSYLVANIA		===================	82	23,076						0.48	58.6%	288,084		
VIRGINIA		SUBTOTALS	19	3,355		Coal	Dry	Tangential		0.47	54.7%	37,942		
		SUBTOTALS	7	1,390		Coal	Dry	Wall		0.50	54.0%	16,424		
		SUBTOTALS	4	1,448		Oil/Gas	Dry	Tangential		0.34	3.9%	931		
TOTAL VIRGINIA		===================	30	6,193						0.44	42.7%	55,297		
SUBTOTALS ---MARAMA			80	20,877		Coal	Dry	Tangential		0.52	62.6%	297,125		
			8	693		Coal	Dry	Vertical		0.50	67.4%	10,236		
			65	18,723		Coal	Dry	Wall		0.65	68.0%	360,423		
			2	376		Coal	Wet	Cyclone		1.17	65.0%	12,471		
			1	50		Coal	Wet	Vertical		0.50	76.0%	831		
			1	144		Coal	Wet	Wall		0.50	50.0%	1,577		

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TABLE A - 1

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

MARAMA.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
			1	156		Oil/Gas	Dry	Cyclone		0.39	33.0%	879		
			18	6,763		Oil/Gas	Dry	Tangential		0.36	19.2%	19,047		
			28	3,290		Oil/Gas	Dry	Wall		0.45	8.5%	5,423		
TOTAL MARAMA			204	51,070				All types		0.54	55.3%	708,010		

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TABLE A - 1

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

MARAMA.WK1

pres yr for age 1995

State	Utility	Plant	Unit No.	Size (MWe)	Years Old	Fuel	Furn. Type	Firing Type	RACT NOx Control	NOx (lb/MMBtu)	CF (%)	TOTAL NOx (tons/yr)	no dt	Heat Rate (Btu/kW-hr)
MARAMA SPREADSHEET SUMMARY DATA														
			153	40,292		Coal	Dry					667,783		
			4	570		Coal	Wet					14,878		
			157	40,862		Coal		All types				682,662		
			47	10,208		Oil/Gas	Dry					25,349		
			0	0		Oil/Gas	Wet					0		
			47	10,208		Oil/Gas		All types				25,349		
BY STATE:														
DE			6	1,008		Coal						13,058		
			8	758		Oil/Gas						6,400		
DC			0	0		Coal						0		
			2	580		Oil/Gas						268		
MD			15	4,840		Coal						108,193		
			13	2,547		Oil/Gas						9,305		
NC			48	12,069		Coal						227,405		
			0	0		Oil/Gas						0		
PA			62	18,201		Coal						279,641		
			20	4,875		Oil/Gas						8,443		
VA			26	4,745		Coal						54,366		
			4	1,448		Oil/Gas						931		
TOTAL			204	51,070								708,010		

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LNB: LNB, LNB+OFA, LNCB
FGT: FLUE GAS TRTMT, SNCR, SCR
RET: RETIRE, STANDBY, MOTHBALL
UTILITY BOILERS IN THECTR: COMB CONTROLS, LEA,FGR, BOOS, CTRL
RPW: REPOWER
UNC: UNCONTROLLED
FSW: FUEL SWITCHING
NRP: NOT REPORTED

/WCS5~{RIGHT}

State	Fuel	Furn. Type	Firing Type	# UNITS	UNITS LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MWe PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	TONS/YEAR NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
DELAW	Coal	Dry	Tangential	2	1	0	0	0	0	1	0	0	167	0	0	0	0	84	0	0	3138	0	0	0	0	1166	0	0
	Coal	Dry	Wall	4	2	0	2	0	0	0	0	0	586	0	171	0	0	0	0	0	5526	0	3227	0	0	0	0	0
	Oil/Gas	Dry	Tangential	2	1	0	0	0	0	0	0	1	444	0	0	0	0	0	0	67	3273	0	0	0	0	0	0	1041
	Oil/Gas	Dry	Wall	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	247	0	0	0	0	0	0	0	2086
TOTAL DELAWARE				14	4	0	2	0	0	1	0	7	1197	0	171	0	0	84	0	314	11937	0	3227	0	0	1166	0	3128
DISTR	Oil/Gas	Dry	Tangential	2	0	0	0	0	0	2	0	0	0	0	0	0	0	580	0	0	0	0	0	0	0	268	0	0
TOTAL DISTRICT OF COLUMBIA				2	0	0	0	0	0	2	0	0	0	0	0	0	0	580	0	0	0	0	0	0	0	268	0	0
MARYL	Coal	Dry	Tangential	6	3	0	0	0	0	3	0	0	1342	0	0	0	0	588	0	0	32725	0	0	0	0	14680	0	0
	Coal	Dry	Wall	7	5	0	0	1	0	1	0	0	2148	0	0	27	0	359	0	0	33740	0	0	104	0	14473	0	0
	Coal	Wet	Cyclone	2	0	0	0	0	0	0	2	0	0	0	0	0	0	0	376	0	0	0	0	0	0	0	12471	0
	Oil/Gas	Dry	Tangential	2	0	0	0	0	0	2	0	0	0	0	0	0	0	1280	0	0	0	0	0	0	0	7235	0	0
	Oil/Gas	Dry	Wall	10	0	0	6	0	0	2	2	0	0	0	397	0	0	501	213	0	0	0	0	0	0	971	220	0
	Oil/Gas	Wet	Tangential	1	0	0	0	1	0	0	0	0	0	0	0	156	0	0	0	0	0	0	0	879	0	0	0	0
TOTAL MARYLAND				28	8	0	6	2	0	8	4	0	3490	0	397	183	0	2728	589	0	66465	0	0	983	0	37359	12691	0
NORTH	Coal	Dry	Tangential	32	9	0	0	0	0	23	0	0	1621	0	0	0	0	4572	0	0	11740	0	0	0	0	60845	0	0
	Coal	Dry	Wall	16	2	0	0	0	0	14	0	0	1368	0	0	0	0	4508	0	0	23916	0	0	0	0	130903	0	0
TOTAL NORTH CAROLINA				48	11	0	0	0	0	37	0	0	2989	0	0	0	0	9080	0	0	35656	0	0	0	0	191748	0	0
PENNS	Coal	Dry	Tangential	21	19	0	0	0	0	0	0	2	8766	0	0	0	0	0	0	382	129994	0	0	0	0	0	0	4894
	Coal	Dry	Vertical	8	3	0	0	0	0	1	0	4	312	0	0	0	0	73	0	308	4441	0	0	0	0	1410	0	4384
	Coal	Dry	Wall	31	18	0	0	0	0	9	0	4	7202	0	0	0	0	870	0	94	116001	0	0	0	0	15017	0	1091
	Coal	Wet	Vertical	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	50	0	0	0	0	0	0	0	831
	Coal	Wet	Wall	1	1	0	0	0	0	0	0	0	144	0	0	0	0	0	0	0	1577	0	0	0	0	0	0	0

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UTILITY BOILERS IN THE

LNB: LNB, LNB+OFA, LNCB
FGT: FLUE GAS TRTMT, SNCR, SCR
RET: RETIRE, STANDBY, MOTHBALL
CTR: COMB CONTROLS, LEA,FGR, BOOS, CTRL
RPW: REPOWER
UNC: UNCONTROLLED
FSW: FUEL SWITCHING
NRP: NOT REPORTED

/WCS5~(RIGHT)

State	Fuel	Furn. Type	Firing Type	# UNITS	UNITS LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MWe PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	TONS/YEAR NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
	Oil/Gas	Dry	Tangential	8	5	0	0	3	0	0	0	0	1983	0	0	961	0	0	0	0	3810	0	0	2488	0	0	0	0
	Oil/Gas	Dry	Wall	12	3	0	5	4	0	0	0	0	335	0	361	1236	0	0	0	0	1698	0	0	447	0	0	0	0
TOTAL PENNSYLVANIA				82	49	0	5	7	0	10	0	11	18741	0	361	2197	0	943	0	834	257521	0	0	2935	0	16427	0	11200
VIRGI	Coal	Dry	Tangential	19	1	0	0	1	0	17	0	0	230	0	0	106	0	3019	0	0	3590	0	0	1371	0	32980	0	0
	Coal	Dry	Wall	7	0	0	0	0	0	7	0	0	0	0	0	0	0	1390	0	0	0	0	0	0	0	16424	0	0
	Oil/Gas	Dry	Tangential	4	0	0	0	0	0	4	0	0	0	0	0	0	0	1448	0	0	0	0	0	0	0	931	0	0
TOTAL VIRGINIA				30	1	0	0	1	0	28	0	0	230	0	0	106	0	5857	0	0	3590	0	0	1371	0	50336	0	0
SUBTO	Coal	Dry	Tangential	80	33	0	0	1	0	44	0	2	12126	0	0	106	0	8263	0	382	181188	0	0	1371	0	109671	0	4894
	Coal	Dry	Vertical	8	3	0	0	0	0	1	0	4	312	0	0	0	0	73	0	308	4441	0	0	0	0	1410	0	4384
	Coal	Dry	Wall	65	27	0	2	1	0	31	0	4	11304	0	171	27	0	7127	0	94	179183	0	3227	104	0	176817	0	1091
	Coal	Wet	Cyclone	2	0	0	0	0	0	0	2	0	0	0	0	0	0	0	376	0	0	0	0	0	0	0	12471	0
	Coal	Wet	Vertical	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	50	0	0	0	0	0	0	0	831
	Coal	Wet	Wall	1	1	0	0	0	0	0	0	0	144	0	0	0	0	0	0	0	1577	0	0	0	0	0	0	0
	Oil/Gas	Dry	Cyclone	1	0	0	0	1	0	0	0	0	0	0	0	156	0	0	0	0	0	0	0	879	0	0	0	0
	Oil/Gas	Dry	Tangential	18	6	0	0	3	0	8	0	1	2427	0	0	961	0	3308	0	67	7082	0	0	2488	0	8435	0	1041
	Oil/Gas	Dry	Wall	28	3	0	11	4	0	2	2	6	335	0	758	1236	0	501	213	247	1698	0	0	447	0	971	220	2086
TOTAL MARAMA			All types	204	73	0	13	10	0	86	4	18	26647	0	929	2486	0	19272	589	1148	375170	0	3227	5290	0	297304	12691	14328

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
DELAW	Coal	Dry	Tangential	2	0.67					0.54		
	Coal	Dry	Wall	4	0.40		0.74					
	Oil/Gas	Dry	Tangential	2	0.37							0.56
	Oil/Gas	Dry	Wall	6								0.49
TOTAL DELAWARE				14	0.42		0.74			0.54		0.51
DISTR	Oil/Gas	Dry	Tangential	2						0.25		
TOTAL DISTRICT OF COLUMBIA				2						0.25		
MARYL	Coal	Dry	Tangential	6	0.74					0.68		
	Coal	Dry	Wall	7	0.45			0.55		1.18		
	Coal	Wet	Cyclone	2							1.17	
	Oil/Gas	Dry	Tangential	2						0.29		
	Oil/Gas	Dry	Wall	10			0.46			0.50	0.23	
	Oil/Gas	Wet	Tangential	1				0.39				
TOTAL MARYLAND				28	0.56		0.46	0.41		0.53	0.83	
NORTH	Coal	Dry	Tangential	32	0.45					0.60		
	Coal	Dry	Wall	16	0.59					1.02		
TOTAL NORTH CAROLINA				48	0.52					0.81		
PENNS	Coal	Dry	Tangential	21	0.46							0.45
	Coal	Dry	Vertical	8	0.50					0.50		0.50
	Coal	Dry	Wall	31	0.52					0.63		0.50
	Coal	Wet	Vertical	1								0.50
	Coal	Wet	Wall	1	0.50							

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
	Oil/Gas	Dry	Tangential	8	0.46			0.30				
	Oil/Gas	Dry	Wall	12	0.45		0.50	0.45				
TOTAL PENNSYLVANIA				82	0.48		0.50	0.38		0.62		0.48
VIRGI	Coal	Dry	Tangential	19	0.37			0.47		0.47		
	Coal	Dry	Wall	7						0.50		
	Oil/Gas	Dry	Tangential	4						0.34		
TOTAL VIRGINIA				30	0.37			0.47		0.45		
SUBTO	Coal	Dry	Tangential	80	0.49			0.47		0.56		0.45
	Coal	Dry	Vertical	8	0.50					0.50		0.50
	Coal	Dry	Wall	65	0.51		0.74	0.55		0.88		0.50
	Coal	Wet	Cyclone	2							1.17	
	Coal	Wet	Vertical	1								0.50
	Coal	Wet	Wall	1	0.50							
	Oil/Gas	Dry	Cyclone	1				0.39				
	Oil/Gas	Dry	Tangential	18	0.45			0.30		0.30		0.56
	Oil/Gas	Dry	Wall	28	0.45		0.48	0.45		0.50	0.23	0.49
TOTAL MARAMA			All types	204	0.49		0.52	0.39		0.63	0.83	0.48

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
MARAMA SPREADSHEET SUMMARY DATA												
	Coal	Dry		153								
	Coal	Wet		4								
	Coal		All types	157								
	Oil/Gas	Dry		47								
	Oil/Gas	Wet		0								
	Oil/Gas		All types	47								
BY STATE:												
DE	Coal			6								
	Oil/Gas			8								
DC	Coal			0								
	Oil/Gas			2								
MD	Coal			15								
	Oil/Gas			13								
NC	Coal			48								
	Oil/Gas			0								
PA	Coal			62								
	Oil/Gas			20								
VA	Coal			26								
	Oil/Gas			4								
TOTAL				204								

09/06/95

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	MAXIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MINIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
					0.00 INDICATES NO DATA								99.99 INDICATES NO DATA							
DELAW	Coal	Dry	Tangential	2	0.67	0.00	0.00	0.00	0.00	0.54	0.00	0.00	0.67	99.99	99.99	99.99	99.99	0.54	99.99	99.99
	Coal	Dry	Wall	4	0.42	0.00	0.81	0.00	0.00	0.00	0.00	0.00	0.34	99.99	0.67	99.99	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Tangential	2	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.56	0.37	99.99	99.99	99.99	99.99	99.99	99.99	0.56
	Oil/Gas	Dry	Wall	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.53	99.99	99.99	99.99	99.99	99.99	99.99	99.99	0.49
TOTAL DELAWARE				14	0.67	0.00	0.81	0.00	0.00	0.54	0.00	0.56	0.34	99.99	0.67	99.99	99.99	0.54	99.99	0.49
DISTR	Oil/Gas	Dry	Tangential	2	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	99.99	99.99	99.99	99.99	99.99	0.25	99.99	99.99
TOTAL DISTRICT OF COLUMBIA				2	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	99.99	99.99	99.99	99.99	99.99	0.25	99.99	99.99
MARYL	Coal	Dry	Tangential	6	0.76	0.00	0.00	0.00	0.00	0.70	0.00	0.00	0.45	99.99	99.99	99.99	99.99	0.65	99.99	99.99
	Coal	Dry	Wall	7	0.48	0.00	0.00	0.55	0.00	1.18	0.00	0.00	0.39	99.99	99.99	0.55	99.99	1.18	99.99	99.99
	Coal	Wet	Cyclone	2	0.00	0.00	0.00	0.00	0.00	0.00	1.23	0.00	99.99	99.99	99.99	99.99	99.99	99.99	1.10	99.99
	Oil/Gas	Dry	Tangential	2	0.00	0.00	0.00	0.00	0.00	0.29	0.00	0.00	99.99	99.99	99.99	99.99	99.99	0.29	99.99	99.99
	Oil/Gas	Dry	Wall	10	0.00	0.00	0.55	0.00	0.00	0.55	0.25	0.00	99.99	99.99	0.28	99.99	99.99	0.30	0.20	99.99
	Oil/Gas	Wet	Tangential	1	0.00	0.00	0.00	0.39	0.00	0.00	0.00	0.00	99.99	99.99	99.99	0.39	99.99	99.99	99.99	99.99
TOTAL MARYLAND				28	0.76	0.00	0.55	0.55	0.00	1.18	1.23	0.00	0.39	99.99	0.28	0.39	99.99	0.29	0.20	99.99
NORTH	Coal	Dry	Tangential	32	0.45	0.00	0.00	0.00	0.00	0.60	0.00	0.00	0.45	99.99	99.99	99.99	99.99	0.60	99.99	99.99
	Coal	Dry	Wall	16	0.68	0.00	0.00	0.00	0.00	1.20	0.00	0.00	0.50	99.99	99.99	99.99	99.99	0.84	99.99	99.99
TOTAL NORTH CAROLINA				48	0.68	0.00	0.00	0.00	0.00	1.20	0.00	0.00	0.45	99.99	99.99	99.99	99.99	0.60	99.99	99.99
PENNS	Coal	Dry	Tangential	21	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.45	0.37	99.99	99.99	99.99	99.99	99.99	99.99	0.45
	Coal	Dry	Vertical	8	0.50	0.00	0.00	0.00	0.00	0.50	0.00	0.50	0.50	99.99	99.99	99.99	99.99	0.50	99.99	0.50
	Coal	Dry	Wall	31	0.58	0.00	0.00	0.00	0.00	0.97	0.00	0.50	0.50	99.99	99.99	99.99	99.99	0.50	99.99	0.50
	Coal	Wet	Vertical	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	99.99	99.99	99.99	99.99	99.99	99.99	99.99	0.50
	Coal	Wet	Wall	1	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	99.99	99.99	99.99	99.99	99.99	99.99	99.99

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	MAXIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	MINIMUM LB/MMBTU NOx PER: LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
	Oil/Gas	Dry	Tangential	8	0.50	0.00	0.00	0.33	0.00	0.00	0.00	0.00	0.28	99.99	99.99	0.26	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Wall	12	0.47	0.00	0.50	0.45	0.00	0.00	0.00	0.00	0.44	99.99	0.50	0.45	99.99	99.99	99.99	99.99
TOTAL PENNSYLVANIA				82	0.58	0.00	0.50	0.45	0.00	0.97	0.00	0.50	0.28	99.99	0.50	0.26	99.99	0.50	99.99	0.45
VIRGI	Coal	Dry	Tangential	19	0.37	0.00	0.00	0.47	0.00	0.62	0.00	0.00	0.37	99.99	99.99	0.47	99.99	0.45	99.99	99.99
	Coal	Dry	Wall	7	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	99.99	99.99	99.99	99.99	99.99	0.50	99.99	99.99
	Oil/Gas	Dry	Tangential	4	0.00	0.00	0.00	0.00	0.00	0.45	0.00	0.00	99.99	99.99	99.99	99.99	99.99	0.24	99.99	99.99
TOTAL VIRGINIA				30	0.37	0.00	0.00	0.47	0.00	0.62	0.00	0.00	0.37	99.99	99.99	0.47	99.99	0.24	99.99	99.99
SUBTO	Coal	Dry	Tangential	80	0.76	0.00	0.00	0.47	0.00	0.70	0.00	0.45	0.37	99.99	99.99	0.47	99.99	0.45	99.99	0.45
	Coal	Dry	Vertical	8	0.50	0.00	0.00	0.00	0.00	0.50	0.00	0.50	0.50	99.99	99.99	99.99	99.99	0.50	99.99	0.50
	Coal	Dry	Wall	65	0.68	0.00	0.81	0.55	0.00	1.20	0.00	0.50	0.34	99.99	0.67	0.55	99.99	0.50	99.99	0.50
	Coal	Wet	Cyclone	2	0.00	0.00	0.00	0.00	0.00	0.00	1.23	0.00	99.99	99.99	99.99	99.99	99.99	99.99	1.10	99.99
	Coal	Wet	Vertical	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	99.99	99.99	99.99	99.99	99.99	99.99	99.99	0.50
	Coal	Wet	Wall	1	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	99.99	99.99	99.99	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Cyclone	1	0.00	0.00	0.00	0.39	0.00	0.00	0.00	0.00	99.99	99.99	99.99	0.39	99.99	99.99	99.99	99.99
	Oil/Gas	Dry	Tangential	18	0.50	0.00	0.00	0.33	0.00	0.45	0.00	0.56	0.28	99.99	99.99	0.26	99.99	0.24	99.99	0.56
	Oil/Gas	Dry	Wall	28	0.47	0.00	0.55	0.45	0.00	0.55	0.25	0.53	0.44	99.99	0.28	0.45	99.99	0.30	0.20	0.49
TOTAL MARAMA			All types	204	0.76	0.00	0.81	0.55	0.00	1.20	1.23	0.56	0.28	99.99	0.28	0.26	99.99	0.24	0.20	0.45

UTILITY BOILERS IN THE MARAMA REGION -- NOx INVENTORY

State	Fuel	Furn. Type	Firing Type	# UNITS	MAXIMUM LB/MMBTU NOx PER:								MINIMUM LB/MMBTU NOx PER:							
					LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP	LNB	FGT	RET	CTR	RPW	UNC	FSW	NRP
MARAMA SPREADSHEET SUMMARY DATA																				
	Coal	Dry		153																
	Coal	Wet		4																

	Coal		All types	157																
	Oil/Gas	Dry		47																
	Oil/Gas	Wet		0																

	Oil/Gas		All types	47																
BY STATE:																				
DE	Coal			6																
	Oil/Gas			8																
DC	Coal			0																
	Oil/Gas			2																
MD	Coal			15																
	Oil/Gas			13																
NC	Coal			48																
	Oil/Gas			0																
PA	Coal			62																
	Oil/Gas			20																
VA	Coal			26																
	Oil/Gas			4																

TOTAL				204																

APPENDIX D

COST DETAIL

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                                                                                                                              CREDITS
                                                                                                                              -----------
<<<<<<<<<<<<<<<<ALGORITHM FOR CALCULATING THE CREDITS AND DEBITS OF REBURNING WITH NATURAL GAS IN COAL-FIRED BOILERS  >>>>>>>>>>>>>>>>>>EFFICIENCY ($0.0081)
                                                                                                                              EMISSIONS  $0.0626
                                                                                                                              CHEAPERCOAL $0.0000
                                        PAYBACK YEARS=     -1.60                                                              CAPACITY   $0.0000
FUELS SPECIFICATIONS                                                                                                          MARGIN     $0.0000
                                                                          SUMMARY OF DEBITS AND CREDITS ($/MMBtu)

COAL (%WEIGHT AS FIRED):   COST ($/TON) =              35          CREDITS:                                        DEBITS:
                                                                   ==============                                  =======
CARBON=              66.9
HYDROGEN=             4.5                                      YES  1 REDUCED DRY GAS HEAT LOSS =       ($0.0111)   1 INCREASE IN GAS MOISTURE = $0.0181
OXYGEN=               8.0
SULFUR=               2.0      BTU/LB (HHV)=        11981      YES  2 REDUCED LOI (CARBON IN ASH)=       $0.0003    2 INCREASE IN FUEL COST =    $0.2225
NITROGEN=            1.38
MOISTURE=            7.56                                      YES  3 REDUCED FAN POWER CONSUMPTION=     $0.0000    3 CAPITAL COST =             $0.0330
ASH=                10.43      COST ($/MMBtu)=    $1.461
                                                               NO   4 IMPROVED AVAILABILITY & MARGIN=    $0.0000
NATURAL GAS (% VOLUME AS FIRED):   COST ($/1000CFT)=   3.15  XX
                                                               YES  5 REDUCED SULFUR EMISSIONS =         $0.0626
CH4=                   95      C3H8=                  2.0
C2H6=                 2.5      C4H10=                 0.5      YES  6 REDUCED FUEL MOISTURE CONTENT =   ($0.0002)
TOTAL GAS SPECIES % =     100.0 BTU/FT^3 (HHV)=      1070
SPECIFC GRAVITY=    0.569      BTU/LB (HHV)=        24736      YES  7 REDUCED ASH DISPOSAL =             $0.0029

NATURAL GAS (% WEIGHT AS FIRED):   COST ($/MMBtu)=     2.94    NO   8 CAPACITY RECOVERY =                $0.0000

CARBON=              75.4                                      NO   9 NOx REDUCTION =                    $0.0000
HYDROGEN=            24.6      CREDITS-DEBITS=    -0.2190
                                                               NO  10 HIGHER SULFUR COAL =               $0.0000
------------------------------------------------------------                                             -----------
BOILER TYPE =   PC             CONVENT. BURNER=   YES               TOTAL CREDITS ($/MMBtu) =====        $0.0545     TOTAL DEBITS ($/MMBtu) === $0.2735
                               FUEL N CONV=
------------------------------------------------------------                 NET EFFECT OF COFIRE (CREDITS-DEBITS) =   ($0.219)
GAS - COAL COST DIFFERENTIAL ($/MMBtu)=           $1.4831                                                            2.190290 MILLS/KWH
------------------------------------------------------              ===============================================================================
PERCENT GAS FIRED (BTU BASIS)=                  15                  PAYBACK ANALYSIS    <<<<<<<<<<<DESIGN CAPACITY (MMBtu/HR)/(KW-HR/HR) =     2500    178571
------------------------------------------------------                                  <<<<<<<<<<<CURRENT LOAD LIMIT (MMBtu/HR)/(KW-HR/HR) =  2375    169643
                                                                                        <<<<<<<<<<<AVG YEARLY LOAD (MMBtu/HR)/(KW-HR/HR) =     1600    114286
 GAS (LB/MMBTU HEAT INPUT)=                   6.06                  CAPITAL COST TO COFIRE ($)
 COAL (LB/MMBTU HEAT INPUT)=                 70.95                  ------------------------------<<<<<<<<<<<NUMBER OF HRS/YR INCREASED PEAKING =      4000
                                                                                                              INCREASED PEAKING POWER USE (KW-HR/YR)=      0
CARBON=             67.57      ASH=                   9.6            HARDWARE ===         2500000
HYDROGEN=            6.04      SULFUR=               1.84            INSTALLATION =       1400000
OXYGEN=              7.38      BTU/LB (HHV)=        12985            ENGINEERING =        1000000
TOT. MOISTURE=       6.96      MIXED $/MMBtu=      $1.683                                                  BOILER CAPACITY FACTOR =       64.0%WITH COAL O
                                                                    TOTAL CAPITAL COST ==           $4,900,000  BOILER CAPACITY FACTOR =       64.0%WITH COFIRE
                                                                         $/kw                             19.6  NET CREDITS - DEBITS =       ($0.219)$/MMBtu
EXCESS O2 AT A.H./ECON OUT (WITH COAL ONLY)=                   3.5                                              NET CREDITS - DEBITS =       *********$/YR
EXCESS O2 AT A.H./ECON OUT (WITH ABOVE PERCENT GAS COFIRE)=    3.3  ANNUALIZED OVER               20 YEARS
                                                                    INTEREST =                     7 PERCENT    ============================
FLUE GAS VOLUME (COAL ONLY) =                  967 LB/MMBtu
                                                                    CAP. RECOVERY FACTOR =               0.094  SIMPLE PAYBACK YEARS =          -1.60
FLUE GAS VOLUME (COAL + GAS) =                 962 LB/MMBtu                                                     ============================
                                                                    ANNUALIZED CAPITAL COST =          0.0330 $/MMBtu
```

CREDITS:

*HEAT GAIN DUE TO REDUCED EXCESS AIR AND GAS TEMPERATURE

A.H/ECONOUT GAS TEMP WITH COFIRE =	386
A.H/ECONOUT GAS TEMP WITH COAL =	388
DRY GAS HEAT LOSS (COFIRE) =	6.80%
DRY GAS HEAT LOSS (COAL ONLY) =	7.07%
CHANGE IN THERMAL EFFICIENCY =	0.27%
TRANSLATED DOLLAR CREDIT($/MMBtu)=	($0.011)

*HEAT GAIN FROM REDUCED LOI (CARBON IN ASH)

LOI IN ASH WITH COAL ONLY =	1.0%
LOI IN ASH WITH COFIRE =	1.0%
EFFICIENCY LOSS WITH COAL ONLY =	0.13%
EFFICIENCY LOSS WITH COFIRE =	0.11%
CHANGE IN EFFICIENCY =	0.02%
TRANSLATED COST CREDIT ($/MMBtu) =	$0.0003

*CREDITS FROM REDUCED FAN POWER CONSUMPTION

GAS FLOW W/ COAL ONLY (ACF/MMBtu)=	20246
GAS FLOW W/ COFIRE (ACF/MMBtu)=	20100
ASSUMED PRESSURE DROP (IN.H2O)=	20
POWER CONSUMP. CHANGE(KW-HR/MMBtu)	0.0003
ELECTRICITY COST ($/kW-HR)=	0.045
TRANSLATED COST CREDIT ($/MMBtu) =	0.000013

*IMPROVED AVAILABILITY AND RESERVE MARGIN

DEBITS: COST EFFECTIVENESS = 1752 $/TON

NOx BEFORE=	0.6 LB/MMBTU
NOx AFTER=	0.3 LB/MMBTU
DELTA NOx ======	0.25

1 HEAT LOSS DUE TO INCREASE IN GAS MOISTURE

A.H./ECON. OUT TEMP(F)=	386
AMBIENT TEMP (F) =	60
ENTHALPY OF GAS @ 1 PSIA	1236
ENTHALPY OF WATER AT T A	261
EFFICIENCY LOSS OF COFIRE =	1.07%
TRANSLATED DOLLAR DEBIT =	$0.0181

2 INCREASE IN FUEL COST

COST OF COAL =	$1.46 PER MMBtu
COST OF GAS+COAL IN COFI	$1.68 PER MMBtu
TRANSLATED DOLLAR DEBIT	$0.222 PER MMBtu

RESERVE MARGIN (MBtu/HR)=	125
RESERVE MARGIN CREDIT ($/MMBtu/HR) =	$0
ANNUALIZATION FACTOR (25 YEARS) =	0.086
RESERVE MARGIN CREDIT ($/MMBtu) =	$0.000
IMPROVEMENT IN AVAILABILITY (%)=	4.8%
IMPROVED AVAILABILITY ($/MMBtu) =	$0.000
IMPROV.AVAILABILIT & MARGIN ($/MMBtu)=	$0.000

::

*CREDIT FOR REDUCED ASH DISPOSAL

LB/MMBtu TOTAL ASH W/ COAL ONLY =	8.705
LB/MMBtu TOTAL ASH W/ COFIRE =	7.400
ASH REDUCTION (LB/MMBtu) =	1.306
ASH DISPOSAL COST ($/TON) =	$4.39
TRANSLATED COST CREDIT ($/MMBtu) =	$0.003

::

*CREDIT FOR REDUCED SULFUR EMISSIONS

LB/MMBtu OF SO2 WITH COAL ONLY =	3.339
LB/MMBtu OF SO2 WITH COFIRE =	2.838
SULFUR REDUCTION (LB/MMBtu) =	0.501
SO2 CREDIT ($/TON) =	$250
TRANSLATED CREDIT ($/MMBtu) =	$0.063

::

*CREDIT FOR REDUCED MOISTURE IN FUEL

FUEL MOISTURE LOSS FOR COAL ONLY =	0.0061
FUEL MOISTURE LOSS FOR COFIRE =	0.0052
CHANGE IN EFFICIENCY =	0.0009
TRANSLATED COST ($/MMBtu)	-0.0002

::

*CREDIT FOR CAPACITY RECOVERY

DERATE RECOVERY (% OF CAPACITY)=	0.0%	0
CURRENT DERATE (MMBtu/HR)=	0	
CURRENT HEAT RATE (BTU/kW-HR)=	14000	

RECOVERED DERATE (KW-HR/HR)=	0	
RECOVERED DERATE (Btu/HR) =	0	
ELECTRICITY PURCHASE PRICE($/KW-HR)=	0.045	
TRANSLATED COFIRE CREDIT ($/MMBtu)=	$0.000	0.00
WHEELING CHARGE ($/MW-MO)=	$4.50	
INCREASED CAPACITY (KW-HR/HR) =	0	
INCREASED CAPACITY (kW-HR/MO) =	0	
INCREASED COST ($/MO) =	$0	
TRANSMISSION SAVINGS ($/MMBtu) =	$0.0000	
TOTAL CREDIT (CAPACITY + TRANSM)=	$0.000	

::

*CREDIT FOR REDUCED NOx

FULL LOAD NOx (COAL ONLY) =	0.55
FULL LOAD NOx (COFIRE) =	0.30
NOx REDUCTION (TON/YR) =	1752
NOx CREDIT ($/TON) =	800
TRANSLATED CREDIT ($/MMBtu) =	$0.000

::

*CREDIT FOR LOWER GRADE COAL USE

CONTINUED ANALYSIS FOR LOWER GRADE FUEL COST

ALLOWABLE SULFUR LIMIT (LB/MMBtu) =	1.67	
SULFUR IN REPLACEMENT COAL (%) =	2.17	
KNOWN COST OF NEW REPLAMNT COAL ?? = NO		
COST OF KNOWN REPLCMNT COAL =		ENTER AMOUNT HERE IF ANSWERED YES ABOVE
COST OF LOWER GRADE FUEL ($/MMBtu)=	$1.261	
COST OF LOWER GRADE FUEL ($/TON)=	30.2	
COST OF NEWER COAL/GAS MIX ($/MMBtu) =	$1.513	
TRANSLATED CREDIT ($/MMBtu) =	$0.000	

Source: 200 MWe Coal-fired utility boiler

Control: RETROFIT OF Full-Scale SNCR - LOW Range of Cap Cost (:

Cost Item	1995 dollars	YEARLY USE $/kWe		Comments & Reference	
CAPITAL:					
- Ducting	$0	$0.0	N	NOT APPLICABLE	
- Fan Upgrade/Replace	$0	$0.0	N	NOT APPLICABLE	
- Structural	$0	$0.0	N	NOT APPLICABLE	
- Ammonia Storage & Distribution	$680,856	$3.4	Y	ESTIMATED FROM DETAILS OF COSTING FOR ADVANCED REBURNING	
- Reactor/Catalyst	$0	$0.0	N	FROM EVANS, ET. AL., SEPTEMBER 993	
- Injectors and Controls	$179,236	$0.9	Y		
- Air Heater	$0	$0.0	N	COSTS INCLUDE FREIGHT TAXES AND ENGINEERING	
- In-plant piping	$0	$0.0	N	NOT APPLICABLE	
- Access to Gas Pipeline	$0	$0.0	N	NOT APPLICABLE	
- Burners Modification	$0	$0.0	N	NOT APPLICABLE	
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE	
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE	
Total Purchased Equipment	$860,091	$4.3		TOTAL EQUIPMENT SUM	
Direct Installation	$903,434	$4.5		FROM MERCER ESTIMATE OF $1.2M FOR 321 MWe BOILER	
TOTAL PROCESS CAPITAL	$1,763,525	$8.8		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION	
INDIRECT COST AND CONTINGENCIES	*$529,058*	*$2.6*		*ESTIMATED TO BE 30% OF TOTAL PROCESS CAPITAL*	
TOTAL PLANT COST	$2,292,583	$11.5		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES	
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0		NOT APPLICABLE	
TOTAL CAPITAL REQUIREMENT	$2,292,583	$11.5		TOTAL: COMPARES FAVORABLY W/ MERCER ADJUSTED FOR SIZE $2,559,728	
	$/YR	mills/kWh			
FIRST YEAR O&M:					
- Labor	$17,447	0.02	Y	FIXED O&M COSTS ESTIMATED FROM EPA, 1994 ACT DOCUMENT	
- Maintenance	$10,820	0.01	Y	USING ALGORITHM 86,000*MW^-0.21 EQUIVALENT TO TOTAL OF	
- Ammonia/Urea (reagent)	$164,536	0.16	Y	$28,267 NO SEVERE MAINTENANCE IMPACT	
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE	
- Catalyst replacement	$0	0.00	N	20 PERCENT ADDED AFTER 3 YEARS AND ALL REPLACED IN 8 YEARS	
- Catalyst installation/disposal	$0	0.00	N	ESTIMATED $160/SCFT ACCORDING TO EPA ACT DOCUMENT	
- Electricity	$22,338	0.02	Y		
- Loss in boiler efficiency	$78,840	0.08	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS	
TOTAL FIRST YEAR O&M DEBITS:	$293,981	0.28			
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL	
- Capacity Recovery		0.00	N		
- Other	$0	0.00	N	LOSS OF FLYASH SALES+DISPOSAL COST (40% OF BASE O&M)	
TOTAL FIRST YEAR O&M CREDITS:	$0	0.00			
NET FIRST YEAR O&M:	$293,981	0.28			
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS	
O&M ANNUALIZATION	1.00				
0.90	$/YR	mills/kWh		UNIT PRICING AND OTHER DATA:	
				NATURAL GAS USE (%TOTAL):	15
TOTAL ANNUALIZED COST	$510,384	0.49		CATALYST LYFE (YRS):	8
(CAPITAL + NET O&M)				FLUE GAS FLOW (SCFH):	25000000
				COAL SULFUR (%):	2
COST EFFECTIVENESS		$/TON		REAGENT / NO (MOLAL RATIO):	1.5 NSR
- 0.05 LB/MMBtu	$510,384	$1,942	Y	SCR CATALYST ($/CFT):	$370
- 0.10 LB/MMBtu	$674,920	$1,284	Y	AMMONIA (REAGENT)($/TON):	$300 29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$1,102,713	$1,049	Y	NATURAL GAS ($/MMBtu):	$2.50
- 0.30 LB/MMBtu	$1,333,063	$845	Y	COAL ($/MMBtu):	$1.50
- 0.40 LB/MMBtu	$1,662,134	$791	Y	OIL ($/MMBtu):	$2.00
- 0.50 LB/MMBtu	$1,991,205	$758	Y	PLANT HEAT RATE (Btu/kWH):	10000
- 0.60 LB/MMBtu	$2,320,277	$736	Y	PLANT REMAINING LIFE (YRS):	20
- 0.70 LB/MMBtu	$2,649,348	$720	Y	PLANT CAPACITY FACTOR (%):	60
- 0.80 LB/MMBtu	$2,978,419	$708	Y	INTEREST RATE (%):	7
- 0.90 LB/MMBtu	*$3,307,490*	*$699*	Y	*CATALYST SPACE VEL. (1/HR):*	*3250 FOR 85% NOx REDUCTION*
- 1.20 LB/MMBtu	$4,294,704	$681	Y	UREA (REAGENT) ($/TON):	200 FOR 50% UREA BY VOLUME
- 1.50 LB/MMBtu	$5,281,918	$670	Y		

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF Full-Scale SNCR - HIGH Range of Cap Cost

Cost Item	1995 dollars	YEARLY USE $/kWe		Comments & Reference
CAPITAL:				
- Ducting	$0	$0.0	N	NOT APPLICABLE
- Fan Upgrade/Replace	$0	$0.0	N	NOT APPLICABLE
- Structural	$0	$0.0	N	NOT APPLICABLE
- Ammonia Storage & Distribution	$680,856	$3.4	Y	ESTIMATED FROM DETAILS OF COSTING FOR ADVANCED REBURNING
- Reactor/Catalyst	$0	$0.0	N	FROM EVANS, ET. AL., SEPTEMBER 993
- Injectors and Controls	$588,044	$2.9	Y	
- Air Heater	$0	$0.0	N	COSTS INCLUDE FREIGHT TAXES AND ENGINEERING
- In-plant piping	$0	$0.0	N	NOT APPLICABLE
- Access to Gas Pipeline	$0	$0.0	N	NOT APPLICABLE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$1,268,900	$6.3		TOTAL EQUIPMENT SUM
Direct Installation	$903,434	$4.5		FROM MERCER ESTIMATE OF $1.2M FOR 321 MWe BOILER
TOTAL PROCESS CAPITAL	$2,172,334	$10.9		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$651,700	$3.3		ESTIMATED TO BE 30% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$2,824,034	$14.1		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0		NOT APPLICABLE
TOTAL CAPITAL REQUIREMENT	$2,824,034	$14.1		TOTAL: COMPARES FAVORABLY W/ MERCER ADJUSTED FOR SIZE $2,559,728

	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$14,939	0.01	Y	FIXED O&M COSTS ESTIMATED FROM EPA, 1994 ACT DOCUMENT
- Maintenance	$13,328	0.01	Y	USING ALGORITHM 86,000*MW^-0.21 EQUIVALENT TO TOTAL OF
- Ammonia/Urea (reagent)	$164,536	0.16	Y	$28,267 NO SEVERE MAINTENANCE IMPACT
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$0	0.00	N	20 PERCENT ADDED AFTER 3 YEARS AND ALL REPLACED IN 8 YEARS
- Catalyst installation/disposal	$0	0.00	N	ESTIMATED $160/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$22,338	0.02	Y	
- Loss in boiler efficiency	$78,840	0.08	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$293,981	0.28		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery		0.00	N	
- Other	$0	0.00	N	LOSS OF FLYASH SALES+DISPOSAL COST (40% OF BASE O&M)
TOTAL FIRST YEAR O&M CREDITS:	$0	0.00		
NET FIRST YEAR O&M:	$293,981	0.28		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			

0.94	$/YR	mills/kWh		UNIT PRICING AND OTHER DATA:	
				NATURAL GAS USE (%TOTAL):	15
TOTAL ANNUALIZED COST (CAPITAL + NET O&M)	$560,550	0.53		CATALYST LYFE (YRS):	8
				FLUE GAS FLOW (SCFH):	25000000
				COAL SULFUR (%):	2
COST EFFECTIVENESS		$/TON		REAGENT / NO (MOLAL RATIO):	1.5 NSR
- 0.05 LB/MMBtu	$560,550	$2,133	Y	SCR CATALYST ($/CFT):	$370
- 0.10 LB/MMBtu	$725,085	$1,380	Y	AMMONIA (REAGENT)($/TON):	$300 29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$1,152,878	$1,097	Y	NATURAL GAS ($/MMBtu):	$2.50
- 0.30 LB/MMBtu	$1,383,228	$877	Y	COAL ($/MMBtu):	$1.50
- 0.40 LB/MMBtu	$1,712,299	$814	Y	OIL ($/MMBtu):	$2.00
- 0.50 LB/MMBtu	$2,041,370	$777	Y	PLANT HEAT RATE (Btu/kWH):	10000
- 0.60 LB/MMBtu	$2,370,442	$752	Y	PLANT REMAINING LIFE (YRS):	20
- 0.70 LB/MMBtu	$2,699,513	$734	Y	PLANT CAPACITY FACTOR (%):	60
- 0.80 LB/MMBtu	$3,028,584	$720	Y	INTEREST RATE (%):	7
- 0.90 LB/MMBtu	$3,357,656	$710	Y	CATALYST SPACE VEL. (1/HR):	3250 FOR 85% NOx REDUCTION
- 1.20 LB/MMBtu	$4,344,870	$689	Y	UREA (REAGENT) ($/TON):	200 FOR 50% UREA BY VOLUME
- 1.50 LB/MMBtu	$5,332,084	$676	Y		

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF Full-Scale SNCR - Low Range of Cap Cost (Seasonal)
SEASONAL USE (5 MONTHS/YR)

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting	$0	$0.0	N	NOT APPLICABLE
- Fan Upgrade/Replace	$0	$0.0	N	NOT APPLICABLE
- Structural	$0	$0.0	N	NOT APPLICABLE
- Ammonia Storage & Distribution	$680,856	$3.4	Y	ESTIMATED FROM DETAILS OF COSTING FOR ADVANCED REBURNING
- Reactor/Catalyst	$0	$0.0	N	FROM EVANS, ET. AL., SEPTEMBER 993
- Injectors and Controls	$179,236	$0.9	Y	
- Air Heater	$0	$0.0	N	COSTS INCLUDE FREIGHT TAXES AND ENGINEERING
- In-plant piping	$0	$0.0	N	NOT APPLICABLE
- Access to Gas Pipeline	$0	$0.0	N	NOT APPLICABLE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$860,091	$4.3		TOTAL EQUIPMENT SUM
Direct Installation	$903,434	$4.5		FROM MERCER ESTIMATE OF $1.2M FOR 321 MWe BOILER
TOTAL PROCESS CAPITAL	$1,763,525	$8.8		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$529,058	$2.6		ESTIMATED TO BE 30% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$2,292,583	$11.5		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0		NOT APPLICABLE
TOTAL CAPITAL REQUIREMENT	$2,292,583	$11.5		TOTAL: COMPARES FAVORABLY W/ MERCER ADJUSTED FOR SIZE $2,559,728

	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$17,447	0.02	Y	FIXED O&M COSTS ESTIMATED FROM EPA, 1994 ACT DOCUMENT
- Maintenance	$10,820	0.01	Y	USING ALGORITHM 86,000*MW^-0.21 EQUIVALENT TO TOTAL OF
- Ammonia/Urea (reagent)	$68,557	0.07	Y	$28,267 NO SEVERE MAINTENANCE IMPACT
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$0	0.00	N	20 PERCENT ADDED AFTER 3 YEARS AND ALL REPLACED IN 8 YEARS
- Catalyst installation/disposal	$0	0.00	N	ESTIMATED $160/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$9,308	0.01	Y	
- Loss in boiler efficiency	$32,850	0.03	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$138,981	0.13		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery		0.00	N	
- Other	$0	0.00	N	LOSS OF FLYASH SALES+DISPOSAL COST (40% OF BASE O&M)
TOTAL FIRST YEAR O&M CREDITS:	$0	0.00		
NET FIRST YEAR O&M:	$138,981	0.13		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			

0.49	$/YR	mills/kWh		UNIT PRICING AND OTHER DATA:		
				NATURAL GAS USE (%TOTAL):	15	
TOTAL ANNUALIZED COST	$355,385	0.34		CATALYST LYFE (YRS):	8	
(CAPITAL + NET O&M)				FLUE GAS FLOW (SCFH):	25000000	
				COAL SULFUR (%):	2	
COST EFFECTIVENESS		$/TON		REAGENT / NO (MOLAL RATIO):	1.5	NSR
- 0.05 LB/MMBtu	$355,385	$3,246	s	SCR CATALYST ($/CFT):	$370	
- 0.10 LB/MMBtu	$423,941	$1,936	s	AMMONIA (REAGENT)($/TON):	$300	29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$602,188	$1,375	s	NATURAL GAS ($/MMBtu):	$2.50	
- 0.30 LB/MMBtu	$698,167	$1,063	s	COAL ($/MMBtu):	$1.50	
- 0.40 LB/MMBtu	$835,280	$954	s	OIL ($/MMBtu):	$2.00	
- 0.50 LB/MMBtu	$972,393	$888	s	PLANT HEAT RATE (Btu/kWH):	10000	
- 0.60 LB/MMBtu	$1,109,506	$844	s	PLANT REMAINING LIFE (YRS):	20	
- 0.70 LB/MMBtu	$1,246,620	$813	s	PLANT CAPACITY FACTOR (%):	60	
- 0.80 LB/MMBtu	$1,383,733	$790	s	INTEREST RATE (%):	7	
- 0.90 LB/MMBtu	$1,520,846	$772	s	CATALYST SPACE VEL. (1/HR):	3250	FOR 85% NOx REDUCTION
- 1.20 LB/MMBtu	$1,932,185	$735	s	UREA (REAGENT) ($/TON):	200	FOR 50% UREA BY VOLUME
- 1.50 LB/MMBtu	$2,343,524	$713	s			

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF Full-Scale SNCR - High Range of Cap Cost

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting	$0	$0.0	N	NOT APPLICABLE
- Fan Upgrade/Replace	$0	$0.0	N	NOT APPLICABLE
- Structural	$0	$0.0	N	NOT APPLICABLE
- Ammonia Storage & Distribution	$680,856	$3.4	Y	ESTIMATED FROM DETAILS OF COSTING FOR ADVANCED REBURNING
- Reactor/Catalyst	$0	$0.0	N	FROM EVANS, ET. AL., SEPTEMBER 993
- Injectors and Controls	$589,858	$2.9	Y	
- Air Heater	$0	$0.0	N	COSTS INCLUDE FREIGHT TAXES AND ENGINEERING
- In-plant piping	$0	$0.0	N	NOT APPLICABLE
- Access to Gas Pipeline	$0	$0.0	N	NOT APPLICABLE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$1,270,713	$6.4		TOTAL EQUIPMENT SUM
Direct Installation	$903,434	$4.5		FROM MERCER ESTIMATE OF $1.2M FOR 321 MWe BOILER
TOTAL PROCESS CAPITAL	$2,174,147	$10.9		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$652,244	$3.3		ESTIMATED TO BE 30% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$2,826,391	$14.1		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0		NOT APPLICABLE
TOTAL CAPITAL REQUIREMENT	$2,826,391	$14.1		TOTAL: COMPARES FAVORABLY W/ MERCER ADJUSTED FOR SIZE $2,559,728

	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$14,928	0.01	Y	FIXED O&M COSTS ESTIMATED FROM EPA, 1994 ACT DOCUMENT
- Maintenance	$13,340	0.01	Y	USING ALGORITHM 86,000*MW^-0.21 EQUIVALENT TO TOTAL OF
- Ammonia/Urea (reagent)	$68,557	0.07	Y	$28,267 NO SEVERE MAINTENANCE IMPACT
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$0	0.00	N	20 PERCENT ADDED AFTER 3 YEARS AND ALL REPLACED IN 8 YEARS
- Catalyst installation/disposal	$0	0.00	N	ESTIMATED $160/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$9,308	0.01	Y	
- Loss in boiler efficiency	$32,850	0.03	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$138,981	0.13		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery		0.00	N	
- Other	$0	0.00	N	LOSS OF FLYASH SALES+DISPOSAL COST (40% OF BASE O&M)
TOTAL FIRST YEAR O&M CREDITS:	$0	0.00		
NET FIRST YEAR O&M:	$138,981	0.13		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			

0.53	$/YR	mills/kWh		UNIT PRICING AND OTHER DATA:		
				NATURAL GAS USE (%TOTAL):	15	
TOTAL ANNUALIZED COST	$405,772	0.39		CATALYST LYFE (YRS):	8	
(CAPITAL + NET O&M)				FLUE GAS FLOW (SCFH):	25000000	
				COAL SULFUR (%):	2	
COST EFFECTIVENESS		$/TON		REAGENT / NO (MOLAL RATIO):	1.5	NSR
- 0.05 LB/MMBtu	$405,772	$3,706	s	SCR CATALYST ($/CFT):	$370	
- 0.10 LB/MMBtu	$474,329	$2,166	s	AMMONIA (REAGENT)($/TON):	$300	29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$652,576	$1,490	s	NATURAL GAS ($/MMBtu):	$2.50	
- 0.30 LB/MMBtu	$748,555	$1,139	s	COAL ($/MMBtu):	$1.50	
- 0.40 LB/MMBtu	$885,668	$1,011	s	OIL ($/MMBtu):	$2.00	
- 0.50 LB/MMBtu	$1,022,781	$934	s	PLANT HEAT RATE (Btu/kWH):	10000	
- 0.60 LB/MMBtu	$1,159,894	$883	s	PLANT REMAINING LIFE (YRS):	20	
- 0.70 LB/MMBtu	$1,297,007	$846	s	PLANT CAPACITY FACTOR (%):	60	
- 0.80 LB/MMBtu	$1,434,120	$819	s	INTEREST RATE (%):	7	
- 0.90 LB/MMBtu	$1,571,233	$797	s	CATALYST SPACE VEL. (1/HR):	3250	FOR 85% NOx REDUCTION
- 1.20 LB/MMBtu	$1,982,572	$754	s	UREA (REAGENT) ($/TON):	200	FOR 50% UREA BY VOLUME
- 1.50 LB/MMBtu	$2,393,912	$729	s			

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF Full-Scale SNCR -- Oil and Gas Units

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting	$0	$0.0	N	NOT APPLICABLE
- Fan Upgrade/Replace	$0	$0.0	N	NOT APPLICABLE
- Structural	$0	$0.0	N	NOT APPLICABLE
- Ammonia Storage & Distribution	$680,856	$3.4	Y	ESTIMATED FROM DETAILS OF COSTING FOR ADVANCED REBURNING
- Reactor/Catalyst	$0	$0.0	N	FROM EVANS, ET. AL., SEPTEMBER 993
- Injectors and Controls	$179,236	$0.9	Y	
- Air Heater	$0	$0.0	N	COSTS INCLUDE FREIGHT TAXES AND ENGINEERING
- In-plant piping	$0	$0.0	N	NOT APPLICABLE
- Access to Gas Pipeline	$0	$0.0	N	NOT APPLICABLE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$860,091	$4.3		TOTAL EQUIPMENT SUM
Direct Installation	$903,434	$4.5		FROM MERCER ESTIMATE OF $1.2M FOR 321 MWe BOILER
TOTAL PROCESS CAPITAL	$1,763,525	$8.8		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$529,058	$2.6		ESTIMATED TO BE 30% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$2,292,583	$11.5		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0		NOT APPLICABLE
TOTAL CAPITAL REQUIREMENT	$2,292,583	$11.5		TOTAL: COMPARES FAVORABLY W/ MERCER ADJUSTED FOR SIZE $2,559,728
	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$17,447	0.02	Y	FIXED O&M COSTS ESTIMATED FROM EPA, 1994 ACT DOCUMENT
- Maintenance	$10,820	0.01	Y	USING ALGORITHM 86,000*MW^-0.21 EQUIVALENT TO TOTAL OF
- Ammonia/Urea (reagent)	$164,536	0.16	Y	$28,267 NO SEVERE MAINTENANCE IMPACT
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$0	0.00	N	20 PERCENT ADDED AFTER 3 YEARS AND ALL REPLACED IN 8 YEARS
- Catalyst installation/disposal	$0	0.00	N	ESTIMATED $160/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$22,338	0.02	Y	
- Loss in boiler efficiency	$78,840	0.08	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$293,981	0.28		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery		0.00	N	
- Other	$0	0.00	N	LOSS OF FLYASH SALES+DISPOSAL COST (40% OF BASE O&M)
TOTAL FIRST YEAR O&M CREDITS:	$0	0.00		
NET FIRST YEAR O&M:	$293,981	0.28		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			
	$/YR	mills/kWh		UNIT PRICING AND OTHER DATA:
				NATURAL GAS USE (%TOTAL): 15
TOTAL ANNUALIZED COST	$510,384	0.49		CATALYST LYFE (YRS): 8
(CAPITAL + NET O&M)				FLUE GAS FLOW (SCFH): 25000000
				COAL SULFUR (%): 2
COST EFFECTIVENESS		$/TON		REAGENT / NO (MOLAL RATIO): 1.5 NSR
- 0.05 LB/MMBtu	$510,384	$1,942		SCR CATALYST ($/CFT): $370
- 0.10 LB/MMBtu	$674,920	$1,284		AMMONIA (REAGENT)($/TON): $300 29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$1,003,991	$955		NATURAL GAS ($/MMBtu): $2.50
- 0.30 LB/MMBtu	$1,333,063	$845		COAL ($/MMBtu): $1.50
- 0.40 LB/MMBtu	$1,662,134	$791		OIL ($/MMBtu): $2.00
- 0.50 LB/MMBtu	$1,991,205	$758		PLANT HEAT RATE (Btu/kWH): 10000
- 0.60 LB/MMBtu	$2,320,277	$736		PLANT REMAINING LIFE (YRS): 20
- 0.70 LB/MMBtu	$2,649,348	$720		PLANT CAPACITY FACTOR (%): 60
- 0.80 LB/MMBtu	$2,978,419	$708		INTEREST RATE (%): 7
- 0.90 LB/MMBtu	$3,307,490	$699		CATALYST SPACE VEL. (1/HR): 3250 FOR 85% NOx REDUCTION
- 1.20 LB/MMBtu	$4,294,704	$681		UREA (REAGENT) ($/TON): 200 FOR 50% UREA BY VOLUME
- 1.50 LB/MMBtu	$5,281,918	$670		

Source: 200 MWe GAS-fired utility boiler
Control: RETROFIT OF IN-DUCT SCR - LOW CAP. COST

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting	$600,000	$3.0	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Fan Upgrade/Replace	$320,000	$1.6	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Structural	$0	$0.0	N	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Ammonia Storage & Distribution	$480,000	$2.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Reactor/Catalyst	$937,500	$4.7	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Injectors and Controls	$179,000	$0.9	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Air Heater/Sootblowing	$0	$0.0	n	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- In-plant piping	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Access to Gas Pipeline	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$2,516,500	$12.6		TOTAL SUM
Direct Installation	$1,258,250	$6.3		ESTIMATED TO BE 50% OF EQUIPMENT COST BASED ON ICAC 94 ESTIMATE
TOTAL PROCESS CAPITAL	$3,774,750	$18.9		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$1,509,900	$7.5		ESTIMATED TO BE 40% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$5,284,650	$26.4		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0	n	ESTIMATE BASED ON ICAC 94 DATA
TOTAL CAPITAL REQUIREMENT	$5,284,650	$26.4		TOTAL INITIAL INVESTMENT
	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$175,000	0.17	Y	TWO MAN YEARS
- Maintenance	$24,942	0.02	Y	
- Ammonia (reagent)	$104,490	0.10	Y	
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$55,147	0.05	Y	20 PERCENT ADDED AFTER 3 YEARS AND ALL REPLACED IN 8 YEARS
- Catalyst installation/disposal	$2,363	0.00	Y	ESTIMATED $15/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$111,690	0.11	Y	
- Loss in boiler efficiency	$78,840	0.08	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$552,472	0.53		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery			N	
- Other			N	
TOTAL FIRST YEAR O&M CREDITS:	$0	$0		
NET FIRST YEAR O&M:	$552,472	0.53		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			

	$/YR	mills/kWh	UNIT PRICING AND OTHER DATA:	
			NATURAL GAS USE (%TOTAL):	15
TOTAL ANNUALIZED COST	$1,051,305	1.00	CATALYST LYFE (YRS):	12
(CAPITAL + NET O&M)			FLUE GAS FLOW (SCFH):	25000000
			COAL SULFUR (%):	2
COST EFFECTIVENESS		$/TON	REAGENT / NO (MOLAL RATIO):	1.04
- 0.05 LB/MMBtu	$1,051,305	$4,000	SCR CATALYST ($/CFT):	$350
- 0.10 LB/MMBtu	$1,155,795	$2,199	AMMONIA (REAGENT)($/TON):	$300 29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$1,364,774	$1,298	NATURAL GAS ($/MMBtu):	$2.50
- 0.30 LB/MMBtu	$1,573,753	$998	COAL ($/MMBtu):	$1.50
- 0.40 LB/MMBtu	$1,782,733	$848	OIL ($/MMBtu):	$2.00
- 0.50 LB/MMBtu	$1,991,712	$758	PLANT HEAT RATE (Btu/kWH):	10000
- 0.60 LB/MMBtu	$2,200,691	$698	PLANT REMAINING LIFE (YRS):	20
- 0.70 LB/MMBtu	$2,409,670	$655	PLANT CAPACITY FACTOR (%):	60
- 0.80 LB/MMBtu	$2,618,649	$623	INTEREST RATE (%):	7
- 0.90 LB/MMBtu	$2,827,628	$598	CATALYST SPACE VEL. (1/HR):	14000 FOR 85% NOx REDUCTION
- 1.20 LB/MMBtu	$3,454,566	$548		
- 1.50 LB/MMBtu	$4,081,504	$518	CATALYST VOLUME(CFT):	1786

Source: 200 MWe GAS-fired utility boiler
Control: RETROFIT OF IN-DUCT SCR - HIGH CAP. COST

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting	$600,000	$3.0	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Fan Upgrade/Replace	$320,000	$1.6	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Structural	$0	$0.0	N	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Ammonia Storage & Distribution	$480,000	$2.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Reactor/Catalyst	$937,500	$4.7	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Injectors and Controls	$179,000	$0.9	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Air Heater/Sootblowing	$480,000	$2.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- In-plant piping	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Access to Gas Pipeline	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$2,996,500	$15.0		TOTAL SUM
Direct Installation	$1,498,250	$7.5		ESTIMATED TO BE 50% OF EQUIPMENT COST BASED ON ICAC 94 ESTIMATE
TOTAL PROCESS CAPITAL	$4,494,750	$22.5		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$1,797,900	$9.0		ESTIMATED TO BE 40% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$6,292,650	$31.5		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0	n	ESTIMATE BASED ON ICAC 94 DATA
TOTAL CAPITAL REQUIREMENT	$6,292,650	$31.5		TOTAL INITIAL INVESTMENT
	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$175,000	0.17	Y	TWO MAN YEARS
- Maintenance	$29,699	0.03	Y	
- Ammonia (reagent)	$104,490	0.10	Y	
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$55,147	0.05	Y	20 PERCENT ADDED AFTER 3 YEARS AND ALL REPLACED IN 8 YEARS
- Catalyst installation/disposal	$2,363	0.00	Y	ESTIMATED $15/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$111,690	0.11	Y	
- Loss in boiler efficiency	$78,840	0.08	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$557,229	0.53		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery			N	
- Other			N	
TOTAL FIRST YEAR O&M CREDITS:	$0	$0		
NET FIRST YEAR O&M:	$557,229	0.53		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			
	$/YR	mills/kWh		UNIT PRICING AND OTHER DATA:
				NATURAL GAS USE (%TOTAL): 15
TOTAL ANNUALIZED COST	$1,151,211	1.10		CATALYST LYFE (YRS): 12
(CAPITAL + NET O&M)				FLUE GAS FLOW (SCFH): 25000000
				COAL SULFUR (%): 2
COST EFFECTIVENESS		$/TON		REAGENT / NO (MOLAL RATIO): 1.04
- 0.05 LB/MMBtu	$1,151,211	$4,381		SCR CATALYST ($/CFT): $350
- 0.10 LB/MMBtu	$1,255,700	$2,389		AMMONIA (REAGENT)($/TON): $300 29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$1,464,680	$1,393		NATURAL GAS ($/MMBtu): $2.50
- 0.30 LB/MMBtu	$1,673,659	$1,061		COAL ($/MMBtu): $1.50
- 0.40 LB/MMBtu	$1,882,638	$895		OIL ($/MMBtu): $2.00
- 0.50 LB/MMBtu	$2,091,617	$796		PLANT HEAT RATE (Btu/kWH): 10000
- 0.60 LB/MMBtu	$2,300,596	$730		PLANT REMAINING LIFE (YRS): 20
- 0.70 LB/MMBtu	$2,509,576	$682		PLANT CAPACITY FACTOR (%): 60
- 0.80 LB/MMBtu	$2,718,555	$647		INTEREST RATE (%): 7
- 0.90 LB/MMBtu	$2,927,534	$619		CATALYST SPACE VEL. (1/HR): 14000 FOR 85% NOx REDUCTION
- 1.20 LB/MMBtu	$3,554,472	$564		
- 1.50 LB/MMBtu	$4,181,409	$530		CATALYST VOLUME(CFT): 1786

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF Full-Scale SCR - Low Range Cap. Cost

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting	$2,160,000	$10.8	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Fan Upgrade/Replace	$320,000	$1.6	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Structural	$540,000	$2.7	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Ammonia Storage & Distribution	$480,000	$2.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Reactor/Catalyst	$3,458,077	$17.3	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Injectors and Controls	INCL.	$0.0	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Air Heater/Sootblowing	$480,000	$2.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- In-plant piping	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Access to Gas Pipeline	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$7,438,077	$37.2		TOTAL SUM
Direct Installation	$3,719,038	$18.6		ESTIMATED TO BE 50% OF EQUIPMENT COST BASED ON ICAC 94 ESTIMATE
TOTAL PROCESS CAPITAL	$11,157,115	$55.8		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$4,462,846	$22.3		ESTIMATED TO BE 40% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$15,619,962	$78.1		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0	n	ESTIMATE BASED ON ICAC 94 DATA
TOTAL CAPITAL REQUIREMENT	$15,619,962	$78.1		TOTAL INITIAL INVESTMENT
	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$175,000	0.17	Y	
- Maintenance	$73,721	0.07	Y	
- Ammonia (reagent)	$110,518	0.11	Y	
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$305,124	0.29	Y	20% ADDED AFTER 3 YRS AND ALL REPLACED IN YRS shown below
- Catalyst installation/disposal	$12,370	0.01	Y	ESTIMATED $15/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$111,690	0.11	Y	
- Loss in boiler efficiency	$78,840	0.08	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$867,263	0.83		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery			N	
- Other			N	
TOTAL FIRST YEAR O&M CREDITS:	$0	$0		
NET FIRST YEAR O&M:	$867,263	0.83		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			
	$/YR	mills/kWh		UNIT PRICING AND OTHER DATA:
				NATURAL GAS USE (%TOTAL): 15
TOTAL ANNUALIZED COST	$2,341,677	2.23		CATALYST LYFE (YRS): 8
(CAPITAL + NET O&M)				FLUE GAS FLOW (SCFH): 25000000
				COAL SULFUR (%): 2
COST EFFECTIVENESS		$/TON		REAGENT / NO (MOLAL RATIO): 1.1
- 0.05 LB/MMBtu	$2,341,677	$8,910		SCR CATALYST ($/CFT): $370
- 0.10 LB/MMBtu	$2,452,195	$4,666		AMMONIA (REAGENT)($/TON): $300 29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$2,673,230	$2,543		NATURAL GAS ($/MMBtu): $2.50
- 0.30 LB/MMBtu	$2,894,266	$1,836		COAL ($/MMBtu): $1.50
- 0.40 LB/MMBtu	$3,115,302	$1,482		OIL ($/MMBtu): $2.00
- 0.50 LB/MMBtu	$3,336,337	$1,270		PLANT HEAT RATE (Btu/kWH): 10000
- 0.60 LB/MMBtu	$3,557,373	$1,128		PLANT REMAINING LIFE (YRS): 20
- 0.70 LB/MMBtu	$3,778,409	$1,027		PLANT CAPACITY FACTOR (%): 60
- 0.80 LB/MMBtu	$3,999,444	$951		INTEREST RATE (%): 7
- 0.90 LB/MMBtu	$4,220,480	$892		CATALYST SPACE VEL. (1/HR): 3250 FOR 85% NOx REDUCTION
- 1.20 LB/MMBtu	$4,883,587	$774		
- 1.50 LB/MMBtu	$5,546,694	$704		CATALYST VOLUME(CFT): 7692

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF Full-Scale SCR - High Range Cap. Cost

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting	$2,160,000	$10.8	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Fan Upgrade/Replace	$320,000	$1.6	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Structural	$540,000	$2.7	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Ammonia Storage & Distribution	$480,000	$2.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Reactor/Catalyst	$4,269,231	$21.3	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Injectors and Controls	INCL.	$0.0	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Air Heater/Sootblowing	$480,000	$2.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- In-plant piping	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Access to Gas Pipeline	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$8,249,231	$41.2		TOTAL SUM
Direct Installation	$4,124,615	$20.6		ESTIMATED TO BE 50% OF EQUIPMENT COST BASED ON ICAC 94 ESTIMATE
TOTAL PROCESS CAPITAL	$12,373,846	$61.9		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$4,949,538	$24.7		ESTIMATED TO BE 40% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$17,323,385	$86.6		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0	n	ESTIMATE BASED ON ICAC 94 DATA
TOTAL CAPITAL REQUIREMENT	$17,323,385	$86.6		TOTAL INITIAL INVESTMENT
	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$175,000	0.17	Y	
- Maintenance	$81,760	0.08	Y	
- Ammonia (reagent)	$110,518	0.11	Y	
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$376,697	0.36	Y	20% ADDED AFTER 3 YRS AND ALL REPLACED IN YRS shown below
- Catalyst installation/disposal	$15,271	0.01	Y	ESTIMATED $15/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$111,690	0.11	Y	
- Loss in boiler efficiency	$78,840	0.08	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$949,776	0.90		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery			N	
- Other			N	
TOTAL FIRST YEAR O&M CREDITS:	$0	$0		
NET FIRST YEAR O&M:	$949,776	0.90		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			

	$/YR	mills/kWh	UNIT PRICING AND OTHER DATA:		
			NATURAL GAS USE (%TOTAL):	15	
TOTAL ANNUALIZED COST	$2,584,981	2.46	CATALYST LYFE (YRS):	8	
(CAPITAL + NET O&M)			FLUE GAS FLOW (SCFH):	25000000	
			COAL SULFUR (%):	2	
COST EFFECTIVENESS		$/TON	REAGENT / NO (MOLAL RATIO):	1.1	
- 0.05 LB/MMBtu	$2,584,981	$9,836	SCR CATALYST ($/CFT):	$370	
- 0.10 LB/MMBtu	$2,695,499	$5,128	AMMONIA (REAGENT)($/TON):	$300	29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$2,916,535	$2,774	NATURAL GAS ($/MMBtu):	$2.50	
- 0.30 LB/MMBtu	$3,137,571	$1,990	COAL ($/MMBtu):	$1.50	
- 0.40 LB/MMBtu	$3,358,606	$1,598	OIL ($/MMBtu):	$2.00	
- 0.50 LB/MMBtu	$3,579,642	$1,362	PLANT HEAT RATE (Btu/kWH):	10000	
- 0.60 LB/MMBtu	$3,800,678	$1,205	PLANT REMAINING LIFE (YRS):	20	
- 0.70 LB/MMBtu	$4,021,713	$1,093	PLANT CAPACITY FACTOR (%):	60	
- 0.80 LB/MMBtu	$4,242,749	$1,009	INTEREST RATE (%):	7	
- 0.90 LB/MMBtu	$4,463,785	$944	CATALYST SPACE VEL. (1/HR):	3250	FOR 85% NOx REDUCTION
- 1.20 LB/MMBtu	$5,126,892	$813			
- 1.50 LB/MMBtu	$5,789,999	$734	CATALYST VOLUME(CFT):	7692	

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF SNCR AND IN-DUCT SCR (HYBRID) - Low range cost

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting	$600,000	$3.0	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Fan Upgrade/Replace	$320,000	$1.6	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Structural	$540,000	$2.7	y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Ammonia Storage & Distribution	$696,000	$3.5	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Reactor/Catalyst	$2,312,500	$11.6	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Injectors and Controls	$179,000	$0.9	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Air Heater	$480,000	$2.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- In-plant piping	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Access to Gas Pipeline	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$5,127,500	$25.6		*TOTAL SUM*
Direct Installation	$2,563,750	$12.8		ESTIMATED TO BE 50% OF EQUIPMENT COST BASED ON ICAC 94 ESTIMATE
TOTAL PROCESS CAPITAL	$7,691,250	$38.5		*SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION*
INDIRECT COST AND CONTINGENCIES	$3,076,500	$15.4		ESTIMATED TO BE 40% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$10,767,750	$53.8		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0	n	ESTIMATE BASED ON ICAC 94 DATA
TOTAL CAPITAL REQUIREMENT	$10,767,750	$53.8		TOTAL INITIAL INVESTMENT
	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$175,000	0.17	Y	TWO MAN YEARS
- Maintenance	$50,820	0.05	Y	
- Ammonia (reagent)	$140,659	0.13	Y	
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$272,059	0.26	Y	20 % ADDED AFTER 3 YRS AND ALL REPLACED IN YRS shown below
- Catalyst installation/disposal	$11,029	0.01	Y	ESTIMATED $15/SCFT according to ICAC
- Electricity	$111,690	0.11	Y	
- Loss in boiler efficiency	$126,144	0.12	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$887,401	0.84		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery			N	
- Other			N	
TOTAL FIRST YEAR O&M CREDITS:	$0	$0		
NET FIRST YEAR O&M:	$887,401	0.84		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			
	$/YR	mills/kWh		UNIT PRICING AND OTHER DATA:
				NATURAL GAS USE (%TOTAL): 15
TOTAL ANNUALIZED COST	$1,903,801	1.81		CATALYST LYFE (YRS): 6
(CAPITAL + NET O&M)				FLUE GAS FLOW (SCFH): 25000000
				COAL SULFUR (%): 2
COST EFFECTIVENESS		$/TON		REAGENT / NO (MOLAL RATIO): 1.4
- 0.05 LB/MMBtu	$1,903,801	$7,244		SCR CATALYST ($/CFT): $370
- 0.10 LB/MMBtu	$2,044,460	$3,890		AMMONIA (REAGENT)($/TON): $300 29% AQUEOUS SOLUTION
- 0.20 LB/MMBtu	$2,325,778	$2,212		NATURAL GAS ($/MMBtu): $2.50
- 0.30 LB/MMBtu	$2,607,096	$1,653		COAL ($/MMBtu): $1.50
- 0.40 LB/MMBtu	$2,888,414	$1,374		OIL ($/MMBtu): $2.00
- 0.50 LB/MMBtu	$3,169,732	$1,206		PLANT HEAT RATE (Btu/kWH): 10000
- 0.60 LB/MMBtu	$3,451,050	$1,094		PLANT REMAINING LIFE (YRS): 20
- 0.70 LB/MMBtu	$3,732,369	$1,014		PLANT CAPACITY FACTOR (%): 60
- 0.80 LB/MMBtu	$4,013,687	$955		INTEREST RATE (%): 7
- 0.90 LB/MMBtu	$4,295,005	$908		CATALYST SPACE VEL. (1/HR): 6000 FOR 85% NOx REDUCTION
- 1.20 LB/MMBtu	$5,138,959	$815		
- 1.50 LB/MMBtu	$5,982,914	$759		CATALYST VOLUME(CFT): 4167

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF SNCR AND IN-DUCT SCR (HYBRID) - High range cost

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting	$600,000	$3.0	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Fan Upgrade/Replace	$320,000	$1.6	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Structural	$540,000	$2.7	y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Ammonia Storage & Distribution	$696,000	$3.5	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Reactor/Catalyst	$3,083,333	$15.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Injectors and Controls	$179,000	$0.9	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- Air Heater	$480,000	$2.4	Y	DATABASED ON DOE ESTIMATE UPGRATED TO 200 MWE BOILER
- In-plant piping	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Access to Gas Pipeline	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Burners Modification	$0	$0.0	N	NOT APPLICABLE
- OFA Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
- FGR Ducting and Fan	$0	$0.0	N	NOT APPLICABLE
Total Purchased Equipment	$5,898,333	$29.5		TOTAL SUM
Direct Installation	$2,949,167	$14.7		ESTIMATED TO BE 50% OF EQUIPMENT COST BASED ON ICAC 94 ESTIMATE
TOTAL PROCESS CAPITAL	$8,847,500	$44.2		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$3,539,000	$17.7		ESTIMATED TO BE 40% OF TOTAL PROCESS CAPITAL
TOTAL PLANT COST	$12,386,500	$61.9		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0	n	ESTIMATE BASED ON ICAC 94 DATA
TOTAL CAPITAL REQUIREMENT	$12,386,500	$61.9		TOTAL INITIAL INVESTMENT
	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$175,000	0.17	Y	TWO MAN YEARS
- Maintenance	$58,460	0.06	Y	
- Ammonia (reagent)	$140,659	0.13	Y	
- Fuel differential cost	$0	0.00	N	NOT APPLICABLE
- Catalyst replacement	$362,745	0.35	Y	20 % ADDED AFTER 3 YRS AND ALL REPLACED IN YRS shown below
- Catalyst installation/disposal	$14,706	0.01	Y	ESTIMATED $15/SCFT according to ICAC
- Electricity	$111,690	0.11	Y	
- Loss in boiler efficiency	$126,144	0.12	Y	0.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$989,404	0.94		
- SO2 Allowance	$0	0.00	N	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery			N	
- Other			N	
TOTAL FIRST YEAR O&M CREDITS:	$0	$0		
NET FIRST YEAR O&M:	$989,404	0.94		

CAPITAL ANNUALIZATION	0.094	DIMENTIONLESS
O&M ANNUALIZATION	1.00	

	$/YR	mills/kWh
TOTAL ANNUALIZED COST (CAPITAL + NET O&M)	$2,158,602	2.05

COST EFFECTIVENESS		$/TON
- 0.05 LB/MMBtu	$2,158,602	$8,214
- 0.10 LB/MMBtu	$2,299,261	$4,375
- 0.20 LB/MMBtu	$2,580,579	$2,455
- 0.30 LB/MMBtu	$2,861,897	$1,815
- 0.40 LB/MMBtu	$3,143,215	$1,495
- 0.50 LB/MMBtu	$3,424,534	$1,303
- 0.60 LB/MMBtu	$3,705,852	$1,175
- 0.70 LB/MMBtu	$3,987,170	$1,084
- 0.80 LB/MMBtu	$4,268,488	$1,015
- 0.90 LB/MMBtu	$4,549,806	$962
- 1.20 LB/MMBtu	$5,393,761	$855
- 1.50 LB/MMBtu	$6,237,715	$791

UNIT PRICING AND OTHER DATA:		
NATURAL GAS USE (%TOTAL):	15	
CATALYST LYFE (YRS):	6	
FLUE GAS FLOW (SCFH):	25000000	
COAL SULFUR (%):	2	
REAGENT / NO (MOLAL RATIO):	1.4	
SCR CATALYST ($/CFT):	$370	
AMMONIA (REAGENT)($/TON):	$300	29% AQUEOUS SOLUTION
NATURAL GAS ($/MMBtu):	$2.50	
COAL ($/MMBtu):	$1.50	
OIL ($/MMBtu):	$2.00	
PLANT HEAT RATE (Btu/kWH):	10000	
PLANT REMAINING LIFE (YRS):	20	
PLANT CAPACITY FACTOR (%):	60	
INTEREST RATE (%):	7	
CATALYST SPACE VEL. (1/HR):	6000	FOR 85% NOx REDUCTION
CATALYST VOLUME(CFT):	4167	

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF ADVANCED GAS REBURN (NGR+SNCR) - Low Cost range

Cost Item	1995 dollars	$/kWe	-	Comments & Reference
CAPITAL:				
- Ducting & insulation	$577,080	$2.9	Y	ESTIMATES BASED ON EVANS. September 1993
- Fan Upgrade/Replace	$0	$0.0	N	ADJUSTED ACCORDING TO BOILER SIZE
- Structural	$0	$0.0	N	ACCORDING TO (200/500)^0.6
- Reagent Storage & Distribution	$480,000	$2.4	Y	
- Reactor/Catalyst	$0	$0.0	N	
- Injectors and Controls	$421,202	$2.1	Y	
- Air Heater	$0	$0.0	N	
- In-plant piping	$106,760	$0.5	Y	ESTIMATES ACORDING TO EVANS, 9/1993
- Access to Gas Pipeline	$0	$0.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Burners Modification & nozzles	$321,156	$1.6	Y	NOT APPLICABLE
- OFA Ducting and Fan	$599,815	$3.0	Y	NOT APPLICABLE
- FGR Ducting and Fan	$345,871	$1.7	Y	NOT APPLICABLE
Total Purchased Equipment	$2,851,883	$14.3		TOTAL SUM
Direct Installation	$2,029,848	$10.1		ESTIMATED TO BE 50% OF EQUIPMENT COST BASED ON ICAC 94 ESTIMATE
TOTAL PROCESS CAPITAL	$4,881,731	$24.4		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$2,323,437	$11.6		20% OF PROCESS CAP.;
TOTAL PLANT COST	$7,205,167	$36.0		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0	N	ESTIMATE BASED ON ICAC 94 DATA
TOTAL CAPITAL REQUIREMENT	$7,205,167	$36.0		TOTAL INITIAL INVESTMENT
	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$175,000	0.17	Y	
- Maintenance	$34,006	0.03	Y	
- Ammonia (reagent)	$102,378	0.10	Y	ESTIMATED FOR 0.05 LB/MMBTU NOx DROP. ADJUSTED BELOW FOR OTHER
- Fuel differential cost	$1,051,200	1.00	Y	SEE BELOWW FOR FUEL UNITS PRICING AND GAS USE
- Catalyst replacement	$0	0.00	N	20 PERCENT ADDED AFTER 3 YEARS AND ALL REPLACED IN 8 YEARS
- Catalyst installation/disposal	$0	0.00	N	ESTIMATED $160/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$111,690	0.11	Y	
- Loss in boiler efficiency	$236,520	0.23	Y	1.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$1,710,794	1.63		
- SO2 Allowance	($606,462)	-0.58	Y	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery			N	
- Other	$0	0.00	N	WHEN INCLUDED, BASED ON 40 PERCENT INCREASE IN SNCR O&M COST
TOTAL FIRST YEAR O&M CREDITS:	($606,462)	($0.6)		
NET FIRST YEAR O&M:	$1,104,332	1.05		
CAPITAL ANNUALIZATION	0.094			DIMENTIONLESS
O&M ANNUALIZATION	1.00			

	$/YR	mills/kWh		
TOTAL ANNUALIZED COST (CAPITAL + NET O&M)	$1,784,449	1.70		
COST EFFECTIVENESS		$/TON		
- 0.05 LB/MMBtu	$1,784,449	$6,790		
- 0.10 LB/MMBtu	$1,886,827	$3,590		
- 0.20 LB/MMBtu	$2,091,582	$1,990		
- 0.30 LB/MMBtu	$2,296,338	$1,456		
- 0.40 LB/MMBtu	$2,501,093	$1,190		
- 0.50 LB/MMBtu	$2,705,849	$1,030		
- 0.60 LB/MMBtu	$2,910,604	$923		
- 0.70 LB/MMBtu	$3,115,359	$847		
- 0.80 LB/MMBtu	$3,320,115	$790		
- 0.90 LB/MMBtu	$3,524,870	$745		
- 1.20 LB/MMBtu	$4,139,137	$656		
- 1.50 LB/MMBtu	$4,753,403	$603		

UNIT PRICING AND OTHER DATA:		
NATURAL GAS USE (%TOTAL):	10	
CATALYST LYFE (YRS):	6	
FLUE GAS FLOW (SCFH):	25000000	
COAL SULFUR (%):	2	
REAGENT / NO (MOLAL RATIO):	1.4	
SCR CATALYST ($/CFT):	$370	
AMMONIA (REAGENT)($/TON):	$300	29% AQUEOUS SOLUTION
NATURAL GAS ($/MMBtu):	$2.50	
COAL ($/MMBtu):	$1.50	
OIL ($/MMBtu):	$2.00	
PLANT HEAT RATE (Btu/kWH):	10000	
PLANT REMAINING LIFE (YRS):	20	
PLANT CAPACITY FACTOR (%):	60	
INTEREST RATE (%):	7	
CATALYST SPACE VEL. (1/HR):	3250	FOR 85% NOx REDUCTION
UREA COST ($/TON):	200	50% UREA SOLUTION
CATALYST VOLUME(CFT):	7692	

Source: 200 MWe Coal-fired utility boiler
Control: RETROFIT OF ADVANCED GAS REBURN (NGR+SNCR) - High Cost range

Cost Item	1995 dollars	$/kWe		Comments & Reference
CAPITAL:				
- Ducting & insulation	$577,080	$2.9	Y	ESTIMATES BASED ON EVANS. September 1993
- Fan Upgrade/Replace	$0	$0.0	N	ADJUSTED ACCORDING TO BOILER SIZE
- Structural	$0	$0.0	N	ACCORDING TO (200/500)^0.6
- Reagent Storage & Distribution	$680,000	$3.4	Y	
- Reactor/Catalyst	$0	$0.0	N	
- Injectors and Controls	$536,618	$2.7	Y	
- Air Heater	$0	$0.0	N	
- In-plant piping	$106,760	$0.5	Y	ESTIMATES ACORDING TO EVANS, 9/1993
- Access to Gas Pipeline	$1,000,000	$5.0	N	ESTIMATED MAXIMUM 5 MILES FROM SUITABLE PIPELINE
- Burners Modification & nozzles	$321,156	$1.6	Y	NOT APPLICABLE
- OFA Ducting and Fan	$599,815	$3.0	Y	NOT APPLICABLE
- FGR Ducting and Fan	$345,871	$1.7	Y	NOT APPLICABLE
Total Purchased Equipment	$4,167,299	$20.8		TOTAL SUM
Direct Installation	$2,029,848	$10.1		ESTIMATED TO BE 50% OF EQUIPMENT COST BASED ON ICAC 94 ESTIMATE
TOTAL PROCESS CAPITAL	$6,197,146	$31.0		SUM OF PURCHASED EQUIPMENT AND DIRECT INSTALLATION
INDIRECT COST AND CONTINGENCIES	$3,020,607	$15.1		20% OF PROCESS CAP.;
TOTAL PLANT COST	$9,217,754	$46.1		SUM OF TOTAL PROCESS CAPITAL AND INDIRECT COST/CONTINGENCIES
ALLOWABLE FUNDS DURING CONSTRUCT	$0	$0.0	N	ESTIMATE BASED ON ICAC 94 DATA
TOTAL CAPITAL REQUIREMENT	$9,217,754	$46.1		TOTAL INITIAL INVESTMENT

	$/YR	mills/kWh		
FIRST YEAR O&M:				
- Labor	$175,000	0.17	Y	
- Maintenance	$43,505	0.04	Y	
- Ammonia (reagent)	$102,378	0.10	Y	ESTIMATED FOR 0.05 LB/MMBTU NOx DROP. ADJUSTED BELOW FOR OTHER
- Fuel differential cost	$1,051,200	1.00	Y	SEE BELOWW FOR FUEL UNITS PRICING AND GAS USE
- Catalyst replacement	$0	0.00	N	20 PERCENT ADDED AFTER 3 YEARS AND ALL REPLACED IN 8 YEARS
- Catalyst installation/disposal	$0	0.00	N	ESTIMATED $160/SCFT ACCORDING TO EPA ACT DOCUMENT
- Electricity	$111,690	0.11	Y	
- Loss in boiler efficiency	$236,520	0.23	Y	1.5 PERCENT LOSS IN ECONOMIZER BYPASS
TOTAL FIRST YEAR O&M DEBITS:	$1,720,292	1.64		
- SO2 Allowance	($606,462)	-0.58	Y	15 PERCENT GAS USE REPLACING 2 % SULFUR COAL
- Capacity Recovery			N	
- Other	$0	0.00	N	WHEN INCLUDED, BASED ON 40 PERCENT INCREASE IN SNCR O&M COST
TOTAL FIRST YEAR O&M CREDITS:	($606,462)	($0.6)		
NET FIRST YEAR O&M:	$1,113,831	1.06		

CAPITAL ANNUALIZATION	0.094	DIMENTIONLESS
O&M ANNUALIZATION	1.00	

	$/YR	mills/kWh
TOTAL ANNUALIZED COST (CAPITAL + NET O&M)	$1,983,922	1.89

COST EFFECTIVENESS		$/TON
- 0.05 LB/MMBtu	$1,983,922	$7,549
- 0.10 LB/MMBtu	$2,086,299	$3,969
- 0.20 LB/MMBtu	$2,291,055	$2,179
- 0.30 LB/MMBtu	$2,495,810	$1,583
- 0.40 LB/MMBtu	$2,700,566	$1,285
- 0.50 LB/MMBtu	$2,905,321	$1,106
- 0.60 LB/MMBtu	$3,110,077	$986
- 0.70 LB/MMBtu	$3,314,832	$901
- 0.80 LB/MMBtu	$3,519,588	$837
- 0.90 LB/MMBtu	$3,724,343	$787
- 1.20 LB/MMBtu	$4,338,610	$688
- 1.50 LB/MMBtu	$4,952,876	$628

UNIT PRICING AND OTHER DATA:		
NATURAL GAS USE (%TOTAL):	10	
CATALYST LYFE (YRS):	6	
FLUE GAS FLOW (SCFH):	25000000	
COAL SULFUR (%):	2	
REAGENT / NO (MOLAL RATIO):	1.4	
SCR CATALYST ($/CFT):	$370	
AMMONIA (REAGENT)($/TON):	$300	29% AQUEOUS SOLUTION
NATURAL GAS ($/MMBtu):	$2.50	
COAL ($/MMBtu):	$1.50	
OIL ($/MMBtu):	$2.00	
PLANT HEAT RATE (Btu/kWH):	10000	
PLANT REMAINING LIFE (YRS):	20	
PLANT CAPACITY FACTOR (%):	60	
INTEREST RATE (%):	7	
CATALYST SPACE VEL. (1/HR):	3250	FOR 85% NOx REDUCTION
UREA COST ($/TON):	200	50% UREA SOLUTION
CATALYST VOLUME(CFT):	7692	

TECHNICAL REPORT DATA

(Please read Instructions on reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-453/R-96-002		

4. TITLE AND SUBTITLE Phase II NO_x Controls for the MARAMA and NESCAUM Regions	5. REPORT DATE November 1995 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Carlo Castaldini	8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Acurex Environmental Corporation Post Office Box 7044 Mountain View, California 94039	10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-D2-0189
12. SPONSORING AGENCY NAME AND ADDRESS Director Office of Air Quality Planning and Standards Office of Air and Radiation U.S. Environmental Protection Agency Research Triangle Park, NC 27711	13. TYPE OF REPORT AND PERIOD COVERED 14. SPONSORING AGENCY CODE EPA/200/04

15. SUPPLEMENTARY NOTES- EPA Contact - Bill Neuffer (919)541-5435; MARAMA Contact - Jim Hambright (717)232-1961; NESCAUM Contact - Praveen Amar (617)367-8540

16. ABSTRACT

This technical report discusses Phase II NOx controls for utility boilers in the Mid-Atlantic Regional Air Management Association(MARAMA) and the Northeast States for Coordinated Air Use Management(NESCAUM) regions. The subject areas include:

- Utility boiler population profile in the MARAMA and NESCAUM regions
- Discussion of RACT controls
- Available NOx controls and their levels of performance
- Costs and cost effectiveness of NOx controls

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Utility boilers NO_x control techniques Low NO_x burners Selective noncatalytic reduction Selective catalytic reduction	Air Pollution control	

DISTRI BUTION STATEMENT	costs 19. SECURITY CLASS *(Report)* Unclassified	21. NO. OF PAGES 230
	20. SECURITY CLASS *(Page)* Unclassified	22. PRICE

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