12
4-6-95 J50

United States
Environmental Protection
Agency

Air and Energy Engineering
Research Laboratory
Research Triangle Park, NC 27711

EPA-600/R-94-208
December 1994

U.S. Department
of Energy

National Renewable
Energy Laboratory
Golden, CO 80401

NREL/TP-430-6742
DE94011834

NO_x Control Technologies Applicable to Municipal Waste Combustion

Interagency
Energy and Environmental
Research Report

U.S. Environmental Protection Agency
Office of Research and Development
Washington, DC

U.S. Department of Energy
Energy Efficiency, Conservation
and Renewable Energy
Washington, DC

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

EPA REVIEW NOTICE

This report has been reviewed by the U.S. Environmental Protection Agency, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policy of the Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

NREL/TP-430-6742
DE94011834

EPA-600/R-94-208
December 1994

NO_x Control Technologies Applicable to Municipal Waste Combustion

Prepared by:

D.M. White
K. L. Nebel
M. Gundappa
K.R. Ferry

Radian Corporation
3200 E. Chapel Hill Road/Nelson Highway
Research Triangle Park, NC 27709

EPA Interagency Agreement DW89935714
NREL Subcontract No. YAR-3-13184-1

EPA Project Officer:

James D. Kilgroe
Air and Energy Engineering
Research Laboratory
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

NREL Technical Monitor:

Philip B. Shepherd
National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, CO 80401-3393

Prepared for:

U.S. Environmental Protection Agency
Office of Research and Development
Washington, DC 20460

U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

MASTER

ABSTRACT

Several technologies are available for reducing NO_x emissions from municipal waste combustors (MWCs). These include combustion controls, natural gas injection (NGI), selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). The objectives of this report are to document the key design and operating parameters, commercial status, demonstrated performance, and cost of NGI, SNCR, and SCR, and to identify technology research and development needs associated with these technologies.

Two distinct NGI processes have been developed. One of these, Methane de- NO_x^{SM} , uses gas injection to inhibit NO_x formation and appears capable of reducing NO_x emissions from MWCs by approximately 60%. The second approach, reburning, uses gas injection to create reducing conditions that convert NO_x formed in the primary combustion zone to N_2 . Long-term emission reductions for SNCR are 45-65% and are 80-90% for SCR. Operation of SNCR near the upper end of the performance range can result in unwanted emissions of ammonia or other byproduct gases. An advanced version of SNCR using furnace pyrometry and advanced process controls appears capable of achieving high NO_x reductions with less reagent than is needed for conventional SNCR. The combination of NGI and SNCR (advanced NGI) may be able to achieve overall NO_x reductions of 80 to 85%.

Comparing costs, SCR is the most capital intensive, followed by advanced SNCR and advanced NGI. Capital costs of NGI and conventional SNCR are comparable. In terms of tipping fee impact and cost effectiveness, conventional SNCR generally has the lowest costs of the evaluated technologies. For NGI, these costs are dependent on whether waste is diverted and tipping fee revenues are lost when applying this technology, along with the price of natural gas. Depending on the selected NGI scenario, the resulting tipping fee impacts and cost effectiveness values can be the highest of the evaluated technologies. After specific NGI scenarios, the next highest tipping fee impacts and cost effectiveness values are for SCR. These high costs result from high capital costs, as well as the cost of catalyst replacement and disposal.

TABLE OF CONTENTS

	Page
Abstract	ii
List of Figures	v
List of Tables	vii
Acronyms	viii
Conversion Factors	x
 1.0 INTRODUCTION AND SUMMARY	 1-1
1.1 Report Background, Objectives, and Organization	1-1
1.2 Background Information of NO _x Formation and Control Technologies	 1-2
1.2.1 NO _x Formation	1-2
1.2.2 NO _x Control Technologies	1-5
1.3 Technical Approach	1-7
1.4 Conclusions	1-8
1.4.1 Technical Status of Evaluated Control Technologies	1-8
1.4.2 Comparative Costs of Evaluated Control Technologies	1-12
1.5 References	1-17
 2.0 NATURAL GAS INJECTION	 2-1
2.1 Process Description	2-1
2.1.1 Reburning	2-1
2.1.2 Methane de-NOX SM	2-5
2.2 Development Status	2-5
2.3 Key Design and Process Variables Affecting Performance	2-10
2.4 Recent Advances and Further Research Needs	2-13
2.5 Cost Analysis	2-15
2.5.1 Design Basis	2-15
2.5.2 Cost Results	2-17
2.5.3 Sensitivity Analysis	2-23
2.6 References	2-26

TABLE OF CONTENTS (Continued)

	Page
3.0 SELECTIVE NON-CATALYTIC REDUCTION	3-1
3.1 Process Description	3-1
3.1.1 Thermal DeNO _x TM	3-1
3.1.2 NO _x OUT TM	3-4
3.2 Development Status	3-6
3.3 Key Design and Process Variables	3-6
3.4 Recent Advances and Further Research Needs	3-14
3.4.1 Temperature Monitoring	3-14
3.4.2 Ammonia Continuous Emissions Monitors	3-18
3.5 Cost Analysis	3-19
3.5.1 Design Basis	3-19
3.5.2 Cost Results	3-21
3.5.3 Sensitivity Analysis	3-30
3.6 References	3-33
4.0 SELECTIVE CATALYTIC REDUCTION	4-1
4.1 Process Description	4-1
4.2 Development Status	4-3
4.3 Key Design and Process Variables	4-6
4.4 Recent Advances and Further Research Needs	4-9
4.5 Cost Analysis	4-10
4.5.1 Design Basis	4-10
4.5.2 Cost Results	4-10
4.5.3 Sensitivity Analysis	4-16
4.6 References	4-19
APPENDIX A Description of Costing Framework	A-1

LIST OF FIGURES

	Page
1-1 Effect of Unit Size, Reagent Cost, and Annualized Capital on Tipping Fee Impact and Cost Effectiveness for Conventional SNCR	1-10
1-2 Comparison of Capital Cost	1-14
1-3 Comparison of Tipping Fee Impact	1-15
1-4 Comparison of Cost Effectiveness	1-16
2-1 Schematic of Reburn Process	2-3
2-2 Effect of Temperature on Reburn NO _x Reduction Efficiency	2-4
2-3 Schematic of Methane de-NOX SM Process	2-6
2-4 Effect of Primary Zone Stoichiometry on CO and NO _x Emissions During Malmö Reburn Testing	2-7
2-5 Effect of Methane de-NOX SM on CO and NO _x Emissions During Olmsted County Methane de-NOX SM Testing	2-9
2-6 Effect of O ₂ Concentration on NO _x Emissions During Olmsted County Methane de-NOX SM Testing	2-11
2-7 Effect of Natural Gas Injection Rate on NO _x Emissions During Olmsted County Methane de-NOX SM Testing	2-12
2-8 Effect of Natural Gas Injection Residence Time on NO _x Emissions During Pilot-Scale Testing of Methane de-NOX SM Process	2-14
2-9 Effect of Unit Size, Fuel Cost, Annualized Capital and Plant Tip Fee on Tipping Fee Impact and Cost Effectiveness for NGI-100 (for MWCs without additional heat input capacity)	2-24
2-10 Effect of NO _x Reduction on Tipping Fee Impact and Cost Effectiveness for NGI-100 (for MWCs without additional heat input capacity)	2-25

LIST OF FIGURES (Continued)

		Page
3-1	Schematic Diagram of SNCR Applied to an MWC	3-2
3-2	Ammonia Reaction Pathways	3-3
3-3	Urea Reaction Pathways	3-5
3-4	Effect of Reagent Feedrate on SNCR Performance	3-9
3-5	Effect of Temperature and Flue Gas Composition on SNCR Performance	3-11
3-6	Schematic Diagram of Advanced SNCR Applied to the Lancaster County MWC	3-16
3-7	Effect of Unit Size, Reagent Cost, and Annualized Capital on Tipping Fee Impact and Cost Effectiveness for Conventional SNCR	3-31
3-8	Effect of NO _x Reduction on Tipping Fee Impact and Cost Effectiveness for Conventional SNCR	3-32
4-1	Schematic of SCR Configurations	4-2
4-2	Effect of Temperature on SCR Performance	4-8
4-3	Effect of Unit Size, Catalyst Replacement Cost, and Annualized Capital on Tipping Fee Impact and Cost Effectiveness for SCR	4-17
4-4	Effect of NO _x Reduction on Tipping Fee Impact and Cost Effectiveness for SCR	4-18

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

LIST OF TABLES

		Page
1-1	Model Plant Cost Estimates for Conventional SNCR	1-9
1-2	Technical Overview of Evaluated NO _x Control Technologies	1-11
2-1	Model Combustor Inputs for NGI	2-18
2-2	Cost Outputs for NGI Applied to the 400 TPD Model Combustor	2-19
2-3	Model Plant Cost Estimates for NGI for MWCs without Additional Heat Input Capacity (NGI-100)	2-20
2-4	Model Plant Cost Estimates for NGI for MWCs with 15% Available Heat Input Capacity (NGI-85)	2-22
3-1	Summary of U.S. SNCR Applications on Municipal Waste Combustors	3-7
3-2	Model Combustor Inputs for Conventional SNCR	3-22
3-3	Cost Outputs for Conventional SNCR Applied to the 400 TPD Model Combustor	3-23
3-4	Model Plant Cost Estimates for Conventional SNCR	3-24
3-5	Model Plant Cost Estimates for Advanced SNCR	3-26
3-6	Comparison of Conventional and Advanced SNCR Systems	3-28
3-7	Model Plant Cost Estimates for Advanced NGI	3-29
4-1	Summary of SCR Applications on European MWCs	4-4
4-2	Summary of SCR Applications on Japanese MWCs	4-5
4-3	Model Combustor Inputs for SCR	4-11
4-4	Cost Outputs for SCR Applied to the 400 TPD Model Combustor	4-12
4-5	Model Plant Cost Estimates for SCR	4-13
4-6	Comparison of Cold- and Hot-side SCR Systems	4-15

ACRONYMS

APCD	=	air pollution control device
As	=	arsenic
Ca	=	calcium
CEM	=	continuous emission monitor
CEMS	=	continuous emissions monitoring system
CO	=	carbon monoxide
CO ₂	=	carbon dioxide
CO(NH ₂) ₂	=	urea
DOAS	=	differential optical adsorption spectroscopy
dscf	=	dry standard cubic foot
dscm	=	dry standard cubic meter
EER	=	Energy & Environmental Research Corporation
EPA	=	Environmental Protection Agency
ESP	=	electrostatic precipitator
FF	=	fabric filter
FGD _N	=	flue gas denitrification
FGR	=	flue gas recirculation
H	=	hydrogen ion
HCl	=	hydrogen chloride
HCN	=	hydrogen cyanide
HNCO	=	cyanic acid
IGT	=	Institute of Gas Technology
IMS	=	ion mobility spectroscopy
IR	=	infrared
K	=	potassium
lb/hr	=	pounds per hour
MB/WW	=	mass burn waterwall
mg	=	milligram
MMBtu	=	million British thermal units
MSW	=	municipal solid waste
MWC	=	municipal waste combustor
Na	=	sodium
NDIR	=	non-dispersive infrared
N ₂	=	nitrogen
N ₂ O	=	nitrous oxide
NGI	=	natural gas injection
NH ₂	=	amide radical
NH ₃	=	ammonia
(NH ₄) ₂ SO ₄	=	ammonium sulfate
NH ₄ Cl	=	ammonium chloride
NH ₄ HSO ₄	=	ammonium bisulfate
NO	=	nitrogen oxide

ACRONYMS (Continued)

NO ₂	=	nitrogen dioxide
NO _x	=	nitrogen oxides
NSPS	=	New Source Performance Standards
NSR	=	normalized stoichiometric ratio
O	=	oxygen radical
O ₂	=	molecular oxygen
OFA	=	overfire air
OH	=	hydroxyl radical
O&M	=	operating and maintenance
OMS	=	Ogden Martin Systems
Pb	=	lead
ppm	=	parts per million
SCR	=	selective catalytic reduction
SNCR	=	selective non-catalytic reduction
SO ₂	=	sulfur dioxide
SO ₃	=	sulfur trioxide
SYSAV	=	Sydvästra Skånes-Avfallsaktiebolag - Southwest Scania Waste Company
tpd	=	tons per day
U.S.	=	United States
UV	=	ultraviolet
V ₂ O ₅ /TiO ₂	=	vanadium pentoxide/titanium oxide
WO ₃	=	tungsten oxide
WSCFM	=	wet standard cubic foot per minute

CONVERSION FACTORS

	To Convert From	To	Multiply By
Area	ft ²	m ²	9.2903E-2
Density	lbm/ft ³	kg/m ³	1.6019E+1
Energy	Btu	J	1.0551E+3
Force	lbf	N	4.4482
Length	ft	m	3.048E-1
	in.	m	2.5400E-2
	in.	mm	2.540E+1
Mass	lbm	kg	4.535E-1
	lbm	g	4.535E+2
	gr	g	6.486E-2
Mass Concentration	gr/ft ³	g/m ³	2.29
Power	ft - lbf/s	W	1.3558
Pressure	lbf/in. ²	Pa	6.895E+3
Temperature	°F	°C	5/9(T ^F - 32°)
Volume	ft ³	m ³	2.8317E-2
Volumetric Flow	ft ³ /s	m ³ /s	2.8317E-2
Weight	ton	Mg	1.10

1.0 INTRODUCTION AND SUMMARY

1.1 Report Background, Objectives, and Organization

Nitrogen oxides (NO_x) are of environmental significance because of their role as a criteria pollutant, acid gas, and ozone precursor. The current New Source Performance Standards (NSPS) for municipal waste combustors (MWCs) (40 CFR Part 60, Subpart Ea) limit NO_x emissions to a daily average of 180 parts per million (ppm) at 7% oxygen (O_2), dry basis.* By comparison, typical NO_x emissions from modern mass burn waterwall (MB/WW) MWCs range from 220 to 320 ppm. To comply with the NSPS, most recently built MWCs have used a combination of combustion controls to limit NO_x formation and selective non-catalytic reduction (SNCR) to convert NO_x to molecular nitrogen (N_2). Because of pressure to achieve even lower emission levels, questions have been raised regarding the potential for advancement in NO_x control technologies. To respond to these questions, the Air and Energy Engineering Research Laboratory and the National Renewable Energy Laboratory initiated this assessment of three alternative NO_x control technologies: natural gas injection (NGI), SNCR, and selective catalytic reduction (SCR). The objectives of this assessment were to (1) document the key design and operating parameters, commercial status, demonstrated performance, and cost of each technology, and (2) identify technology research and development needs.

The assessment of achievable NO_x emissions presented throughout the report is based on the average NO_x reduction potential of these technologies applied to "typical" MWCs. The assessment does not examine the potential severity or length of short-duration excursions in performance that can affect continuously achievable NO_x emission rates associated with short averaging periods. The assessment also does not

* Unless otherwise noted, all NO_x concentrations used in this report are corrected to 7% O_2 and are on a dry basis.

consider potential limitations on technology performance that may result from combustor-specific design or operating restrictions.

This report is divided into four chapters. The first chapter provides an overview of NO_x emissions from MWCs and available control methods, the study's technical approach, and key findings related to NGI, SNCR, and SCR. Chapters 2, 3, and 4 provide a more in-depth review of these three technologies.

1.2 Background Information of NO_x Formation and Control Technologies

1.2.1 NO_x Formation

The chemistry of NO_x formation is directly tied to reactions between nitrogen and oxygen. To understand NO_x formation in an MWC, a basic understanding of combustor design and operation is useful. Combustion air systems in MB/WW MWCs include both undergrate (also called, primary) air and overgrate (also called, secondary or overfire) air. Undergrate air, supplied through plenums located under the firing grate, is forced through the grate to sequentially dry (evolve water), devolatilize (evolve volatile hydrocarbons), and burn out (oxidize nonvolatile hydrocarbons) the waste bed. The quantity of undergrate air is adjusted to minimize excess air during initial combustion of the waste while maximizing burn out of carbonaceous materials in the waste bed. Overgrate air, injected through air ports located above the grate, is used to provide turbulent mixing and destruction of hydrocarbons evolved from the waste bed. Overall excess air levels for a typical MB/WW MWC are approximately 80% (180% of stoichiometric [i.e., theoretical] air requirements), with undergrate air accounting for 60 to 70% of the total air. In addition to destruction of organics, one of the objectives of this "staged" combustion approach is to minimize NO_x formation.

NO_x is formed during combustion through two primary mechanisms: fuel NO_x formation and thermal NO_x formation. Fuel NO_x results from oxidation of

organically-bound nitrogen present in the municipal solid waste (MSW) stream. Thermal NO_x results from oxidation of atmospheric nitrogen (N_2).

Fuel NO_x is formed within the flame zone through reaction of organically-bound nitrogen in MSW materials and oxygen. Key variables determining the rate of fuel NO_x formation are the availability of O_2 within the flame zone, the amount of fuel-bound nitrogen, and the chemical structure of the nitrogen-containing material. Fuel NO_x reactions can occur at relatively low temperatures [$<1,100^\circ\text{C}$ ($<2,000^\circ\text{F}$)]. Depending on the availability of O_2 in the flame, the nitrogen compounds will react to form either N_2 or NO_x . When the availability of O_2 is low, N_2 is the predominant reaction product. If substantial O_2 is available, an increased fraction of the fuel-bound nitrogen is converted to NO_x . Testing conducted in the 1970's and 1980's using coal showed that in oxygen-rich, highly mixed systems approximately 50% of the fuel-bound nitrogen can convert to NO_x ; in oxygen-starved staged-combustion systems, however, the rate of conversion decreases to near 5%.¹ Other testing has shown that nitrogen associated with volatile compounds is more readily converted to fuel NO_x than nitrogen associated with nonvolatile materials.² Still other research involving coal and oil combustion indicates that the extent of conversion is related to the amount of nitrogen available, with the degree of conversion decreasing as the amount of fuel-bound nitrogen increases.³

Thermal NO_x is formed in high-temperature flame zones through reactions between N_2 and oxygen radicals. The key variables determining the rate of thermal NO_x formation are temperature, the availability of O_2 and N_2 , and residence time. The key reactions resulting in thermal NO_x formation are:

followed by:

Because of the high activation energy required for reaction 1-1, thermal NO_x formation does not become significant until flame temperatures reach 1,100°C (2,000°F). Kinetic calculations (assuming 30% excess air, average MSW properties, and a residence time of 0.5 seconds), predict thermal NO_x concentrations of less than 10 ppm in MWCs.⁴ However, local flame temperatures may exceed 1,100°C (2,000°F) and thermal NO_x concentrations may be greater than these calculated models results.

Examination of MWC operating conditions suggests that most of the NO_x emitted from MWCs (>80%) is attributable to fuel-bound nitrogen. Based on typical MSW nitrogen contents of 0.3 to 0.7%, the expected NO_x emissions--assuming all of the fuel-bound nitrogen is converted to NO_x--would be 1,000 to 2,500 ppm at 7% O₂. As noted earlier, however, actual emissions are generally between 220-320 ppm at 7% O₂, indicating that perhaps 10 to 30% of the fuel nitrogen is converted to NO_x, with most of the remainder forming N₂.

A number of evaluations of MWC NO_x emissions data have attempted to define the role of nitrogen-containing materials in MSW (e.g., grass, leaves, wood, and food wastes) on NO_x emissions. The first of these evaluations was presented in 1987 and suggested that fluctuations in measured NO_x levels were attributable to seasonal fluctuations in MSW composition.⁵ This evaluation was based on NO_x compliance test data obtained from a number of MWCs in the U.S. and overseas at different times of the year, and concluded that the seasonal variations in measured NO_x concentrations might be the result of variations in the amount of yardwaste in the MSW at different times of the year. Because of the large number of facilities included in the evaluation and the limited number of measurements taken from a single MWC at different times of the year, however, this conclusion may have been attributable to coincidental differences in the NO_x-forming characteristics of the various MWCs, rather than variations in the nitrogen content of MSW. A similar comparison of NO_x emission concentrations versus time of year for a number of U.S. MWCs compiled by the U.S. EPA in 1989 to support the MWC NSPS did not show any significant relationship between NO_x concentration and time of year.⁶

A more recent evaluation of NO_x continuous emission monitor (CEM) data from 11 MWCs located in the northeast U.S. found no seasonal variations in NO_x concentrations.⁷ This evaluation compared monthly average NO_x data from the individual MWCs (covering 12 to 36 consecutive months of operation for each unit) with the estimated fraction of yardwaste found in northeastern MSW during each of the four seasons. Monthly average NO_x concentrations from these units varied from 140 to 310 ppm, but did not show any consistent relationship between NO_x concentrations and the estimated percentage of yardwaste.

Yet another evaluation compared NO_x concentrations measured during nine test runs conducted at the MB/WW MWC in Burnaby, British Columbia to the amount of high-nitrogen organics (grass, leaves, brush, stumps, wood, food waste, textiles, rubber, and footwear) in the MSW fired during each run.⁸ The testing was conducted in June 1991 and included sampling of the MSW fired during each run, sorting the collected sample to evaluate waste stream composition, and elemental analysis of each of the sorted subsamples. During these tests, high-nitrogen organics accounted for 25 to 47% and yardwastes accounted for 4 to 30% of the total waste stream. The estimated average nitrogen content of the entire stream during each run ranged from 0.34 to 0.66%. NO_x concentrations in the flue gas during the runs varied from 261 to 304 ppm. Statistical analysis of the MSW and flue gas data from each run showed no relationship (at a screening 80% confidence level) between NO_x concentrations and MSW characteristics. These data suggest that because of the staged-combustion design of the Burnaby MWC and other modern MB/WW MWCs, variations in NO_x emissions appear to be attributable to differences in combustor design and operation, rather than waste composition.

1.2.2 NO_x Control Technologies

NO_x control technologies can be divided into two subgroups: combustion controls and post-combustion controls. Combustion controls are designed to limit the formation of NO_x during the combustion process by reducing the availability of O₂

within the flame and lowering combustion zone temperatures. These technologies include staged combustion, low excess air, flue gas recirculation (FGR), and NGI. Staged combustion and low excess air are used to reduce the flow of undergrate air in order to reduce O_2 availability in the combustion zone. Another option is FGR in which a portion of the combustor exhaust is returned to the combustion air supply to both lower combustion zone O_2 and suppress flame temperatures by reducing the ratio of O_2 to inerts (N_2 and CO_2) in the combustion air system. One or more of these approaches are used by most modern MWCs. Test data for these techniques indicate that they can reduce NO_x concentrations by 10-30% compared to baseline levels from the same units.⁶ NGI selectively uses natural gas either to inhibit NO_x formation or convert NO_x that is formed to N_2 . NGI is discussed in more detail in Chapter 2 of this report.

The most used post-combustion NO_x controls for MWCs include SNCR and SCR. SNCR reduces NO_x to N_2 without the use of catalysts. With SNCR, one or more reducing agents (e.g., ammonia [NH_3], urea) is injected into the upper furnace of the MWC to react with NO_x and form N_2 . SNCR is discussed in Chapter 3. SCR is an add-on control technology that catalytically promotes the reaction between NH_3 and NO_x . SCR is discussed in Chapter 4.

In addition to SNCR and SCR, commercial post-combustion NO_x controls also include flue gas denitrification (FGD_N). FGD_N can be used by MWCs that use a multiple-stage wet scrubber for hydrogen chloride (HCl) and sulfur dioxide (SO_2) control. In these systems, the first scrubbing stage typically operates at a very low pH (<3) to remove HCl, followed by a second stage operating at a higher pH (>5) to remove sulfur dioxide (SO_2). In these systems, an oxidizing agent can be added to the first scrubber stage to convert nitrogen oxide (NO) to nitrogen dioxide (NO_2). NO generally accounts for over 90% of the total NO_x from combustion systems and is relatively insoluble in liquids. NO_2 , however, is soluble and can be collected in the second scrubber stage along with SO_2 . Test data from an FGD_N system installed on an MWC in Europe has shown NO_x reductions of up to 85%.⁹ Because of the

predominant use of spray dryer absorber technology is the U.S. for SO₂ and HCl control, however, significant use of FGD_N in the U.S. appears unlikely.

1.3 Technical Approach

This assessment was conducted using information obtained from published literature and contacts with technology vendor and MWC industry personnel. For each technology, information was collected on the key process variables; commercial applications in Europe, Japan, and the U.S.; recent research and development activities; and costs. In addition to the current versions of NGI and SNCR, advanced concepts for these two technologies were examined. These include advanced NGI, which combines conventional NGI and SNCR; and advanced SNCR, which employs additional process control equipment to enhance conventional SNCR performance. This information was then used to develop a series of computer-based spreadsheets designed to maintain basic material and energy balances for the technology and to calculate technology costs. The costing approach is further described in Appendix A.

The output from these spreadsheets is presented in two formats. The first format is as a table presenting capital costs, tipping fee impacts, and cost effectiveness levels** for each NO_x control technology as a function of MWC size and a second key technology variable. An example of this output, based on conventional SNCR, is shown

** Capital costs include purchased equipment costs, installation, engineering and home office expenses, and process and project contingencies. Tipping fee impact is calculated by dividing the technology's total annualized cost by the annual tonnage of MSW processed. Tipping fee impact is an incremental cost that indicates the potential cost of the technology on the MSW generator. However, it does not necessarily reflect the amount by which the plant's tip fee will increase as a result of applying the control technology. Cost effectiveness is calculated by dividing the technology's total annualized cost by the tonnage of reduced NO_x emissions and indicates the cost of the control relative to its environmental benefit.

in Table 1-1. For example, the estimated capital cost for SNCR operating at 60% NO_x reduction on a 400 ton per day (tpd)^{***} MWC is \$1,980/tpd of capacity. For the same NO_x reduction level and MWC size, the tipping fee impact is estimated at approximately \$1.50 per ton of MSW processed, and the cost effectiveness value is approximately \$1,270 per ton of NO_x removed from the flue gas.

The second output format is a graph showing the sensitivity of tipping fee impact and cost effectiveness to key process variables. An example of this output, also based on conventional SNCR, is presented in Figure 1-1. For example, the process variable having the greatest effect on cost is MWC size. Compared to the 400 tpd "reference" MWC, reducing plant size to 100 tpd increases the tipping fee impact from roughly \$1.50 per ton of MSW to almost \$4.00 per ton (shown on the left Y-axis), and increases the cost effectiveness value from \$1,270 per ton of NO_x removed to \$3,380 per ton (shown on the right Y-axis).

1.4 Conclusions

1.4.1 Technical Status of Evaluated Control Technologies

The technical status of each of the evaluated control technologies is summarized in Table 1-2. As shown, two distinct NGI processes have been developed. One of these, Methane de-NO_xSM, uses gas injection to inhibit NO_x formation and appears capable of reducing NO_x emissions from MWCs by approximately 60%. The second approach, reburning, uses gas injection to create reducing conditions that convert NO_x formed in the primary combustion zone to N₂. Because of the relatively high temperatures required for these NO_x-reduction reactions, it may be difficult to successfully apply reburning to modern MB/WW MWCs. Short-duration tests of these

^{***}Readers who are more familiar with metric units may use the factors listed at the end of the front matter to convert to that system.

Table 1-1
Model Plant Cost Estimates For Conventional SNCR (a)

	Total Capital Cost (\$1000/TPD capacity)			Tipping Fee Impact (\$/ton MSW)			Cost Effectiveness (\$/ton NOx)		
NOx Reduction (%)	45	60	65	45	60	65	45	60	65
100 TPD Mass Burn MWC	5.05	5.06	5.07	3.74	3.91	4.06	4,308	3,378	3,235
400 TPD Mass Burn MWC	1.97	1.98	2.00	1.30	1.47	1.62	1,496	1,268	1,289
750 TPD Mass Burn MWC	1.49	1.50	1.52	0.92	1.09	1.24	1,058	940	986

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

Figure 1-1. Effect of Unit Size, Reagent Cost, and Annualized Capital on Tipping Fee Impact and Cost Effectiveness for Conventional SNCR

Table 1-2

Technical Overview of Evaluated NO_x Control Technologies

Technology	Commercial Status	NO _x Control Performance	Technical Issues
NGI: Methane deNOX SM	Tested on MWC in Olmsted County, Minnesota	Testing achieved up to 60% NO _x reduction without increasing CO emissions.	Scaleup of technology to larger furnace sizes (> 100 tpd).
NGI: Reburning	Applied to fossil fuel boilers; use on MWCs limited to test program in Malmo, Sweden	MWC testing encountered high CO levels when NO _x reductions exceeded 30 to 40%.	Reburn zone temperatures in MWCs may be too low for NO _x reduction reactions.
SNCR: Thermal DeNO _x TM	Applied to six MWCs in U.S. plus others overseas	Achieved short-term reductions of 45 to 75%, depending on NH ₃ injection rate. Plume visible at higher reduction levels.	Impact of furnace temperature swings on NO _x and NH ₃ emissions. Control of NH ₃ slip and visible plume.
SNCR: NO _x OUT TM	Applied to two MWCs in U.S. plus others overseas	Comparable to NH ₃ injection.	Similar to NH ₃ injection. N ₂ O emissions also of concern.
Advanced SNCR (improved process control)	Tested at MWCs in Lancaster, Pennsylvania and Munich, Germany	Achieved 60 to 75% NO _x reduction with less reagent than is needed with conventional SNCR. Plume visible at higher reduction levels.	Demonstration of long-term performance capability. Additional process controls may benefit other combustor operations.
Advanced NGI (conventional NGI plus SNCR)	Concept only.	Potential for 80% reduction.	Interaction of temperature and residence time needs for each technology.
SCR	Installed at 20 MWC plants in Europe and Japan	80 to 90% NO _x reduction.	Catalyst life in hot-side systems

processes have been conducted at MWCs in the U.S. and Europe. However, neither process has been adequately developed and demonstrated to be considered ready for commercial application.

The SNCR processes used predominantly to date include Thermal DeNO_xTM, which is based on NH₃ injection and NO_xOUTTM, which uses urea injection. Both of these SNCR processes and SCR are considered to be commercially available. Long-term NO_x reductions are 45-65% for SNCR and 80-90% for SCR. Operation of SNCR near the upper end of the performance range can result in unwanted emissions of unreacted NH₃ or other byproduct gases. An advanced version of SNCR using furnace pyrometry and additional process controls has been tested on at least two MWCs and appears capable of achieving high NO_x reductions with less reagent than is needed for conventional SNCR. Combination of NGI and SNCR to achieve an overall NO_x reduction of 80 to 85% may be feasible, but will require testing to evaluate the interactions between the temperature and residence time requirements of each technology.

1.4.2 Comparative Costs of Evaluated Control Technologies

As part of this study, cost evaluations were conducted for several variations of NGI, SNCR, and SCR. For the evaluation of NGI, two scenarios were examined. The first scenario, referred to as NGI-100, assumes the MWC is firing MSW at 100% of its design heat input capacity. Therefore, under this scenario, the rate of waste fired must be reduced by an amount comparable to the heat input from natural gas. This results in a reduction of tipping fee revenues. The second scenario, referred to as NGI-85, assumes the MWC is firing MSW at 85% of its design heat input capacity because of insufficient MSW flow or because the unit was designed with excess heat input capacity. In this case, natural gas can be used to reduce NO_x emissions without displacing any waste, and therefore, without a loss of tipping fee revenues. The average NO_x reduction assumed in both scenarios is 60%.

Four variations of SNCR technology were examined: (1) conventional SNCR, with an average NO_x reduction of 60%, (2) advanced SNCR, with an average NO_x reduction of 60% based on lower reagent use compared to conventional SNCR, (3) a second advanced SNCR option with a NO_x reduction of 70% at a higher reagent feed rate, and (4) advanced NGI, which combines conventional NGI with conventional SNCR to achieve a NO_x reduction of 80%. The SCR evaluation focused on a cold-side system with a NO_x reduction level of 80%. A limited evaluation of a hot-side SCR system was also conducted.

A comparison of the costs for the different control technologies is presented in Figures 1-2, 1-3, and 1-4. Figure 1-2 presents the capital costs for each of the technologies. The advanced SNCR system with the 70% NO_x reduction and the hot-side SCR system are not represented, since only limited analyses of these scenarios were conducted. As shown by the figure, the capital costs for each of the technologies increase with increasing unit size. SCR is the most capital intensive of the technologies, costing 4 to 5 times more than the next highest technology. Advanced SNCR and advanced NGI have the next highest capital costs, with both technologies estimated to cost approximately \$1 to 2 million per combustor. The capital costs associated with NGI and conventional SNCR are comparable, at approximately \$1 million per combustor and less.

The tipping fee impacts and cost effectiveness values presented in Figures 1-3 and 1-4 include both annualized capital costs and operating and maintenance costs. Conventional SNCR generally has the lowest costs of the technologies. NGI-100 has the highest tipping fee impacts for all but the 100 tpd MWC, for which SCR has slightly higher costs. Cost effectiveness values for NGI-100 are the highest for all combustor sizes. Both of the NGI-100 and NGI-85 scenarios result in an incremental cost increase, however, the revenue loss associated with diverting MSW when firing natural gas under NGI-100 results in much higher costs for this control technique. These revenues are not lost with the NGI-85 scenario, plus revenues are received under this scenario from sale of additional electrical production. The other key variable affecting

Figure 1-2. Comparison of Capital Cost

Figure 1-3. Comparison of Tipping Fee Impact

Figure 1-4. Comparison of Cost Effectiveness

both NGI scenarios is the price of natural gas. The average gas price used in these figures is \$3.50/MMBtu; the affect of lower and higher natural gas prices is examined in Section 2.5.2.

The high tipping fee impacts and cost effectiveness values with SCR result from the high capital costs for this technology, as well as from the cost of catalyst replacement and disposal. Advanced SNCR and advanced NGI have higher costs than NGI-85 applied to the small combustor size, but are fairly similar when applied to the medium and large combustor sizes. More details on the costs of NGI, SNCR, and SCR technologies are presented in Sections 2.5, 3.5 and 4.5, respectively.

1.5 References

1. Chen, S. L., M. P. Heap, D. W. Pershing, and G. B. Martin. Influence of Coal Composition on the Fate of Volatile and Char Nitrogen During Combustion. Presented at the 19th International Symposium on Combustion, The Combustion Institute, Pittsburgh, PA. 1982.
2. DeSoete, G. G. Overall Reaction Rates on NO and N₂ Formation from Fuel Nitrogen. Presented at the 15th International Symposium on Combustion, The Combustion Institute, Pittsburgh, PA. 1975.
3. Habelt, W. W. and B. M. Howell. The Influence of Coal Oxygen to Coal Nitrogen Ratio on NO_x Formation. Presented at the 70th Annual AIChE Meeting, New York, 1977. Referenced in Singer, J. G. Combustion, Fossil Power Systems. Combustion Engineering, Inc. Windsor, CT. 1981.
4. Seeker, W. R., W. S. Lanier, and M. P. Heap. Municipal Waste Combustion Study: Combustion Control of Organic Emissions. EPA/530-SW87-021c (NTIS PB87-206090), U.S. Environmental Protection Agency, 1987.
5. Hahn, J. L. and D. S. Sofaer. Variability of NO_x Emissions from Modern Mass-fired Resource Recovery Facilities. Presented at the 81st Annual Meeting of the Air Pollution Control Association (now Air & Waste Management Association), Dallas, TX. 1988.
6. U.S. Environmental Protection Agency. Municipal Waste Combustors--Background Information for Proposed Standards: Control of NO_x

Emissions. EPA-450/3-89-27d (NTIS PB90-154873). Office of Air Quality Planning and Standards. Research Triangle Park, NC. 1989.

7. Stultz, J. R., M. L. Wilson, and F. A. Ferraro. A Critical Review of Source Separation on High-Nitrogen Municipal Wastes Fuel Components on Nitrogen Oxide (NO_x) Emissions from Waste-to-Energy Facilities. Presented at the 86th Annual Meeting of the Air & Waste Management Association, Denver, CO. 1993.
8. Rigo & Rigo Associates, Inc. Supplemental Analysis of the WASTE Program's Burnaby Test Results for Relationships Between Oxides of Nitrogen and Solid Waste Components. Prepared for Wheelabrator Technologies Inc., Hampton, NH. 1993.
9. Jones, G., Belco Technologies Corporation. European Air Quality Control Progress. Presented at the 1993 International Conference on Municipal Waste Combustion, Williamsburg, VA. March 1993.

2.0 NATURAL GAS INJECTION

2.1 Process Description

Natural gas injection into the overgrate region of the furnace can be used to control NO_x emissions from the combustor. For MWCs, two different natural gas-based processes have been developed: reburning and Methane de- NO_x^{SM} .

Reburning is a three-stage combustion process designed to convert NO_x to N_2 by injecting natural gas into a distinct "reburn" zone located above the primary combustion zone. In contrast, Methane de- NO_x injects natural gas directly into the primary combustion zone to inhibit the formation of NO_x .

2.1.1 **Reburning**

The reburning process was originally developed to reduce NO_x emissions from fossil fuel-fired boilers.^{1,2} The chemistry of reburning as applied to these boilers is a three-stage process. In the first stage, 80 to 85% of the normal fuel input to the boiler is introduced into the primary combustion zone at slightly fuel-lean conditions. In the second stage, the remaining 15 to 20% of the heat input (in the form of natural gas, oil, or pulverized coal) is injected into the combustion products from the primary zone to produce a fuel-rich mixture. Under these conditions, hydrocarbon radicals produced from the reburn fuel react with NO_x formed in the primary combustion zone to form N_2 :

followed by

followed by

In the third stage, additional air is introduced into this fuel-rich mixture to complete combustion. The temperature in this final burnout zone is lower than in the primary zone, such that there is limited reoxidation of N_2 to NO_x .

The application of reburning to MWCs has been developed primarily by Energy and Environmental Research Corporation (EER). A schematic of this process is shown in Figure 2-1. As with a conventional MWC, primary zone combustion air is introduced as underfire air through the grate and as overfire air (OFA) through air injection ports located above the grate in the lower furnace. With reburning, however, excess air levels in the primary combustion zone are significantly lower (~10 to 20%) than normal (~60 to 80%). By reducing the excess air level, gas temperatures at this location are estimated to be 100 to 300°C (200 to 500°F) higher than in a conventional MWC. This temperature rise, however, is sensitive to the rate of heat absorption by the furnace walls and is difficult to predict without detailed furnace modeling.

A mixture of natural gas and recirculated flue gas (used to enhance mixing) is introduced through nozzles located on the front and rear walls of the furnace to create reducing conditions. The rate limiting reactions associated with reburning are those associated with production of the hydrocarbon radicals (e.g., CH , CH_2) and the conversion of NO to HCN and HNCO . As shown in Figure 2-2, for these reactions to occur rapidly, temperatures of 1,300°C (2,400°F) or greater are needed.^{3,4} At lower temperatures, the NO_x reduction reactions are significantly slower. Note also from Figure 2-2 that substoichiometric (fuel-rich) conditions are required in the reburn zone to achieve significant NO_x reduction. Finally, additional combustion air is introduced through

Figure 2-1. Schematic of Reburn Process²

Figure 2-2. Effect of Temperature on Reburn NO_x Reduction Efficiency

overfire air ports located at the top of the reburn zone to burn out the combustibles. The overall excess air of the process is approximately 40%.

2.1.2 Methane de-NOXSM

Methane de-NOX, developed by the Institute of Gas Technology (IGT), is designed to compensate for the lower combustion zone temperatures in MWCs by using NGI to limit formation of NO_x, rather than on reducing NO_x after it forms, as is the case with reburning.^{5,6,7,8} As shown in Figure 2-3, this is done by injecting natural gas and recirculated flue gas (added to improve mixing) directly into the primary combustion zone to reduce the availability of O₂. Under these conditions, a portion of the NO_x precursors (e.g., NH and HCN) decompose and react to form N₂, rather than being oxidized to NO_x. Overfire air is injected high enough in the furnace to allow sufficient residence time (~1 to 2 seconds) for reduction of NO_x precursors to N₂ before the remaining hydrocarbons are combusted. As with reburning, the overall excess air level is reduced by about 50% compared to a conventionally operated MWC.

2.2 Development Status

There are currently no commercial-scale applications of these processes on MWCs. However, field evaluations of these processes have been completed at two full-scale MWCs and a commercial application is planned in Europe.

The reburn process was evaluated in 1992 on one of two MWCs located at the SYSAV (Sydvästra Skånes-Avfallsaktiebolag--Southwest Scania Waste Co.) facility in Malmö, Sweden.² Each combustor is designed to combust 340 tons per day (tpd) of municipal and industrial wastes. The test unit is also equipped with a urea-based SNCR system; however, this system was not used during the reburn tests. As shown in Figure 2-4, NO_x reductions of up to 50% were achieved during these tests when using 20% natural gas (on a heat input basis) and a primary zone stoichiometry (air/fuel ratio) of ~1.1. CO emissions at this operating condition, however, were significantly higher

Figure 2-3. Schematic of Methane de-NO_xSM Process

Figure 2-4. Effect of Primary Zone Stoichiometry on CO and NO_x Emissions During Malmö Reburn Testing

than without reburn (up to 2,000 ppm versus less than 100 ppm without reburn).^{*} To reduce CO emissions during reburn testing, the primary zone stoichiometry was increased to 1.2. At this higher primary zone stoichiometry and gas reburn rates of 10 to 20%, NO_x emissions were only 20 to 30% lower than baseline levels. Possible explanations for the relatively low NO_x reduction achieved during these tests are that the residence time (~0.5 sec) and flue gas temperatures in the reburn zone were too low for the needed NO_x reduction reactions. This problem may be reduced by installing the reburn injection nozzles lower in the furnace. However, given typical MWC operating conditions, it is uncertain whether an acceptable injection location is available.

The Methane de-NOX process was evaluated during 1990 and 1991 using one of the two combustors at the Olmsted County MWC facility in Rochester, Minnesota.^{3,4,5} Each unit is designed to burn 100 tpd of MSW. The testing at Olmsted County was preceded by laboratory furnace simulation experiments on a 1.7 MMBtu/hr facility at IGT and pilot-scale testing using a 2.5 MMBtu/hr MSW-fired combustor operated by Riley Stoker Corporation. As shown in Figure 2-5, the tests at Olmsted County achieved an average reduction of 60% for NO_x and 50% for CO compared to baseline levels when injecting 15% natural gas at optimized conditions. Flue gas residence time prior to OFA injection was 1 to 1.5 seconds. The testing also found that 20% NO_x reduction could be achieved with FGR alone, but resulted in higher CO emissions from incomplete combustion.

To address uncertainties associated with the performance of these two approaches, the new MWC in Herning, Denmark is being designed with the ability to use both approaches.⁹ The facility is being designed and constructed by Volund Ecology Systems, with the gas injection system design being performed through a partnership between Volund R&D Centre and Nordic Gas Technology Centre. The facility is

^{*}CO is used as an indicator of good combustion practices for destruction of organic emissions. To achieve this objective, CO concentrations are generally maintained below 100 ppm. As a result, increases in CO emissions such as measured at SYSAV are not acceptable in a commercial MWC.

Figure 2-5. Effect of Methane de-NOXSM on CO and NO_x Emissions During Olmsted County Methane de-NOXSM Testing

scheduled for construction in 1994, with performance evaluations of reburning and Methane de-NOX scheduled for the spring of 1995. The design objective for the facility is 50% NO_x reduction without adversely impacting emissions of other pollutants.

2.3

Key Design and Process Variables Affecting Performance

Based on the testing conducted to date on MWCs, key parameters affecting NO_x control performance of gas injection processes include combustion zone stoichiometry, gas injection location, and residence time prior to OFA injection.

The effect of primary zone stoichiometry is critical to both CO and NO_x emissions. As shown in Figure 2-4 for the testing at Malmö, CO emissions increased sharply without reburning as the primary zone stoichiometry decreases to 1:1 and lower. The reburn tests suggest that a portion of the injected natural gas was oxidized to CO, but that the temperatures in the burnout zone were too low or residence times were too short to complete oxidation of CO to CO₂. As a result, it was necessary to increase the primary zone stoichiometry to more than 1.2 to minimize CO emissions. When the primary zone stoichiometry was increased, however, NO_x emissions also increased. As a result, only a portion of the expected reduction in NO_x emissions was achieved.

With the Methane de-NOX process, natural gas is injected directly above the grate, such that there are not distinct primary and secondary zones. As shown in Figures 2-6 and 2-7, the primary influences of combustion zone stoichiometry on NO_x appears to be low O₂ levels and optimized operation of the FGR system, and secondarily gas injection rate. As shown in Figure 2-7, varying the gas injection rate between 9 and 15% had a relatively small impact on NO_x reduction. With low O₂ and FGR alone, however, there was an increase in CO levels. The benefit of gas injection is that it allowed the combustor to simultaneously achieve both low NO_x and low CO. Note from Figure 2-6 that it was not necessary for gas injection to fully deplete O₂ (i.e., create fuel-rich conditions), but rather only to reduce O₂ availability.

Figure 2-6. Effect of O₂ Concentration on NO_x Emissions
During Olmsted County Methane de-NOXSM Testing

Figure 2-7. Effect of Natural Gas Injection Rate on NO_x Emissions During Olmsted County Methane de-NOXSM Testing

As already discussed, gas injection location is important because it defines whether fuel nitrogen compounds are still present in the combustion gas as NO_x precursors or have been oxidized to NO_x . If natural gas is injected into the combustion zone while NO_x precursors are still present, the gas will reduce the availability of O_2 and result in reduced formation of NO_x . If gas is injected after NO_x is formed, NO_x reduction reactions are required. As indicated in Figure 2-2, however, the gas temperatures in MWC may be too low for these reactions to proceed rapidly, thus limiting the achievable NO_x reduction.

The effect of NGI residence time on NO_x emissions reduction is shown in Figure 2-8 for the Methane de-NOX process. These data, based on synthetic combustion gases generated by a laboratory furnace, show that at a given natural gas injection rate, NO_x emissions decreased with increasing residence time prior to OFA injection. For example, with 15% gas injection, NO_x emissions decreased from 135 ppm at a residence time of 0.6 seconds to about 100 ppm at 1.6 seconds and 75 ppm at 4.5 seconds (about 40% reduction). The effect of increasing natural gas usage on NO_x emissions is also shown in Figure 2-8. Compared to slightly over 200 ppm NO_x with no natural gas addition, NO_x levels decreased by 15% with 4% gas and 50 to 60% with 15% gas. Full-scale data from Olmsted County suggest a 1 to 1.5 second residence time is sufficient for 60% reduction.

2.4 Recent Advances and Further Research Needs

Both gas injection approaches have been tested at commercial MWCs--reburning at Malmö and Methane de-NOX at Olmsted County. Based on the data from these two test programs, Methane de-NOX appears to be better able to reduce NO_x without adversely impacting CO emissions. However, the Methane de-NOX testing has been limited to a single, relatively small (100 tpd) combustor. If this approach is to be applied to other existing MWCs, further analysis of the ability to achieve adequate gas penetration into the primary combustion zone of larger MWCs is needed to define achievable NO_x reductions. Further, additional testing to assess continuously achievable

Figure 2-8. Effect of Natural Gas Injection Residence Time on NO_x Emissions During Pilot-Scale Testing of Methane de-NOXSM Process

NO_x reduction capabilities at various load conditions and to investigate possible long-term impacts on MWC operation are needed prior to commercialization of the process. Although the initial explanation for the high CO levels measured during the Malmö testing is that furnace temperatures in MWCs are too low for the needed NO_x reduction reactions, further assessment of this issue is warranted.

Greater reductions in NO_x emissions (75 to 85%) may be possible if gas injection is combined with SNCR. With this approach, referred to as advanced NGI, the NO_x level is first controlled by gas injection to reduce NO_x emissions by 50 to 60%, followed by injection of ammonia or urea to achieve an additional 50 to 60% reduction. This concept has been tested by combining reburning with SNCR on a 10 MMBtu/hr pilot-scale coal-fired furnace.¹⁰ Based on the existing SNCR system at the plant, the Malmö MWC would appear to be an ideal site for testing this concept. Such a program could also address the use of Methane de-NOX in an MWC with less furnace residence time than at Olmsted County. The economic benefits of advanced NGI are discussed in Section 3.5.

2.5 Cost Analysis

2.5.1 Design Basis

As discussed in Section 2.1, two different NGI processes have been developed for MWC's: reburning and Methane de-NOX. Although the performance estimates used in this section are based on the Methane de-NOX testing conducted at the Olmsted County MWC, the costs estimates are believed to be generally representative of both processes. Costs for reburn could be higher because of the increased number of injectors, tube penetrations, associated piping, etc. needed with this process.

The design basis for the NGI system includes 60% NO_x reduction at 15% natural gas heat input and natural gas is available at the plant boundary. Based on an

uncontrolled NO_x concentration of 250 ppm at 7% O₂, the average stack concentration associated with this system is 100 ppm at 7% O₂. The 60% reduction represents long-term (annual average) performance capabilities. Performance at individual plants will vary, and this average performance level may not be achievable at all plants, especially when considering retrofit situations.

Capital cost estimates for commercial gas injection systems applied to MWCs are limited to a comparative analysis of gas injection and SNCR processes prepared by IGT and Ogden Martin Systems for a 264 tpd MWC.⁷ That analysis concluded that the capital costs for these two processes were essentially equal. As a result, the capital cost estimate used in this analysis is based on the SNCR costing procedures described in Section 3.5 and Appendix A. Based on the limited commercial experience of this control technique, a process contingency of 20% is assumed. As discussed in Section 2.5.2, capital costs have a relatively small impact on the overall economics of NGI. As a result, the lack of detailed procedures for estimating NGI capital cost is not critical to defining key cost factors affecting process economics.

A key economic assumption associated with gas injection is whether the combustor typically operates at 100% of design heat input or at less than design heat input because of insufficient MSW flow or other factors. If the MWC operates at 100% of design heat input capacity, application of NGI may require the facility to reduce the MSW feed rate by an amount comparable to the heat input of the natural gas. As a result, NGI may reduce the amount of MSW burned and the associated tipping fee revenues, while the plant electrical output remains constant. As discussed in Section 2.3, it may be possible to operate the combustor at lower excess air levels and, therefore, higher thermal efficiency when injecting gas than when operating with 100% MSW. However, because of the complexity of the combustor heat transfer and steam generating systems, operation at higher thermal efficiency does not necessarily result in more steam generation and turbine electrical output. Therefore, costs discussed in the following sections do not include economic credit for operation at higher thermal efficiency. If the

NGI system is built into the system as part of the original design, the heat recovery capacity could be optimized to provide additional revenue from electricity/steam sales.

If the MWC is operating at less than 15% of its design heat input capacity, NGI can be used to increase the total heat input to the combustor and to increase the amount of steam supplied to the turbine. In this case, the total amount of waste fired and associated tipping fee revenues remain unchanged, but electrical sales revenues will increase. An alternative case would be if the MWC's MSW input rate is air-supply limited (e.g., inadequate fan capacity), but the MWC has adequate heat transfer and turbine capacity to operate at greater than design thermal input. Provided that the MWC's operating permit is not thermally limited, the ability to reduce excess air levels by using NGI may allow some MWC's operating at 100% of design MSW flow to use NGI without reducing MSW flow, and gain additional revenues from the increased sale of electricity.

Cost estimates for NGI applied to an MWC operating at maximum MSW and heat input and to an MWC operating at reduced load and heat input are presented in Section 2.5.2.

2.5.2 Cost Results

Cost estimates for the NGI system were developed for 100, 400, and 750 tpd model combustors, assuming the units are able to operate at 100% of design capacity on MSW alone (referred to as NGI-100). System-specific input and output values for the 400 tpd model combustor are shown in Tables 2-1 and 2-2. Additional inputs (e.g., labor rates, fuel price) are presented in Table A-1 of Appendix A.

Table 2-3 presents the estimated capital cost per ton of capacity, tipping fee impact, and NO_x control cost effectiveness for the NGI system applied to the three model MWCs. The tipping fee impacts are calculated based on the actual amount of MSW burned when NGI is applied, not on the design capacity of the combustor. In

Table 2-1
Model Combustor Inputs For NGI (a)

Plant Characteristics	
Unit Size (tpd)	400
Flowrate (dscfm @ 7% O ₂)	41,271
Flowrate (wscfm @ 11% O ₂)	70,462
Capacity Factor	0.9
Uncontrolled NO _x (ppmv, dry)	250
NO _x Removal Efficiency (%/100)	0.60
NGI Percentage (%/100)	0.15
Outlet NO _x (ppmv, dry)	100
Tons of NO _x removed (tons/yr)	152
Plant Tipping Fee (\$/ton MSW)	80
Original MSW Heat Input (MMBtu/hr)	150
Natural Gas Heat Input (MMBtu/hr)	23
Resulting MSW Heat Input (MMBtu/hr)	128
Actual Tons/day of MSW Processed (tons/day)	340
Actual Tons/yr of MSW Processed (tons/yr)	111,690
Capital Recovery Factor (1/yr)	0.0944

(a) For an MWC which does not have additional heat input capacity (NGI-100).

Table 2-2
Cost Outputs for NGI
Applied to the 400 TPD Model Combustor (a), (b)

Capital Cost Section (\$1000)	
Total Process Capital (\$1000)	429
Engineering	86
Contingency	206
Total Control Cost (\$1000)	720
Pre-Production	32
Inventory Capital	31
Total Capital Requirement (\$1000)	783
Total Capital per Capacity (\$1000/TPD)	1.96
Total Annualized Capital Requirement (\$1000/yr)	74
Variable O&M Cost Section (\$1000/yr)	
Fuel Cost	621
Electricity	3
Lost Revenue	1,577
Total Variable O&M (\$1000/yr)	2,201
Fixed O&M Cost Section (\$1000/yr)	
Operating Labor	22
Maintenance Material	5
Maintenance Labor	3
Administrative & Support Labor	8
Total Fixed O&M (\$1000/yr)	38
Total Cost Section	
Total Annualized Cost (\$1000/yr)	2,313
Tipping Fee Impact (\$/ton of MSW)	20.7
Cost Effectiveness (\$/ton of NOx)	15,204

(a) For an MWC which does not have additional heat input capacity (NGI-100).

(b) \$/ton can be converted to \$/Mg by multiplying by 1.1.

Table 2-3

Model Plant Cost Estimates for NGI for MWCs without Additional Heat Input Capacity (NGI-100) (a)

NOx Reduction (%)	Total Capital Cost (\$1000/TPD capacity)			Tipping Fee Impact (\$/ton MSW)			Cost Effectiveness (\$/ton NOx)		
	45	60	65	45	60	65	45	60	65
100 TPD Mass Burn MWC	5.18	5.22	5.23	14.5	22.7	25.7	15,103	16,687	17,053
400 TPD Mass Burn MWC	1.92	1.96	1.97	12.6	20.7	23.7	13,126	15,204	15,684
750 TPD Mass Burn MWC	1.41	1.45	1.46	12.3	20.4	23.3	12,818	14,974	15,471

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

addition to the costs for a 60% NO_x reduction, costs are also presented for 45% and a 65% NO_x reduction. This represents the expected range of performance considering the control technique and plant-to-plant performance variations. The natural gas injection heat input levels associated with the 45% and 65% NO_x levels of reduction are 9% and 17%, respectively. As shown in Table 2-3, capital costs, tipping fee impacts, and NO_x control cost effectiveness values decrease with increasing combustor size.

For a given combustor size, variations in NO_x reduction level have little impact on costs. A greater impact is observed for tipping fee impact and cost effectiveness. For all three combustors, the tipping fee impact and cost effectiveness value increase with increasing NO_x reduction. This is primarily caused by the increased revenue loss resulting from displacement of MSW when firing more natural gas. Increased fuel (natural gas) costs are also incurred with increasing NO_x reduction.

These data indicate that NGI economics are driven by the cost associated with displacing the MSW with natural gas. A more attractive application of NGI is for an MWC that has unused capacity such that little or no MSW is displaced when using gas injection. Table 2-4 presents the results of NGI applied to the model combustors assuming they have 15% additional heat input capacity available (referred to as NGI-85).^{**} The capital cost associated with this application is the same as those presented in Table 2-3. However, the tipping fee impacts and cost effectiveness values are 70 to 90% lower than for the previous case. The lower end of this difference occurs at the higher NO_x reduction level. For the 65% NO_x reduction, the higher amount of natural gas needed (17% versus 15%) exceeds the additional available heat input capacity. Therefore, a portion of the waste is displaced, and the costs associated with this are accounted for.

^{**}The costs associated with this scenario are also generally representative of the case for an MWC whose heat input is limited only by fan capacity such that the MWC can continue to operate at design waste feed while using NGI.

Table 2-4

Model Plant Cost Estimates for NGI for MWCs with 15% Available Heat Input Capacity (NGI-85). (a)

	Total Capital Cost (\$1000/TPD capacity)			Tipping Fee Impact (\$/ton MSW)			Cost Effectiveness (\$/ton NOx)		
	45	60	65	45	60	65	45	60	65
100 TPD Mass Burn MWC	5.18	5.22	5.23	3.50	4.15	6.73	3,649	3,044	4,459
400 TPD Mass Burn MWC	1.92	1.96	1.97	1.60	2.13	4.66	1,672	1,561	3,090
750 TPD Mass Burn MWC	1.41	1.45	1.46	1.31	1.81	4.34	1,365	1,331	2,878

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

2.5.3

Sensitivity Analysis

To account for site-specific differences and other uncertainties in costs used to develop Table 2-3 (NGI-100: MSW displaced case), an analysis of the sensitivity of tipping fee impacts and NO_x control cost effectiveness to differences in plant size (100 to 700 tpd), fuel cost (\$2 to 5/MMBtu), annualized capital cost ($\pm 30\%$), plant tip fee (\$40 to 120/ton), and NO_x reduction (45 to 65%) was performed. Figure 2-9 presents the effect of plant size, fuel cost, plant tip fee, and annualized capital cost on tipping fee impact and cost effectiveness. Figure 2-10 presents the sensitivity of tipping fee impact and cost effectiveness to NO_x reduction. Since a 60% reduction is the design reference plant reduction, the intersection of tipping fee impact and cost effectiveness occur at this point.

The range in annualized capital cost accounts for differences in the actual capital cost of a natural gas injection system, contingency factors, and the cost of money used for project financing. For example, the annualized capital charge for a natural gas injection system would be 24% higher if the capital discount rate (cost of money) is 10% compared to the model combustor, which is based on a 7% capital discount rate. The plant tip fee represents the amount of revenue a plant would lose per ton of MSW displaced. The variation in NO_x control efficiency results from varying the amount of NGI to achieve higher or lower NO_x reductions, rather than the variability in NO_x reductions that may be achieved by different combustors operating at the same NGI level.

As shown in these figures, the tipping fee impact and NO_x control cost effectiveness associated with the reference MWC (the center point on Figure 2-9 and 2-10) are approximately \$21/ton of MSW and \$15,200/ton of NO_x removed. Of the parameters shown in Figures 2-9 and 2-10, the variation in plant tip fee has the greatest effect on tipping fee impact and cost effectiveness because this parameter is tied to the amount of revenue lost when less MSW is burned. Going from the reference plant tip fee of \$80/ton of MSW to \$120/ton of MSW results in almost a 35% increase in tipping

Figure 2-9. Effect of Unit Size, Fuel Cost, Annualized Capital and Plant Fee on Tipping Fee Impact and Cost Effectiveness for NGI-100 (for MWCs without additional heat input capacity)

Figure 2-10. Effect of NOx Reduction on Tipping Fee Impact and Cost Effectiveness for NGI-100 (for MWCs without additional heat input capacity)

fee impact and cost effectiveness value. Similarly, a decrease to \$40/ton MSW results in a comparable decrease in tipping fee impact and cost effectiveness value.

Changes in NO_x reduction also have a large effect on tipping fee impact, since the amount of MSW that must be displaced increases with the increased amount of natural gas needed for the larger NO_x reduction. As discussed earlier, when MSW is displaced by natural gas, revenues from that MSW are lost. With an increase in NO_x reduction from 60% to 65%, the tipping fee impact increases by close to 15%. A decrease of NO_x reduction to 45% results in a decrease in tipping fee impact by close to 40%. Changes in NO_x reduction have a smaller impact on cost effectiveness. Increasing NO_x reduction to 65% results in small (<5%) increases in cost effectiveness values. Decreasing NO_x reduction to 45% reduces cost effectiveness values by close to 15%. This results from a relatively constant balance between the amount of additional NO_x removed and the increased costs associated with the burning more gas. As a result, the ratio of cost to the amount of NO_x removed remains essentially unchanged.

Variations in fuel cost from \$2.00 to \$5.00/MMBtu result in the next largest effect on tipping fee impact and cost effectiveness, with these values increasing linearly with the price of natural gas. Changes in annualized capital cost and unit size have smaller effects, with annualized capital having almost no affect on tipping fee impact and cost effectiveness. Unit size has a more pronounced effect on costs for the small combustors.

2.6 References

1. Seeker, W. R., G. C. England, R. Lyon, and P. Duggan. Advanced Pollution Control in Municipal Waste Combustors Using Natural Gas. In Proceedings: 1991 International Conference on Municipal Waste Combustion. Vol. 1, EPA-600/R-92-209a (NTIS PB93-124170), November 1992.
2. Bergstrom, J. NO_x Reduction Using Reburning with Natural Gas--Final Report From Full-Scale Trial at SYSAV's Waste Incineration Plant in

Malmö. Nordic Gas Technology Center, Hørsholm, Denmark.
September 1993.

3. Hura, H. and B. Breen. Mixing and Heat Loss Effects on Nitric Oxide Reduction During Natural Gas Reburning in Pulverized Coal Boilers. Presented at the Tenth Annual Pittsburgh Coal Conference, Pittsburgh, PA. September 1993.
4. Pasini, S. and G. DeMichele. Reburning Scaling Via Mathematical Modeling. Presented at the 7th Topic Oriented Technical Meeting of the International Flame Research Foundation, Gas Research Institute, and American Flame Research Council, Chicago, IL. 1993.
5. Abbasi, H., M. Khinkis, C. Penterson, F. Zone, R. Dunnette, K. Nakazato, P. Duggan, and D. Linz. Development of Natural Gas Injection Technology for NO_x Reduction from Municipal Waste Combustors. In Proceedings: 1991 International Conference on Municipal Waste Combustion, Vol. 1, EPA-600/R-92-209a (NTIS PB93-124170), November 1992.
6. Biljetina, R., H. Abbasi, M. Cousino, and R. Dunnette. Field Evaluation of Methane de-NOX at Olmsted Waste-to-Energy Facility. Presented at the 7th Annual Waste-to-Energy Symposium. Minneapolis, MN. January 1992.
7. Abbasi, H., M. Khinkis, and R. Scherrer. An Engineering and Economic Evaluation of the Methane de-NOX Technology. Presented at the Third International Specialty Conference on Municipal Waste Combustion. Williamsburg, VA. April 1993.
8. Abbasi, H. A. and F. J. Zone. Emissions Reduction from MWC Combustion Systems Using Natural Gas, Task 3--Field Evaluation. Gas Research Institute, Chicago, IL. GRI-92/0370. December 1992.
9. Gas Reburning at a Waste Incineration Plant in Denmark. NGC News, Nordic Gas Technology Centre, Hørsholm, Denmark. October 1993. p.6.
10. Sanyal, A., T. M. Sommer, B. A. Folsom, L. Angello, and R. Payne. Cost Effective Technologies for SO₂ and NO_x Control. Presented at Power-Gen 1992. Orlando, FL. November 1992.

3.0 SELECTIVE NON-CATALYTIC REDUCTION

3.1 Process Description

Selective non-catalytic reduction refers to add-on NO_x control techniques that reduce NO_x to N₂ without the use of catalysts.¹ A generalized schematic of SNCR applied to MWCs is shown in Figure 3-1. As indicated in the figure, one or more of several reducing reagents is injected into the upper furnace to react with NO_x and form N₂ and water. Specific SNCR processes include Thermal DeNO_xTM (originally licensed by Exxon Research and Engineering), based on ammonia (NH₃) injection,² NO_xOUTTM (Electric Power Research Institute/Nalco Fuel Tech) which uses urea [CO(NH₂)₂] injection,^{3,4} and the addition of urea followed by methanol.⁵ This discussion is limited to the Thermal DeNO_x and the NO_xOUT processes because of their predominant use.

3.1.1 Thermal DeNO_xTM

With Thermal DeNO_x, either aqueous or anhydrous NH₃ is injected into the upper furnace of the combustor. Ammonia and NO_x react according to the following generalized reactions:

At 870 to 980°C (1,600 to 1,800°F), the first reaction dominates and NO_x is reduced to N₂. Above 1,100°C (2,000°F), the second reaction dominates and NH₃ is oxidized to NO. Below 870°C (1,600°F), both reactions proceed slowly and a significant fraction of the NH₃ remains unreacted. These reaction pathways are illustrated in Figure 3-2.

As shown in Figure 3-2, the amount of amide radical (NH₂) formed through thermal decomposition of NH₃ is critical to the destruction of NO_x. Flue gas temperature and carbon monoxide (CO) concentrations influence both the

Figure 3-1. Schematic Diagram of SNCR Applied to an MWC

Figure 3-2. Ammonia Reaction Pathways

decomposition of NH_3 to NH_2 and the interaction of NH_2 with NO . If there is too much CO present, excess hydroxyl (OH) radical is formed, which react with NH_2 to eventually form NO rather than reducing NO to N_2 .

3.1.2 $\text{NO}_x\text{OUT}^{\text{TM}}$

The $\text{NO}_x\text{OUT}^{\text{TM}}$ process uses stabilized urea injection to reduce NO_x to N_2 , CO_2 , and water. The generalized reaction pathways for this control technology are shown in Figure 3-3.⁶

As shown in Figure 3-3, urea decomposes to NH_3 and HNCO . The reaction of NH_3 with NO is similar to Thermal DeNO_x discussed above. The reaction of NCO (produced by reaction of HNCO with hydroxyl [OH] radical) provides several additional reaction paths. At temperatures above $1,100^\circ\text{C}$ ($2,000^\circ\text{F}$), NCO reacts with hydrogen and oxygen radicals:

At these temperatures, NH can react with O_2 and OH to form NO . Between 800°C ($1,500^\circ\text{F}$) and $1,100^\circ\text{C}$ ($2,000^\circ\text{F}$), the primary reaction is:

This alternate reaction is important because both of the products, nitrous oxide (N_2O) and CO , are of environmental concern (N_2O is of special concern because of its role as a global warming "greenhouse" gas). However, at temperatures above 950°C ($1,750^\circ\text{F}$), N_2O will decompose thermally or react with oxygen to produce N_2 , and CO will react with oxygen to produce CO_2 :

Figure 3-3. Urea Reaction Pathways

At lower temperatures, however, the rates of reaction are relatively slow and the potential exists for significant emissions of NH_3 , N_2O , and CO . To reduce these emissions, a variety of chemicals can be injected to promote reactions at temperatures as low as 800°C ($1,500^\circ\text{F}$) and thereby minimize byproduct emissions.⁷

3.2 Development Status

SNCR has been applied to a number of MWCs in Japan, Europe, and the U.S. MWCs in the U.S. that have permanently installed SNCR, have conducted demonstration tests, or are currently in the planning stage are listed in Table 3-1.

3.3 Key Design and Process Variables

Five factors influence the performance of ammonia- or urea-based SNCR systems: reagent-to- NO_x ratio, flue gas composition, temperature, reagent distribution, and residence time.

The reagent-to- NO_x molar ratio, or more specifically the NH_2 -to- NO_x ratio (also known as the normalized stoichiometric ratio--NSR), ultimately determines the potentially achievable NO_x reduction.^{4,7,8} For NH_3 -based systems, the reagent ratio is equal to the NH_2 -to- NO_x molar ratio*. For urea-based systems, each mole of urea contains two moles of NH_3 , such that a urea-to- NO_x ratio of 0.5 results in an NSR of 1.0. Figure 3-4 shows that at an NSR of 1.0, reported NO_x reductions from MWCs are 40 to 60%. Although not directly indicated on the figure, much of the variability in

*Molar ratio, as used in this instance, refers to the number of moles of reagent (e.g., NH_3) to the number of moles of NO_x in the flue gas.

Table 3-1

Summary of U.S. SNCR Applications on Municipal Waste Combustors

Name/Location Capacity	Other APCDs ^a	Reagent	New or Retrofit	Permitted NO _x ^b	Averaging Time	Measured NO _x ^{b,c}
City of Commerce, CA 1 x 380 tpd	SD/FF	NH ₃	New 1987	175 ppm ^{d,e}	15-min	103 ppm
Stanislaus County, CA 2 x 400 tpd	SD/FF	NH ₃	New 1988	200 ppm ^f 175 ppm ^g 165 ppm ^h	8-hr 3-hr 24-hr	140 ppm
Long Beach, CA (SERRF) 3 X 460 tpd	SD/FF/FGR	NH ₃	New 1989	175 ppm ^{d,i} 116 ppm	15-min 1-hr	52 ppm
Huntington, NY 3 x 250 tpd	SD/FF	NH ₃	New 1991	190 ppm ^j	3-hr rolling	150 ppm ^k
Hennepin County, MN 2 x 600 tpd	SD/FF	NH ₃	New 1989	250 ppm ^l	8-hr	--
New Hanover, NC 1 x 249 tpd	SD/FF	Urea	New 1991	116 ppm	24-hr	98 ppm
Millbury, MA 1 x 750 tpd	SD/ESP	Urea	Demo	--	--	96 ppm
Spokane, WA 2 x 400 tpd	SD/FF	NH ₃	New 1991	165 ppm 225 ppm	8-hr 3-hr	<165 ppm
Rochester, MA (SEMASS) 1 x 1,000 tpd	SD/ESP	Urea	New 1993	180 ppm	24-hr	70 ppm
Lancaster, PA 1 x 400 tpd	SD/FF	NH ₃	Demo	--	--	70 ppm
Lee County, FL 2 x 600 tpd	SD/FF/CI	NH ₃	New 1995	180 ppm	24-hr block	--
Union County, NJ 3 x 480 tpd	SD/FF/CI	NH ₃	New 1994	225 ppm ^m	3-hr	--

(continued)

Table 3-1

(Continued)

Name/Location Capacity	Other APCDs ^a	Reagent	New or Retrofit	Permitted NO _x ^b	Averaging Time	Measured NO _x ^{b,c}
Falls Township, PA 2 x 750 tpd	SD/FF/CI	Urea	New 1994	180 ppm	24-hr	--
Montgomery County, MD 3 x 600 tpd	SD/FF/CI	NH ₃	New 1995	180 ppm	24-hr block	--
Onondaga County, NY 3 x 330 tpd	SD/FF/CI	NH ₃	New 1995	180 ppm ⁿ 200 ppm	24-hr block 3-hr rolling	--

^a APCD = air pollution control device

SD = spray dryer

FF = fabric filter

FGR = flue gas recirculation

ESP = electrostatic precipitator

CI = carbon injection

^b Emissions corrected to 7% O₂ unless otherwise noted.^c Measured values reflect performance test and/or typical values, and are not appropriate for setting short-term permit limits.^d Limit is a South Coast Air Quality Management District limit for all liquid and solid fuel-fired units in the basin.^e Also must meet a 40 lb/hr limit (1-hr basis) and a 825 lb/day limit.^f Must also meet a 1130 lb/day limit. Also has an NH₃ limit of 50 ppm at actual O₂.^g Or 160.5 lb over a 3-hr period, whichever is more stringent.^h Or 1200 lb/day, whichever is more stringent.ⁱ Also must meet a 34 lb/hr limit (1-hr basis) and a 720 lb/day limit.^j Also must meet a 65.5 lb/hr/furnace limit (8-hr basis).^k Emissions corrected to 12% CO₂.^l Corrected to 12% CO₂. Based on a permit that expired 1/92.^m Also must meet a 80 lb/hr limit.ⁿ Also must meet a 58 lb/hr limit (3-hr rolling average) and a 0.35 lb/MMBtu limit.

Figure 3-4. Effect of Reagent Feedrate on SNCR Performance

reported performance levels reflects the differences in NO_x reductions achieved between individual MWCs, rather than variability in performance at a single MWC. The performance curves shown on the figure are generally reflective of the relationship between NO_x reduction and NSR experienced at individual facilities. At an NSR near 2:1, NO_x reductions of 50 to 80% have been reported. Increasing the ratio beyond 2:1 has little additional effect on NO_x reduction. However, at high NSR ratios, emissions of unreacted NH_3 (known as " NH_3 slip") can be significant. Note from Figure 3-4 that there is not a clear distinction in NO_x reduction between NH_3 and urea.

Second, the composition of the flue gas is also critical in determining the potential efficiency of SNCR.⁶ The concentration of NO_x determines the necessary amount of reagent injection. In addition, CO and O_2 levels at the point of reagent injection affect process chemistry. High levels of O_2 (above 6%) tend to improve performance. CO concentration above 100 ppm can shift the reaction kinetics and lower the effective temperature range for the NH_3/NO_x reaction. Other constituents typically present in MWC flue gas, such as chlorides, do not seem to have a significant effect on process gas phase chemistry.⁹

The third factor affecting NO_x is flue gas temperature. Figure 3-5, which is based on urea injection but is generally representative of NH_3 injection, shows the effect of combustion gas temperature and composition on NO_x removal.⁶ At temperatures below the acceptable operating range of 700 to 800°C (1,300 to 1,500°F), the desired NO_x reduction reactions do not occur and NH_3 slip increases. Above the acceptable temperature range, NH_3 is oxidized to NO_x , resulting in low NO_x reduction efficiency and reagent utilization. Also shown in Figure 3-5, N_2O emissions are highest between 800 and 1,000°C (1,500 and 1,800°F).

For MWCs, the required temperature window occurs in the upper section of the furnace. Because of variability in MSW composition, however, there can be significant variations in combustion gas temperatures over relatively short time intervals. This can lead to significant changes in gas temperature at a given furnace elevation. As

Figure 3-5. Effect of Temperature and Flue Gas Composition on SNCR Performance

a result, MWCs typically have installed several rows of reagent injection nozzles in order to allow injection of reagent within the required temperature window. Because of difficulty in monitoring furnace temperature, however, existing facilities have conducted SNCR optimization tests soon after the MWC has commenced operation to determine the injector elevation that generally provides the best balance between NO_x reduction and NH_3 slip.^{8,10} During subsequent operation of the SNCR system, reagent is injected through the injector row that was found to have the best performance during the optimization test. Because of high and low temperature fluctuations that occur during normal operation, however, the reagent can oxidize to increase NO_x emissions or may not fully react and result in NH_3 slip. Recently developed techniques for providing real-time monitoring of furnace temperature are discussed in Section 3.4.

The fourth factor affecting SNCR performance is distribution of the reagent with the flue gas. The zone surrounding each reagent injection nozzle is mixed by the turbulence of the flue gas. Distribution in regions distant from an injection nozzle depends on adequate reagent velocity and momentum for penetration. Because of reduced flue gas turbulence, stratification of the reagent and flue gas can be a problem at low combustor loads.

The fifth factor affecting SNCR performance is the residence time of the injected reagent within the required temperature window. A residence time of 0.5 seconds is generally adequate in most systems. If the residence times are too short, there will be insufficient time for completion of the desired reactions between NO_x and NH_3 . Based on gas velocities and cooling rates in the upper furnace of MWCs, residence time limitations are less severe than in many fossil fuel-fired combustor applications.

Additional concerns related to SNCR processes are associated with secondary environmental impacts caused by high reagent feed rates. These impacts include NH_3 emissions to the atmosphere and NH_3 concentrations in APCD ash. At an NR of 1.5 and less, NH_3 slip rates are generally less than 10 ppm and NH_3 levels in

APCD ash are low.^{4,7,8} As injection rates increase beyond an NSR of 1.5, NH_3 slip and ash concentrations increase substantially. In addition, because of health and safety concerns associated with accidental release of NH_3 during reagent transport, handling, and storage operations, most SNCR systems are being designed for aqueous NH_3 or urea.

The variability in the reported data suggests that NH_3 slip measurements are also highly dependent on system design variations (residence time, temperature, reagent distribution, APCD type), sampling location (prior to or after APCD), and sampling method. Currently, there is not an established method (i.e., EPA standard) for measuring NH_3 . Potential NH_3 measurement problems include the loss of NH_3 on cool surfaces in the sampling train where water or ammonium salts may form and the release of NH_3 from sampling train impingers if acidic pH is not maintained.

Unreacted NH_3 can react with residual HCl exiting the stack to form a detached ammonium chloride (NH_4Cl) plume. These plumes are whitish in color and can create concerns with visible emissions. Such plumes have been observed under certain process and atmospheric conditions at several of the U.S. MWCs with SNCR. In addition, ammonium sulfate salts can form when the unreacted NH_3 contacts SO_3 in the flue gas. These salts can potentially lead to heat transfer surface scaling and corrosion; however, these problems have not been reported to date by U.S. MWCs. If NH_3 levels in APCD ash are high (due to high NSR injection levels), it may be necessary to install NH_3 stripping and vapor collection equipment to protect worker health and safety during ash handling operations.

An unresolved issue related to NH_3 slip is the NH_3 collection efficiency of a fabric filter (FF) versus an ESP. Most of the NH_3 slip data are from systems using a FF for particulate control. Relatively little data are available on units equipped with ESPs or where NH_3 levels have been measured prior to and after the control device. Testing at a FF-equipped coal-fired boiler reported significant NH_3 reduction across the FF.¹¹ Testing at an MWC indicated that NH_3 levels following the FF were low except

after extended operation at high NH_3 feed rates.⁸ Discussions with MWC personnel indicate that an NH_3 odor is present in collected ash.¹² All of these data suggest that the filter cake removes a significant portion of the NH_3 in the flue gas unless inlet NH_3 levels are sufficiently high to exceed the adsorption capacity of the filter cake. It is unclear, however, that an ESP will be equally effective at controlling NH_3 slip emissions. As a result, NH_3 slip levels and the potential for an NH_4Cl plume may be higher for an MWC equipped with an ESP than for a unit with a FF.

3.4 Recent Advances and Further Research Needs

As discussed above, SNCR performance depends on injection of the reagent within the desired gas temperature window. Because of the variability in MSW composition, however, it has been difficult to monitor the flue gas temperature within the furnace and to adjust the reagent injection elevation accordingly. As a result, a high temperature excursion within the furnace can result in oxidation of NH_3 to NO_x , while a low temperature excursion will delay the NH_3/NO_x reactions, which results in reduced NO_x reduction and increased NO_x and NH_3 emissions. High NH_3 emissions during low temperature excursions can be further increased if the SNCR control system is designed to increase NH_3 or urea feed rate in response to the higher NO_x reading by the NO_x CEM located downstream of the furnace.

To overcome these limitations, two new technologies have been applied: real-time furnace pyrometry to continuously monitor gas temperature and continuous NH_3 monitoring.

3.4.1 Temperature Monitoring

Two advanced techniques exist for continuously monitoring furnace temperature.¹³ These are infrared (IR) pyrometry, which measures IR radiation emitted from the hot combustion gases, and acoustic pyrometry, which determines gas temperature based on the speed at which sound travels through heated gases. Infrared

pyrometry is a simpler technology that measures IR emissions from solid "black body" particles entrained in the combustion gases. Because of variations in the "dirtiness" of the combustion gases over time, however, the black body emissivity characteristics of the gas vary. As a result, the IR signal received by the pyrometer can vary independently of temperature. For example, a relatively clean gas (one containing few solid particles) and a dirty gas (one containing significant soot, "sparklers", or other solid particles) at the same temperature will result in different IR responses. Despite these limitations, however, IR pyrometry can be used to monitor fluctuations in gas temperature and to detect flames (as opposed to hot gases) in the instrument's viewing plane.

Acoustic pyrometers determine the mean gas temperature between two points by measuring the travel time for a sound signal and then converting this time to a temperature based on the travel distance and the relationship between the speed of sound and gas temperature. The advantage of this approach is that the speed of sound in combustion gases is relatively insensitive to the dirtiness of the gas and, therefore, provides a direct indication of gas temperature. In addition, by installing several pyrometers in the furnace and measuring the travel time between each pyrometer pair, a temperature (i.e., isotherm) map of the furnace can be generated.

Use of IR pyrometry to improve SNCR performance was evaluated during a technology demonstration test funded by Ogden Martin Systems (OMS) at the Lancaster, Pennsylvania MWC (conducted in January-March 1993).¹⁴ The system used during this test, shown in Figure 3-6, included an IR pyrometer in the lower furnace to monitor lower furnace temperature and flame height, two reagent injection rows, separate aqueous NH_3 and dilution water tanks, NO_x and NH_3 CEMS (see Section 3.4.2), and a process controller. The pyrometer was used to determine which injector row to use, while the CEMS were used to control the NH_3 injection rate. Dilution water was used to assure proper reagent injection momentum (i.e., good distribution) as the NH_3 feed rate varied. Using this scheme, during high temperature periods, all of the NH_3 was injected through the upper row, while the lower row was used during low temperature periods. In addition, the NH_3 analyzer was used to avoid

(NOTE: During subsequent testing, a NO_x signal from the economizer was used for process control instead of the NH₃ signal).

Figure 3-6. Schematic Diagram of Advanced SNCR Applied to the Lancaster County MWC^{14,15}

overfeeding NH_3 during periods of increased NO_x resulting from slow NH_3/NO_x reactions at low furnace temperatures. During the initial testing at Lancaster County, NO_x levels (corrected to 7% O_2) varied between 30 and 120 ppm and averaged approximately 70 ppm.¹⁴ Based on an assumed uncontrolled NO_x level of 250 ppm, the average emission rate of 70 ppm equates to a reduction of approximately 70%. These tests indicated, however, that at the NSR levels required to achieve this NO_x reduction, there were periodic excursions in NH_3 slip that resulted in visible emissions. To better define the ability of advanced SNCR to control visible emissions, OMS conducted additional testing at Lancaster County in September-October 1993.¹⁵ As part of these subsequent tests, process control was maintained by measuring NO_x with a fast response analyzer located at the economizer, instead of using the NH_3 analyzer. OMS replaced the NH_3 analyzer because it was not as reliable for process control as originally anticipated. During these additional tests, OMS reduced the NSR and achieved visible emissions of less than 10% opacity (based on 6-minute averages) at all times and of 5% or lower opacity for 90% of the time. During these approximately 550 hours of testing, NO_x emissions averaged 100 ppm with a maximum recorded 3-hour average of 126 ppm. Based on these data, OMS believes that a 3-hour emission limit of 140 ppm can be continuously achieved with advanced SNCR.

Acoustic pyrometry has been in use at the North Munich MWC in Munich, Germany since the summer of 1991.¹² This system consists of a six pyrometer array (two each on the rear and two side walls) located approximately 33 feet (10 meters) above the grate. As opposed to using the system solely to determine the NH_3 injection elevation, the system is also used to control the rate of waste feeding and the distribution of undergrate and overgrate air to minimize both temporal and spatial variations in combustion gas temperatures. Although emissions performance data have not been reported, the system is claimed to have reduced the variation in instantaneous furnace gas temperatures from 300°C (540°F) using the previous control scheme to approximately 150°C (270°F) and reduced CO spikes due to better combustion control. By allowing more careful control of the localized combustion conditions, the system is also claimed to

be capable of reducing furnace and superheater tube wastage caused by localized hot spots and reducing environments.

3.4.2 Ammonia Continuous Emissions Monitors

As SNCR and SCR have become more common NO_x control methods, the need for real-time measurement of NH_3 for process control has increased. Ammonia measurements can be used as part of a feedback loop to optimize SNCR-based NO_x control systems by allowing increased NH_3 or urea injection rates while minimizing NH_3 slip.

To meet this need, a number of vendors have been working to develop NH_3 CEMs. These instruments use a variety of spectrographic techniques, including chemiluminescence, non-dispersive infrared (NDIR), ultraviolet (UV), ion mobility (IMS), and differential optical adsorption (DOAS). Based on vendor data, UV and IMS have the best measurement accuracy ($\pm 1\%$) in low SO_2 flue gases, but cannot be used in high- SO_2 environments ($\text{SO}_2:\text{NH}_3$ ratio ≥ 80) due to measurement interference. NDIR has somewhat lower accuracy ($\pm 3\%$), but can operate at SO_2 levels of up to 2,000 ppm. Chemiluminescence measurement of NH_3 uses two monitors, one measuring the NO_x level in the flue gas and the other measuring the NO_x concentration following a reactor chamber that converts NH_3 in the flue gas to NO_x . Although chemiluminescence can be used in high- SO_2 environments, it has relatively low accuracy ($\pm 10\%$) due to potential measurement errors of the two monitors.

Based on typical MWC flue gas composition, any of these monitors may be feasible. However, long-term operating and reliability data are limited and their use as a process control or an emission compliance monitor has not been validated.

3.5

Cost Analysis

3.5.1

Design Basis

Several variations of SNCR technology exist, depending on the reagent type and method of injection. As discussed in Section 3.1, reagent options include anhydrous NH_3 , aqueous NH_3 , and urea. An anhydrous NH_3 system generally will have the lowest capital cost, but requires storage of potentially hazardous anhydrous NH_3 . Aqueous NH_3 (typically consisting of 25 to 29% NH_3 dissolved in water) is safer to store than anhydrous NH_3 , but requires a larger storage tank. Aqueous NH_3 can be injected either as a vapor, with an injection system similar to that described for an anhydrous NH_3 system, or as a liquid. If it is injected as a vapor, a steam- or electrically-heated vaporizer is used to liberate the NH_3 from the water carrier. If aqueous NH_3 is injected as a liquid or if urea is used, the cost of the vaporizer and high-pressure carrier gas system are avoided; however, the thermal efficiency of the combustion process is reduced because of the energy loss resulting from vaporization of the carrier water by the combustion gases.

The costs presented in this section are based on injection of aqueous NH_3 as a liquid. The capital costs for this system are similar to the costs for a urea-based system, although the costs may be distributed somewhat differently. The capital cost for an anhydrous NH_3 system is expected to be slightly lower, while the cost of aqueous NH_3 system with a vaporizer will be somewhat higher. The SNCR system designs examined include: a conventional SNCR system similar to that described in Section 3.1, two variations of the advanced SNCR system based on the concepts presented in Section 3.4, and an advanced NGI system, which combines SNCR and NGI as described in Section 2.4.

The design basis for the conventional SNCR system includes two rows of reagent injectors, an average NO_x reduction of 60%, and manual control of the NH_3 injection system. Based on a typical uncontrolled NO_x concentration of 250 ppm at 7%

O₂, this NO_x reduction results in an average stack concentration of 100 ppm at 7% O₂. The 60% reduction represents long-term (annual average) performance capabilities when considering performance at all facilities. Performance at individual plants will vary, and this average performance level may not be achievable at all plants, especially when considering retrofit situations. The average NSR needed to achieve this reduction is assumed to be 1.4.** The number of reagent injectors in each row is based on the assumption of one injector per 40 tpd of MWC capacity. Control of the reagent injection system is handled manually by the combustor operator based on visual observation of furnace conditions and the measured NO_x level in the stack. Because the furnace camera and NO_x CEM used for these purposes are required for other reasons, the cost of these items are not included in the SNCR capital cost. Based on the commercial status of this technology, the process contingency assumed for conventional SNCR is 10%.

The advanced SNCR system design also includes two rows of reagent injectors, as in the conventional SNCR system, but also includes automatic control of the NH₃ injection system. The NH₃ injection control system includes an acoustic pyrometer, an NH₃ CEM, and a control system designed to vary injection location and rate based on the pyrometer and CEM measurements. Through the use of this control system, a 60% reduction is assumed to be achievable with an NSR of 1.0 (versus 1.4 with the conventional SNCR system). As with the conventional SNCR system, this NO_x reduction results in an average stack concentration of 100 ppm at 7% O₂, based on an inlet concentration of 250 ppm at 7% O₂. As stated above, this reduction level represents long-term performance capabilities. A limited examination of an advanced SNCR system with a 70% NO_x reduction and an average stack concentration of 75 ppm is also presented. An NSR of 2.0 is assumed to achieve the higher reduction. Also, because of the potential for high NH₃ levels in the ash resulting from the higher NSR,

** This level was selected as a reasonable balance between NO_x reduction and NH₃ slip. Because of fluctuations in "uncontrolled" NO_x levels and furnace temperatures, however, instantaneous NSRs, NO_x reductions, and NH₃ slip rates may be higher or lower.

NH₃ stripping and vapor collection equipment to protect worker health and safety during ash handling operations are included. Based on the limited number of advanced SNCR demonstrations, a process contingency of 25% is used for both advanced SNCR scenarios to cover additional testing and potential costs for system modification.

The advanced NGI system design reduces NO_x emissions by first using natural gas injection to achieve a 60% reduction in NO_x, followed by a 50% reduction through the liquid injection of aqueous NH₃. This results in an overall NO_x reduction of 80%, which equals an outlet level of 50 ppm at 7% O₂ assuming an uncontrolled NO_x level of 250 ppm at 7% O₂.

For the gas injection portion of the system, natural gas is injected equalling a heat input level of 15 percent. It is assumed that the MWC has additional heat input capacity available such that lost revenue does not occur from diverting waste. The SNCR portion of the system is the same as for the conventional SNCR system except that to reduce the SNCR inlet NO_x level (100 ppm) by 50%, an NSR of 0.8 is used.

3.5.2 Cost Results

Cost estimates for the conventional and advanced SNCR and for advanced NGI were developed for 100, 400, and 750 tpd model combustors.

Conventional SNCR

Conventional SNCR-specific input and output values for the 400 tpd model combustor are shown in Tables 3-2 and 3-3. Additional inputs (e.g., labor rates, electricity price) used in the cost analysis of both technologies are presented in Table A-2 of Appendix A. Table 3-4 presents the estimated capital cost per tpd of capacity, tipping fee impact, and NO_x control cost effectiveness for the conventional SNCR system applied to the three model combustors. In addition to 60% NO_x reduction, the table also presents the estimated cost for 45% and 65% NO_x reduction.

Table 3-2
Model Combustor Inputs For Conventional SNCR

Injection System	
Number of Wall Injectors	2
Reagent	Aqueous Ammonia
Injection Method	Liquid
Fuel	MSW
Plant Characteristics	
Unit Size (tpd)	400
Flowrate (dscfm @ 7% O ₂)	41,271
Flowrate (wscfm @ 11% O ₂)	70,462
Capacity Factor	0.9
Tons/yr of MSW Processed (tons/yr)	131,400
Uncontrolled NO _x (ppmv, dry)	250
NO _x Removal Efficiency (%/100)	0.60
Normalized Stoichiometric Ratio (N/NO)	1.4
Reagent Injection Rate (lb/hr)	32
Outlet NO _x (ppmv, dry)	100
Tons of NO _x removed (tons/yr)	152
Capital Recovery Factor (1/yr)	0.0944

Table 3-3
Cost Outputs For Conventional SNCR
Applied to the 400 TPD Model Combustor (a)

Capital Cost Section (\$1000)	
Storage	71
Injection System	178
Compressor	94
Instrumentation	0
Installation	86
Total Process Capital (\$1000)	429
Engineering	86
Contingency	154
Total Control Cost (\$1000)	669
License Fee	96
Pre-Production	24
Inventory Capital	5
Total Capital Requirement (\$1000)	793
Total Capital per Capacity (\$1000/tpd)	1.98
Total Annualized Capital Requirement (\$1000/yr)	75
Variable O&M Cost Section (\$1000/yr)	
Reagent Cost	38
Electric - Compressor	2
Energy Loss - Vaporization	2
Dilution Water	0.16
Total Variable O&M (\$1000/yr)	42
Fixed O&M Cost Section (\$1000/yr)	
Operating Labor	44
Maintenance Material	10
Maintenance Labor	7
Administrative & Support Labor	15
Total Fixed O&M (\$1000/yr)	76
Total Cost Section	
Total Annualized Cost (\$1000/yr)	193
Tipping Fee Impact (\$/ton of MSW)	1.47
Cost Effectiveness (\$/ton of NO_x)	1,268

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

Table 3-4
Model Plant Cost Estimates For Conventional SNCR (a)

	Total Capital Cost (\$1000/TPD capacity)			Tipping Fee Impact (\$/ton MSW)			Cost Effectiveness (\$/ton NOx)		
NOx Reduction (%)	45	60	65	45	60	65	45	60	65
100 TPD Mass Burn MWC	5.05	5.06	5.07	3.74	3.91	4.06	4,308	3,378	3,235
400 TPD Mass Burn MWC	1.97	1.98	2.00	1.30	1.47	1.62	1,496	1,268	1,289
750 TPD Mass Burn MWC	1.49	1.50	1.52	0.92	1.09	1.24	1,058	940	986

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

This represents the range of performance considering the control technique and plant-to-plant performance variations. To achieve these alternate NO_x reduction levels, NSR of 0.6 and 2.0 were assumed. Although not quantified, the higher NO_x reduction rate is expected to also have higher NH₃ slip levels and higher NH₃ levels in the ash. Costs for NH₃ stripping and ash handling equipment are not included in the estimates presented in Table 3-4. As shown in Table 3-4, capital costs, tipping fee impacts, and NO_x control cost effectiveness values decrease with increasing combustor size. Within a model combustor size range, the impact on costs caused by variations in NO_x reduction level is smaller. This is especially true for capital cost. A more significant change is observed in tipping fee impact and NO_x control cost effectiveness. For all three model combustors, the tipping fee impact increases with increased NO_x reduction, primarily due to increased reagent costs. NO_x control cost effectiveness values for the 400 and 700 tpd model combustors are lowest at the 60% NO_x reduction level, with increased cost effectiveness values at the lower and higher reduction levels. For the 100 tpd model combustor, cost effectiveness values are highest at the 45% NO_x reduction level and lowest at the 65% NO_x reduction level.

Advanced SNCR

The estimated capital cost per tpd of capacity, tipping fee impact, and NO_x control cost effectiveness for the advanced SNCR system at a 60% reduction are presented in Table 3-5 for the three model combustors. As discussed in Section 3.5.1, this advanced SNCR system is assumed to achieve this reduction with an NSR of 1.0. To address the uncertainty of cost associated with this concept, the capital cost is varied $\pm 30\%$ from the model case. Depending on the capital cost variance of $\pm 30\%$, the capital costs associated with this system range from 16% higher to 3 times higher than for the conventional system because of the costs of the controls and the higher process contingency. The tipping fee impacts and cost effectiveness values, which consider operating costs as well as capital costs, are 5 to 90% higher for the advanced system than for the conventional system. As would be expected, the cost differential between advanced and conventional systems is greatest for the 100 tpd MWC and decreases as

Table 3-5
Model Plant Cost Estimates for Advanced SNCR (a), (b)

Capital Cost Variance (%)	Total Capital Cost (\$1000/TPD capacity)			Tipping Fee Impact (\$/ton MSW)			Cost Effectiveness (\$/ton NOx)		
	-30%	0%	+30%	-30%	0%	+30%	-30%	0%	+30%
100 TPD Mass Burn MWC	8.30	11.9	15.4	5.24	6.26	7.28	4,524	5,407	6,289
400 TPD Mass Burn MWC	2.62	3.74	4.86	1.69	2.01	2.33	1,460	1,738	2,016
750 TPD Mass Burn MWC	1.73	2.47	3.22	1.14	1.35	1.56	983	1,167	1,351

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

(b) Based on a 60% NOx reduction and an NSR of 1.0.

MWC size increases. Although not quantifiable in a cost sense, the advanced system operating at the lower NSR is expected to have lower levels of NH_3 slip.

Another option for applying advanced SNCR is to increase the NSR to 2.0 to achieve a NO_x reduction level of 70%. As with the conventional system, increasing the amount of reagent increases the amount of NH_3 slip and the levels of NH_3 in the ash. As presented for the advanced system at a 60% reduction level, the amount of reagent required to achieve this level of reduction with the advanced system is less than with the conventional system. Similarly, operating the advanced system to achieve a 70% reduction would require an NSR of 2.0 as compared to a conventional system which would have to operate at an NSR of 3.0 or higher. Nonetheless, the secondary impacts still result with the NSR of 2.0. As discussed in Section 3.3, NH_3 stripping equipment and a vapor recovery system can be used to address the issue of potential ash handling problems. The estimated costs for the advanced SNCR system operating at a 70% reduction, including equipment costs for NH_3 stripping and vapor recovery for ash handling, are presented in Table 3-6 for the 400 tpd model combustor. Also shown in this table are costs for the conventional and advanced SNCR systems at 60% reduction. Although higher NO_x reduction is achievable with the advanced SNCR system at the NSR of 2.0, this additional reduction comes with higher costs and the potential for NH_3 slip levels equal to or greater than the systems operating at 60% reduction.

Advanced NGI

The results of the advanced NGI cost evaluation are presented in Table 3-7. The estimated capital cost per tpd of capacity, tipping fee impact, and NO_x control cost effectiveness are shown for the three model combustors. In this evaluation, the price of natural gas is varied from \$2 to 5/MMBtu, as this parameter has the greatest effect on the economics of this control technique. As discussed in Section 3.5.1, the design basis for this process assumes a 60% NO_x reduction based on gas injection and a 50% reduction based on SNCR. This equals an overall NO_x reduction of 80%. As shown in Table 3-7, advanced NGI is a capital intensive control technique, especially

Table 3-6
Comparison of Conventional and Advanced SNCR Systems (a),(b)

Plant Characteristics	Conventional	Advanced	Advanced
Unit Size (tpd)	400	400	400
Uncontrolled NOx (ppmv, dry)	250	250	250
NOx Removal Efficiency (%/100)	0.60	0.60	0.70
Normalized Stoichiometric Ratio (N/NO)	1.4	1.0	2.0
Reagent Injection Rate (lb/hr)	32	24	48
Outlet NOx (ppmv, dry)	100	100	75
Tons of NOx removed (tons/yr)	152	152	177
Capital Cost Section (\$1000)			
Storage	71	71	73
Injection System	178	178	178
Compressor	94	94	94
Injection System Installation	86	86	86
Instrumentation	0	350	350
NH3 Stripper and Ash Handling	0	0	780
Total Process Capital (\$1000)	429	778	1,561
Engineering	86	156	312
Contingency	154	420	843
Total Control Cost (\$1000)	669	1353	2,715
License Fee	96	96	96
Pre-Production	24	38	70
Inventory Capital	5	8	16
Total Capital Requirement (\$1000)	793	1,495	2,898
Total Capital per Capacity (\$1000/tpd)	1.98	3.74	7.24
Total Annualized Capital Requirement (\$1000/yr)	75	141	274
O&M Cost Section (\$1000/yr)			
Total Variable O&M (\$1000/yr)	42	32	61
Total Fixed O&M (\$1000/yr)	76	92	127
Total Cost Section			
Total Annualized Cost (\$1000/yr)	193	264	461
Tipping Fee Impact (\$/ton of MSW)	1.47	2.01	3.51
Cost Effectiveness (\$/ton of NOx)	1,268	1,738	2,599

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

(b) All three systems are assumed to have two rows of reagent injectors.

Table 3-7

Model Plant Cost Estimates for Advanced NGI (a), (b)

	Total Capital Cost (\$1000/TPD capacity)			Tipping Fee Impact (\$/ton MSW)			Cost Effectiveness (\$/ton NOx)		
Fuel Price (\$/MMBtu)	2.00	3.50	5.00	2.00	3.50	5.00	2.00	3.50	5.00
100 TPD Mass Burn MWC	10.2	10.3	10.3	5.21	7.25	9.28	3,214	4,471	5,728
400 TPD Mass Burn MWC	3.88	3.92	3.97	1.05	3.09	5.13	648	1,905	3,163
750 TPD Mass Burn MWC	2.89	2.94	2.98	0.40	2.44	4.48	249	1,506	2,764

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

(b) Based on an 80% NOx reduction and assumes the MWCs do have additional heat input capacity.

for smaller MWCs. Both unit size and gas price have a large effect on tipping fee impact and cost effectiveness. For all three model combustors, the costs increase with decreasing unit size and increasing gas price.

3.5.3 Sensitivity Analysis

To account for site-specific differences and other uncertainties in the costs used to develop Table 3-4 for conventional SNCR, an analysis of the sensitivity of tipping fee impacts and NO_x control cost effectiveness to differences in plant size (100 to 700 tpd), reagent cost ($\pm 30\%$), annualized capital cost ($\pm 30\%$), and NO_x reduction (45 to 65%) was performed. Figure 3-7 presents the effect of plant size, chemical cost, and annualized capital cost on tipping fee and cost effectiveness. Figure 3-9 presents the sensitivity of tipping fee impact and cost effectiveness to NO_x reduction. Since the 60% reduction level represents the design reference plant reduction, the intersection of the tipping fee impact and cost effectiveness occur at this point.

As discussed in Section 2.5.3 for the NGI sensitivity analysis, the range in annualized capital cost accounts for differences in the actual capital cost of a system, contingency factors, and the cost of money used for project financing. The variation in NO_x control efficiency effectiveness reflects the impact of varying the reagent feed rate to achieve higher or lower NO_x reductions rather than the variability in NO_x reductions that may be achieved by different combustors operating at the same reagent feed rate. Again, although not quantified, variations in reagent feed rate to achieve higher or lower NO_x reductions will also impact NH₃ slip rates and NH₃ levels in the ash.

As shown in these figures, the tipping fee impact and NO_x control cost effectiveness associated with the reference MWC (the centerline point) are approximately \$1.50 of MSW and \$1,270/ton of NO_x removed. Of the parameters shown in Figures 3-7 and 3-8, the variation of unit size from 100 tpd to 700 tpd has the greatest effect on tipping fee impact and cost effectiveness. Both the tipping fee impact and cost effectiveness value are inversely related to unit size, and thus, as unit size

Figure 3-7. Effect of Unit Size, Reagent Cost, and Annualized Capital on Tipping Fee Impact and Cost Effectiveness for Conventional SNCR

Figure 3-8. Effect of NOx Reduction on Tipping Fee Impact and Cost Effectiveness for Conventional SNCR

decreases, the tipping fee impact and cost effectiveness value increase. This is especially noticeable for a small MWCs, where a decrease in unit size from 400 tpd to 100 tpd results in an almost three-fold increase in tipping fee impact and cost effectiveness values.

Variations in reagent cost and annualized capital cost of $\pm 30\%$ have a smaller impact on tipping fee and cost effectiveness and follow a similar trend to each other. (Reagent cost refers to the cost of the reagent, not the solution.) This trend is opposite that for varying unit size. The effect of variations in NO_x reduction on tipping fee impact is similar to varying reagent cost and annualized capital cost. Cost effectiveness values are lowest at the 60% NO_x reduction level. At lower NO_x reductions, the increase in cost effectiveness value reflects the reduced tonnage of NO_x reduction over which fixed costs are distributed. At higher NO_x reductions, the increase in cost effectiveness value reflects the higher reagent injection requirements and costs.

3.6 References

1. U.S. Environmental Protection Agency. Municipal Waste Combustors--Background Information for Proposed Standards: Control of NO_x Emissions, Vol. 4. EPA-450/3-89-27d (NTIS PB90-154873). Research Triangle Park, NC. August 1989.
2. Hurst, B. and C. White. Thermal De NO_x : A Commercial Selective Non-Catalytic Reduction Process for Waste-to-Energy Applications. Presented at the ASME National Waste Processing Conference, Denver, CO. June 1986.
3. Wolfenden, L. R., W. F. Flowers, III, B. K. Luftglass, and S. M. Peters. Commercial Application of the NO_x Out Process at a Municipal Waste Combustor. Presented at the 84th Annual Meeting of AWMA. Vancouver, British Columbia. June 1991.
4. Albanese, V., J. Hofmann, and R. Pachaly. NO_x Control for Waste Combustors. Presented at the 1993 International MWC Conference, Williamsburg, VA. April 1993.
5. Jones, D. G., L. J. Munzio, E. Stocker, P. C. Nüesch, S. Negrea, G. Lautenschlager, E. Wachter, and G. Rose. Two-Stage De NO_x Process Test Data from Switzerland's Largest Incineration Plant. In Proceedings: 1989 International Conference on Municipal Waste Combustion, Vol. 4, EPA-600/R-92-052d (NTIS PB92-174687), March 1992.

6. EER Inc. and Westinghouse Resource Energy Systems Division. Technical and Cost Analysis for Urea Injection Used for NO_x Emission Reduction. Submitted to the Michigan Department of Natural Resources in Support of the Oakland County, Michigan Resource Recovery Facility Project. September 1990.
7. Sun, W. H., P. G. Carmignani, J. E. Hofmann, D. A. Prodan, D. E. Shore, L. J. Muzio, G. C. Quartucy, R. C. O'Sullivan, J. W. Stallings, and R. D. Teetz. Control of By-product Emissions Through Additives for Selective Non-Catalytic Reduction of NO_x with Urea. Presented at the Power-Gen American '93. Dallas, TX. November 17 to 19, 1993.
8. Personal communications between K. Nebel (Radian Corporation) and J. Hofmann (Nalco Fuel Tech). April 1994.
9. McDonald, B. L., G.R. Fields, and M. D. McDannel. Selective Non-Catalytic Reduction (SNCR) Performance on Three California Waste-to-Energy Facilities. In Proceedings: 1991 International Conference on Municipal Waste Combustion, Vol. 1, EPA-600/R-92-209a (NTIS PB93-124170), November 1992.
10. Tozin, G. and L. Brasowski. Thermal DeNO_x Optimization Program at the Huntington MWC. Presented at the 86th Annual Meeting of AWMA. 1993.
11. Hunt, T., G. Schott, R. Smith, L. Muzio, D. Jones, and J. Steinberger. Selective Non-Catalytic Operating Experience Using Both Urea and Ammonia. Presented at the 1993 EPRI/EPA NO_x Symposium. Miami, FL. May 1993.
12. Personal communications between D. White (Radian Corporation) and C. Tripp (City of Long Beach, California), F. Ferraro (Wheelabrator), and L. Brazowski (Ogden Projects). May 1993.
13. Kleppe, J. The Reduction of NO_x and NH₃ Slip in Waste-to-Energy Boilers Using Acoustic Pyrometry. Presented at Power-Gen Americas '93. Dallas, TX. November 1993.
14. RTP Environmental Associates, Inc. BACT Determination for NO_x Emissions for the Proposed Mercer and Atlantic Counties Regional Resource Recovery Facility. June 1993.
15. Ogden Martin Systems of Clark, Limited Partnership. Update of the BACT Analysis for NO_x Submitted in the PSD Application and the Ohio EPA PTI Document of November 12, 1992 for the Mad River Energy Recovery Facility. April 1994.

4.0

SELECTIVE CATALYTIC REDUCTION

4.1

Process Description

Selective catalytic reduction is an add-on control technology that catalytically promotes the reaction between NH_3 and NO_x to form N_2 and water.¹ SCR systems can be designed to utilize aqueous or anhydrous NH_3 , with the primary differences being the size of the NH_3 vaporization system and the safety requirements. The primary reactions in an SCR system are:

These overall reactions are the same as those occurring in NH_3 -based SNCR systems; however, the temperature at which they occur are much lower. Depending upon the catalyst, reaction 1 can take place at temperatures from 190°C (375°F) to over 535°C (1000°F); however, most individual catalyst formulations used by MWC's work best within a temperature window of 250 to 350°C (480 to 660°F). The oxidation of NH_3 (reaction 2) begins around 400°C (750°F) and becomes significant above 480°C (900°F). Below the minimum recommended temperature for a given catalyst, the NO/NH_3 reaction becomes very slow and significant amounts of NH_3 can be emitted. Ammonia slip levels from a properly operated system are less than 10 ppm.

Two options exist for achieving the required catalyst temperature. These options are shown schematically in Figure 4-1. The first option, sometimes referred to as "cold-side" or "clean-gas" SCR, is the more common approach applied to MWCs. With this approach, the catalyst is installed downstream of the other air pollution control (APC) devices in order to avoid damage to the catalyst caused by acid gases, metals, and particulate matter in the untreated flue gas. Because of the reduced flue gas temperature following the final APC device, typically $<150^\circ\text{C}$ ($<300^\circ\text{F}$), it is necessary to heat the flue gas to an acceptable catalyst operating temperature. The other option,

Cold-Side SCR System

Hot-Side SCR System

Figure 4-1. Schematic of SCR Configurations

referred to as "hot-side" or "dirty-gas" SCR, is the generally used approach where catalyst damage from contaminants in untreated flue gas are acceptable. This approach avoids the need for flue gas reheat, but is a harsher environment for the catalyst.

Most MWC SCR catalysts utilize a base metal oxide, such as vanadium pentoxide and titanium oxide (V_2O_5/TiO_2) or V_2O_5/TiO_2 impregnated with tungsten oxide (WO_3). The exact composition of the catalyst can be varied to control its operating characteristics. For instance, WO_3 is used to increase catalyst resistance to chemical deactivation and to reduce SO_2 oxidation to SO_3 . Because of the critical role of long-term catalyst performance on overall SCR system economics, catalyst resistance to poisoning (chemical deactivation), pluggage (mechanical deactivation), and erosion (physical wear) are key considerations in SCR system design. Specific MWC flue gas constituents influencing catalyst design include acid gases (SO_2 and HCl), alkali metal oxides (Ca, Na, and K), several trace metals (Pb and As), and particulate loading. The significance of individual flue gas constituents on catalyst performance is discussed in Section 4.3.

4.2 Development Status

To date, SCR has not been applied to any MWCs in the U.S. However, as shown in Tables 4-1 and 4-2, SCR has been or is scheduled to be installed on a number of units in Europe and Japan. The initial applications were installed in Japan in 1987 and in Europe in 1990.^{2,3} Most of these systems were cold-side designs. Although operating data from these facilities are limited, deactivation of catalysts located downstream of the particulate matter and acid gas control equipment has been within acceptable limits. Vendor guarantees on catalyst life for these systems are approximately 24,000 hours (3 years); actual lifetimes are expected to be longer.

Several hot-side systems have been installed in Japan and Europe, mostly since 1992. The oldest of these systems, the Hikarigoaka MWC in Tokyo, is the only hot-side system with significant operating experience. This system was a retrofit

Table 4-1

Summary of SCR Applications on European MWCs

Name/Location Capacity	Other APCDs ^a	SCR Location & Temperature	Year Startup New or Retrofit	Target NO _x ppm ^b	Measured NO _x ppm & % Red. ^{b,c}
Munich South, Germany 2 x 960 tpd	DSI/FF	After FF 590°F w/ reheat	1990 Retrofit	48 ppm	39 ppm/84%
Spittelau/Vienna, Austria 1 x 960 tpd	ESP/3-stage WS	After WS 536°F w/ reheat	1990 Retrofit	70 ppm	52 ppm/--
Josefstrasse/Zurich, Switzerland 1 x 300 tpd	SD/ESP	After ESP 500°F w/ reheat	1991 Retrofit	48 ppm	35 ppm/83%
Flotzersteig/Vienna, Austria 1 x 720 tpd	ESP/3-stage WS	After WS 500°F w/ reheat	1992 Retrofit	70 ppm	--/--
Ingolstadt, Germany 1 x 180 tpd	ESP/WS	After WS 500°F w/ reheat	1992 Retrofit	34 ppm	29 ppm/--
Hagenholz/Zurich, Switzerland 2 x 300 tpd	ESP/WS	Between ESP & WS 500°F w/o reheat	1993 Retrofit	44 ppm	29 ppm/91%
AVR/Rotterdam, Holland 6 x 620 tpd	ESP/2-stage WS/CF	After CF 360°F w/ reheat	1993 Retrofit	48 ppm	--/--
ROTEB/Rotterdam, Holland 4 x 330 tpd	ESP/2-stage WS/CF	After CF 360°F w/ reheat	1993 Retrofit	48 ppm	--/--
Stuttgart, Germany 2 x 440 tpd	ESP/WS/ESP	After 2nd ESP 580°F w/ reheat	1993 Retrofit	48 ppm	--/--
Augsburg, Germany 3 x 180 tpd	ESP/WS	After WS 500°F w/ reheat	1993 --	50 ppm	--/--
ARN/Nijmegen, Holland 1 x 240 tpd, 1 x 530 tpd	ESP/SD/ESP/Q/CF	After quench 570°F w/ reheat	1995 New & Retrofit ^d	48 ppm	--/--

^a APCD = air pollution control device

DSI = dry sorbent injection

FF = fabric filter

SD = spray dryer

ESP = electrostatic precipitator

WS = wet scrubber

CF = carbon filter bed

Q = quench chamber

^b Emissions corrected to 7% O₂.^c Measured values reflect performance test and/or typical values, and are not appropriate for setting short-term permit limits.^d Both the new and existing units will be equipped with SCR.

Table 4-2

Summary of SCR Applications on Japanese MWCs

Name/Location Capacity	Other APCDs ^a	SCR Location & Temperature	Year Startup	Target NO _x ppm & % Red. ^b	Measured NO _x ppm & % Red. ^{b,c}
Iwatsuki 2 x 65 tpd	SD/FF	After FF 410°F	1987	155 ppm/33%	30 ppm/87%
Hikarigaoka/Tokyo 2 x 150 tpd	ESP/WS	After ESP 428°F	1987/1989	120 ppm/38%	93 ppm/62%
Katsushika/Tokyo 3 x 400 tpd	DSI/ESP	After ESP 482°F	1989/1991	180 ppm/35%	40 ppm/64%
Sagamihara 3 x 150 tpd	SD/FF	After FF 392°F	1991	80 ppm/58%	--/--
Toyohashi 1 x 150 tpd	Q/FF	After FF 410°F	1991	80 ppm/67%	--/--
Kashawafuji 3 x 150 tpd	ESP/WS	After ESP 554°F	1992	80 ppm/58%	--/--
Nerima/Tokyo 2 x 300 tpd	ESP/WS	After ESP 518°F	1992	95 ppm/25%	--/--
Chitose/Tokyo 1 x 600 tpd	SD/FF/WS	After FF 410°F	1995	75 ppm/51%	--/--
Takatsuki/Osaka 2 x 180 tpd	ESP/WS	After WS 410°F	1995	80 ppm/67%	--/--
Urawa/Saitama 3 x 150 tpd	SD/FF/WS	After FF 410°F	1995	80 ppm/67%	--/--
Tsurumi/Yokohama 3 x 400 tpd	Q/FF/WS	After FF 392°F	1994	80 ppm/50%	--/--
Nishi/Kobe 3 x 200 tpd	SD/FF	After FF 392°F	1994	80 ppm/75%	--/--
Rinkai/Tokyo 2 x 200 tpd	SD/FF/WS	After WS 410°F	1994	110 ppm/46%	--/--
Yao/Osaka 2 x 300 tpd	SD/FF	After FF 392°F	1995	80 ppm/58%	--/--
Sankaku/Chiba 3 x 190 tpd	SD/FF	After FF 392°F	1996	80 ppm/72%	--/--

^a APCD = air pollution control device
 DSI = dry sorbent injection
 FF = fabric filter
 ESP = electrostatic precipitator
 WS = wet scrubber
 SD = spray dryer
 Q = quench chamber

^b Emissions corrected to 7% O₂.
^c Measured values are based on performance tests, not continuous emission monitoring data, and are not appropriate for setting short-term permit limits.

application designed to achieve a 30% NO_x reduction. Testing conducted following approximately two years of operation found some catalyst deactivation, but performance recovered to near original conditions following washing.⁴ Information on other hot-side SCR systems should become available with the next few years.

4.3 Key Design and Process Variables

Key SCR design considerations include flue gas composition, flue gas velocity, catalyst volume and surface area, catalyst temperature, NSR, and outlet NH_3 slip concentration.⁵

Flue gas composition plays a critical role in SCR design and performance. As discussed in Section 4.1, flue gas composition is the key factor dictating whether a cold-side or hot-side SCR system is required. Primary concerns are the levels of particulates, acid gases, and metals in the flue gas. Particulate matter is critical because of its erosive effect of the catalyst and its potential for plugging or blinding of the catalyst surface. Because of these concerns, the maximum allowable particulate loading into the catalyst is generally 50 mg/dscm (0.02 gr/dscf).⁶ The reported particulate loading exiting the ESP and entering the hot-side SCR at the Hagenholz MWC in Zürich, Switzerland is 10 mg/dscm (0.004 gr/dscf).⁷ By comparison, typical flue gas particulate loadings exiting most U.S. MWCs are 2,000 to 6,000 mg/dscm (1 to 3 gr/dscf). As a result, use of a cold-side SCR system or a high-efficiency particulate matter control device (e.g., an ESP) upstream of a hot-side SCR system is required.

Acid gases are of significance because of the potential for catalyst poisoning from ammonia salts such as ammonium chloride (NH_4Cl), ammonium sulfate $[(\text{NH}_4)_2\text{SO}_4]$, and ammonium bisulfate (NH_4HSO_4). Depending on the concentration of NH_3 , HCl , and SO_3 present in the flue gas, these salts can condense on and deactivate the catalyst surface at temperatures of 200-350°C (400-660°F) and lower.^{8,9} Catalysts can also be deactivated by various metals, including Pb, As, P, and various alkali metals. In general, the greater the basicity of the metal oxide, the greater the deactivation rate.

Addition of WO_3 to the catalyst significantly reduces the rate of deactivation from both acid gases and metals.

Gas velocity is significant in SCR design because of the erosion potential from particulate matter and because of the impact of velocity on gas residence time within the catalyst. Gas residence time is typically referred to as "gas hourly space velocity" [defined as the standard volumetric gas flow rate (at 20°C [68°F]) divided by the catalyst volume, $\text{vol/hr} \div \text{vol} = \text{hr}^{-1}$] or "area velocity" [the standard volumetric gas flow rate divided by the total surface area of the catalyst exposed to the gas flow, $\text{vol/hr} \div \text{area} = \text{m-hr}^{-1}$ (ft-hr^{-1})]. In addition to residence time, these two parameters also reflect the configuration of the reactor and catalyst. In general, NO_x reduction increases as space velocity and/or area velocity decrease (i.e., catalyst volume and surface area increase). However, as catalyst volume and surface area increase, pressure drop also generally increases due to limitations in cross-sectional area. Most systems have a limit on the allowable pressure drop (usually on the order of 20 to 25 centimeters [8 to 10 inches] water for MWCs). Based on vendor data, NO_x reductions on the order of 80% can be achieved on MWCs with space velocities ranging from approximately 4,000 to 6,000 hr^{-1} , while keeping NH_3 slip below 10 ppm.

Figure 4-2 illustrates the impact of temperature on NO_x reduction. All SCR catalysts have design operating temperatures for producing the maximum NO_x reduction. Below this temperature range, NH_3 slip increases and NO_x removal decreases. Above this range, NH_3 oxidation to NO_x increases. For cold-side SCR systems, the catalyst operating temperature is critical because it defines the amount of flue gas reheat required. At several Japanese and European MWCs producing steam for district heating purposes, steam is used for flue gas reheat. In these applications, the flue gas reheat temperature is 180 to 210°C (360 to 410°F). To minimize catalyst poisoning at these temperatures, target SO_x levels are less than 5 ppm.⁶ At MWCs generating electricity (as is common in the U.S.), use of steam for flue gas reheat may not be feasible. In these situations, auxiliary fuel is generally fired directly into the flue gas to provide the needed temperature increase. For this type of application, an

Figure 4-2. Effect of Temperature on SCR Performance

operating temperature of 250 to 290°C (480 to 550°F) is typically used to provide longer catalyst lifetimes.

SCR systems are generally designed to maintain near theoretical stoichiometric performance (1 mole NH_3 per mole NO_x reduced) up to approximately 70 or 80% reduction. At these reductions, the fractional NO_x reduction equals the NSR. Because of incomplete mixing and secondary reactions, however, somewhat higher NH_3 levels must be injected to achieve higher NO_x reductions. At NO_x reductions near 90% and higher, the higher required NSR ratio results in incomplete use of NH_3 and, thus, increased NH_3 slip. To reduce NH_3 slip at these high NO_x reduction rates, additional catalyst is needed.

4.4 Recent Advances and Further Research Needs

Because of catalyst poisoning concerns, most MWC SCR systems have been installed downstream of the particulate and acid gas control systems. Because the outlet temperatures from these systems are typically 50 to 150°C (90 to 270°F) below the operating range for the catalysts, flue gas reheat has been required. As discussed in Section 4.5, flue gas reheat can have a significant impact on NO_x control costs. As a result, significant research has been conducted by catalyst manufacturers to develop catalyst formulations that are tolerant to common poisons. As discussed in Section 4.2, several hot-side SCR systems have been installed in Europe and Japan since 1992 which should provide information needed for assessing catalyst performance and lifetimes of these systems. The economic tradeoffs of hot-side versus cold-side SCR systems are discussed in Section 4.5.

4.5 Cost Analysis

4.5.1 Design Basis

The design basis assumes a cold-side SCR system, a NO_x reduction level of 80%, and an NSR of 0.84. The 80% reduction represents long-term (annual average) performance capabilities. Performance at individual plants will vary, and this average performance level may not be achievable at all plants, especially considering retrofit situations. The space velocity at the 80% reduction level is $4,400 \text{ hr}^{-1}$, and the expected NH_3 slip is 8 ppm. The catalyst operates at a temperature of 290°C (550°F) and has a catalyst life of 3 years. Reheat of the flue gas from 260°C (500°F) to 290°C (550°F) is required. Based on the 80% NO_x reduction and a typical uncontrolled NO_x concentration of 250 ppm at 7% O_2 , the average stack concentration associated with this system is 50 ppm at 7% O_2 .

4.5.2 Cost Results

Cost estimates for the SCR system were developed for 100, 400, and 750 tpd model combustors.^{2,3} The system-specific input and output values for the 400 tpd model combustor are shown in Tables 4-3 and 4-4. Additional inputs (e.g., labor rates, fuel price) are presented in Table A-3 of Appendix A.

Table 4-5 presents the estimated capital cost per ton of capacity, tipping fee impact, and NO_x control cost effectiveness for the SCR system applied to the three model combustors. In addition to the costs for a 80% NO_x reduction, costs are also presented for a 70% and a 90% NO_x reduction, which represents the expected range of performance considering the control technology and plant-to-plant performance variations. The NSR associated with these levels of reduction are 0.74 and 0.94, respectively. As shown in Table 4-5, capital costs, tipping fee impacts, and NO_x control cost effectiveness values increase with decreasing combustor size. Within a given combustor range, variations in NO_x reduction level have less of an impact on costs. For

Table 4-3
Model Combustor Inputs for SCR

Plant Characteristics	
Unit Size (tpd)	400
Flowrate (dscfm @ 7% O ₂)	41,271
Flowrate (wscfm @ 11% O ₂)	70,462
Capacity Factor	0.9
Tons/yr of MSW Processed (tons/yr)	131,400
Uncontrolled NO _x (ppmv, dry)	250
NO _x Removal Efficiency (%/100)	0.80
Outlet NO _x (ppmv, dry)	50
Tons of NO _x removed (tons/yr)	203
Space Velocity (1/hr)	4,400
Catalyst Volume (ft ³)	895
Catalyst Life (yrs)	3
Normalized Stoichiometric Ratio (N/NO)	0.84
Ammonia Injection Rate (lb/hr)	20
Reheat Fuel (MMBtu/hr)	5.9
Capital Recovery Factor (1/yrs)	0.0944

Table 4-4
Cost Outputs for SCR Applied to the 400 TPD Model Combustor (a)

Capital Cost Section (\$1000)	
Flue Gas Handling	
-ducting and reactor housing	754
Ammonia Handling, Storage, and Injection	53
Instrumentation & Controls	352
Reheat System	1,209
Installation	2,162
Total Process Capital (\$1000)	4,531
Engineering	906
Contingency	1,631
Total Control Cost (\$1000)	7,069
Pre-Production	267
Inventory Capital	36
Initial Catalyst Charge	958
Total Capital Requirement (\$1000)	8,330
Total Capital per Capacity (\$1000/TPD)	20.8
Total Annualized Capital Requirement (\$1000/yr) (b)	696
Variable O&M Cost Section (\$1000/yr)	
Ammonia Cost	24
Catalyst Replacement & Disposal	365
Fuel Cost (Reheat)	164
Electricity	51
Total Variable O&M (\$1000/yr)	604
Fixed O&M Cost Section (\$1000/yr)	
Operating Labor	44
Maintenance Material	109
Maintenance Labor	72
Administrative & Support Labor	35
Total Fixed O&M (\$1000/yr)	260
Total Cost Section	
Total Annualized Cost (\$1000/yr)	1,560
Tipping Fee Impact (\$/ton MSW)	11.9
Cost Effectiveness (\$/ton NO_x)	7,689

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

(b) Initial catalyst charge not included in total annualized capital requirement.

Table 4-5
Model Plant Cost Estimates for SCR (a), (b)

	Total Capital Cost (\$1000/TPD capacity)			Tipping Fee Impact (\$/ton MSW)			Cost Effectiveness (\$/ton NOx)		
	70	80	90	70	80	90	70	80	90
NOx Reduction									
100 TPD Mass Burn MWC	49.7	49.9	50.4	23.8	24.0	24.3	17,588	15,525	14,021
400 TPD Mass Burn MWC	20.6	20.8	21.3	11.7	11.9	12.3	8,635	7,689	7,055
750 TPD Mass Burn MWC	14.9	15.1	15.6	9.35	9.56	9.94	6,924	6,191	5,723

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

(b) Based on an 80% NOx reduction.

example, an increase in ammonia injection rate and catalyst volume at the higher NO_x reduction levels results in a small increase in capital cost and tipping fee impact. For cost effectiveness, the values decrease with increasing NO_x reduction, since the increase in cost of the SCR system associated with the higher NO_x reduction is smaller than the additional amount of NO_x removed at the higher NO_x reduction levels.

A comparison of the costs for the cold-side SCR system to those for a hot-side SCR system are presented in Table 4-6. As discussed earlier, hot-side systems typically follow a PM control device upstream of acid gas controls. Such a system could be installed on an existing ESP-equipped MWC that is considering acid gas and NO_x control retrofits, if the ESP-controlled PM level is low enough [50 mg/dscm (0.02 gr/dscf)] and the flue gas temperature is greater than 250°C (480°F).

Table 4-6 presents selected plant characteristics and costs to demonstrate potential differences between cold-side and hot-side systems. To address uncertainties regarding the catalyst performance of the hot-side systems, two systems are presented; one with a catalyst life of 3 years, and one with a catalyst life of 2 years.

As shown in Table 4-6, the process capital for the hot-side systems is 30% less than for the cold-side system because no reheat system is required. However, because of the potential for increased catalyst degradation, the hot-side system will require either more catalyst volume or installation of a high efficiency particulate matter control device prior to the SCR inlet. For the example presented, increased catalyst volume is utilized, and the initial catalyst charge for the hot-side system is assumed to be twice that for the cold-side system. As a result, the total capital requirements for the hot-side systems are only 15% less than for the cold-side system. The reason for the difference between the total capital requirements for the two hot-side systems, specifically the preproduction costs, is the cost for catalyst replacement and disposal which factors into the preproduction cost.

Table 4-6
Comparison of Cold- and Hot-side SCR Systems (a)

Plant Characteristics	Cold	Hot	Hot
Unit Size (tpd)	400	400	400
Uncontrolled NO _x (ppmv, dry)	250	250	250
NO _x Removal Efficiency (%/100)	0.80	0.80	0.80
Space Velocity (1/hr)	4,400	2,200	2,200
Catalyst Volume (ft ³)	895	1,791	1,791
Catalyst Life (yrs)	3	3	2
Reheat Fuel (MMBtu/hr)	5.9	0	0
Capital Cost Section (\$1000)			
Total Process Capital (\$1000)	4,531	3,153	3,153
Total Control Cost (\$1000)	7,069	4,973	4,973
Pre-Production	267	239	269
Inventory Capital	36	26	26
Initial Catalyst Charge	958	1,916	1,916
Total Capital Requirement (\$1000)	8,330	7,154	7,184
Total Capital per Capacity (\$1000/TPD)	20.8	17.9	18.0
Total Annualized Capital Requirement (\$1000/yr)	696	494	497
O&M Cost Section (\$1000/yr)			
Catalyst Replacement & Disposal	365	730	1,060
Fuel Cost (Reheat)	164	0	0
Others (Ammonia, Electricity)	51	77	77
Total Variable O&M (\$1000/yr)	604	802	1,132
Total Fixed O&M (\$1000/yr)	260	198	198
Total Cost Section			
Total Annualized Cost (\$1000/yr)	1,560	1,495	1,827
Tipping Fee Impact (\$/ton MSW)	11.9	11.4	13.9
Cost Effectiveness (\$/ton NO _x)	7,689	7,370	9,010

(a) \$/ton can be converted to \$/Mg by multiplying by 1.1.

The catalyst replacement and disposal cost takes into account the amount of catalyst that must be disposed (proportional to the catalyst volume) and the life of the catalyst. Therefore, the cost for the hot-side systems is greater than for the cold-side system, especially for the hot-side system with the 2-year catalyst life. As a result of the catalyst replacement and disposal cost, the variable O&M costs for these systems may be higher than cold-side systems, even though the hot-side systems do not require reheat (no fuel cost incurred). Fixed O&M costs for the hot-side systems are slightly lower than for the cold-side system because of the lower process capital associated with the hot-side systems.

Overall, the total annualized costs, tipping fee impact, and cost effectiveness for the cold-side system fall between the costs for the hot-side systems. As shown, the shorter catalyst life results in higher costs. More information on the long-term effects of flue gas properties on catalyst degradation and poisoning is needed to fully evaluate the economics of a hot-side system.

4.5.3 Sensitivity Analysis

To account for site-specific differences and other uncertainties in the costs used to develop Table 4-5, an analysis of the sensitivity of tipping fee impacts and NO_x control cost effectiveness to differences in plant size (100 to 700 tpd), catalyst replacement cost ($\pm 50\%$), annualized capital cost ($\pm 30\%$), and NO_x reduction (70 to 90%) was performed. Figure 4-3 presents the effect of plant size, catalyst replacement cost, and annualized capital cost on tipping fee and cost effectiveness. Figure 4-4 presents the sensitivity of tipping fee and cost effectiveness to NO_x reduction.

The range in annualized capital cost accounts for differences in the actual capital cost of an SCR system, contingency factors, and the cost of money used for project financing. The variation in NO_x control cost effectiveness reflects the impact of varying the amount of ammonia injection to achieve higher or lower NO_x reductions.

Figure 4-3. Effect of Unit Size, Catalyst Replacement Cost, and Annualized Capital on Tipping Fee Impact and Cost Effectiveness for SCR

Figure 4-4. Effect of NOx Reduction on Tipping Fee Impact and Cost Effectiveness for SCR

As shown in these figures, the tipping fee impact and NO_x control cost effectiveness associated with the reference MWC (the centerline point) are approximately \$12/ton of MSW and \$7,690/ton of NO_x removed. Of the parameters shown in Figures 4-3 and 4-4, the variation in unit size has the greatest impact on tipping fee and cost effectiveness. The costs increase with decreasing unit size, with the cost for units between 100 to 300 tpd showing the steepest increase. From the reference unit size of 400 tpd to the 100 tpd unit, tipping fee impact and the cost effectiveness value roughly double. The costs decrease by less than 20% when going from the 400 tpd unit to the 700 tpd unit.

Variations in catalyst replacement cost of $\pm 50\%$ and annualized capital costs by $\pm 30\%$ have practically the same effect on tipping fee impact and cost effectiveness. Increases in catalyst replacement cost and annualized capital cost increase the tipping fee impact and the cost effectiveness value. Variations in NO_x reduction have a similar but opposite impact on cost effectiveness, with increases in NO_x reduction resulting in a decrease in the cost effectiveness value. The effect of NO_x reduction on tipping fee impact is smaller, with increases in NO_x reduction resulting in a slight increase in the tipping fee impact.

4.6 References

1. U. S. Environmental Protection Agency. Municipal Waste Combustors--Background Information for Proposed Standards: Control of NO_x Emissions. EPA-450/3-89-27d (NTIS PB90-154873). Research Triangle Park, NC. August 1989.
2. FAX from M. Tomiku, Mitsubishi International Corporation, to D. White, Radian Corporation. SCR Study for Waste to Energy Plant. October 5, 1993 and February 11, 1994.
3. FAX from V. Patel, Joy Environmental Technologies, to D. White, Radian Corporation. SCR for MSW Plants. October 6, 1993.
4. California Environmental Protection Agency. Air Resources Board. Air Pollution Control at Resources Recovery Facilities--1991 Update.

5. Becker, E. R. Selective Catalytic Reduction of NO_x-Catalysis and Reactor Design. Environmental Catalyst Consultants Short Course. Presented May 8-10, 1990. Boston, MA.
6. FAX from M. Tomiku, Mitsubishi International Corporation, to D. White, Radian Corporation. MWC SCR Data. December 13, 1993.
7. FAX from H. Meier, Abfuhrwesen Zürich, to D. White, Radian Corporation. Municipal waste combustor plants Hagenholz and Josefstrasse. February 23, 1994.
8. Technical and Economic Feasibility of Ammonia-Based Postcombustion NO_x Control. Electric Power Research Institute. EPRI CS-2713.
9. Chen, J., R.T. Yang, and J.E. Cichanowicz, Poisoning of SCR Catalysts. In Proceedings: 1991 Joint Symposium on Stationary Combustion NO_x Control, Vol. 2, EPA-600/R-92-093b (NTIS PB93-212850), July 1992.

APPENDIX A

Description of Costing Framework

A.1 Inputs

The NO_x control costs for NGI, SNCR, and SCR are dependent on a number of parameters including plant unit size (tpd and flue gas flowrates), fuel or chemical costs, and economic assumptions. Table A-1 presents the inputs (e.g., O₂ level, higher heating value) needed for calculating the flue gas flowrates of the model plants. The flowrates were calculated using EPA Method 19. For the purpose of sizing and costing equipment, the flowrates were multiplied by a factor of 1.15 to account for variability of short-term flowrates relative to design flowrates. Tables A-2, A-3, and A-4, present the additional inputs (e.g., costs of chemicals) needed to calculate the outputs for NGI, SNCR, and SCR, respectively.

A.2 Methodology

The basic methodology used to determine NO_x control cost and cost effectiveness is described in this section.

A.2.1 Capital Costs

A.2.1.1 Total Process Capital

Total process capital (TPC) includes equipment and installation costs and is technology dependent. The equipment required and associated installation costs are discussed in the individual sections of the report for each technology.

Table A-1
Generic Inputs For Flowrate Calculations

Parameter	Units	Input
Corrected O2	(%/100)	0.07
Actual O2	(%/100)	0.11
Higher Heating Value	(Btu/lb)	4,500
H2O, exhaust	(%/100)	0.18

Table A-2
Generic Inputs For NGI

Parameter	Units	Input
Density of Air	(lb/scf)	0.075
Specific Heat of Air	(Btu/lb F)	0.28
Energy per ton Constant	(kWh/ton MSW)	550
Compressor Demand	(kW/wscfm)	0.091
Fuel Cost (NG)	(\$/MMBtu)	3.5
Electrical Cost	(\$/kWhr)	0.046
City Water	(\$/1000 gal)	0.6
Labor Rate	(\$/hr)	20
Operating Labor	(hr/shift)	1.0
Discount Rate	(%/100)	0.070
Book Life	(yrs)	20
Maintenance	(%/100)	0.02
Admin & Support	(%/100)	0.3
Process Contingency	(%/100)	0.2
Project Contingency	(%/100)	0.2

Table A-3
Generic Inputs For SNCR

Parameter	Units	Input
Molecular Weight	(lb/lb mole)	17
Weight Ratio	(lb solution/lb reagent)	3.4
Reagent N content	(mol reagent/ mol N)	1
Dilution Ratio	(lb reagent/lb inj sol)	0.1
Density of Air	(lb/scf)	0.075
Specific Heat of Air	(Btu/lb F)	0.28
Energy per ton Constant	(kWh/ton MSW)	550
Compressor Demand	(kW/wscfm)	0.091
Reagent Cost	(\$/ton)	300
Electrical Cost	(\$/kWhr)	0.046
City Water	(\$/1000 gal)	0.6
Labor Rate	(\$/hr)	20
Operating Labor	(hr/shift)	2.0
Discount Rate	(%/100)	0.070
Book Life	(yrs)	20
Maintenance	(%/100)	0.04
Admin & Support	(%/100)	0.3
Process Contingency	(%/100)	0.1
Project Contingency	(%/100)	0.2
Heat of Reaction	(Btu/lb)	-7671
Change in Enthalpy for H2O	(Btu/lb)	1114.6

Table A-4
Generic Inputs For SCR

Parameter	Units	Input
Molecular Weight	(lb/lb mole)	17
Weight Ratio	(lb solution/lb reagent)	3.4
Reagent N content	(mol reagent/ mol N)	1
Density of Air	(lb/scf)	0.075
Specific Heat of Air	(Btu/lb F)	0.28
Energy per ton Constant	(kWh/ton MSW)	550
Compressor Demand	(kW/wscfm)	0.091
Chemical Cost (reagent)	(\$/ton)	300
Catalyst Cost	(\$/ft ³)	1,070
Catalyst Startup cost	(\$)	60,000
Fuel Cost	(\$/MMBTU)	3.5
Waste Disposal	(\$/ton)	8.9
Electrical Cost	(\$/kWhr)	0.046
City Water	(\$/1000 gal)	0.6
Labor Rate	(\$/hr)	20
Operating Labor	(hr/shift)	2.0
Discount Rate	(%/100)	0.070
Book Life	(yrs)	20
Maintenance	(%/100)	0.04
Admin & Support	(%/100)	0.3
Process Contingency	(%/100)	0.1
Project Contingency	(%/100)	0.2
SCR Temperature	(F)	550
Stack Temperature	(F)	280
Heat Ex. Exit Temperature	(F)	496
Catalyst Pressure Drop	(in H ₂ O)	8

A.2.1.2 Total Control Cost

Total control cost (TCC) includes TPC plus costs for engineering and contingency. Assumptions used for engineering and contingency are discussed below.

Engineering. Engineering is assumed to be 20% of TPC and includes engineering home office, overhead, and general facilities.

Contingency. Contingency is comprised of process contingency and project contingency. Process contingency is calculated as a percentage of TPC, and project contingency is calculated as a percentage of TPC plus engineering and process contingency. The percentage assumptions for each NO_x control technology are presented in Tables A-1, A-2, and A-3.

A.2.1.3 Total Capital Requirement

Total capital requirement (TCR) includes TCC, preproduction costs, inventory capital, and other technology specific costs such as license fee for SNCR or initial catalyst charge for SCR. Information on preproduction costs and inventory capital are provided below.

Preproduction Costs. Preproduction costs cover operator training, equipment checkout, extra maintenance, and inefficient use of fuel and materials during start-up. To estimate this, preproduction costs are calculated to be one month fixed O&M costs, one month variable O&M costs at full capacity, excluding fuel, 25% of full-capacity fuel cost for one month (SCR and NGI only), and two percent of TCC.

Inventory Capital. Inventory capital is estimated to be 0.5% of TCC and the cost of two weeks' inventory of chemicals (SNCR, SCR) or fuel (NGI).

A.2.1.4 Total Capital Per Capacity

To calculate capital costs in terms of capacity, the TCC is divided by the unit size of the plant.

A.2.1.5 Total Annualized Capital Requirement

Capital costs are annualized by multiplying TCR by a capital recovery factor. Equations to calculate the CRF and the annualized costs are shown below.

$$\text{CRF (1/yr)} = i(1 + i)^n / [(1 + i)^n - 1]$$

where:

i = discount rate (decimal fraction)
n = book life of the loan

A.2.2 Operating and Maintenance Costs

Operating and maintenance costs include variable and fixed O&M costs.

A.2.2.1 Variable Operating and Maintenance Costs

Variable O&M costs include those O&M costs that are directly proportional to the amount of time the facility is operating. Examples of variable O&M costs are chemical, fuel, and electricity costs for a specific control technology.

A.2.2.2 Fixed Operating and Maintenance Costs

Fixed O&M costs include operating labor, maintenance materials, maintenance labor, and administrative and support labor.

Costs for operating labor depend on how many hours of labor per shift are required for each technology and the labor rate. Tables A-1, A-2, and A-3 include the inputs for these for each technology.

Total maintenance costs (materials and labor) are calculated based on a percentage of TPC. The assumed percentage for each technology are included in Tables A-1, A-2, and A-3. These costs are broken into the specific components (materials and labor) based on a 60/40 breakout (60% attributable to materials and 40% attributable to labor).

Overhead charges are assumed to be the cost for administrative and support labor. This cost is taken as 30% of the O&M labor. General and administrative expenses are not included, because they will be site specific, dependent on management philosophy.

REPORT DOCUMENTATION PAGE

Form Approved
OMB NO. 0704-0188

Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Washington Headquarters Services, Directorate for Information Operations and Reports, 1215 Jefferson Davis Highway, Suite 1204, Arlington, VA 22202-4302, and to the Office of Management and Budget, Paperwork Reduction Project (0704-0188), Washington, DC 20503.

1. AGENCY USE ONLY (Leave blank)		2. REPORT DATE January 1995	3. REPORT TYPE AND DATES COVERED Final Report	
4. TITLE AND SUBTITLE NO _x Control Technologies Applicable to Municipal Solid Waste Combustion			5. FUNDING NUMBERS (C) YAR-3-13184-1 (TA) WM111010	
6. AUTHOR(S) D. White, K. Nebel, M. Gundappa, K. Ferry				
7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES) Radian Corporation 3200 E. Chapel Hill Road Research Triangle Park, NC 27709			8. PERFORMING ORGANIZATION REPORT NUMBER DE94011834	
9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES) National Renewable Energy Laboratory 1617 Cole Boulevard Golden, CO 80401-3393			10. SPONSORING/MONITORING AGENCY REPORT NUMBER NREL/TP-430-6742 EPA-600/R-94-208	
11. SUPPLEMENTARY NOTES				
12a. DISTRIBUTION/AVAILABILITY STATEMENT National Technical Information Service U.S. Department of Commerce 5285 Port Royal Road Springfield, VA 22161			12b. DISTRIBUTION CODE UC-1414	
13. ABSTRACT (Maximum 200 words) Several technologies are available for reducing NO _x emissions from municipal waste combustors (MWCs). These include combustion controls, natural gas injection (NGI), selective non-catalytic reduction (SNCR). This report documents the key design and operating parameters, commercial status, demonstrated performance, and cost of NGI < SNCR < and SCR, and identifies technology research and development needs associated with these technologies.				
14. SUBJECT TERMS Municipal solid waste, biomass, combustion, emissions, landfills, recycling			15. NUMBER OF PAGES	
			16. PRICE CODE	
17. SECURITY CLASSIFICATION OF REPORT	18. SECURITY CLASSIFICATION OF THIS PAGE	19. SECURITY CLASSIFICATION OF ABSTRACT	20. LIMITATION OF ABSTRACT	

NSN 7540-01-280-5500

Standard Form 298 (Rev. 2-89)
Prescribed by ANSI Std. Z39-18
298-10